JENNINGS EXHIBIT NO. 1
*****REDACTED VERSION*****

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1276

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of)
)
Application of Duke Energy Progress, LLC for Approval of Renewable Energy and Energy Efficiency Portfolio Standard Compliance Report and Rider Pursuant to N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67(c))
)
)
)
)

DUKE ENERGY PROGRESS,
LLC 2020 RENEWABLE
ENERGY & ENERGY
EFFICIENCY PORTFOLIO
STANDARD COMPLIANCE
REPORT

OFFICIAL COPY

Jun 15 2021

DUKE ENERGY PROGRESS, LLC
RENEWABLE ENERGY AND ENERGY EFFICIENCY PORTFOLIO STANDARD (“REPS”)
COMPLIANCE REPORT

TABLE OF CONTENTS

(A) INTRODUCTION

Duke Energy Progress, LLC ("Duke Energy Progress" or the "Company") submits its Renewable Energy and Energy Efficiency Portfolio Standard ("REPS") Compliance Report ("Compliance Report") in accordance with N.C. Gen. Stat. § 62-133.8 and Commission Rule R8-67(c). This Compliance Report provides the required information for the calendar year 2020.[1]

(B) REPS COMPLIANCE REPORT

I. RENEWABLE ENERGY CERTIFICATES:

The table below reflects the renewable energy certificates ("RECs") used to comply with N.C. Gen. Stat. § 62-133.8(d) for the year 2020.
[BEGIN CONFIDENTIAL]

[END CONFIDENTIAL]

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[1] Pursuant to NCUC Rule R8-67(c)(1), this Compliance Report reflects Duke Energy Progress' efforts to meet the REPS requirements for the previous calendar year.

II. ACTUAL 2020 TOTAL NORTH CAROLINA RETAIL SALES AND YEAR-END NUMBER OF ACCOUNTS, BY CUSTOMER CLASS:

	2020
NC Retail MWh Sales	36,168,687

Account Type	2020 year-end number of retail REPS accounts
Residential	1,333,721
General	214,081
Industrial	1,908

III. AVOIDED COST RATES

The avoided cost rates below, applicable to energy received pursuant to REPS compliance power purchase agreements, represent the annualized avoided cost rates in the following avoided cost proceedings:

Non-hydro:

ANNUALIZED TOTAL CAPACITY AND ENERGY RATES

(CENTS PER KWH)

Docket No.:	**E-100 Sub 158 (Current)**	**E-100 Sub 158 (Current)**	**E-100 Sub 158 (Current)**	**E-100 Sub 148**	**E-100, Sub 140**	**E-100, Sub 136**	**E-100, Sub 127**	**E-100, Sub 117**	**E-100, Sub 106**
	Uncontrolled Solar (1)	**Swine-Poultry (2)**	**All Other (3)**	**All Other (4)**					
Year filed:	2018	2018	2018	2016	2014	2012	2010	2008	2006
Variable Rate	3.21	3.82	3.45	3.35	4.29	4.76	5.79	5.69	4.54
5 Year	N/A	N/A	N/A	N/A	4.42	4.97	6.18	5.82	4.67
10 Year	3.39	3.72	3.63	3.79	5.09	5.47	6.82	6.05	4.85
15 Year	N/A	N/A	N/A	N/A	5.53	5.87	7.29	6.10	4.98

(1) Uncontrolled Solar includes SISC (System Integration Services Charge) per Order approving E-100 Sub 158 rates April 15, 2020.
(2) Exception to IRP-designated first year of capacity need standard N.C. Gen. Stat. § 62-156(b)(3).
(3) All Other Except Uncontrolled Solar, Swine-Poultry and Hydro No Storage per Order approving E-100 Sub 158 rates April 15, 2020.
(4) All Other Except Hydro No Storage.

Hydro:

ANNUALIZED TOTAL CAPACITY AND ENERGY RATES (CENTS PER KWH)								
Docket No.:	**E-100 Sub 158 (Current)**	**E-100 Sub 158 (Current)**	**E-100 Sub 148**	**E-100, Sub 140**	**E-100, Sub 136**	**E-100, Sub 127**	**E-100, Sub 117**	**E-100, Sub 106**
	Certain Hydroelectric Generation without Storage (5)	**All Other Hydroelectric Generation without Storage (6)**	**Hydroelectric - No Storage (6)**					
Year filed:	2018	2018	2016	2014	2012	2010	2008	2006
Variable Rate	4.46	3.77	3.35	4.79	5.35	6.49	6.34	4.96
5 Year	N/A	N/A	N/A	4.93	5.58	6.90	6.50	5.11
10 Year	4.39	4.21	4.09	5.63	6.12	7.57	6.77	5.32
15 Year	N/A	N/A	N/A	6.10	6.55	8.06	6.86	5.47

(5) Exception to IRP-designated first year of capacity need standard N.C. Gen. Stat. § 62-156(b)(3).
(6) Hydroelectric no storage N.C.G.S. § 62-156(b)(3).

IV. ACTUAL TOTAL AND INCREMENTAL COSTS INCURRED IN 2020

REPS compliance costs incurred for calendar year 2020 comprise the cost of renewable energy purchases, the cost of purchases of various types of RECs, and other reasonable and prudent costs incurred to meet the requirements of the REPS statute. In addition, annual Solar Rebate Program costs incurred pursuant to N.C. Gen. Stat. § 62-155 are recovered in the REPS rider as directed in N.C. Gen. Stat. § 62-133.8(h)(1)d.

Actual Costs Incurred	Energy and REC Costs	Other	Total Costs
REPS compliance - avoided cost	$202,539,497	$ 0	$202,539,497
REPS compliance – incremental cost	$37,758,630	$ 2,406,946	$ 40,165,576(a)
REPS compliance - total cost	**$240,298,127**	**$2,406,946**	**$ 242,705,073**
Solar Rebate Program cost	$ 0	$1,507,509	$ 1,507,509(b)
Incremental REPS compliance costs and Solar Rebate Program costs for REPS rider recovery		(a) + (b) above	**$ 41,673,085**

V. ACTUAL INCREMENTAL COSTS COMPARISON TO THE ANNUAL COST CAP

Account Type	Total 2019 year-end number of retail REPS accounts	Annual per-account cost cap	Total annual cost cap
Residential	1,242,912	$27	$33,558,624
General	200,154	$150	$30,023,100
Industrial	1,801	$1,000	$1,801,000
Total annual REPS compliance cost cap – 2020			**$65,382,724**
Incremental REPS compliance costs incurred – 2020			**$40,165,576**

VI. STATUS OF COMPLIANCE WITH REPS REQUIREMENTS

Pursuant to N.C. Gen. Stat. § 62-133.8(b) for Duke Energy Progress retail customers, the REPS requirement for calendar year 2020 is set at 10% of 2019 North Carolina ("NC") retail sales. In order to comply with the REPS obligation for Duke Energy Progress retail customers, the Company submitted 3,793,823 RECs, representing 10% of 2019 retail megawatt-hour sales of 37,938,229. Details of the composition of RECs retired to meet the total REPS compliance requirement are contained in Section I. of this report.

Pursuant to N.C. Gen. Stat. § 62-133.8(d), for calendar year 2020, at least 0.20% of total NC retail sales (measured according to prior calendar year NC retail sales) shall be supplied by a combination of new solar electric facilities and new metered solar thermal energy facilities. As a result, 75,877 solar RECs were used to meet the Solar Set-Aside Requirement. An additional 1,602,475 solar RECs were submitted for retirement toward compliance with the general requirement (the total REPS requirement net of solar, poultry waste and swine waste set-aside obligations).

In its December 16, 2019 *Order Modifying the Swine and Poultry Waste Set-Aside Requirements and Providing Other Relief* and its February 13, 2020 *Errata Order* ("2019 Delay Orders") issued in Docket No. E-100, Sub 113, the Commission delayed by one year the scheduled increases in the swine waste set-aside requirement to 0.07% in 2020. To comply with the swine waste set-aside requirement applicable to DEP's NC retail sales, the Company submitted for retirement 26,557 swine RECs.

The 2019 Delay Orders also delayed by one year the scheduled increases in the poultry waste set-aside requirement to 700,000 MWh state-wide in 2020. In its December 16, 2019 *Order Establishing 2019, 2020, and 2021 Poultry Waste Set-Aside Requirement Allocation* issued in Docket No. E-100, Sub 113, the Commission directed the annual aggregate poultry waste set-aside requirement to be allocated among electric power suppliers and utility compliance aggregators according to the load ratio share calculations shown on Appendix A to the order. These percentages were applied to the modified 2020 state-wide requirement to determine the poultry waste set-aside requirements applicable to DEP NC retail for the 2020 reporting year. The Company submitted for retirement 195,649 poultry RECs, and met its 2020 poultry waste set-aside requirement.

VII. IDENTIFICATION OF RECs CARRIED FORWARD

The table below reflects RECs generated through year-end 2020, excluding those RECs that have already been retired to meet compliance, that the Company has banked for use in future compliance years.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

VIII. DATES AND AMOUNTS OF ALL PAYMENTS MADE FOR RENEWABLE ENERGY CERTIFICATES

Confidential Appendix 1 illustrates the dates and amounts of all payments made for renewable energy certificates during calendar year 2020.

(C) METHODOLOGY FOR DETERMINING NUMBER OF CUSTOMERS AND CUSTOMER CAP

Consistent with the Commission's order issued November 12, 2009 in Docket No. E-2, Sub 948, for purposes of REPS billing, the Company defines as a single customer all accounts (metered and unmetered) serving the same customer of the same revenue classification located on the same or contiguous properties. If a customer has accounts which serve in an auxiliary role to a main account on the same premises, no REPS charge applies to the auxiliary accounts, regardless of their revenue classification.

Respectfully submitted this the 15th day of June, 2021.

Robert W. Kaylor

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Duke Energy Progress, LLC
Docket No. E-2, Sub 1276
2020 REPS Compliance Report
Dates and Amounts of Payments for RECs - Calendar Year 2020

Redacted Version*
Jennings Exhibit No. 1, Appendix 1
June 15, 2021

Counterparty and Payment Dates	**REC cost**
[BEGIN CONFIDENTIAL]	
[redacted]	40,533.36
Apr-2020	2,716.91
Aug-2020	4,332.37
Dec-2020	3,084.06
Feb-2020	1,688.89
Jan-2020	1,174.88
Jul-2020	3,891.79
Jun-2020	5,213.53
Mar-2020	2,496.62
May-2020	3,524.64
Nov-2020	3,598.07
Oct-2020	3,965.22
Sep-2020	4,846.38
[redacted]	55,802.55
Apr-2020	5,426.67
Aug-2020	7,372.08
Dec-2020	4,914.72
Feb-2020	2,559.75
Jan-2020	3,481.26
Jul-2020	12,184.41
Jun-2020	5,836.23
Mar-2020	3,378.87
Nov-2020	4,812.33
Oct-2020	5,836.23
[redacted]	3,723.48
Apr-2020	310.29
Aug-2020	413.72
Dec-2020	310.29
Feb-2020	310.29
Jan-2020	206.86
Jul-2020	310.29
Jun-2020	310.29
Mar-2020	206.86
May-2020	413.72
Nov-2020	206.86
Oct-2020	310.29
Sep-2020	413.72
[redacted]	587.44
Apr-2020	146.86
Feb-2020	73.43
Jan-2020	73.43
Jul-2020	73.43
Jun-2020	146.86
May-2020	73.43
[redacted]	18,630.00
Apr-2020	1,250.00
Aug-2020	1,815.00
Dec-2020	1,580.00
Feb-2020	1,200.00
Jan-2020	1,290.00
Jul-2020	1,850.00
Jun-2020	1,975.00
Mar-2020	1,295.00
May-2020	1,520.00
Nov-2020	1,105.00
Oct-2020	1,750.00
Sep-2020	2,000.00
[redacted]	44,945.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Apr-2020	3,735.00
Aug-2020	4,955.00
Dec-2020	3,215.00
Feb-2020	3,320.00
Jan-2020	2,750.00
Jul-2020	4,230.00
Jun-2020	4,610.00
Mar-2020	3,155.00
May-2020	4,170.00
Nov-2020	3,525.00
Oct-2020	3,320.00
Sep-2020	3,960.00
[redacted]	14,166.00
Apr-2020	1,235.25
Aug-2020	195.75
Dec-2020	1,145.25
Feb-2020	1,066.50
Jan-2020	1,003.50
Jul-2020	1,563.75
Jun-2020	1,514.25
Mar-2020	1,012.50
May-2020	1,644.75
Nov-2020	1,309.50
Oct-2020	1,012.50
Sep-2020	1,462.50
[redacted]	6,201.00
Apr-2020	324.00
Aug-2020	699.75
Dec-2020	567.00
Feb-2020	348.75
Jan-2020	360.00
Jul-2020	643.50
Jun-2020	598.50
Mar-2020	351.00
May-2020	470.25
Nov-2020	564.75
Oct-2020	582.75
Sep-2020	690.75
[redacted]	68,263.80
Apr-2020	4,964.64
Aug-2020	7,860.68
Dec-2020	4,964.64
Feb-2020	3,826.91
Jan-2020	3,413.19
Jul-2020	6,412.66
Jun-2020	7,550.39
Mar-2020	3,930.34
May-2020	6,412.66
Nov-2020	5,068.07
Oct-2020	6,309.23
Sep-2020	7,550.39
[redacted]	17,990.35
Apr-2020	1,321.74
Aug-2020	2,349.76
Dec-2020	1,395.17
Feb-2020	881.16
Jan-2020	1,248.31
Jul-2020	1,321.74
Jun-2020	1,028.02

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2020 REPS Compliance Report | **June 15, 2021**
Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	REC cost
Mar-2020	1,101.45
May-2020	1,542.03
Nov-2020	1,542.03
Oct-2020	2,056.04
Sep-2020	2,202.90
[redacted]	48,316.94
Apr-2020	6,314.98
Aug-2020	5,874.40
Dec-2020	6,608.70
Feb-2020	2,643.48
Jan-2020	2,643.48
Jul-2020	9,766.19
May-2020	4,993.24
Oct-2020	4,479.23
Sep-2020	4,993.24
[redacted]	32,047.47
Apr-2020	1,760.85
Aug-2020	3,052.14
Dec-2020	2,817.36
Feb-2020	1,878.24
Jan-2020	4,460.82
Jul-2020	2,934.75
Jun-2020	3,052.14
May-2020	2,465.19
Nov-2020	3,169.53
Sep-2020	6,456.45
[redacted]	33,432.00
Apr-2020	2,780.00
Aug-2020	3,640.00
Dec-2020	2,464.00
Feb-2020	2,468.00
Jan-2020	2,208.00
Jul-2020	2,764.00
Jun-2020	2,576.00
Mar-2020	2,432.00
May-2020	3,612.00
Nov-2020	2,852.00
Oct-2020	2,592.00
Sep-2020	3,044.00
[redacted]	26,229.00
Apr-2020	2,103.00
Aug-2020	2,925.00
Dec-2020	1,833.00
Feb-2020	1,812.00
Jan-2020	1,599.00
Jul-2020	2,310.00
Jun-2020	2,721.00
Mar-2020	1,800.00
May-2020	2,712.00
Nov-2020	2,172.00
Oct-2020	1,947.00
Sep-2020	2,295.00
[redacted]	954.59
Aug-2020	146.86
Dec-2020	73.43
Feb-2020	73.43
Jan-2020	73.43
Jul-2020	73.43
Jun-2020	73.43

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Mar-2020	73.43
May-2020	146.86
Nov-2020	73.43
Oct-2020	73.43
Sep-2020	73.43
[redacted]	1,174.88
Apr-2020	73.43
Aug-2020	73.43
Dec-2020	146.86
Feb-2020	73.43
Jan-2020	73.43
Jul-2020	146.86
Jun-2020	146.86
Mar-2020	73.43
May-2020	73.43
Nov-2020	73.43
Oct-2020	73.43
Sep-2020	146.86
[redacted]	33,180.00
Apr-2020	2,612.00
Aug-2020	3,740.00
Dec-2020	2,284.00
Feb-2020	2,116.00
Jan-2020	2,016.00
Jul-2020	3,308.00
Jun-2020	3,192.00
Mar-2020	2,040.00
May-2020	3,392.00
Nov-2020	2,764.00
Oct-2020	2,704.00
Sep-2020	3,012.00
[redacted]	3,639.09
Apr-2020	352.17
Aug-2020	352.17
Dec-2020	234.78
Feb-2020	117.39
Jan-2020	234.78
Jul-2020	352.17
Jun-2020	352.17
Mar-2020	234.78
May-2020	352.17
Nov-2020	234.78
Oct-2020	352.17
Sep-2020	469.56
[redacted]	2,896.04
Apr-2020	310.29
Aug-2020	206.86
Dec-2020	206.86
Feb-2020	103.43
Jan-2020	206.86
Jul-2020	310.29
Jun-2020	413.72
Mar-2020	103.43
May-2020	103.43
Nov-2020	310.29
Oct-2020	206.86
Sep-2020	413.72
[redacted]	22,583.27
Apr-2020	-

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Aug-2020	7,928.12
Dec-2020	-
Feb-2020	-
Jan-2020	-
Jul-2020	8,765.37
Jun-2020	-
Mar-2020	-
May-2020	-
Nov-2020	-
Oct-2020	1,891.80
Sep-2020	3,997.98
[redacted]	40,900.51
Apr-2020	2,423.19
Aug-2020	4,405.80
Dec-2020	2,863.77
Feb-2020	1,835.75
Jan-2020	2,129.47
Jul-2020	4,332.37
Jun-2020	4,405.80
Mar-2020	2,276.33
May-2020	4,038.65
Nov-2020	3,230.92
Oct-2020	3,965.22
Sep-2020	4,993.24
[redacted]	149,436.75
Apr-2020	11,592.00
Aug-2020	16,680.75
Dec-2020	9,832.50
Feb-2020	9,608.25
Jan-2020	9,211.50
Jul-2020	15,542.25
Jun-2020	14,317.50
Mar-2020	8,849.25
May-2020	15,732.00
Nov-2020	11,557.50
Oct-2020	12,989.25
Sep-2020	13,524.00
[redacted]	35,748.00
Apr-2020	2,812.00
Aug-2020	4,032.00
Dec-2020	2,492.00
Feb-2020	2,372.00
Jan-2020	2,076.00
Jul-2020	3,536.00
Jun-2020	3,584.00
Mar-2020	2,148.00
May-2020	3,720.00
Nov-2020	2,996.00
Oct-2020	2,744.00
Sep-2020	3,236.00
[redacted]	1,344,184.20
Apr-2020	118,885.12
Aug-2020	120,771.52
Dec-2020	98,973.12
Feb-2020	111,465.28
Jan-2020	119,281.80
Jul-2020	126,263.04
Jun-2020	129,972.96
Mar-2020	107,734.40

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2020 REPS Compliance Report **June 15, 2021**
Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	**REC cost**
May-2020	110,459.20
Nov-2020	113,267.84
Oct-2020	101,404.48
Sep-2020	85,705.44
[redacted]	44,080.00
Apr-2020	3,525.00
Aug-2020	4,845.00
Dec-2020	3,050.00
Feb-2020	3,125.00
Jan-2020	2,745.00
Jul-2020	3,930.00
Jun-2020	4,405.00
Mar-2020	3,135.00
May-2020	4,555.00
Nov-2020	3,620.00
Oct-2020	3,395.00
Sep-2020	3,750.00
[redacted]	35,512.00
Apr-2020	2,824.00
Aug-2020	3,904.00
Dec-2020	2,544.00
Feb-2020	2,392.00
Jan-2020	2,160.00
Jul-2020	3,316.00
Jun-2020	3,624.00
Mar-2020	2,152.00
May-2020	3,740.00
Nov-2020	2,976.00
Oct-2020	2,700.00
Sep-2020	3,180.00
[redacted]	33,680.00
Apr-2020	2,676.00
Aug-2020	4,092.00
Dec-2020	2,184.00
Feb-2020	1,848.00
Jan-2020	1,492.00
Jul-2020	3,648.00
Jun-2020	3,460.00
Mar-2020	1,732.00
May-2020	3,664.00
Nov-2020	2,744.00
Oct-2020	2,864.00
Sep-2020	3,276.00
[redacted]	42,250.00
Apr-2020	3,425.00
Aug-2020	4,525.00
Dec-2020	2,890.00
Feb-2020	2,950.00
Jan-2020	2,620.00
Jul-2020	3,870.00
Jun-2020	4,295.00
Mar-2020	3,020.00
May-2020	4,400.00
Nov-2020	3,585.00
Oct-2020	3,135.00
Sep-2020	3,535.00
[redacted]	74,319.51
Apr-2020	11,422.52
Aug-2020	4,479.24

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2020 REPS Compliance Report **June 15, 2021**
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Counterparty and Payment Dates	REC cost
Dec-2020	6,989.08
Feb-2020	6,977.24
Jan-2020	6,409.95
Jul-2020	6,292.92
Jun-2020	6,155.52
May-2020	6,283.76
Nov-2020	6,247.12
Oct-2020	6,201.32
Sep-2020	6,860.84
[redacted]	33,880.00
Apr-2020	2,660.00
Aug-2020	3,824.00
Dec-2020	2,312.00
Feb-2020	2,316.00
Jan-2020	2,068.00
Jul-2020	3,380.00
Jun-2020	2,852.00
Mar-2020	2,124.00
May-2020	3,628.00
Nov-2020	2,868.00
Oct-2020	2,676.00
Sep-2020	3,172.00
[redacted]	4,305,840.00
Aug-2020	645,900.00
Dec-2020	552,960.00
Jul-2020	440,700.00
Jun-2020	503,520.00
Nov-2020	729,540.00
Oct-2020	751,980.00
Sep-2020	681,240.00
[redacted]	158,077.26
Apr-2020	11,508.95
Aug-2020	18,674.90
Dec-2020	11,508.95
Feb-2020	9,771.75
Jan-2020	8,678.06
Jul-2020	15,851.95
Jun-2020	14,983.35
Mar-2020	8,686.00
May-2020	16,503.40
Nov-2020	13,029.00
Oct-2020	13,680.45
Sep-2020	15,200.50
[redacted]	38,386.53
Apr-2020	2,817.36
Aug-2020	4,343.43
Dec-2020	2,934.75
Feb-2020	2,465.19
Jan-2020	2,347.80
Jul-2020	3,639.09
Jun-2020	3,639.09
Mar-2020	2,230.41
May-2020	3,873.87
Nov-2020	3,404.31
Oct-2020	3,169.53
Sep-2020	3,521.70
[redacted]	30,169.23
Aug-2020	3,639.09
Dec-2020	3,052.14

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Feb-2020	2,113.02
Jan-2020	2,582.58
Jul-2020	3,873.87
Jun-2020	3,756.48
Mar-2020	1,291.29
Nov-2020	2,934.75
Oct-2020	3,052.14
Sep-2020	3,873.87
[redacted]	7,121.25
Apr-2020	461.25
Aug-2020	357.75
Dec-2020	582.75
Feb-2020	506.25
Jan-2020	486.00
Jul-2020	697.50
Jun-2020	886.50
Mar-2020	508.50
May-2020	582.75
Nov-2020	681.75
Oct-2020	648.00
Sep-2020	722.25
[redacted]	35,912.00
Apr-2020	2,896.00
Aug-2020	3,864.00
Dec-2020	2,512.00
Feb-2020	2,540.00
Jan-2020	2,128.00
Jul-2020	3,280.00
Jun-2020	3,624.00
Mar-2020	2,388.00
May-2020	3,800.00
Nov-2020	3,076.00
Oct-2020	2,716.00
Sep-2020	3,088.00
[redacted]	57,153.88
Apr-2020	2,258.36
Aug-2020	6,036.77
Dec-2020	6,080.20
Feb-2020	2,084.64
Jan-2020	2,301.79
Jul-2020	5,863.05
Jun-2020	7,296.24
Mar-2020	2,214.93
May-2020	4,473.29
Nov-2020	5,472.18
Oct-2020	5,689.33
Sep-2020	7,383.10
[redacted]	34,580.00
Apr-2020	2,844.00
Aug-2020	3,436.00
Dec-2020	2,456.00
Feb-2020	2,472.00
Jan-2020	2,192.00
Jul-2020	3,188.00
Jun-2020	3,464.00
Mar-2020	2,448.00
May-2020	3,636.00
Nov-2020	2,848.00
Oct-2020	2,580.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Sep-2020	3,016.00
[redacted]	18,630.00
Apr-2020	1,152.00
Aug-2020	1,939.50
Dec-2020	1,379.25
Feb-2020	1,408.50
Jan-2020	1,235.25
Jul-2020	1,683.00
Jun-2020	1,885.50
Mar-2020	1,316.25
May-2020	1,935.00
Nov-2020	1,631.25
Oct-2020	1,449.00
Sep-2020	1,615.50
[redacted]	41,645.00
Apr-2020	3,285.00
Aug-2020	4,845.00
Dec-2020	2,580.00
Feb-2020	2,720.00
Jan-2020	2,495.00
Jul-2020	4,220.00
Jun-2020	4,190.00
Mar-2020	2,440.00
May-2020	4,480.00
Nov-2020	3,370.00
Oct-2020	3,415.00
Sep-2020	3,605.00
[redacted]	41,230.00
Apr-2020	3,125.00
Aug-2020	4,450.00
Dec-2020	3,120.00
Feb-2020	2,445.00
Jan-2020	2,535.00
Jul-2020	4,145.00
Jun-2020	4,070.00
Mar-2020	2,395.00
May-2020	4,325.00
Nov-2020	3,330.00
Oct-2020	3,440.00
Sep-2020	3,850.00
[redacted]	3,991.26
Apr-2020	234.78
Aug-2020	469.56
Dec-2020	352.17
Feb-2020	117.39
Jan-2020	234.78
Jul-2020	352.17
Jun-2020	469.56
Mar-2020	234.78
May-2020	352.17
Nov-2020	352.17
Oct-2020	352.17
Sep-2020	469.56
[redacted]	26,061.00
Apr-2020	2,169.00
Aug-2020	3,141.00
Dec-2020	1,707.00
Feb-2020	1,728.00
Jan-2020	1,509.00

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Duke Energy Progress, LLC **Redacted Version***
Docket No. E-2, Sub 1276 **Jennings Exhibit No. 1, Appendix 1**
2020 REPS Compliance Report **June 15, 2021**
Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	REC cost
Jul-2020	2,778.00
Jun-2020	2,748.00
Mar-2020	1,761.00
May-2020	2,106.00
Nov-2020	1,584.00
Oct-2020	2,247.00
Sep-2020	2,583.00
[redacted]	36,168.00
Apr-2020	2,704.00
Aug-2020	4,012.00
Dec-2020	2,680.00
Feb-2020	2,340.00
Jan-2020	2,188.00
Jul-2020	3,644.00
Jun-2020	3,484.00
Mar-2020	2,108.00
May-2020	3,740.00
Nov-2020	2,808.00
Oct-2020	3,088.00
Sep-2020	3,372.00
[redacted]	2,859,344.00
Apr-2020	214,907.50
Aug-2020	239,356.00
Dec-2020	230,739.50
Feb-2020	232,035.75
Jan-2020	330,433.00
Jul-2020	280,213.00
Jun-2020	164,227.25
Mar-2020	247,694.00
May-2020	211,300.75
Nov-2020	255,530.00
Oct-2020	222,764.50
Sep-2020	230,142.75
[redacted]	3,951,455.75
Apr-2020	268,157.25
Aug-2020	317,487.25
Dec-2020	286,731.50
Feb-2020	360,428.75
Jan-2020	445,547.00
Jul-2020	396,707.50
Jun-2020	268,201.50
Mar-2020	320,485.75
May-2020	293,461.75
Nov-2020	385,946.75
Oct-2020	310,055.25
Sep-2020	298,245.50
[redacted]	6,998,158.36
Apr-2020	733,935.54
Feb-2020	706,959.00
Jan-2020	758,104.00
Jun-2020	959,495.16
Mar-2020	920,861.76
Nov-2020	2,095,713.36
Oct-2020	823,089.54
[redacted]	34,096.00
Apr-2020	2,680.00
Aug-2020	3,976.00
Dec-2020	2,180.00
Feb-2020	2,064.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jan-2020	1,784.00
Jul-2020	3,496.00
Jun-2020	3,332.00
Mar-2020	2,028.00
May-2020	3,564.00
Nov-2020	2,808.00
Oct-2020	2,928.00
Sep-2020	3,256.00
[redacted]	44,060.00
Apr-2020	3,490.00
Aug-2020	4,665.00
Dec-2020	3,150.00
Feb-2020	2,815.00
Jan-2020	2,585.00
Jul-2020	4,305.00
Jun-2020	4,645.00
Mar-2020	2,795.00
May-2020	4,580.00
Nov-2020	3,725.00
Oct-2020	3,420.00
Sep-2020	3,885.00
[redacted]	24,369.00
Apr-2020	1,836.00
Aug-2020	2,634.00
Dec-2020	1,767.00
Feb-2020	1,617.00
Jan-2020	1,515.00
Jul-2020	2,334.00
Jun-2020	2,403.00
Mar-2020	1,431.00
May-2020	2,463.00
Nov-2020	1,986.00
Oct-2020	2,094.00
Sep-2020	2,289.00
[redacted]	310.29
Dec-2020	310.29
[redacted]	8,440.00
Apr-2020	950.00
Aug-2020	430.00
Dec-2020	650.00
Feb-2020	860.00
Jan-2020	900.00
Jul-2020	705.00
Jun-2020	425.00
Mar-2020	910.00
May-2020	760.00
Nov-2020	570.00
Oct-2020	435.00
Sep-2020	845.00
[redacted]	38,915.00
Apr-2020	3,270.00
Aug-2020	3,580.00
Dec-2020	2,860.00
Feb-2020	3,025.00
Jan-2020	2,630.00
Jul-2020	3,725.00
Jun-2020	4,150.00
Mar-2020	2,980.00
May-2020	4,275.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Nov-2020	2,780.00
Oct-2020	2,560.00
Sep-2020	3,080.00
[redacted]	2,699.97
Apr-2020	234.78
Aug-2020	352.17
Dec-2020	117.39
Feb-2020	117.39
Jan-2020	117.39
Jul-2020	234.78
Jun-2020	352.17
Mar-2020	117.39
May-2020	234.78
Nov-2020	234.78
Oct-2020	234.78
Sep-2020	352.17
[redacted]	40,255.00
Apr-2020	3,110.00
Aug-2020	4,100.00
Dec-2020	2,880.00
Feb-2020	3,025.00
Jan-2020	2,520.00
Jul-2020	3,745.00
Jun-2020	4,255.00
Mar-2020	2,425.00
May-2020	4,255.00
Nov-2020	3,455.00
Oct-2020	2,945.00
Sep-2020	3,540.00
[redacted]	19,320.75
Apr-2020	1,545.75
Aug-2020	1,977.75
Dec-2020	1,415.25
Feb-2020	1,379.25
Jan-2020	1,224.00
Jul-2020	1,752.75
Jun-2020	1,917.00
Mar-2020	1,300.50
May-2020	2,018.25
Nov-2020	1,633.50
Oct-2020	1,428.75
Sep-2020	1,728.00
[redacted]	7,674.75
Apr-2020	578.25
Aug-2020	801.00
Dec-2020	614.25
Feb-2020	497.25
Jan-2020	488.25
Jul-2020	722.25
Jun-2020	810.00
Mar-2020	632.25
May-2020	749.25
Nov-2020	425.25
Oct-2020	681.75
Sep-2020	675.00
[redacted]	1,408.68
Apr-2020	117.39
Dec-2020	117.39
Feb-2020	117.39

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* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Jan-2020	117.39
Jul-2020	352.17
Mar-2020	117.39
May-2020	117.39
Oct-2020	117.39
Sep-2020	234.78
[redacted]	39,530.00
Apr-2020	3,230.00
Aug-2020	4,345.00
Dec-2020	3,105.00
Feb-2020	1,620.00
Jan-2020	2,055.00
Jul-2020	3,730.00
Jun-2020	3,940.00
Mar-2020	2,790.00
May-2020	4,215.00
Nov-2020	3,680.00
Oct-2020	3,170.00
Sep-2020	3,650.00
[redacted]	32,104.00
Apr-2020	2,664.00
Aug-2020	3,840.00
Dec-2020	2,404.00
Feb-2020	2,248.00
Jan-2020	2,176.00
Jul-2020	2,008.00
Jun-2020	2,356.00
Mar-2020	2,116.00
May-2020	3,480.00
Nov-2020	2,864.00
Oct-2020	2,816.00
Sep-2020	3,132.00
[redacted]	33,435.00
Apr-2020	2,630.00
Aug-2020	3,770.00
Dec-2020	2,360.00
Feb-2020	2,235.00
Jan-2020	2,055.00
Jul-2020	3,285.00
Jun-2020	2,945.00
Mar-2020	2,190.00
May-2020	3,505.00
Nov-2020	2,790.00
Oct-2020	2,600.00
Sep-2020	3,070.00
[redacted]	41,915.00
Apr-2020	3,265.00
Aug-2020	4,595.00
Dec-2020	3,045.00
Feb-2020	2,825.00
Jan-2020	2,635.00
Jul-2020	3,850.00
Jun-2020	4,020.00
Mar-2020	2,685.00
May-2020	4,465.00
Nov-2020	3,575.00
Oct-2020	3,255.00
Sep-2020	3,700.00
[redacted]	42,295.68

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Duke Energy Progress, LLC | **Redacted Version***
Docket No. E-2, Sub 1276 | **Jennings Exhibit No. 1, Appendix 1**
2020 REPS Compliance Report | **June 15, 2021**
Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	REC cost
Apr-2020	2,276.33
Aug-2020	4,479.23
Dec-2020	3,598.07
Feb-2020	2,276.33
Jan-2020	3,010.63
Jul-2020	4,626.09
Jun-2020	4,699.52
Mar-2020	2,423.19
May-2020	2,790.34
Nov-2020	3,451.21
Oct-2020	3,818.36
Sep-2020	4,846.38
[redacted]	10,920.00
Apr-2020	820.00
Aug-2020	1,140.00
Dec-2020	1,056.00
Feb-2020	796.00
Jan-2020	792.00
Jul-2020	1,124.00
Jun-2020	1,416.00
Mar-2020	892.00
May-2020	900.00
Nov-2020	940.00
Oct-2020	344.00
Sep-2020	700.00
[redacted]	42,095.00
Apr-2020	3,295.00
Aug-2020	4,535.00
Dec-2020	3,085.00
Feb-2020	2,955.00
Jan-2020	2,665.00
Jul-2020	4,010.00
Jun-2020	4,070.00
Mar-2020	2,660.00
May-2020	4,440.00
Nov-2020	3,525.00
Oct-2020	3,270.00
Sep-2020	3,585.00
[redacted]	156,624.65
Apr-2020	18,839.76
Aug-2020	17,611.08
Dec-2020	21,092.34
Jan-2020	18,873.32
Jul-2020	32,560.02
Mar-2020	8,432.76
May-2020	13,720.26
Oct-2020	12,593.97
Sep-2020	12,901.14
[redacted]	3,639.09
Apr-2020	234.78
Aug-2020	469.56
Dec-2020	234.78
Feb-2020	234.78
Jan-2020	117.39
Jul-2020	352.17
Jun-2020	469.56
Mar-2020	117.39
May-2020	352.17
Nov-2020	234.78

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Oct-2020	352.17
Sep-2020	469.56
[redacted]	60,319.19
Apr-2020	4,837.02
Aug-2020	6,703.94
Dec-2020	5,006.74
Feb-2020	3,469.84
Jan-2020	2,878.39
Jul-2020	5,388.61
Jun-2020	6,576.65
Mar-2020	3,691.41
May-2020	5,812.91
Nov-2020	4,709.73
Oct-2020	6,109.92
Sep-2020	5,134.03
[redacted]	63,155.82
Apr-2020	5,399.94
Aug-2020	4,812.99
Dec-2020	5,869.50
Feb-2020	4,226.04
Jan-2020	4,578.21
Jul-2020	5,165.16
Jun-2020	5,399.94
Mar-2020	4,226.04
May-2020	7,278.18
Nov-2020	6,104.28
Oct-2020	5,282.55
Sep-2020	4,812.99
[redacted]	14,523.75
Apr-2020	1,116.00
Aug-2020	1,534.50
Dec-2020	1,003.50
Feb-2020	1,014.75
Jan-2020	877.50
Jul-2020	1,345.50
Jun-2020	1,451.25
Mar-2020	1,026.00
May-2020	1,521.00
Nov-2020	1,235.25
Oct-2020	1,134.00
Sep-2020	1,264.50
[redacted]	6,651.00
Apr-2020	436.50
Aug-2020	663.75
Dec-2020	573.75
Feb-2020	425.25
Jan-2020	515.25
Jul-2020	616.50
Jun-2020	645.75
Mar-2020	441.00
May-2020	513.00
Nov-2020	546.75
Oct-2020	549.00
Sep-2020	724.50
[redacted]	16,610.00
Apr-2020	1,210.00
Aug-2020	1,640.00
Dec-2020	1,350.00
Feb-2020	1,095.00

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* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Jan-2020	985.00
Jul-2020	1,475.00
Jun-2020	1,940.00
Mar-2020	1,185.00
May-2020	1,380.00
Nov-2020	1,305.00
Oct-2020	1,415.00
Sep-2020	1,630.00
[redacted]	6,619.52
Aug-2020	1,241.16
Dec-2020	620.58
Feb-2020	413.72
Jan-2020	206.86
Jul-2020	930.87
Jun-2020	103.43
Mar-2020	103.43
Nov-2020	827.44
Oct-2020	1,034.30
Sep-2020	1,137.73
[redacted]	27,865.62
Apr-2020	1,835.46
Aug-2020	2,920.05
Dec-2020	2,085.75
Feb-2020	1,501.74
Jan-2020	1,585.17
Jul-2020	2,669.76
Jun-2020	2,920.05
Mar-2020	1,585.17
May-2020	2,669.76
Nov-2020	2,169.18
Oct-2020	2,586.33
Sep-2020	3,337.20
[redacted]	35.00
Feb-2020	17.50
Jan-2020	17.50
[redacted]	29,010.00
Apr-2020	2,350.00
Aug-2020	3,220.00
Dec-2020	2,010.00
Feb-2020	2,085.00
Jan-2020	1,805.00
Jul-2020	2,665.00
Jun-2020	2,970.00
Mar-2020	2,150.00
May-2020	3,045.00
Nov-2020	2,155.00
Oct-2020	1,920.00
Sep-2020	2,635.00
[redacted]	41,270.00
Apr-2020	3,295.00
Aug-2020	4,435.00
Dec-2020	2,915.00
Feb-2020	2,865.00
Jan-2020	2,505.00
Jul-2020	3,910.00
Jun-2020	4,310.00
Mar-2020	2,505.00
May-2020	4,300.00
Nov-2020	3,435.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Oct-2020	3,055.00
Sep-2020	3,740.00
[redacted]	41,320.00
Apr-2020	3,395.00
Aug-2020	4,275.00
Dec-2020	2,975.00
Feb-2020	2,195.00
Jan-2020	2,510.00
Jul-2020	3,865.00
Jun-2020	4,290.00
Mar-2020	2,875.00
May-2020	4,430.00
Nov-2020	3,580.00
Oct-2020	3,320.00
Sep-2020	3,610.00
[redacted]	7,512.96
Apr-2020	586.95
Aug-2020	939.12
Dec-2020	469.56
Feb-2020	352.17
Jan-2020	469.56
Jul-2020	821.73
Jun-2020	939.12
Mar-2020	234.78
May-2020	586.95
Nov-2020	586.95
Oct-2020	821.73
Sep-2020	704.34
[redacted]	44,780.00
Apr-2020	3,485.00
Aug-2020	4,700.00
Dec-2020	3,210.00
Feb-2020	2,780.00
Jan-2020	2,795.00
Jul-2020	4,420.00
Jun-2020	4,280.00
Mar-2020	2,770.00
May-2020	4,650.00
Nov-2020	3,870.00
Oct-2020	3,870.00
Sep-2020	3,950.00
[redacted]	8,019.00
Apr-2020	1,028.25
Dec-2020	663.75
Feb-2020	517.50
Jan-2020	551.25
Jul-2020	1,503.00
Jun-2020	855.00
Mar-2020	510.75
Nov-2020	720.00
Sep-2020	1,669.50
[redacted]	45,200.00
Apr-2020	3,465.00
Aug-2020	5,120.00
Dec-2020	3,190.00
Feb-2020	2,895.00
Jan-2020	2,715.00
Jul-2020	4,115.00
Jun-2020	4,420.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Mar-2020	2,855.00
May-2020	4,785.00
Nov-2020	3,945.00
Oct-2020	3,570.00
Sep-2020	4,125.00
[redacted]	45,510.00
Apr-2020	3,575.00
Aug-2020	5,305.00
Dec-2020	3,355.00
Feb-2020	2,555.00
Jan-2020	2,370.00
Jul-2020	4,705.00
Jun-2020	4,585.00
Mar-2020	2,365.00
May-2020	4,755.00
Nov-2020	3,865.00
Oct-2020	3,720.00
Sep-2020	4,355.00
[redacted]	43,790.00
Apr-2020	2,615.00
Aug-2020	4,645.00
Dec-2020	3,180.00
Feb-2020	2,710.00
Jan-2020	2,760.00
Jul-2020	4,365.00
Jun-2020	4,275.00
Mar-2020	2,740.00
May-2020	4,710.00
Nov-2020	3,915.00
Oct-2020	3,830.00
Sep-2020	4,045.00
[redacted]	33,708.00
Apr-2020	2,688.00
Aug-2020	3,836.00
Dec-2020	2,344.00
Feb-2020	1,644.00
Jan-2020	1,892.00
Jul-2020	3,288.00
Jun-2020	3,348.00
Mar-2020	2,024.00
May-2020	3,720.00
Nov-2020	2,844.00
Oct-2020	2,944.00
Sep-2020	3,136.00
[redacted]	40,940.00
Apr-2020	3,195.00
Aug-2020	4,680.00
Dec-2020	2,745.00
Feb-2020	2,660.00
Jan-2020	2,255.00
Jul-2020	4,005.00
Jun-2020	4,335.00
Mar-2020	2,550.00
May-2020	4,330.00
Nov-2020	3,390.00
Oct-2020	3,205.00
Sep-2020	3,590.00
[redacted]	15,720.00
Apr-2020	2,124.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Aug-2020	1,144.00
Dec-2020	2,376.00
Jan-2020	1,996.00
Jul-2020	1,508.00
Jun-2020	1,660.00
Mar-2020	1,044.00
Oct-2020	1,264.00
Sep-2020	2,604.00
[redacted]	55,760.25
Apr-2020	3,286.92
Aug-2020	3,756.48
Dec-2020	3,404.31
Feb-2020	2,934.75
Jan-2020	3,052.14
Jul-2020	6,104.28
Jun-2020	6,691.23
Mar-2020	3,052.14
May-2020	5,282.55
Nov-2020	4,695.60
Oct-2020	6,691.23
Sep-2020	6,808.62
[redacted]	167,407.05
Apr-2020	9,071.07
Aug-2020	17,814.27
Dec-2020	11,912.61
Feb-2020	8,223.78
Jan-2020	7,889.48
Jul-2020	17,377.11
Jun-2020	20,655.81
Mar-2020	9,872.53
May-2020	11,402.59
Nov-2020	14,972.73
Oct-2020	15,810.62
Sep-2020	22,404.45
[redacted]	8,217.30
Apr-2020	1,995.63
Jan-2020	1,643.46
Mar-2020	4,108.65
May-2020	469.56
[redacted]	29,112.72
Apr-2020	1,173.90
Aug-2020	3,404.31
Dec-2020	2,230.41
Feb-2020	1,643.46
Jan-2020	1,760.85
Jul-2020	2,934.75
Jun-2020	3,169.53
Mar-2020	1,760.85
May-2020	2,699.97
Nov-2020	2,582.58
Oct-2020	2,582.58
Sep-2020	3,169.53
[redacted]	27,280.00
Apr-2020	2,104.00
Aug-2020	3,020.00
Dec-2020	1,848.00
Feb-2020	1,828.00
Jan-2020	1,664.00
Jul-2020	2,632.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Jun-2020	2,660.00
Mar-2020	1,736.00
May-2020	2,832.00
Nov-2020	2,308.00
Oct-2020	2,124.00
Sep-2020	2,524.00
[redacted]	25,140.00
Apr-2020	2,073.00
Aug-2020	2,799.00
Dec-2020	1,986.00
Feb-2020	1,878.00
Jan-2020	1,683.00
Jul-2020	1,863.00
Jun-2020	1,878.00
Mar-2020	1,746.00
May-2020	2,721.00
Nov-2020	2,223.00
Oct-2020	1,989.00
Sep-2020	2,301.00
[redacted]	12,976.00
Apr-2020	956.00
Aug-2020	1,384.00
Dec-2020	1,060.00
Feb-2020	704.00
Jan-2020	804.00
Jul-2020	1,100.00
Jun-2020	1,380.00
Mar-2020	844.00
May-2020	1,212.00
Nov-2020	996.00
Oct-2020	1,196.00
Sep-2020	1,340.00
[redacted]	14,086.80
Apr-2020	939.12
Aug-2020	1,995.63
Feb-2020	586.95
Jan-2020	704.34
Jul-2020	1,526.07
Jun-2020	1,760.85
Mar-2020	704.34
May-2020	1,291.29
Nov-2020	1,173.90
Oct-2020	1,526.07
Sep-2020	1,878.24
[redacted]	35,268.00
Apr-2020	2,696.00
Aug-2020	3,956.00
Dec-2020	2,452.00
Feb-2020	2,200.00
Jan-2020	2,084.00
Jul-2020	3,472.00
Jun-2020	3,144.00
Mar-2020	2,348.00
May-2020	3,712.00
Nov-2020	3,064.00
Oct-2020	2,948.00
Sep-2020	3,192.00
[redacted]	34,448.00
Apr-2020	2,844.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Aug-2020	3,716.00
Dec-2020	2,568.00
Feb-2020	2,544.00
Jan-2020	2,248.00
Jul-2020	3,172.00
Jun-2020	3,488.00
Mar-2020	2,124.00
May-2020	3,496.00
Nov-2020	2,896.00
Oct-2020	2,536.00
Sep-2020	2,816.00
[redacted]	27,414.00
Apr-2020	2,262.00
Aug-2020	2,928.00
Dec-2020	1,959.00
Feb-2020	1,878.00
Jan-2020	1,641.00
Jul-2020	2,646.00
Jun-2020	2,805.00
Mar-2020	1,728.00
May-2020	2,883.00
Nov-2020	2,244.00
Oct-2020	2,070.00
Sep-2020	2,370.00
[redacted]	-
Apr-2020	-
Aug-2020	-
Dec-2020	-
Feb-2020	-
Jan-2020	-
Jul-2020	-
Jun-2020	-
Mar-2020	-
May-2020	-
Nov-2020	-
Oct-2020	-
Sep-2020	-
[redacted]	25,030.06
Apr-2020	1,758.31
Aug-2020	3,413.19
Dec-2020	1,758.31
Feb-2020	1,137.73
Jan-2020	1,241.16
Jul-2020	2,585.75
Jun-2020	2,585.75
Mar-2020	1,241.16
May-2020	2,896.04
Nov-2020	1,241.16
Oct-2020	2,378.89
Sep-2020	2,792.61
[redacted]	92,941.74
Dec-2020	30,559.77
Nov-2020	28,923.84
Sep-2020	33,458.13
[redacted]	9,428.00
Apr-2020	1,260.00
Aug-2020	920.00
Dec-2020	792.00
Jan-2020	604.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jul-2020	908.00
Jun-2020	924.00
Mar-2020	608.00
May-2020	908.00
Nov-2020	776.00
Oct-2020	852.00
Sep-2020	876.00
[redacted]	477,383.78
Apr-2020	43,448.00
Aug-2020	22,071.67
Dec-2020	38,088.00
Feb-2020	35,864.00
Jan-2020	33,244.00
Jul-2020	58,941.60
Jun-2020	53,652.00
Mar-2020	36,592.00
May-2020	58,636.00
Nov-2020	46,844.00
Oct-2020	20,364.98
Sep-2020	29,637.53
[redacted]	265,688.00
Apr-2020	21,724.00
Aug-2020	28,008.00
Dec-2020	19,076.00
Feb-2020	19,380.00
Jan-2020	17,104.00
Jul-2020	23,724.00
Jun-2020	25,516.00
Mar-2020	18,808.00
May-2020	27,188.00
Nov-2020	21,976.00
Oct-2020	19,460.00
Sep-2020	23,724.00
[redacted]	32,196.00
Apr-2020	2,532.00
Aug-2020	3,608.00
Dec-2020	2,264.00
Feb-2020	2,056.00
Jan-2020	1,684.00
Jul-2020	3,076.00
Jun-2020	3,192.00
Mar-2020	2,200.00
May-2020	3,392.00
Nov-2020	2,728.00
Oct-2020	2,612.00
Sep-2020	2,852.00
[redacted]	-
Apr-2020	-
Aug-2020	-
Dec-2020	-
Feb-2020	-
Jan-2020	-
Jul-2020	-
Jun-2020	-
Mar-2020	-
May-2020	-
Nov-2020	-
Oct-2020	-
Sep-2020	-

* *Information in italics is confidential*

Duke Energy Progress, LLC | **Redacted Version***
Docket No. E-2, Sub 1276 | **Jennings Exhibit No. 1, Appendix 1**
2020 REPS Compliance Report | **June 15, 2021**
Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	REC cost
[redacted]	32,548.00
Apr-2020	2,520.00
Aug-2020	3,516.00
Dec-2020	2,188.00
Feb-2020	2,148.00
Jan-2020	1,952.00
Jul-2020	3,108.00
Jun-2020	3,332.00
Mar-2020	2,264.00
May-2020	3,424.00
Nov-2020	2,688.00
Oct-2020	2,636.00
Sep-2020	2,772.00
[redacted]	13,788.00
Apr-2020	1,452.00
Dec-2020	2,132.00
Jan-2020	1,744.00
Jul-2020	2,624.00
Jun-2020	1,340.00
Mar-2020	804.00
Oct-2020	1,200.00
Sep-2020	2,492.00
[redacted]	33,408.00
Apr-2020	2,756.00
Aug-2020	3,852.00
Dec-2020	2,400.00
Feb-2020	2,304.00
Jan-2020	1,988.00
Jul-2020	3,048.00
Jun-2020	3,168.00
Mar-2020	2,116.00
May-2020	3,544.00
Nov-2020	2,764.00
Oct-2020	2,464.00
Sep-2020	3,004.00
[redacted]	33,428.00
Apr-2020	2,624.00
Aug-2020	3,720.00
Dec-2020	2,376.00
Feb-2020	2,308.00
Jan-2020	2,024.00
Jul-2020	3,196.00
Jun-2020	3,340.00
Mar-2020	2,188.00
May-2020	3,484.00
Nov-2020	2,792.00
Oct-2020	2,516.00
Sep-2020	2,860.00
[redacted]	6,288.00
Apr-2020	656.00
Dec-2020	976.00
Jan-2020	816.00
Jul-2020	1,172.00
Jun-2020	600.00
Mar-2020	384.00
Oct-2020	536.00
Sep-2020	1,148.00
[redacted]	4,624.00
Apr-2020	212.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Dec-2020	960.00
Jan-2020	268.00
Jul-2020	1,172.00
Jun-2020	212.00
Mar-2020	132.00
Oct-2020	536.00
Sep-2020	1,132.00
[redacted]	2,699.97
Apr-2020	234.78
Aug-2020	704.34
Dec-2020	117.39
Feb-2020	117.39
Jan-2020	234.78
Jun-2020	352.17
Mar-2020	117.39
May-2020	352.17
Nov-2020	234.78
Oct-2020	234.78
[redacted]	4,501,009.33
Apr-2020	437,179.65
Aug-2020	466,560.24
Dec-2020	369,595.47
Feb-2020	359,625.48
Jan-2020	320,936.62
Jul-2020	945,737.37
Jun-2020	5,117.34
Mar-2020	266,278.14
May-2020	430,385.94
Nov-2020	212,722.53
Oct-2020	375,506.88
Sep-2020	311,363.67
[redacted]	3,639.09
Apr-2020	234.78
Aug-2020	352.17
Dec-2020	234.78
Feb-2020	117.39
Jan-2020	234.78
Jul-2020	469.56
Jun-2020	352.17
Mar-2020	234.78
May-2020	352.17
Nov-2020	352.17
Oct-2020	352.17
Sep-2020	352.17
[redacted]	3,639.09
Apr-2020	234.78
Aug-2020	469.56
Dec-2020	352.17
Feb-2020	234.78
Jan-2020	234.78
Jul-2020	352.17
Jun-2020	469.56
Mar-2020	117.39
May-2020	234.78
Nov-2020	234.78
Oct-2020	352.17
Sep-2020	352.17
[redacted]	33,720.00
Apr-2020	2,604.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Aug-2020	3,452.00
Dec-2020	2,440.00
Feb-2020	2,292.00
Jan-2020	2,080.00
Jul-2020	3,268.00
Jun-2020	3,332.00
Mar-2020	2,148.00
May-2020	3,584.00
Nov-2020	2,836.00
Oct-2020	2,612.00
Sep-2020	3,072.00
[redacted]	9,645.00
Apr-2020	681.00
Aug-2020	702.00
Dec-2020	861.00
Feb-2020	645.00
Jan-2020	696.00
Jul-2020	954.00
Jun-2020	1,149.00
Mar-2020	738.00
May-2020	591.00
Nov-2020	774.00
Oct-2020	858.00
Sep-2020	996.00
[redacted]	33,465.00
Apr-2020	2,580.00
Aug-2020	3,480.00
Dec-2020	2,480.00
Feb-2020	2,375.00
Jan-2020	2,170.00
Jul-2020	3,310.00
Jun-2020	3,725.00
Mar-2020	1,940.00
May-2020	3,620.00
Nov-2020	2,730.00
Oct-2020	2,240.00
Sep-2020	2,815.00
[redacted]	17,952.00
Apr-2020	1,428.00
Aug-2020	2,012.00
Dec-2020	1,268.00
Feb-2020	1,164.00
Jan-2020	1,072.00
Jul-2020	1,852.00
Jun-2020	1,740.00
Mar-2020	1,068.00
May-2020	1,828.00
Nov-2020	1,392.00
Oct-2020	1,524.00
Sep-2020	1,604.00
[redacted]	42,105.00
Apr-2020	3,345.00
Aug-2020	4,635.00
Dec-2020	3,010.00
Feb-2020	2,985.00
Jan-2020	2,615.00
Jul-2020	3,955.00
Jun-2020	4,325.00
Mar-2020	2,645.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
May-2020	4,360.00
Nov-2020	3,440.00
Oct-2020	3,135.00
Sep-2020	3,655.00
[redacted]	7,935.75
Apr-2020	567.00
Aug-2020	787.50
Dec-2020	634.50
Feb-2020	540.00
Jan-2020	454.50
Jul-2020	729.00
Jun-2020	792.00
Mar-2020	567.00
May-2020	778.50
Nov-2020	634.50
Oct-2020	663.75
Sep-2020	787.50
[redacted]	33,068.00
Apr-2020	752.00
Aug-2020	3,764.00
Dec-2020	2,484.00
Feb-2020	2,492.00
Jan-2020	2,200.00
Jul-2020	3,352.00
Jun-2020	3,584.00
Mar-2020	1,976.00
May-2020	3,624.00
Nov-2020	2,956.00
Oct-2020	2,668.00
Sep-2020	3,216.00
[redacted]	821.73
Aug-2020	117.39
Jun-2020	117.39
Mar-2020	117.39
May-2020	117.39
Nov-2020	117.39
Oct-2020	117.39
Sep-2020	117.39
[redacted]	51,164.56
Apr-2020	-
Aug-2020	8,186.15
Dec-2020	-
Feb-2020	-
Jan-2020	-
Jul-2020	26,463.96
Jun-2020	-
Mar-2020	-
May-2020	-
Nov-2020	-
Oct-2020	6,566.90
Sep-2020	9,947.55
[redacted]	734.30
Aug-2020	73.43
Dec-2020	73.43
Jul-2020	73.43
Jun-2020	73.43
Mar-2020	73.43
May-2020	73.43
Nov-2020	73.43

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Oct-2020	73.43
Sep-2020	146.86
[redacted]	32,640.00
Apr-2020	2,564.00
Aug-2020	3,676.00
Dec-2020	2,108.00
Feb-2020	2,196.00
Jan-2020	1,984.00
Jul-2020	3,228.00
Jun-2020	3,248.00
Mar-2020	2,024.00
May-2020	3,308.00
Nov-2020	2,732.00
Oct-2020	2,552.00
Sep-2020	3,020.00
[redacted]	18,660.00
Apr-2020	1,160.00
Aug-2020	1,905.00
Dec-2020	1,585.00
Feb-2020	1,265.00
Jan-2020	1,260.00
Jul-2020	1,785.00
Jun-2020	1,800.00
Mar-2020	1,170.00
May-2020	1,555.00
Nov-2020	1,650.00
Sep-2020	3,525.00
[redacted]	758,497.13
Aug-2020	61,841.07
Dec-2020	218,860.38
Jul-2020	29,743.20
Jun-2020	154,664.07
May-2020	113,070.26
Oct-2020	180,318.15
[redacted]	17,831.25
Apr-2020	1,437.75
Aug-2020	1,869.75
Dec-2020	1,298.25
Feb-2020	1,302.75
Jan-2020	1,131.75
Jul-2020	1,611.00
Jun-2020	1,836.00
Mar-2020	1,170.00
May-2020	1,757.25
Nov-2020	1,523.25
Oct-2020	1,323.00
Sep-2020	1,570.50
[redacted]	17,889.75
Apr-2020	1,462.50
Aug-2020	1,890.00
Dec-2020	1,282.50
Feb-2020	1,278.00
Jan-2020	1,125.00
Jul-2020	1,635.75
Jun-2020	1,831.50
Mar-2020	1,172.25
May-2020	1,838.25
Nov-2020	1,462.50
Oct-2020	1,347.75

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Sep-2020	1,563.75
[redacted]	2,585,242.89
Apr-2020	551,630.55
Aug-2020	298,752.24
Feb-2020	296,693.90
Jan-2020	345,443.64
Jul-2020	339,662.91
Jun-2020	257,983.10
May-2020	282,009.54
Sep-2020	213,067.01
[redacted]	1,241.16
Aug-2020	206.86
Dec-2020	103.43
Feb-2020	103.43
Jul-2020	103.43
Jun-2020	206.86
Mar-2020	103.43
May-2020	103.43
Nov-2020	103.43
Oct-2020	103.43
Sep-2020	103.43
[redacted]	2,792.61
Apr-2020	206.86
Aug-2020	413.72
Dec-2020	206.86
Feb-2020	103.43
Jan-2020	206.86
Jul-2020	206.86
Jun-2020	310.29
Mar-2020	206.86
May-2020	206.86
Nov-2020	206.86
Oct-2020	310.29
Sep-2020	206.86
[redacted]	734.30
Apr-2020	73.43
Aug-2020	73.43
Dec-2020	73.43
Jan-2020	73.43
Jul-2020	146.86
Mar-2020	73.43
May-2020	73.43
Oct-2020	146.86
[redacted]	36,640.00
Apr-2020	2,856.00
Aug-2020	4,024.00
Dec-2020	2,596.00
Feb-2020	2,540.00
Jan-2020	2,136.00
Jul-2020	3,432.00
Jun-2020	3,736.00
Mar-2020	2,324.00
May-2020	3,832.00
Nov-2020	3,088.00
Oct-2020	2,792.00
Sep-2020	3,284.00
[redacted]	1,028.02
Apr-2020	73.43
Aug-2020	146.86

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Dec-2020	73.43
Jan-2020	73.43
Jul-2020	73.43
Jun-2020	146.86
Mar-2020	73.43
May-2020	73.43
Nov-2020	73.43
Oct-2020	73.43
Sep-2020	146.86
[redacted]	40,620.00
Apr-2020	3,130.00
Aug-2020	4,465.00
Dec-2020	2,925.00
Feb-2020	2,900.00
Jan-2020	2,085.00
Jul-2020	3,355.00
Jun-2020	4,115.00
Mar-2020	2,920.00
May-2020	4,260.00
Nov-2020	3,500.00
Oct-2020	3,385.00
Sep-2020	3,580.00
[redacted]	36,848.00
Apr-2020	2,840.00
Aug-2020	4,180.00
Dec-2020	2,564.00
Feb-2020	2,392.00
Jan-2020	2,236.00
Jul-2020	3,556.00
Jun-2020	3,664.00
Mar-2020	2,408.00
May-2020	3,656.00
Nov-2020	3,076.00
Oct-2020	2,940.00
Sep-2020	3,336.00
[redacted]	19,300.50
Apr-2020	1,615.50
Aug-2020	2,065.50
Dec-2020	1,383.75
Feb-2020	1,449.00
Jan-2020	1,269.00
Jul-2020	1,766.25
Jun-2020	1,955.25
Mar-2020	1,374.75
May-2020	2,002.50
Nov-2020	1,534.50
Oct-2020	1,485.00
Sep-2020	1,399.50
[redacted]	38,435.00
Apr-2020	3,130.00
Aug-2020	4,315.00
Dec-2020	2,865.00
Feb-2020	2,675.00
Jan-2020	2,520.00
Jul-2020	4,145.00
Jun-2020	4,090.00
Mar-2020	2,385.00
May-2020	4,195.00
Nov-2020	3,170.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Oct-2020	3,375.00
Sep-2020	1,570.00
[redacted]	42,370.00
Apr-2020	3,230.00
Aug-2020	4,710.00
Dec-2020	3,035.00
Feb-2020	2,750.00
Jan-2020	2,550.00
Jul-2020	4,245.00
Jun-2020	4,115.00
Mar-2020	2,400.00
May-2020	4,395.00
Nov-2020	3,470.00
Oct-2020	3,570.00
Sep-2020	3,900.00
[redacted]	216,885.20
Apr-2020	16,530.00
Aug-2020	23,878.60
Dec-2020	15,062.60
Feb-2020	13,589.40
Jan-2020	13,160.20
Jul-2020	21,906.60
Jun-2020	20,781.40
Mar-2020	12,429.40
May-2020	22,637.40
Nov-2020	18,362.80
Oct-2020	18,797.80
Sep-2020	19,749.00
[redacted]	33,460.00
Apr-2020	2,648.00
Aug-2020	3,696.00
Dec-2020	2,452.00
Feb-2020	2,264.00
Jan-2020	2,120.00
Jul-2020	3,204.00
Jun-2020	3,112.00
Mar-2020	1,888.00
May-2020	3,500.00
Nov-2020	2,688.00
Oct-2020	2,852.00
Sep-2020	3,036.00
[redacted]	113,577.46
Apr-2020	11,983.36
Aug-2020	5,912.32
Dec-2020	8,094.72
Feb-2020	12,638.08
Jan-2020	11,322.10
Jul-2020	7,142.40
Jun-2020	10,872.32
Mar-2020	12,181.76
May-2020	10,039.04
Nov-2020	8,630.40
Oct-2020	7,876.48
Sep-2020	6,884.48
[redacted]	46,960.00
Apr-2020	3,620.00
Aug-2020	5,325.00
Dec-2020	3,415.00
Feb-2020	2,860.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jan-2020	2,555.00
Jul-2020	4,625.00
Jun-2020	4,770.00
Mar-2020	2,995.00
May-2020	4,835.00
Nov-2020	3,980.00
Oct-2020	3,620.00
Sep-2020	4,360.00
[redacted]	39,890.00
Apr-2020	3,050.00
Aug-2020	2,910.00
Dec-2020	3,030.00
Feb-2020	2,930.00
Jan-2020	2,580.00
Jul-2020	4,095.00
Jun-2020	4,335.00
Mar-2020	2,605.00
May-2020	4,385.00
Nov-2020	3,365.00
Oct-2020	2,895.00
Sep-2020	3,710.00
[redacted]	33,215.00
Apr-2020	2,545.00
Aug-2020	3,780.00
Dec-2020	2,180.00
Feb-2020	2,080.00
Jan-2020	1,825.00
Jul-2020	3,345.00
Jun-2020	3,310.00
Mar-2020	1,925.00
May-2020	3,560.00
Nov-2020	2,805.00
Oct-2020	2,730.00
Sep-2020	3,130.00
[redacted]	33,785.00
Apr-2020	2,670.00
Aug-2020	3,820.00
Dec-2020	2,350.00
Feb-2020	2,095.00
Jan-2020	2,015.00
Jul-2020	3,365.00
Jun-2020	3,340.00
Mar-2020	1,980.00
May-2020	3,670.00
Nov-2020	2,665.00
Oct-2020	2,700.00
Sep-2020	3,115.00
[redacted]	36,248.00
Apr-2020	2,812.00
Aug-2020	4,068.00
Dec-2020	2,488.00
Feb-2020	2,232.00
Jan-2020	1,956.00
Jul-2020	3,612.00
Jun-2020	3,668.00
Mar-2020	2,068.00
May-2020	3,856.00
Nov-2020	3,036.00
Oct-2020	3,016.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Sep-2020	3,436.00
[redacted]	13,012.00
Apr-2020	800.00
Aug-2020	1,528.00
Dec-2020	1,000.00
Feb-2020	1,012.00
Jan-2020	876.00
Jul-2020	752.00
Jun-2020	1,260.00
Mar-2020	852.00
May-2020	1,072.00
Nov-2020	1,284.00
Oct-2020	1,172.00
Sep-2020	1,404.00
[redacted]	8,370.00
Apr-2020	790.00
Aug-2020	380.00
Dec-2020	350.00
Feb-2020	940.00
Jan-2020	765.00
Jul-2020	700.00
Jun-2020	765.00
Mar-2020	845.00
May-2020	705.00
Nov-2020	675.00
Oct-2020	570.00
Sep-2020	885.00
[redacted]	170,802.45
Apr-2020	13,382.46
Aug-2020	17,373.72
Dec-2020	11,739.00
Feb-2020	10,212.93
Jan-2020	9,391.20
Jul-2020	16,199.82
Jun-2020	16,669.38
Mar-2020	11,739.00
May-2020	14,321.58
Nov-2020	13,734.63
Oct-2020	17,021.55
Sep-2020	19,017.18
[redacted]	40,160.00
Apr-2020	2,765.00
Aug-2020	4,565.00
Dec-2020	2,470.00
Feb-2020	2,915.00
Jan-2020	2,655.00
Jul-2020	4,045.00
Jun-2020	4,025.00
Mar-2020	2,710.00
May-2020	4,205.00
Nov-2020	3,435.00
Oct-2020	3,215.00
Sep-2020	3,155.00
[redacted]	135,110.73
Apr-2020	18,153.74
Dec-2020	19,456.64
Jan-2020	17,762.87
Jul-2020	23,843.07
Jun-2020	13,376.44

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Mar-2020	7,904.26
Oct-2020	10,553.49
Sep-2020	24,060.22
[redacted]	6,925.50
Apr-2020	1,003.50
Dec-2020	605.25
Feb-2020	461.25
Jan-2020	510.75
Jul-2020	1,248.75
Jun-2020	771.75
Mar-2020	438.75
Nov-2020	603.00
Sep-2020	1,282.50
[redacted]	18,218.25
Apr-2020	1,453.50
Aug-2020	1,656.00
Dec-2020	1,379.25
Feb-2020	1,257.75
Jan-2020	1,206.00
Jul-2020	1,489.50
Jun-2020	1,818.00
Mar-2020	1,314.00
May-2020	1,957.50
Nov-2020	1,633.50
Oct-2020	1,525.50
Sep-2020	1,527.75
[redacted]	34,276.00
Apr-2020	2,772.00
Aug-2020	4,308.00
Dec-2020	2,588.00
Feb-2020	2,364.00
Jan-2020	2,196.00
Jul-2020	1,864.00
Jun-2020	3,224.00
Mar-2020	2,096.00
May-2020	3,708.00
Nov-2020	2,924.00
Oct-2020	3,024.00
Sep-2020	3,208.00
[redacted]	40,475.00
Apr-2020	3,135.00
Aug-2020	3,965.00
Dec-2020	2,995.00
Feb-2020	2,795.00
Jan-2020	2,505.00
Jul-2020	3,820.00
Jun-2020	3,925.00
Mar-2020	2,925.00
May-2020	4,075.00
Nov-2020	3,570.00
Oct-2020	3,370.00
Sep-2020	3,395.00
[redacted]	57,920.00
Jan-2020	57,920.00
[redacted]	18,589.50
Apr-2020	1,464.75
Aug-2020	2,031.75
Dec-2020	1,338.75
Feb-2020	1,100.25

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jan-2020	1,046.25
Jul-2020	1,795.50
Jun-2020	1,845.00
Mar-2020	1,307.25
May-2020	1,887.75
Nov-2020	1,617.75
Oct-2020	1,514.25
Sep-2020	1,640.25
[redacted]	131,667.09
Apr-2020	10,084.10
Aug-2020	14,893.44
Dec-2020	9,618.68
Feb-2020	8,455.13
Jan-2020	7,632.66
Jul-2020	13,497.18
Jun-2020	12,954.19
Mar-2020	7,369.15
May-2020	13,962.60
Nov-2020	10,859.80
Oct-2020	11,170.08
Sep-2020	11,170.08
[redacted]	120,586.35
Apr-2020	8,983.11
Aug-2020	13,588.17
Dec-2020	9,923.58
Feb-2020	6,938.04
Jan-2020	6,207.72
Jul-2020	10,961.34
Jun-2020	12,777.42
Mar-2020	7,296.75
May-2020	10,734.33
Nov-2020	9,729.00
Oct-2020	11,869.38
Sep-2020	11,577.51
[redacted]	35,100.00
Sep-2020	35,100.00
[redacted]	38,735.00
Apr-2020	3,225.00
Aug-2020	4,305.00
Dec-2020	2,745.00
Feb-2020	2,695.00
Jan-2020	2,425.00
Jul-2020	3,615.00
Jun-2020	4,000.00
Mar-2020	2,660.00
May-2020	3,960.00
Nov-2020	3,050.00
Oct-2020	2,795.00
Sep-2020	3,260.00
[redacted]	40,019.35
Apr-2020	2,790.34
Aug-2020	4,699.52
Dec-2020	2,790.34
Feb-2020	1,909.18
Jan-2020	2,056.04
Jul-2020	3,598.07
Jun-2020	5,066.67
Mar-2020	2,863.77
May-2020	4,112.08

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Nov-2020	2,863.77
Oct-2020	3,377.78
Sep-2020	3,891.79
[redacted]	26,916.00
Apr-2020	2,128.00
Aug-2020	2,880.00
Dec-2020	1,852.00
Feb-2020	1,764.00
Jan-2020	1,700.00
Jul-2020	2,492.00
Jun-2020	2,668.00
Mar-2020	1,856.00
May-2020	2,776.00
Nov-2020	2,336.00
Oct-2020	2,064.00
Sep-2020	2,400.00
[redacted]	39,505.00
Apr-2020	3,245.00
Aug-2020	4,245.00
Dec-2020	1,540.00
Feb-2020	2,870.00
Jan-2020	2,745.00
Jul-2020	3,935.00
Jun-2020	3,965.00
Mar-2020	2,760.00
May-2020	4,155.00
Nov-2020	3,625.00
Oct-2020	3,360.00
Sep-2020	3,060.00
[redacted]	19,520.00
Apr-2020	1,572.50
Aug-2020	1,860.00
Dec-2020	1,380.00
Feb-2020	1,432.50
Jan-2020	1,305.00
Jul-2020	1,745.00
Jun-2020	1,940.00
Mar-2020	1,420.00
May-2020	2,057.50
Nov-2020	1,667.50
Oct-2020	1,497.50
Sep-2020	1,642.50
[redacted]	45,370.00
Apr-2020	3,500.00
Aug-2020	5,075.00
Dec-2020	3,180.00
Feb-2020	3,000.00
Jan-2020	2,715.00
Jul-2020	4,180.00
Jun-2020	4,525.00
Mar-2020	2,975.00
May-2020	4,720.00
Nov-2020	3,835.00
Oct-2020	3,555.00
Sep-2020	4,110.00
[redacted]	11,550.00
Apr-2020	920.50
Aug-2020	1,284.50
Dec-2020	808.50

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Feb-2020	673.75
Jan-2020	659.75
Jul-2020	1,081.50
Jun-2020	1,186.50
Mar-2020	712.25
May-2020	1,249.50
Nov-2020	992.25
Oct-2020	953.75
Sep-2020	1,027.25
[redacted]	39,335.00
Apr-2020	2,905.00
Aug-2020	4,425.00
Dec-2020	2,935.00
Feb-2020	2,500.00
Jan-2020	2,515.00
Jul-2020	4,070.00
Jun-2020	3,925.00
Mar-2020	1,995.00
May-2020	4,060.00
Nov-2020	3,120.00
Oct-2020	3,305.00
Sep-2020	3,580.00
[redacted]	14,404.00
Apr-2020	1,052.00
Aug-2020	1,420.00
Dec-2020	1,080.00
Feb-2020	916.00
Jan-2020	832.00
Jul-2020	948.00
Jun-2020	1,520.00
Mar-2020	1,032.00
May-2020	1,540.00
Nov-2020	1,200.00
Oct-2020	1,468.00
Sep-2020	1,396.00
[redacted]	63,919.74
Apr-2020	4,137.20
Aug-2020	7,653.82
Dec-2020	5,068.07
Feb-2020	3,723.48
Jan-2020	3,620.05
Jul-2020	5,998.94
Jun-2020	6,929.81
Mar-2020	3,516.62
May-2020	6,309.23
Nov-2020	4,447.49
Oct-2020	5,895.51
Sep-2020	6,619.52
[redacted]	29,582.28
Apr-2020	2,465.19
Aug-2020	2,817.36
Dec-2020	1,643.46
Feb-2020	1,995.63
Jan-2020	1,760.85
Jul-2020	3,286.92
Jun-2020	3,521.70
Mar-2020	1,878.24
May-2020	3,756.48
Nov-2020	1,878.24

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Oct-2020	2,113.02
Sep-2020	2,465.19
[redacted]	2,497.60
Feb-2020	2,497.60
[redacted]	36,328.00
Apr-2020	2,832.00
Aug-2020	3,680.00
Dec-2020	2,740.00
Feb-2020	2,428.00
Jan-2020	2,420.00
Jul-2020	3,384.00
Jun-2020	3,456.00
Mar-2020	2,384.00
May-2020	3,772.00
Nov-2020	3,236.00
Oct-2020	2,960.00
Sep-2020	3,036.00
[redacted]	38,500.00
Apr-2020	3,345.00
Aug-2020	4,155.00
Dec-2020	3,080.00
Feb-2020	2,345.00
Jan-2020	2,130.00
Jul-2020	4,090.00
Jun-2020	4,200.00
Mar-2020	2,445.00
May-2020	4,435.00
Nov-2020	2,755.00
Oct-2020	2,500.00
Sep-2020	3,020.00
[redacted]	38,170.00
Apr-2020	3,170.00
Aug-2020	3,920.00
Dec-2020	2,710.00
Feb-2020	2,695.00
Jan-2020	2,605.00
Jul-2020	3,410.00
Jun-2020	3,350.00
Mar-2020	2,540.00
May-2020	4,065.00
Nov-2020	3,195.00
Oct-2020	3,175.00
Sep-2020	3,335.00
[redacted]	14,908.00
Apr-2020	1,044.00
Aug-2020	1,544.00
Dec-2020	1,176.00
Feb-2020	968.00
Jan-2020	868.00
Jul-2020	1,364.00
Jun-2020	1,532.00
Mar-2020	980.00
May-2020	1,412.00
Nov-2020	1,172.00
Oct-2020	1,304.00
Sep-2020	1,544.00
[redacted]	65,855.75
Apr-2020	4,957.92
Aug-2020	7,127.01

* *Information in italics is confidential*

Duke Energy Progress, LLC
Docket No. E-2, Sub 1276
2020 REPS Compliance Report
Dates and Amounts of Payments for RECs - Calendar Year 2020

Redacted Version*
Jennings Exhibit No. 1, Appendix 1
June 15, 2021

Counterparty and Payment Dates	REC cost
Dec-2020	4,785.77
Feb-2020	3,891.60
Jan-2020	2,951.13
Jul-2020	5,612.09
Jun-2020	6,782.71
Mar-2020	4,303.75
May-2020	6,438.41
Nov-2020	5,784.24
Oct-2020	6,438.41
Sep-2020	6,782.71
[redacted]	38,865.00
Apr-2020	3,135.00
Aug-2020	4,410.00
Dec-2020	2,655.00
Feb-2020	2,450.00
Jan-2020	2,115.00
Jul-2020	4,055.00
Jun-2020	3,975.00
Mar-2020	2,120.00
May-2020	4,265.00
Nov-2020	2,860.00
Oct-2020	3,195.00
Sep-2020	3,630.00
[redacted]	1,080.00
Mar-2020	1,080.00
[redacted]	420.00
Mar-2020	420.00
[redacted]	8,077.30
Apr-2020	587.44
Aug-2020	1,028.02
Feb-2020	440.58
Jan-2020	367.15
Jul-2020	1,028.02
Jun-2020	954.59
Mar-2020	440.58
May-2020	881.16
Nov-2020	514.01
Oct-2020	881.16
Sep-2020	954.59
[redacted]	17,912.25
Apr-2020	1,341.00
Aug-2020	1,896.75
Dec-2020	1,287.00
Feb-2020	1,255.50
Jan-2020	1,156.50
Jul-2020	1,685.25
Jun-2020	1,777.50
Mar-2020	1,291.50
May-2020	1,836.00
Nov-2020	1,469.25
Oct-2020	1,381.50
Sep-2020	1,534.50
[redacted]	7,931.25
Apr-2020	546.75
Aug-2020	713.25
Dec-2020	625.50
Feb-2020	535.50
Jan-2020	519.75
Jul-2020	726.75

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jun-2020	884.25
Mar-2020	582.75
May-2020	681.75
Nov-2020	555.75
Oct-2020	704.25
Sep-2020	855.00
[redacted]	44,371.47
Apr-2020	2,999.47
Aug-2020	4,861.21
Dec-2020	3,826.91
Feb-2020	2,378.89
Jan-2020	2,689.18
Jul-2020	4,654.35
Jun-2020	3,206.33
Mar-2020	2,585.75
May-2020	2,896.04
Nov-2020	3,930.34
Oct-2020	4,757.78
Sep-2020	5,585.22
[redacted]	19,336.50
Apr-2020	1,498.50
Aug-2020	2,076.75
Dec-2020	1,408.50
Feb-2020	1,307.25
Jan-2020	1,188.00
Jul-2020	1,815.75
Jun-2020	1,905.75
Mar-2020	1,255.50
May-2020	1,971.00
Nov-2020	1,651.50
Oct-2020	1,489.50
Sep-2020	1,768.50
[redacted]	41,965.00
Apr-2020	3,400.00
Aug-2020	4,525.00
Dec-2020	2,950.00
Feb-2020	3,000.00
Jan-2020	2,625.00
Jul-2020	3,865.00
Jun-2020	4,255.00
Mar-2020	2,825.00
May-2020	4,440.00
Nov-2020	3,340.00
Oct-2020	3,215.00
Sep-2020	3,525.00
[redacted]	35,916.00
Apr-2020	2,788.00
Aug-2020	3,840.00
Dec-2020	2,568.00
Feb-2020	2,372.00
Jan-2020	2,200.00
Jul-2020	3,208.00
Jun-2020	3,664.00
Mar-2020	2,264.00
May-2020	3,540.00
Nov-2020	3,140.00
Oct-2020	2,900.00
Sep-2020	3,432.00
[redacted]	35,320.00

* *Information in italics is confidential*

Counterparty and Payment Dates	**REC cost**
Apr-2020	2,956.00
Aug-2020	3,944.00
Dec-2020	2,552.00
Feb-2020	2,592.00
Jan-2020	2,260.00
Jul-2020	3,396.00
Jun-2020	3,784.00
Mar-2020	2,188.00
May-2020	3,644.00
Nov-2020	2,172.00
Oct-2020	2,820.00
Sep-2020	3,012.00
[redacted]	25,455.00
Apr-2020	1,640.00
Aug-2020	2,985.00
Dec-2020	1,870.00
Feb-2020	1,675.00
Jan-2020	1,560.00
Jul-2020	2,610.00
Jun-2020	2,535.00
Mar-2020	1,515.00
May-2020	2,665.00
Nov-2020	2,035.00
Oct-2020	1,975.00
Sep-2020	2,390.00
[redacted]	38,095.00
Apr-2020	3,160.00
Aug-2020	4,175.00
Dec-2020	2,850.00
Feb-2020	2,905.00
Jan-2020	2,040.00
Jul-2020	2,780.00
Jun-2020	3,585.00
Mar-2020	2,930.00
May-2020	3,885.00
Nov-2020	3,300.00
Oct-2020	3,180.00
Sep-2020	3,305.00
[redacted]	40,515.00
Apr-2020	3,095.00
Aug-2020	4,350.00
Dec-2020	2,785.00
Feb-2020	2,560.00
Jan-2020	2,490.00
Jul-2020	4,140.00
Jun-2020	3,925.00
Mar-2020	2,455.00
May-2020	4,255.00
Nov-2020	3,385.00
Oct-2020	3,455.00
Sep-2020	3,620.00
[redacted]	41,030.00
Apr-2020	3,175.00
Aug-2020	4,890.00
Dec-2020	2,440.00
Feb-2020	2,665.00
Jan-2020	2,530.00
Jul-2020	4,355.00
Jun-2020	4,195.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Mar-2020	2,360.00
May-2020	4,300.00
Nov-2020	2,655.00
Oct-2020	3,525.00
Sep-2020	3,940.00
[redacted]	287,200.00
Apr-2020	83,850.00
Dec-2020	46,995.00
Feb-2020	29,215.00
Jan-2020	49,185.00
Mar-2020	18,445.00
Nov-2020	32,885.00
Oct-2020	26,625.00
[redacted]	32,696.00
Apr-2020	2,596.00
Aug-2020	3,744.00
Dec-2020	2,340.00
Feb-2020	2,136.00
Jan-2020	1,920.00
Jul-2020	3,388.00
Jun-2020	3,080.00
Mar-2020	1,928.00
May-2020	3,292.00
Nov-2020	2,300.00
Oct-2020	2,812.00
Sep-2020	3,160.00
[redacted]	43,000.00
Apr-2020	3,280.00
Aug-2020	4,525.00
Dec-2020	3,145.00
Feb-2020	2,880.00
Jan-2020	2,745.00
Jul-2020	4,280.00
Jun-2020	4,260.00
Mar-2020	2,520.00
May-2020	4,185.00
Nov-2020	3,465.00
Oct-2020	3,650.00
Sep-2020	4,065.00
[redacted]	38,190.00
Apr-2020	3,160.00
Aug-2020	3,765.00
Dec-2020	3,015.00
Feb-2020	3,150.00
Jan-2020	2,380.00
Jul-2020	3,360.00
Jun-2020	3,990.00
Mar-2020	3,120.00
May-2020	4,140.00
Nov-2020	2,210.00
Oct-2020	2,800.00
Sep-2020	3,100.00
[redacted]	320,438.86
Apr-2020	29,493.02
Aug-2020	37,343.68
Dec-2020	18,671.84
Feb-2020	20,793.64
Jan-2020	14,475.30
Jul-2020	31,614.82

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jun-2020	40,314.20
Mar-2020	22,703.26
May-2020	35,646.24
Nov-2020	24,825.06
Oct-2020	25,249.42
Sep-2020	19,308.38
[redacted]	36,685.00
Apr-2020	3,170.00
Aug-2020	3,795.00
Dec-2020	1,300.00
Feb-2020	2,585.00
Jan-2020	2,385.00
Jul-2020	3,775.00
Jun-2020	3,865.00
Mar-2020	2,660.00
May-2020	3,710.00
Nov-2020	3,040.00
Oct-2020	3,245.00
Sep-2020	3,155.00
[redacted]	31,108.35
Apr-2020	1,995.63
Aug-2020	3,756.48
Dec-2020	2,230.41
Feb-2020	1,526.07
Jan-2020	1,526.07
Jul-2020	3,521.70
Jun-2020	3,521.70
Mar-2020	1,291.29
May-2020	2,934.75
Nov-2020	2,582.58
Oct-2020	2,934.75
Sep-2020	3,286.92
[redacted]	44,795.00
Apr-2020	3,415.00
Aug-2020	5,140.00
Dec-2020	2,940.00
Feb-2020	3,040.00
Jan-2020	2,750.00
Jul-2020	4,540.00
Jun-2020	4,525.00
Mar-2020	2,685.00
May-2020	4,585.00
Nov-2020	3,530.00
Oct-2020	3,560.00
Sep-2020	4,085.00
[redacted]	34,476.00
Apr-2020	2,700.00
Aug-2020	3,864.00
Dec-2020	2,396.00
Feb-2020	2,248.00
Jan-2020	2,108.00
Jul-2020	3,412.00
Jun-2020	3,296.00
Mar-2020	2,120.00
May-2020	3,500.00
Nov-2020	2,916.00
Oct-2020	2,804.00
Sep-2020	3,112.00
[redacted]	3,286.92

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Apr-2020	234.78
Aug-2020	352.17
Dec-2020	234.78
Feb-2020	234.78
Jan-2020	234.78
Jul-2020	234.78
Jun-2020	352.17
Mar-2020	234.78
May-2020	234.78
Nov-2020	234.78
Oct-2020	352.17
Sep-2020	352.17
[redacted]	1,760.85
Apr-2020	117.39
Aug-2020	117.39
Dec-2020	117.39
Feb-2020	117.39
Jan-2020	234.78
Jul-2020	234.78
Jun-2020	117.39
Mar-2020	117.39
May-2020	234.78
Nov-2020	117.39
Sep-2020	234.78
[redacted]	52,749.30
Apr-2020	3,826.91
Aug-2020	5,688.65
Dec-2020	3,723.48
Feb-2020	2,792.61
Jan-2020	2,999.47
Jul-2020	5,274.93
Jun-2020	5,792.08
Mar-2020	3,413.19
May-2020	5,171.50
Nov-2020	3,930.34
Oct-2020	4,550.92
Sep-2020	5,585.22
[redacted]	137,672.25
Apr-2020	11,229.75
Aug-2020	13,765.50
Dec-2020	9,780.75
Feb-2020	9,884.25
Jan-2020	8,694.00
Jul-2020	9,849.75
Jun-2020	14,024.25
Mar-2020	10,125.75
May-2020	14,800.50
Nov-2020	11,919.75
Oct-2020	11,281.50
Sep-2020	12,316.50
[redacted]	25,584.00
Apr-2020	2,152.00
Aug-2020	2,840.00
Dec-2020	1,848.00
Feb-2020	1,804.00
Jan-2020	1,544.00
Jul-2020	2,456.00
Jun-2020	2,652.00
Mar-2020	1,624.00

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* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
May-2020	2,440.00
Nov-2020	1,996.00
Oct-2020	1,896.00
Sep-2020	2,332.00
[redacted]	43,305.00
Apr-2020	3,435.00
Aug-2020	4,860.00
Dec-2020	3,110.00
Feb-2020	3,000.00
Jan-2020	2,690.00
Jul-2020	4,170.00
Jun-2020	4,550.00
Mar-2020	2,750.00
May-2020	4,275.00
Nov-2020	3,530.00
Oct-2020	3,250.00
Sep-2020	3,685.00
[redacted]	41,175.00
Apr-2020	3,245.00
Aug-2020	3,710.00
Dec-2020	2,965.00
Feb-2020	2,790.00
Jan-2020	2,585.00
Jul-2020	4,000.00
Jun-2020	4,030.00
Mar-2020	2,930.00
May-2020	4,330.00
Nov-2020	3,580.00
Oct-2020	3,410.00
Sep-2020	3,600.00
[redacted]	1,179,733.70
Apr-2020	99,850.05
Aug-2020	99,362.58
Dec-2020	107,736.12
Feb-2020	93,893.03
Jan-2020	95,532.21
Jul-2020	90,474.74
Jun-2020	97,931.01
Mar-2020	86,556.70
May-2020	92,573.69
Nov-2020	107,176.34
Oct-2020	103,085.64
Sep-2020	105,561.59
[redacted]	34,032.00
Apr-2020	2,620.00
Aug-2020	3,968.00
Dec-2020	2,256.00
Feb-2020	1,972.00
Jan-2020	1,736.00
Jul-2020	3,596.00
Jun-2020	3,444.00
Mar-2020	1,940.00
May-2020	3,600.00
Nov-2020	2,680.00
Oct-2020	2,924.00
Sep-2020	3,296.00
[redacted]	17,770.00
Apr-2020	1,170.00
Aug-2020	1,905.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Dec-2020	1,395.00
Feb-2020	950.00
Jan-2020	1,060.00
Jul-2020	1,535.00
Jun-2020	1,950.00
Mar-2020	1,135.00
May-2020	1,705.00
Nov-2020	1,380.00
Oct-2020	1,670.00
Sep-2020	1,915.00
[redacted]	42,220.00
Apr-2020	3,260.00
Aug-2020	4,870.00
Dec-2020	3,040.00
Feb-2020	2,745.00
Jan-2020	2,580.00
Jul-2020	4,335.00
Jun-2020	4,180.00
Mar-2020	2,460.00
May-2020	4,230.00
Nov-2020	3,150.00
Oct-2020	3,475.00
Sep-2020	3,895.00
[redacted]	40,580.00
Apr-2020	3,165.00
Aug-2020	4,245.00
Dec-2020	3,015.00
Feb-2020	2,800.00
Jan-2020	2,755.00
Jul-2020	3,820.00
Jun-2020	3,485.00
Mar-2020	2,755.00
May-2020	3,910.00
Nov-2020	3,665.00
Oct-2020	3,465.00
Sep-2020	3,500.00
[redacted]	36,260.00
Apr-2020	2,652.00
Aug-2020	4,020.00
Dec-2020	2,500.00
Feb-2020	2,192.00
Jan-2020	2,212.00
Jul-2020	3,764.00
Jun-2020	3,452.00
Mar-2020	2,224.00
May-2020	3,792.00
Nov-2020	3,116.00
Oct-2020	3,120.00
Sep-2020	3,216.00
[redacted]	36,556.00
Apr-2020	2,720.00
Aug-2020	3,948.00
Dec-2020	2,540.00
Feb-2020	2,256.00
Jan-2020	2,248.00
Jul-2020	3,716.00
Jun-2020	3,464.00
Mar-2020	2,240.00
May-2020	3,872.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Nov-2020	3,188.00
Oct-2020	3,092.00
Sep-2020	3,272.00
[redacted]	43,045.00
Apr-2020	3,260.00
Aug-2020	4,740.00
Dec-2020	3,280.00
Feb-2020	2,910.00
Jan-2020	2,665.00
Jul-2020	4,160.00
Jun-2020	4,040.00
Mar-2020	2,570.00
May-2020	4,420.00
Nov-2020	3,550.00
Oct-2020	3,590.00
Sep-2020	3,860.00
[redacted]	36,494.71
Apr-2020	2,496.62
Aug-2020	4,185.51
Dec-2020	2,863.77
Feb-2020	1,762.32
Jan-2020	2,276.33
Jul-2020	3,598.07
Jun-2020	3,891.79
Mar-2020	1,909.18
May-2020	2,863.77
Nov-2020	2,790.34
Oct-2020	3,818.36
Sep-2020	4,038.65
[redacted]	20,642.50
Apr-2020	1,602.50
Aug-2020	2,140.00
Dec-2020	1,505.00
Feb-2020	1,410.00
Jan-2020	1,290.00
Jul-2020	1,922.50
Jun-2020	2,032.50
Mar-2020	1,467.50
May-2020	2,125.00
Nov-2020	1,760.00
Oct-2020	1,627.50
Sep-2020	1,760.00
[redacted]	31,970.00
Apr-2020	3,185.00
Aug-2020	4,280.00
Dec-2020	2,910.00
Jul-2020	3,740.00
Jun-2020	4,035.00
Mar-2020	575.00
May-2020	4,170.00
Nov-2020	3,290.00
Oct-2020	2,560.00
Sep-2020	3,225.00
[redacted]	39,995.00
Apr-2020	3,105.00
Aug-2020	4,410.00
Dec-2020	2,970.00
Feb-2020	2,990.00
Jan-2020	2,680.00

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
Jul-2020	3,900.00
Jun-2020	4,190.00
Mar-2020	2,730.00
May-2020	3,305.00
Nov-2020	3,285.00
Oct-2020	2,730.00
Sep-2020	3,700.00
[redacted]	38,405.00
Apr-2020	3,280.00
Aug-2020	4,345.00
Dec-2020	2,545.00
Feb-2020	2,915.00
Jan-2020	2,560.00
Jul-2020	3,755.00
Jun-2020	3,050.00
Mar-2020	2,665.00
May-2020	3,775.00
Nov-2020	3,215.00
Oct-2020	2,815.00
Sep-2020	3,485.00
[redacted]	35,956.00
Apr-2020	2,780.00
Aug-2020	3,876.00
Dec-2020	2,540.00
Feb-2020	2,384.00
Jan-2020	2,164.00
Jul-2020	3,524.00
Jun-2020	3,580.00
Mar-2020	2,248.00
May-2020	3,792.00
Nov-2020	3,032.00
Oct-2020	2,800.00
Sep-2020	3,236.00
[redacted]	8,998.41
Apr-2020	827.44
Dec-2020	724.01
Feb-2020	517.15
Jan-2020	517.15
Jul-2020	1,448.02
Mar-2020	620.58
May-2020	1,137.73
Nov-2020	827.44
Oct-2020	1,034.30
Sep-2020	1,344.59
[redacted]	39,765.00
Apr-2020	3,135.00
Aug-2020	4,420.00
Dec-2020	2,990.00
Feb-2020	2,790.00
Jan-2020	2,510.00
Jul-2020	3,820.00
Jun-2020	3,840.00
Mar-2020	2,430.00
May-2020	4,150.00
Nov-2020	3,135.00
Oct-2020	2,995.00
Sep-2020	3,550.00
[redacted]	33,556.00
Apr-2020	2,700.00

* *Information in italics is confidential*

Dates and Amounts of Payments for RECs - Calendar Year 2020

Counterparty and Payment Dates	REC cost
Aug-2020	3,624.00
Dec-2020	2,432.00
Feb-2020	2,420.00
Jan-2020	2,140.00
Jul-2020	3,244.00
Jun-2020	3,564.00
Mar-2020	2,060.00
May-2020	3,588.00
Nov-2020	2,432.00
Oct-2020	2,516.00
Sep-2020	2,836.00
[redacted]	4,213.50
Apr-2020	331.50
Aug-2020	502.50
Dec-2020	242.50
Feb-2020	272.00
Jan-2020	252.00
Jul-2020	447.00
Jun-2020	432.50
Mar-2020	249.50
May-2020	448.50
Nov-2020	273.00
Oct-2020	360.50
Sep-2020	402.00
[redacted]	43,985.00
Apr-2020	3,360.00
Aug-2020	5,090.00
Dec-2020	3,200.00
Feb-2020	2,770.00
Jan-2020	2,560.00
Jul-2020	4,440.00
Jun-2020	4,215.00
Mar-2020	2,600.00
May-2020	4,590.00
Nov-2020	3,540.00
Oct-2020	3,640.00
Sep-2020	3,980.00
[redacted]	33,940.00
Apr-2020	2,632.00
Aug-2020	3,908.00
Dec-2020	2,440.00
Feb-2020	2,136.00
Jan-2020	1,968.00
Jul-2020	3,492.00
Jun-2020	3,164.00
Mar-2020	2,024.00
May-2020	3,588.00
Nov-2020	2,804.00
Oct-2020	2,708.00
Sep-2020	3,076.00
[redacted]	18,362.25
Apr-2020	1,431.00
Aug-2020	2,052.00
Dec-2020	1,347.75
Feb-2020	1,197.00
Jan-2020	1,109.25
Jul-2020	1,842.75
Jun-2020	1,795.50
Mar-2020	1,111.50

* *Information in italics is confidential*

Counterparty and Payment Dates	REC cost
May-2020	1,912.50
Nov-2020	1,514.25
Oct-2020	1,480.50
Sep-2020	1,568.25
[redacted]	27,477.00
Apr-2020	2,127.00
Aug-2020	2,982.00
Dec-2020	1,935.00
Feb-2020	1,854.00
Jan-2020	1,704.00
Jul-2020	2,610.00
Jun-2020	2,673.00
Mar-2020	1,896.00
May-2020	2,766.00
Nov-2020	2,310.00
Oct-2020	2,196.00
Sep-2020	2,424.00
[redacted]	35,608.00
Apr-2020	2,780.00
Aug-2020	3,964.00
Dec-2020	2,436.00
Feb-2020	2,288.00
Jan-2020	2,048.00
Jul-2020	3,476.00
Jun-2020	3,516.00
Mar-2020	2,444.00
May-2020	3,652.00
Nov-2020	3,040.00
Oct-2020	2,880.00
Sep-2020	3,084.00
Grand Total	37,426,436.22

[END CONFIDENTIAL]

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* *Information in italics is confidential*

REDACTED VERSION

Jennings Exhibit No. 2
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June 15, 2021

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1276

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED VERSION

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1276

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	**Renewable Resource**	**RECs only**	**Total Units** Note 3	**Cost per Unit**	**Total Cost**	**RECs**	**Total Units** Note 3	**Cost per Unit**	**Total Cost**	**RECs**
30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
51	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
52	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
53	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
55	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
56	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
57	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
58	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

REDACTED VERSION

DUKE ENERGY PROGRESS, LLC
Docket No. E-2, Sub 1276

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	**Renewable Resource**	**RECs only**	**Total Units** Note 3	**Cost per Unit**	**Total Cost**	**RECs**	**Total Units** Note 3	**Cost per Unit**	**Total Cost**	**RECs**
59	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
61	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
62	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
63	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
64	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
65	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
66	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
67	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
68	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
69	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
70	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
71	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
72	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
73	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
74	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
77	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
78	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
84	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
85	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
86	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
88	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
91	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
93	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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114	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
115	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
116	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
117	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
118	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
119	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
120	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
121	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
122	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
123	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
124	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
125	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
126	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
128	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
129	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
130	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
131	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
132	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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134	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
135	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
136	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
137	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
138	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
139	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
140	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
141	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
142	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
143	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
144	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
145	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
146	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
147	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
			Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
148	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
149	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
150	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
151	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
152	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
153	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
154	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
155	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
156	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
157	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
158	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
159	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
161	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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163	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
164	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
165	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
166	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
167	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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170	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
171	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
172	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
173	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
174	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
175	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
176	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

Line No.	Renewable Resource	RECs only	EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
			Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
177	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
178	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
179	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
180	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
181	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
182	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
183	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
184	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
185	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
186	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
187	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
188	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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190	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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198	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
199	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
201	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
202	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
203	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
204	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
205	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
206	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
207	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
208	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
209	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
210	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
211	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
212	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
213	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
214	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
215	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
216	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
217	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
218	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
219	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
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226	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
227	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
228	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
229	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
230	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
231	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
232	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
233	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
234	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
235	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
236	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
237	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
238	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
239	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
240	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
241	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
241	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
242	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
243	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
244	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
245	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
246	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
247	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
248	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
249	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
250	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
251	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
252	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
253	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs
254	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
255	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
256	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
257	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
258	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
259	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
260	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
261	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
262	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
263	Other Incremental Cost (see Jennings Exhibit No. 3 for Incremental Cost worksheet}				$ 1,406,287				$ 1,489,400	
264	Billing Period estimated credits for receipts related to contracts (see Jennings Exhibit No. 3)				$ -	**Note 1**			$ (400,000)	**Note 1**
265	Solar Rebate Program (see Jennings Exhibit No. 3 for cost detail)				$ 1,655,566				$ 2,331,000	
266	Research (see Jennings Exhibit No. 3 for Research cost detail)				$ 998,132				$ 950,700	
267	**Total Research and Other Incremental Cost**				**$ 4,059,985**				**$ 4,371,100**	
268	**Total REPS Cost - to Williams Exhibit No. 1**				**$ 214,720,037**				**$ 162,337,876**	
269	EMF Period actual credits for receipts related to contracts - to Williams Exhibit No.4 - footnote (2)				$ (67,900) **Jennings Exhibit No.3**	**Note 1**				

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Compliance Costs

			EMF Period April 1, 2020 - March 31, 2021				Billing Period December 1, 2021 - November 30, 2022			
Line No.	Renewable Resource	RECs only	Total Units Note 3	Cost per Unit	Total Cost	RECs	Total Units Note 3	Cost per Unit	Total Cost	RECs

Notes:

Note 1: EMF Period contract receipts are not included in the under/overcollection calculation on Williams Exhibit No. 2, instead they are credited directly to customer class on Williams Exhibit No. 4. Estimated contract receipts are included in Billing Period total other incremental cost as a reduction in REPS charges proposed for the Billing Period.

Note 2: The revenue requirements associated with each of the Company's solar generating facilities were included in total in the Company's most recent base rate case. The Commission accepted DEP's conclusion that the facility costs included in its proposed base rates were prudently incurred and approved recovery through base rates. Annual levelized costs are no longer calculated and reported in this exhibit.

Note 3: Total units refers to MWhs for bundled energy and REC purchases or to RECs for purchases denoted as RECs only.

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Jennings Exhibit No. 3
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REDACTED VERSION*

Line No.	Incremental Cost Worksheet:	EMF Period April 1, 2020 - March 31, 2021	Billing Period December 1, 2021 - November 30, 2022
	Labor by activity:		
1	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]
19	**Total Other Incremental Cost**	**$ 1,406,287**	**$ 1,489,400**
	Solar Rebate Program Cost Detail (recovery in REPS pursuant to G.S. 62-155(f)): (1)		
20	Annual Amortization of Incentives Provided to Customers, plus return on unamortized balance	$ 1,568,103	$ 2,171,300
21	Annual Amortization of Program Administrative Labor Costs, plus return on unamortized balance	[redacted]	[redacted]
22	Annual Amortization of Program Administrative Contract Labor & Other Administrative Costs, plus return on unamortized balance	[redacted]	[redacted]
23	**Total Solar Rebate Program Cost**	**$ 1,655,566**	**$ 2,331,000**

(1) All annual Solar Rebate Program costs reflect amortization of incurred costs over 20 years, including a return on the unamortized balance.

Information in italics is confidential

REDACTED VERSION*

Line No.	**Incremental Cost Worksheet:**	EMF Period April 1, 2020 - March 31, 2021	Billing Period December 1, 2021 - November 30, 2022
	Research Cost Detail:		
24	Astrape Battery Storage Effective Load Carrying Capability Study	[redacted]	
25	Coalition for Renewable Natural Gas Membership	[redacted]	
26	Eos Energy Storage Technology Development - McAlpine	[redacted]	
27	EPRI - DER Interconnection Standards & Practices	[redacted]	
28	EPRI - Inverter Reactive Power and Voltage Control Effectiveness and Application Study	[redacted]	
29	EPRI - Membership	[redacted]	
30	EPRI - Supplemental Projects	[redacted]	
31	ETO - Control Hardware-in-the-Loop (CHIL) Circuit and DER Simulation	[redacted]	
32	IEEE 1547 Conformity Assessment Education and Credentialing Program Development	[redacted]	
33	Navigant - Impact of Enabling Inverter Based Resource Reactive Power Controls	[redacted]	
34	NCSU - Adopting DVAR to Mitigate PV Impact on a Distribution System	[redacted]	
35	NCSU - Distributed Generation Cost-of-Service Impacts	[redacted]	
36	NCSU - Future Renewable Electric Energy Delivery & Mgmt Center (FREEDM Center)	[redacted]	
37	NCSU - Low Energy Drying of Swine Sludge	[redacted]	
38	NREL - Carbon-free Resource Integration Study	[redacted]	
39	PNNL -- Dynamic Var Compensator ("DVC") Pilot	[redacted]	
40	Research Triangle Institute - Biogas Utilization in NC	[redacted]	
41	Smart Electric Power Alliance	[redacted]	
42	Southeastern Wind Coalition	[redacted]	
43	UNCC - Energy Storage Integration Study	[redacted]	
44	**Total Research Cost**	**$ 998,132**	**$ 950,700**
45	**Total Other Incremental Cost**	$ 1,406,287	$ 1,489,400
46	Projected credits for receipts related to contract amendments/liquidated damages, etc	$ -	$ (400,000)
47	**Total Other Incremental Cost and other credits**	$ 1,406,287	$ 1,089,400
48	**Total Solar Rebate Program Cost**	$ 1,655,566	$ 2,331,000
49	**Total Research Cost**	$ 998,132	$ 950,700
50	**Grand Total - Other Incremental, Solar Rebate Program, and Research Cost, other credits**	**$ 4,059,985**	**$ 4,371,100**
51	EMF Period actual credits for receipts related to contracts - see **Note 1**	$ (67,900)	
52	**Net Other Incremental, Solar Rebate Program and Research Cost**	**$ 3,992,085**	**$ 4,371,100**

Note 1: EMF Period contract receipts are not included in the under/overcollection calculation on Williams Exhibit No. 2, instead they are credited directly to customer class on Williams Exhibit No. 4. Estimated contract receipts are included in Billing Period total other incremental cost as a reduction in REPS charges proposed for the Billing Period.

*** *Information in italics is confidential***

****Information in italics is confidential***

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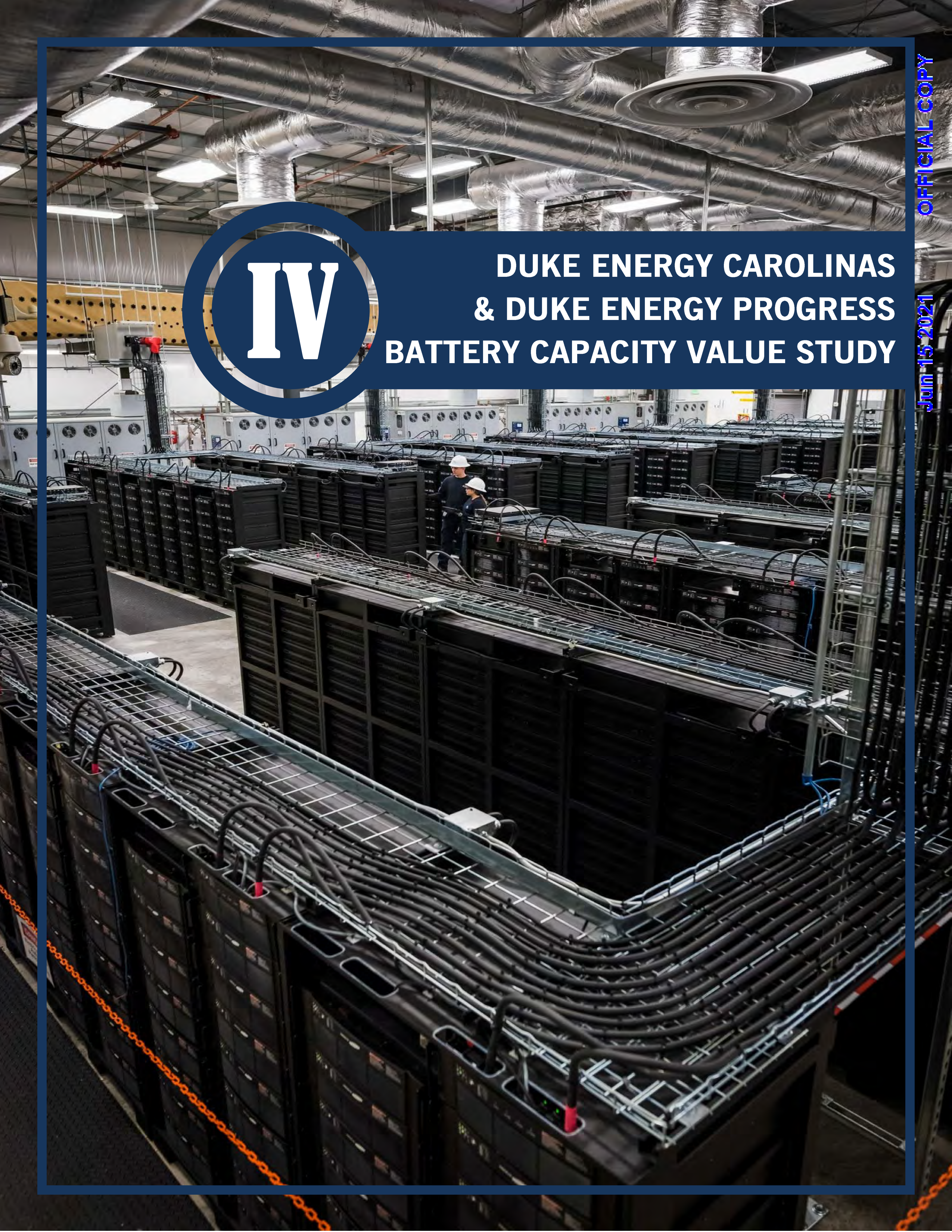
Jun 15 2021

DUKE ENERGY
PROGRESS
INTEGRATED RESOURCE PLAN

2020

ATTACHMENT IV
DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS STORAGE EFFECTIVE LOAD CARRYING CAPABILITY (ELCC) STUDY



IV

DUKE ENERGY CAROLINAS & DUKE ENERGY PROGRESS BATTERY CAPACITY VALUE STUDY

Jennings Exhibit No. 4
Docket No. E-2, Sub 1276

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Jun 15 2021

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas and Duke Energy Progress Storage Effective Load Carrying Capability (ELCC) Study

9/1/2020

PREPARED FOR

Duke Energy

PREPARED BY

Kevin Carden
Nick Wintermantel
Cole Benson
Astrapé Consulting

Contents

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I. Summary of Methodology and Results

This study was requested by Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) to analyze the capacity value of battery technology within each system. Capacity value is the reliability contribution of a generating resource and is the fraction of the rated capacity considered to be firm. This value is used for reserve margin calculation purposes. Because battery systems have limited energy storage capability and must be recharged, either from the grid or a dedicated generation resource, a battery's ability to reliably provide MW capacity when it is needed will differ from that of a fully dispatchable resource such as a gas-fired turbine, which can be called upon in any hour to produce energy, notwithstanding unit outages. Imperfect foresight of factors such as generator outages, load, and renewable energy generation leads to suboptimal battery charge and discharge scheduling, which can further impact the capacity contribution of energy storage resources. This study addresses the effects of both stored energy limits and imperfect foresight on the capacity value of battery energy storage systems. The study results provide the capacity value for battery energy storage systems used in the DEC and DEP Integrated Resource Plans.

Both DEC and DEP experience the majority of reliability risks in the winter, and battery energy storage systems are well-suited, up to certain penetration levels, to provide energy during the short peaks seen on cold winter mornings. This study analyzes the capacity contribution of 2-hour, 4-hour, and 6-hour stand-alone energy storage projects, and of paired battery plus solar systems, at several levels of market penetration by batteries, and two different levels of market penetration by solar for each utility. As market penetration increases, the system's net load peaks are flattened.

This lowers the capacity value of incremental energy storage as battery systems must discharge for longer periods to serve the wider net load peak.

A. Methodology

Astrapé performed this Effective Load Carrying Capacity (ELCC) study using the Strategic Energy Risk Valuation Model (SERVM) which is the same model used for the DEC and DEP 2020 Resource Adequacy Studies. The underlying load and resource modeling are documented in the Resource Adequacy Reports. Additional details of the model setup and assumptions are included in the Technical Modeling Appendix of this report.

The Effective Load Carrying Capacity (ELCC) methodology was used to calculate the capacity value of energy storage resources. A “base” case of the system is first established which involves calibrating DEC and DEP to the 1 day in 10-year industry standard of 0.1 Loss of Load Expectation (LOLE). This is a common industry standard as documented in the Resource Adequacy Reports and ensures that battery capacity is being valued within a reliable system. It is expected that battery energy storage would not perform well as a capacity resource in a system with LOLE much greater than 0.1, because periods in which firm load shed occurs would be longer in duration. Once the “base” case is established, the battery energy storage resources are added to the system. The additional resources improve LOLE to less than 0.1. Next, load is increased by adding a perfectly negative resource[1], until the LOLE is returned to 0.1 days per year[2]. The ratio of the additional

---

[1] Within the modeling, a perfectly negative unit is added to the system which is a unit that produces the same negative output in every hour of the year. This is equivalent to adding load in every hour of the year.

[2] Because it is difficult to return cases back to exactly 0.1 days per year, several load levels were analyzed for each battery setup and interpolation was performed to estimate the amount of load added to return to the Base Case LOLE.

load MW to the battery MW is the reliability contribution or capacity value of the battery resource. For example, if 100 MW of battery is added and achieves the same Base Case LOLE after adding 90 MW of load, the capacity value is 90 MW divided by 100 MW which equals 90%.

B. Study Scope

Astrapé calculated the average capacity value of battery energy storage systems with three different storage durations and at four levels of cumulative battery capacity for each utility (DEP and DEC). Tables 1 and 2 below show the different combinations of cumulative battery capacity and energy storage duration modeled for each utility. In addition, each capacity/duration combination was simulated with base and high total solar capacity assumption as indicated in the table headings.

Table 1. DEP Run Matrix (Base Solar = 4,000; High Solar = 5,500 MW)

	Standalone Battery Duration (hrs)		
Duration / Cumulative Battery Capacity	2	4	6
800 MW			
1,600 MW (incr 800)			
2,400 MW (incr 800)			
3,200 MW (incr 800)			

Table 2. DEC Run Matrix (Base Solar = 2,700; High Solar = 4,500 MW)

	Standalone Battery Duration (hrs)		
Duration / Cumulative Battery Capacity	2	4	6
400 MW			
800 MW (incr 400)			
1,200 MW (incr 400)			
1,600 MW (incr 400)			

Combined storage plus solar projects were also analyzed. Capacity contributions for 500 MW and 1,000 MW solar projects were analyzed for DEC, and 800 MW and 1,600 MW for DEP. The maximum MW output of each combined solar plus storage system was capped at the project's AC solar capacity, which is common for solar plus storage resources. Three different battery-to-solar MW capacity ratios were modeled, and it was assumed that the battery could be charged only from the solar array, and not from the grid. The solar generation profiles used were based on single-axis tracking systems with 1.5 inverter loading ratios. The individual permutations are shown in Tables 3 and 4 below and were replicated for both 2-hour and 4-hour storage durations.

Table 3. DEP Storage Plus Solar Permutations

Project Max Capacity (MW)	Solar Capacity (MW)	Battery Capacity (MW/% of solar)	Existing Standalone Solar Capacity (MW)
800	800	80 (10%)	3,200
800	800	240 (30%)	3,200
800	800	400 (50%)	3,200
1,600	1,600	160 (10%)	3,900
1,600	1,600	480 (30%)	3,900
1,600	1,600	800 (50%)	3,900

Table 4. DEC Storage Plus Solar Permutations

Project Max Capacity (MW)	Solar Capacity (MW)	Battery Capacity (MW/% of solar)	Existing Standalone Solar Capacity (MW)
500	500	80 (10%)	2,200
500	500	240 (30%)	2,200
500	500	400 (50%)	2,200
1,000	1,000	160 (10%)	3,200
1,000	1,000	480 (30%)	3,200
1,000	1,000	800 (50%)	3,200

C. Battery Modeling

For this study, battery resources were modeled in three operating modes using SERVM. We describe these as (1) Preserve Reliability Mode (2) Economic Arbitrage Mode and (3) Fixed Dispatch Mode based on a set rate schedule.

The objective of Preserve Reliability Mode is to provide energy only during reliability events. In this mode, SERVM maintains full charge on the storage resource at all times and only dispatches the resource during these reliability events. This mode allows the battery to run a small number of days per year but provides a high degree of reliability. This option assumes that the utility has full control of the battery and that it would be used in the most conservative way possible. While this method would provide the most capacity value, it provides little to no economic value and is not how batteries are typically expected to be run on the system. For this reason, Preserve Reliability Mode is largely an academic exercise that provides a theoretical maximum capacity value but is not directly useful for planning purposes.

The objective of Economic Arbitrage Mode is to maximize the economic value of the battery. In this mode, SERVM schedules the battery to charge at times when system energy costs are low, and to discharge when system energy costs are high. Generally, this type of dispatch aligns well with resource adequacy risks, meaning the battery will be available to discharge during peak net load conditions when loss of load events are most likely to occur. In this mode, SERVM offers recourse options during a reliability event. In other words, SERVM allows the schedule of the battery to be adjusted in real time, and discharge if its state of charge is greater than zero to avoid firm load shed. This method also assumes the utility has full control of the battery and best represents how stand-alone batteries are expected to be operated.

Operation in Fixed Dispatch Mode assumes that the utility has no control over battery operations and that the battery owner simply charges and discharges to maximize net revenue based on a set rate schedule. A battery operating in this mode provides much less capacity value than a battery controlled by the utility. It is not anticipated that stand-alone batteries would be operated in this mode, but Fixed Dispatch is an appropriate assumption for solar plus storage projects that are subject to Public Utility Regulatory Policies Act (PURPA) avoided cost contracts and rates. The study results show that the capacity value of batteries operated in Fixed Dispatch Mode declines significantly over time if the rate structure remains fixed, because loss of load hours will shift out of alignment with the hours in which the rate structure incentivizes battery discharging as the system evolves.

For all three modes, batteries were assumed to have no limits on ramping capability or constraints on number of cycles per day outside of the ability to charge the battery. Capacity values were calculated for stand-alone batteries under all three modes described above. Astrapé recommends capacity values used in the IRPs to reflect the results for Economic Arbitrage Mode for stand-alone batteries and for solar plus storage projects over which the utility has full dispatch rights. For solar plus storage projects subject to PURPA rates, Astrapé recommends that IRP capacity values reflect the results for Fixed Dispatch Mode.

D. Imperfect Foresight for Unit Commitment

SERVM does not have perfect day-ahead foresight around generator outages, load, and solar generation as it commits and dispatches resources. This imperfect knowledge does not impact the commitment and dispatch of batteries modeled under the Preserve Reliability Mode or Fixed Dispatch Mode. However, these uncertainties do impact batteries modeled in Economic Arbitrage Mode because SERVM is scheduling to minimize production costs, and day-ahead schedules will be sub-optimal to the extent that day-ahead forecasts do not perfectly match real time conditions. The day ahead solar and load uncertainty distributions are included in the Technical Appendix. Generator forced outages used in this study are the same as those used in the 2020 Resource Adequacy Study. The impact of these forecast uncertainties on the capacity value of batteries in Economic Arbitrage Mode can be estimated by comparing the difference between the capacity value of batteries in this mode and that of batteries in Preserve Reliability Mode, which maximizes capacity value at the expense of economic value.

E. Stand Alone Battery Results

Tables 5 and 6 shows the average capacity value results for stand-alone batteries in DEP up to cumulative system battery capacity of 3,200 MW, assuming two different levels of cumulative solar capacity. As discussed above, the capacity value for batteries in Preserve Reliability Mode is approximately 5-10% greater than that of batteries in Economic Arbitrage Mode. This is due to the fact that the Economic Arbitrage Mode schedules the resource day ahead to flatten the net load shape. As load, solar generation, or generator availability changes, the hours in which the resource may be needed for a reliability event could change as well, reducing the reliability of the battery resource to the extent that state of charge is misaligned with the new reliability event hours. If the battery is forced to follow a fixed dispatch schedule with no ability to respond during reliability events, the capacity value is substantially lower. This effect, combined with the fact that battery capacity values decline as cumulative battery capacity increases, indicates that it is imperative for the utility to have control of these resources as battery penetrations increase. Although as stated previously, stand-alone batteries are not expected to operate in Fixed Dispatch Mode, and it is likely that rate structures would be adjusted as cumulative battery capacity increased so as to maintain alignment between fixed dispatch scheduling and resource adequacy needs. Because of this, it is expected that the capacity values in the higher battery penetration cases with fixed dispatch are unreasonably low.

Table 5. DEP Standalone Capacity Value Results

			Full control and reserved for LOLE events (Academic Only)	Full control, dispatched for economic arbitrage - allowed to change dispatch during reliability events (Recommended)	No control, dispatch based on rate schedule; no change in dispatch during reliability events (Academic Only)
Solar Capacity (MW)	**Duration (hr)**	**Battery Capacity (MW)**	**Average Capacity Value - Preserve Reliability**	**Average Capacity Value - Economic Arbitrage**	**Average Capacity Value -Fixed Schedule**
4,000	2	800	95%	88%	55%
4,000	4	800	97%	94%	62%
4,000	6	800	97%	95%	62%
4,000	2	1,600	77%	66%	37%
4,000	4	1,600	93%	87%	40%
4,000	6	1,600	95%	90%	40%
4,000	2	2,400	65%	57%	27%
4,000	4	2,400	86%	78%	27%
4,000	6	2,400	92%	84%	28%
4,000	2	3,200	56%	50%	22%
4,000	4	3,200	76%	69%	22%
4,000	6	3,200	86%	78%	23%
5,500	2	800	96%	90%	60%
5,500	4	800	100%	97%	69%
5,500	6	800	100%	98%	75%
5,500	2	1,600	80%	72%	39%
5,500	4	1,600	94%	88%	41%
5,500	6	1,600	97%	93%	41%
5,500	2	2,400	68%	60%	29%
5,500	4	2,400	86%	80%	29%
5,500	6	2,400	94%	87%	28%
5,500	2	3,200	57%	52%	21%
5,500	4	3,200	80%	72%	21%
5,500	6	3,200	89%	82%	21%

The DEC results for stand-alone batteries are shown in the following table.

Table 6. DEC Standalone Capacity Value Results

			Full control and reserved for LOLE events (Academic Only)	Full control, dispatched for economic arbitrage - allowed to change dispatch during reliability events (Recommended)	No control, dispatch based on rate schedule; no change in dispatch during reliability events (Academic Only)
Solar Capacity (MW)	**Duration (hr)**	**Battery Capacity (MW)**	**Average Capacity Value - Preserve Reliability**	**Average Capacity Value - Economic Arbitrage**	**Average Capacity Value -Fixed Schedule**
2,700	2	400	91%	85%	74%
2,700	4	400	98%	92%	80%
2,700	6	400	100%	100%	82%
2,700	2	800	88%	75%	59%
2,700	4	800	96%	91%	66%
2,700	6	800	96%	93%	79%
2,700	2	1,200	74%	64%	48%
2,700	4	1,200	94%	84%	56%
2,700	6	1,200	95%	90%	73%
2,700	2	1,600	65%	57%	39%
2,700	4	1,600	88%	80%	41%
2,700	6	1,600	95%	89%	57%
4,500	2	400	96%	90%	74%
4,500	4	400	100%	100%	80%
4,500	6	400	100%	100%	83%
4,500	2	800	92%	81%	62%
4,500	4	800	97%	90%	69%
4,500	6	800	97%	93%	79%
4,500	2	1,200	81%	66%	53%
4,500	4	1,200	94%	87%	58%
4,500	6	1,200	95%	93%	75%
4,500	2	1,600	73%	65%	42%
4,500	4	1,600	92%	86%	45%
4,500	6	1,600	94%	91%	61%

F. Sensitivity – 6-Hour Standalone Battery at Higher Market Penetration Levels

Finally, sensitivity analysis was performed on stand-alone battery capacity to assess the effect of adding additional battery capacity above the 1,600 MW for DEC and 3,200 MW for DEP 4-hour configurations. Two 800 MW blocks of 6-hour battery capacity were added to DEP, and two 400 MW blocks of 6-hour battery capacity were added to DEC. The results in Tables 7 and 8 show that despite the additional storage having 6-hour duration, the overall average capacity value for storage still declines.

Table 7. DEP Sensitivity Results

DEP	Battery Penetration	Capacity Value - Economic Arbitrage
all 4-hour	800	97%
all 4-hour	1,600	88%
all 4-hour	2,400	80%
all 4-hour	3,200	72%
additional 6-hour	4,000	67%
additional 6-hour	4,800	63%

Table 8. DEC Sensitivity Results

DEC	Battery Penetration	Capacity Value - Economic Arbitrage
all 4-hour	400	100%
all 4-hour	800	90%
all 4-hour	1,200	87%
all 4-hour	1,600	86%
additional 6-hour	2,000	82%
additional 6-hour	2,400	79%

G. Combined Solar Plus Storage Battery Results

The combined solar plus storage results are shown in Table 9 and 10 below. For these runs, only the Economic Arbitrage Mode and the Fixed Schedule Mode analyses were conducted. The capacity values are shown as a percentage of the MW capacity of the paired solar project. Because solar capacity value in the winter is minimal, it is likely that the battery contributes most of the value shown for the combined solar plus storage system. Solar provides slightly more value in DEC, where there is a very small amount of summer LOLE that corresponds well to solar generation. Because the penetration of battery capacity wasn't increased as high as the standalone battery analysis, the battery capacity remained high. It is expected that battery capacity value would decline as cumulative installed battery capacity, whether coupled with solar or charged solely from the grid, increased further, as indicated by the standalone battery analysis.

Table 9. DEP Solar Plus Storage Results

Standalone Solar Capacity (MW)	Duration (hr)	Project Max Capacity (MW)	Battery Capacity (MW / % of Solar)	Solar Capacity Paired with Storage (MW)	Economic Arbitrage - Utility Controlled Average Capacity Value (% of Project Max Capacity)	No Dispatch Rights - Fixed Schedule Average Capacity Value (% of Project Max Capacity)
3,200	2	800	80 (10%)	800	12%	8%
3,200	2	800	240 (30%)	800	31%	21%
3,200	2	800	400 (50%)	800	45%	25%
3,200	4	800	80 (10%)	800	12%	11%
3,200	4	800	240 (30%)	800	31%	27%
3,200	4	800	400 (50%)	800	49%	34%
3,900	2	1,600	160 (10%)	1,600	12%	8%
3,900	2	1,600	480 (30%)	1,600	30%	17%
3,900	2	1,600	800 (50%)	1,600	46%	23%

3,900	4	1,600	160 (10%)	1,600	12%	11%
3,900	4	1,600	480 (30%)	1,600	31%	23%
3,900	4	1,600	800 (50%)	1,600	51%	27%

Table 10. DEC Solar Plus Storage Results

Standalone Solar Capacity (MW)	Duration (hr)	Project Max Capacity (MW)	Battery Capacity (MW / % of Solar)	Solar Capacity Paired with Storage (MW)	Economic Arbitrage - Utility Controlled Average Capacity Value (% of Project Max Capacity)	No Dispatch Rights - Fixed Schedule Average Capacity Value (% of Project Max Capacity)
2,200	2	500	50 (10%)	500	11%	8%
2,200	2	500	150 (30%)	500	28%	20%
2,200	2	500	250 (50%)	500	43%	28%
2,200	4	500	50 (10%)	500	14%	14%
2,200	4	500	150 (30%)	500	30%	28%
2,200	4	500	250 (50%)	500	44%	43%
3,200	2	1,000	100 (10%)	1,000	9%	7%
3,200	2	1,000	300 (30%)	1,000	26%	19%
3,200	2	1,000	500 (50%)	1,000	41%	30%
3,200	4	1,000	100 (10%)	1,000	10%	9%
3,200	4	1,000	300 (30%)	1,000	28%	25%
3,200	4	1,000	500 (50%)	1,000	43%	41%

To further illustrate the potential misalignment between a fixed dispatch schedule and Expected Unserved Energy (EUE) hours, Figures 1 and 2 below show the solar plus storage profiles for January of systems operating according to a fixed dispatch schedule (primary axis) with the EUE hours (secondary axis). The fixed dispatch schedule aligns better with the EUE hours for DEC than for DEP, resulting in a higher capacity value for these systems in DEC. The misalignment shown in both charts would be expected to increase over time if rate schedules were not adjusted, as battery storage is added to the system or other factors change.

Figure 1. DEP Fixed Dispatch for Combined Cases

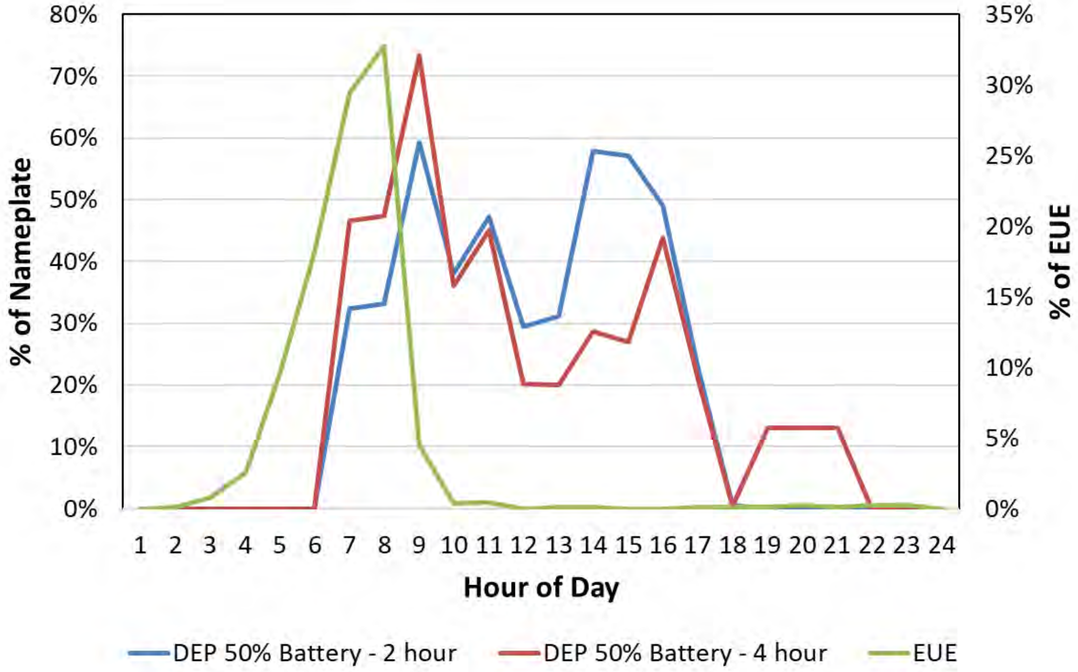
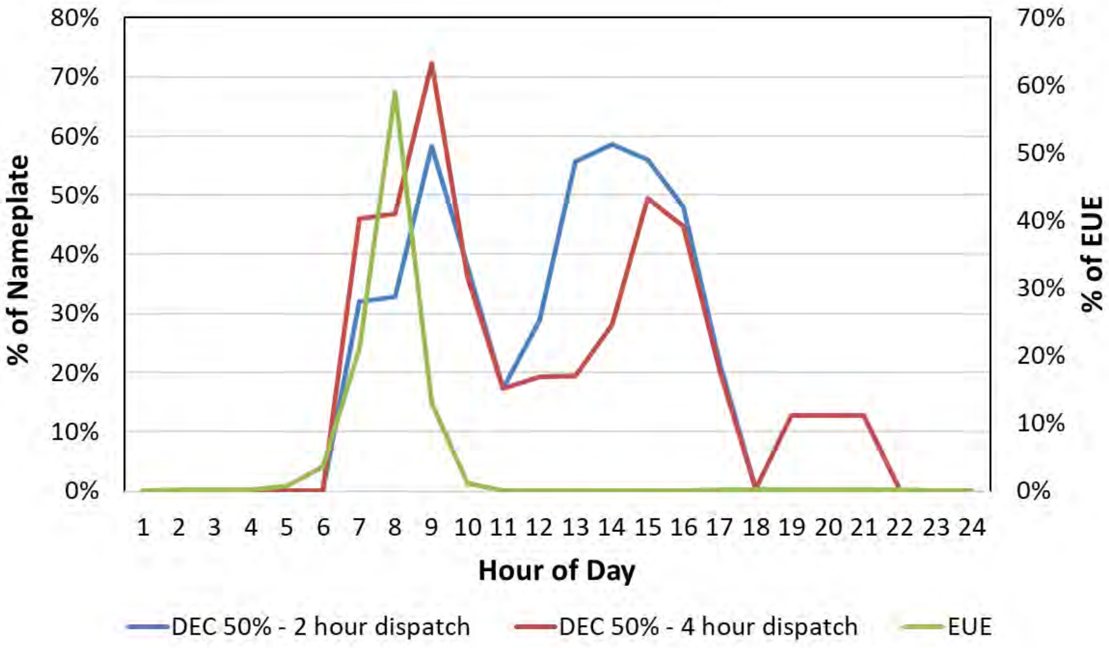


Figure 2. DEC Fixed Dispatch for Combined Cases



H. Conclusions

The results of the ELCC Study estimate significant capacity value, that reduces as penetration increases, for 4-hour and 6-hour storage for both Companies to assist in offsetting the winter reliability risks. In DEP, 2,400 MW of 4-hour storage is estimated to have an average capacity value of 80%. In DEC, 1,600 MW of 4 – hour storage is estimated to have an average capacity value of greater than 85%. The study reveals significant capacity value in scenarios where the utility had dispatch rights over the storage compared to the owner discharging or charging based only on an economic rate schedule. The combined solar plus storage projects, including those with a battery to solar ratio of 50%, showed capacity values commensurate with the battery size. While this study does include some level of operator uncertainty due to day-ahead dispatch of storage, there are potentially additional operational constraints of storage technology that were not explored in this study. For example, there were no charging/discharging constraints, ramping constraints, daily cycle constraints, or degradation assumed in this Study. As the Companies and industry gain experience about the large-scale deployment of storage, these estimates should be revisited.

II. Technical Modeling Appendix

The following sections include a discussion on the setup and assumptions used to evaluate the capacity value of battery. The Study utilized the load and resource assumptions from the 2020 Resource Adequacy Study and Framework which are detailed in Sections III and IV of those reports.[3]

A. SERVM Framework and Cases

The study uses the same 2024 study year framework as the Base Case 2020 Resource Adequacy Study and includes 39 weather years (1980 – 2018), five load forecast error multipliers, and Monte Carlo generator outages. For capacity value studies in which significant levels of cumulative battery capacity are analyzed, the number of iterations and run times are extensive. For example, each of the weather year and load forecast error multipliers was simulated with 100 generator outage iterations. Two measures were taken to reduce the number of iterations and the simulation time.

First, since the capacity value is calculated from only cases that contain LOLE, weather years with zero LOLE were removed from the analysis. This trimmed down the simulations from 39 years to 24 years. Each weather year was still given a 1/39 chance of occurring. Second, instead of modeling all external neighbors, an hourly purchase resource was developed based on the Base Case reserve margin study which allowed external neighbors to be eliminated from the modeling

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[3] Duke Energy Carolinas 2020 Resource Adequacy Study
Duke Energy Progress 2020 Resource Adequacy Study

to significantly reduce run time. To develop the market purchase resource, hourly purchase reports from the Base Case were used and the relationship between net load and purchases was estimated by hour of day and month. This relationship expressing purchases as a function of net load was then applied to all the weather years in the modeling. Because the Base Case simulations target 0.1 LOLE, this assumption is reasonable and was used for all the incremental battery simulations. With these two changes, the run times were reduced significantly. Each level of battery was studied with 24 weather years, five load forecast error multipliers, and 100 iterations of generator outage draws.

B. Load and Solar Uncertainty

Historical hourly load and solar generation were compared to day-ahead forecasts to determine day ahead forecast uncertainty. The following tables show the data that was used. The first column of values displays the forecast error and the columns to the right show probabilities of the forecast error occurring. As one would expect, the day ahead forecast for load was fairly low while the solar error was much higher. As discussed in the summary, SERVM draws from this set of forecast error to develop day ahead net load forecasts to commit and dispatch units. Then in real time the actual net load is realized, and the fleet must adjust to meet net load.

Table 11. DEP Day Ahead Load Uncertainty

		DEP Normalized Load						
		30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Load	-20%	0%	0%	0%	0%	0%	0%	0%
	-18%	0%	0%	0%	0%	0%	0%	0%
	-16%	0%	0%	0%	0%	0%	0%	0%
	-14%	0%	0%	0%	0%	0%	0%	0%
	-12%	0%	0%	0%	0%	0%	0%	0%
	-10%	0%	0%	1%	1%	0%	0%	0%
	-8%	0%	0%	1%	2%	2%	1%	0%
	-6%	1%	2%	4%	6%	6%	4%	0%
	-4%	6%	11%	14%	16%	15%	17%	3%
	-2%	53%	40%	32%	28%	28%	24%	9%
	0%	36%	38%	34%	26%	25%	24%	32%
	2%	4%	7%	12%	14%	12%	13%	32%
	4%	0%	1%	3%	6%	8%	7%	14%
	6%	0%	0%	0%	1%	3%	7%	8%
	8%	0%	0%	0%	0%	1%	1%	1%
	10%	0%	0%	0%	0%	0%	1%	1%
	12%	0%	0%	0%	0%	0%	1%	0%
	14%	0%	0%	0%	0%	0%	0%	0%
	16%	0%	0%	0%	0%	0%	0%	0%
	18%	0%	0%	0%	0%	0%	0%	0%
	20%	0%	0%	0%	0%	0%	0%	0%

Table 12. DEC Day Ahead Load Uncertainty

		DEC Normalized Load						
		30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Load	-20%	0%	0%	0%	0%	0%	0%	0%
	-18%	0%	0%	0%	0%	0%	0%	0%
	-16%	0%	0%	0%	0%	0%	0%	0%
	-14%	0%	0%	0%	0%	0%	0%	0%
	-12%	0%	0%	0%	0%	0%	0%	0%
	-10%	0%	0%	0%	0%	0%	0%	0%
	-8%	0%	0%	0%	1%	1%	0%	0%
	-6%	0%	1%	2%	2%	3%	3%	0%
	-4%	5%	6%	8%	13%	16%	14%	3%
	-2%	56%	37%	31%	30%	24%	26%	9%
	0%	40%	49%	44%	30%	30%	25%	38%
	2%	0%	6%	12%	16%	14%	12%	16%
	4%	0%	0%	2%	6%	7%	9%	12%
	6%	0%	0%	0%	2%	4%	4%	7%
	8%	0%	0%	0%	0%	1%	5%	5%
	10%	0%	0%	0%	0%	0%	2%	5%
	12%	0%	0%	0%	0%	0%	0%	6%
	14%	0%	0%	0%	0%	0%	0%	0%
	16%	0%	0%	0%	0%	0%	0%	0%
	18%	0%	0%	0%	0%	0%	0%	0%
	20%	0%	0%	0%	0%	0%	0%	0%

Table 13. DEP Day Ahead Solar Uncertainty

		Normalized Solar									
		0%-10%	10%-20%	20%-30%	30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Solar Output	-60%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-55%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-50%	0%	0%	0%	1%	1%	0%	0%	0%	0%	0%
	-45%	0%	0%	1%	3%	1%	1%	0%	0%	0%	0%
	-40%	0%	0%	1%	3%	5%	2%	0%	0%	0%	0%
	-35%	0%	1%	2%	4%	9%	6%	1%	0%	0%	0%
	-30%	0%	0%	6%	9%	12%	9%	8%	0%	0%	0%
	-25%	0%	1%	8%	10%	17%	15%	17%	4%	0%	0%
	-20%	0%	4%	9%	12%	17%	16%	23%	21%	1%	0%
	-15%	0%	13%	14%	14%	14%	18%	25%	36%	38%	0%
	-10%	1%	15%	16%	11%	11%	17%	13%	25%	42%	20%
	-5%	68%	23%	13%	15%	5%	9%	7%	9%	9%	59%
	0%	30%	25%	14%	8%	4%	3%	4%	2%	6%	20%
	5%	1%	14%	8%	5%	2%	2%	1%	1%	2%	0%
	10%	0%	3%	7%	2%	1%	2%	0%	1%	1%	2%
	15%	0%	0%	2%	2%	1%	0%	1%	0%	1%	0%
	20%	0%	0%	0%	1%	0%	1%	0%	0%	0%	0%
	25%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	30%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 14. DEC Day Ahead Solar Uncertainty

		Normalized Solar									
		0%-10%	10%-20%	20%-30%	30%-40%	40%-50%	50%-60%	60%-70%	70%-80%	80%-90%	90%-100%
Over- Forecast (Negative is Under-Forecast) in Normalized Solar Output	-50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	-45%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%
	-40%	0%	0%	1%	1%	1%	1%	0%	0%	0%	0%
	-35%	0%	0%	1%	2%	2%	2%	2%	0%	0%	0%
	-30%	0%	0%	1%	3%	3%	5%	3%	1%	0%	0%
	-25%	0%	2%	4%	5%	4%	7%	6%	2%	0%	0%
	-20%	0%	3%	7%	10%	7%	9%	9%	6%	3%	0%
	-15%	0%	8%	9%	13%	9%	10%	16%	18%	16%	0%
	-10%	1%	9%	16%	13%	20%	11%	17%	23%	18%	5%
	-5%	35%	18%	13%	15%	22%	19%	14%	18%	14%	16%
	0%	63%	22%	14%	13%	12%	18%	14%	14%	19%	23%
	5%	1%	20%	11%	9%	10%	9%	10%	7%	16%	17%
	10%	0%	15%	13%	9%	6%	5%	5%	7%	8%	17%
	15%	0%	2%	9%	3%	2%	1%	2%	1%	3%	10%
	20%	0%	0%	1%	3%	1%	1%	2%	1%	1%	8%
	25%	0%	0%	0%	0%	2%	0%	0%	0%	0%	3%
	30%	0%	0%	0%	0%	0%	0%	0%	1%	0%	0%
	35%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	40%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	45%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

C. Stand Alone Battery Fixed Dispatch

Although the fixed dispatch analysis for a stand-alone battery is not used in the IRP, the fixed dispatch schedule based on North Carolinas Utilities Commission Docket No. E-100 Sub 158 ("Sub 158") avoided cost rates are shown below. The tables represent the dispatch of a 100 MW battery for 2, 4, and 6 hour durations.

Table 15. DEP Stand Alone Fixed Dispatch 2-Hour

2-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
1	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39

Table 16. DEP Stand Alone Fixed Dispatch 4-Hour & 6-Hour

4-Hour, 6-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

Table 17. DEC Stand Alone Fixed Dispatch 2-Hour

2-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
7	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
8	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
9	Weekday	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
1	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
2	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
3	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
8	Weekend	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20	0	0	0	0	0	50	50	50	50	0	0	0	-20
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-39	-39	-39	-39	-39	0	67	67	67	0	-39	-39	-39	-39	-39	-39	0	0	67	67	67	0	0	-39

Table 18. DEC Stand Alone Fixed Dispatch 4-Hour

4-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
2	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
7	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekday	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-78	-78	-78	-78	-78	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	50	100	100	100	50	0	-78
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

Table 19. DEC Stand Alone Fixed Dispatch 6-Hour

6-Hour (MW)		Hour																							
Month	Calendar	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
2	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
3	Weekday	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
7	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
8	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
9	Weekday	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	-59	0	33	33	33	33	100	100	100	100	33	33	0	-59
10	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekday	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekday	-98	-98	-98	-98	-98	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	100	100	100	100	100	0	-98
1	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
2	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
3	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59
4	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
8	Weekend	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	-39	0	0	0	0	0	100	100	100	100	0	0	0	-39
9	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Weekend	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Weekend	-59	-59	-59	-59	-59	0	100	100	100	0	-59	-59	-59	-59	-59	-59	0	0	100	100	100	0	0	-59

D. Combined Solar Plus Storage Fixed Dispatch

The fixed dispatch profiles for solar plus storage were provided by Duke Energy using internal dispatch optimization models. Figure 3 and Figure 4 show the average dispatch of these resources for January and July. Battery charging and discharging were optimized to capture clipped DC solar energy and to maximize revenue based on Sub 158 avoided cost rates. The models utilize "perfect foresight" of solar generation over 3-day periods. As stated in the summary, for combined solar plus storage projects that are subject to PURPA, Astrapé recommends these capacity values; however, for utility-controlled projects Astrapé recommends the capacity values using the Economic Arbitrage Mode.

Figure 3. DEP Combined Solar Plus Storage Fixed Dispatch

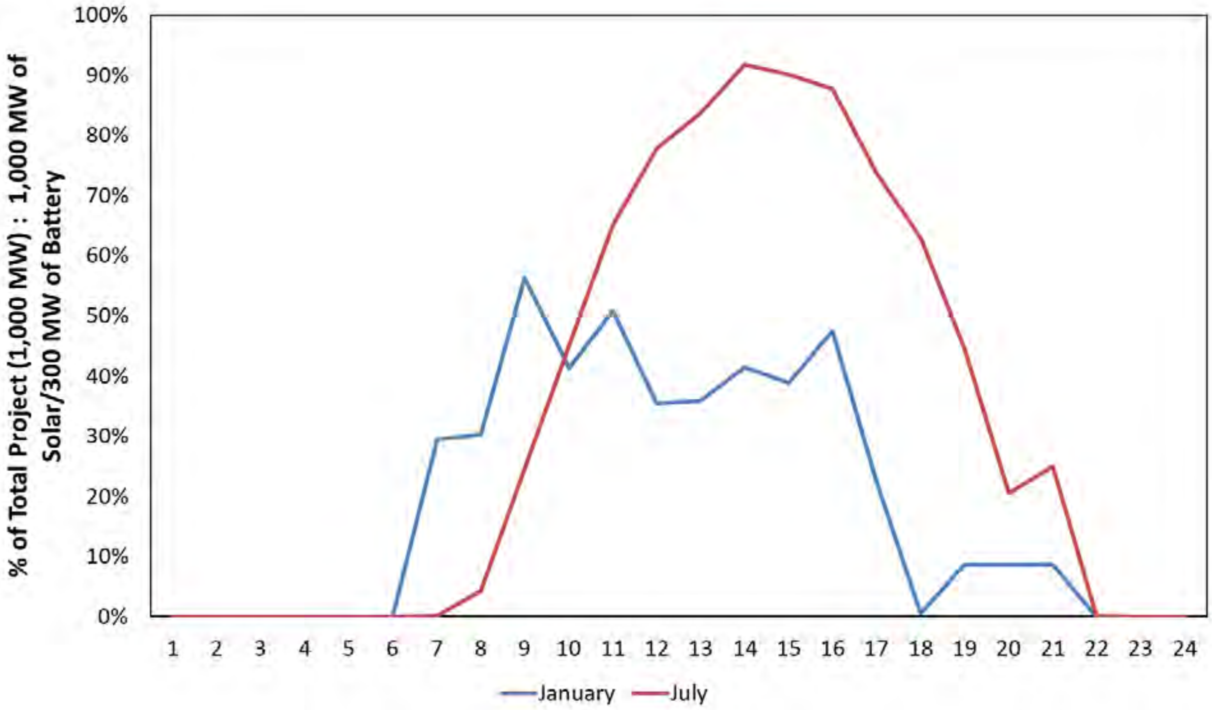
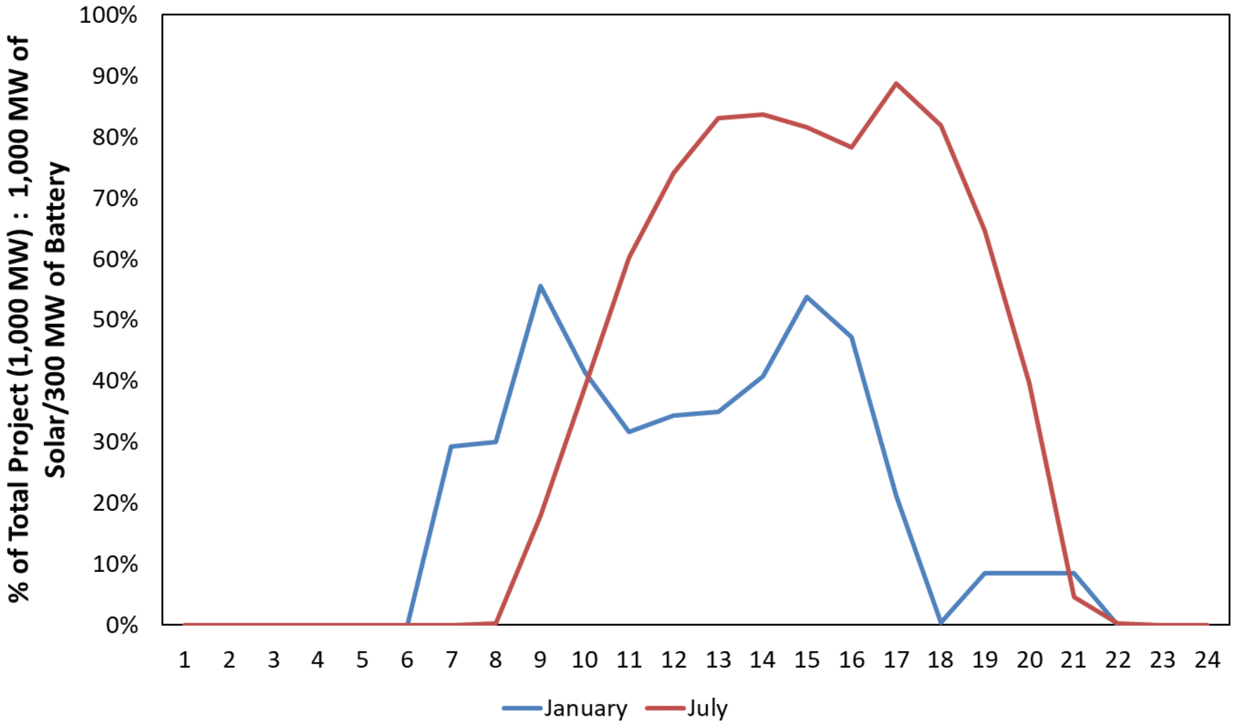


Figure 4. DEC Combined Solar Plus Storage Fixed Dispatch



E. Firm Load Shed Event

Loss of Load Expectation is defined as any day that has hourly firm load shed and is consistent with the Resource Adequacy Studies. A firm load shed event is defined as any day in which resources could not meet load, even after utilizing neighbor assistance and demand response programs, regardless of the number of hours affected. Regulating reserves of 218 MW in DEC and 150 MW in DEP were always maintained. Batteries were allowed to serve regulating reserves.

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JENNINGS CONFIDENTIAL EXHIBIT

NOS. 5 - 6

DOCKET NO. E-2, SUB 1276

CONFIDENTIAL – FILED UNDER SEAL

Jennings Exhibit No. 7
Docket No. E-2, Sub 1276
Page 1

TSRG: Inverter Volt-VAR Study Scope Review

Anthony C Williams, DER Technical Standards

September 2, 2020

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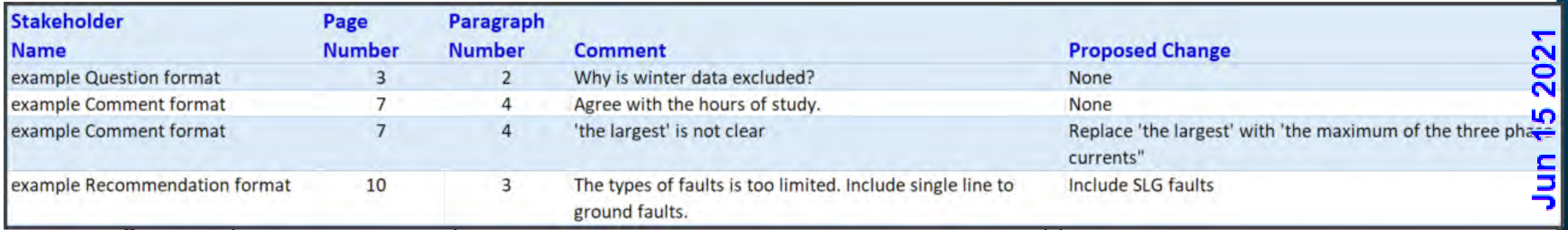
Logistics

- Clarifying questions will be answered during the presentation; major discussions at the end
- Written feedback and comments will be solicited using comment form
  - Note questions then lets discuss – don't really want all the questions sent in that are mainly just for clarification – this takes a lot of time to address that could be spent on the comments and recommendations
  - It would be helpful to provide more Comment and Proposed Change details :



Stakeholder Name	Page Number	Paragraph Number	Comment	Proposed Change
example Question format	3	2	Why is winter data excluded?	None
example Comment format	7	4	Agree with the hours of study.	None
example Comment format	7	4	'the largest' is not clear	Replace 'the largest' with 'the maximum of the three pha currents"
example Recommendation format	10	3	The types of faults is too limited. Include single line to ground faults.	Include SLG faults

response.

- Comments will be taken during the discussion and the form will be distributed after the meeting
- Share the feedback form using email: Duke-IEEE1547@duke-energy.com for stakeholders to provide their written feedback

Inverter Volt-VAR Study Overview

- North Carolina Commission had tasked Duke to evaluate software-based controls of advanced inverters according to IEEE 1547-2018 standard.
- Evaluate the use of autonomous voltage-reactive power control functions at multiple inverter-based distributed energy resources connected to the same feeder. Understand whether and how these controls cooperate with existing integrated voltage and VAR control systems.
- Evaluate the benefit and effectiveness of distributed voltage-reactive power controls at the distribution feeder level.
- Evaluate mitigation options required at the distribution feeder level to meet transmission imposed requirements for reactive power

First Study Recommended Next Steps

- Conduct time series power flow studies to look at system response over many hours
- Voltage controller concerns
  - With the IVVC commitments, how will those controls manage DER reactive power if something other than a fixed pf is used
  - Consider how to control the feeder head compensation capacitor with autonomous controls
  - Impact on feeders with regulators that use resistive drop compensation; could require significant feeder changes if the drop compensation is removed to accommodate DER reactive power control
  - Use the time series to investigate how well the existing voltage control device controllers manage the DER reactive power
- Consider controls that get more var absorption to hold voltage under 1.05
- Review the impact of higher var absorption on the feeders (closer examination of reactive power flow on the feeder)
- Consider pf based controls for voltage independence and voltage reference to absorb less reactive power at steady state
- Identify potential pilot sites; following further clarification from the additional steps above

Second Study Overview

- Expand the attributes monitored during the study; to inform conclusions
- Calculate P and Q responses
- Quasi-Static Time Series (QSTS) simulation using 8760 hourly load and solar profile
- Consider a broader variety of controller types
  - Limited controller setting variations: approximately 6 volt-var, 8 pf, 5 watt-var
  - Continued use of volt-watt to backup the primary controller
- More emphasis on higher voltage feeders so that less DER forces the overvoltage
- Compare monitored attributes across the feeders for the various controller types
  - Inform policy development to guide application of DER voltage and reactive power controls, and
  - Develop methods to a) provide a quick assessment of reactive power control effectiveness at a potential UDER interconnection point, and b) indicate the most appropriate type of control
- Interim update at October TSRG
- Final report February, presentation at the following TSRG

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TSRG: Inverter Volt-VAR Study Update

Anthony C Williams, DER Technical Standards

October 28, 2020

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Second Study Overview

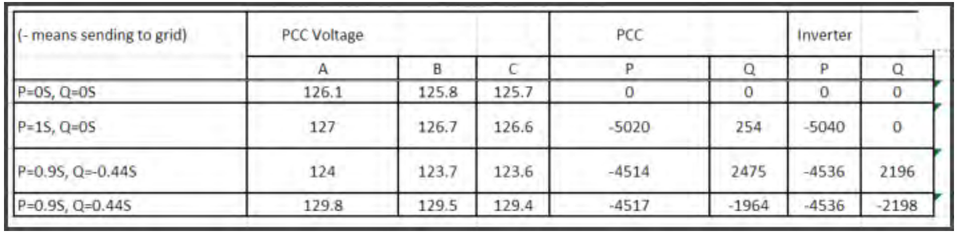
- More emphasis on higher voltage feeders so that less DER forces the overvoltage
- Calculate P and Q responses
- Consider a broader variety of controller types
    - Limited controller setting variations: approximately 6 volt-var, 8 pf, 5 watt-var
    - Continued use of volt-watt to backup the primary controller
- Expand the attributes monitored during the study; to inform conclusions
- Quasi-Static Time Series (QSTS) simulation using 8760 hourly load and solar profile
- Compare monitored attributes across the feeders for the various controller types
    - Inform policy development to guide application of DER voltage and reactive power controls, and
    - Develop methods to a) provide a quick assessment of reactive power control effectiveness at a potential UDER interconnection point, and b) indicate the most appropriate type of control
- Interim update at October TSRG
- Final report February, presentation at the following TSRG

Feeder Selection

- Attributes that may indicate feeders more relevant for volt-VAR studies
    - Initial system voltage near voltage limit
    - Short circuit MVA at the PCC – low, typical, high
    - DER kW on the feeder (not penetration)
    - Upstream voltage regulation devices with droop compensation
- Weighted
- Sorted by feeders with the highest value

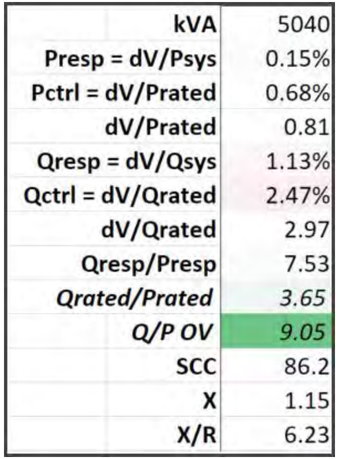
P and Q responses

1. Using data from a few operating points



(- means sending to grid)	PCC Voltage			PCC		Inverter	
	A	B	C	P	Q	P	Q
P=0S, Q=0S	126.1	125.8	125.7	0	0	0	0
P=1S, Q=0S	127	126.7	126.6	-5020	254	-5040	0
P=0.9S, Q=-0.44S	124	123.7	123.6	-4514	2475	-4536	2196
P=0.9S, Q=0.44S	129.8	129.5	129.4	-4517	-1964	-4536	-2198

2. Several characteristics of the feeder can be determined



kVA	5040
Presp = dV/Psys	0.15%
Pctrl = dV/Prated	0.68%
dV/Prated	0.81
Qresp = dV/Qsys	1.13%
Qctrl = dV/Qrated	2.47%
dV/Qrated	2.97
Qresp/Presp	7.53
Qrated/Prated	*3.65*
Q/P OV	*9.05*
SCC	86.2
X	1.15
X/R	6.23

3. To assist with evaluating the initial settings

Sample of Controller Configurations

- power factor control (pf)
  - Baseline options
    - 1.0 pf (0%)
    - 0.95 pf (31%)
    - 0.90 pf (44%)
  - Full compensation (offset voltage change at Prated)
  - Overvoltage compensation (offset overvoltage at Prated)
    - A good limiting case, but probably not a practical case
  - Likely adding a few more pf points across the range of interest will be most useful; provide a common baseline
    - 0.97 (24%)
    - 0.98 (20%)
    - 0.99 (14%)

Sample of Controller Configurations

- voltage – reactive power control (v-var)
  - Baseline options
    - IEEE default A and B
    - Study 1 setting, 1.04 pu, 2% slope to Qrated
  - Continue the Boundary cases
    - Full compensation (offset voltage change at Prated)
    - Overvoltage compensation (offset overvoltage at Prated)
  - Considering other standardized controls, for example
    - A setting that exhausts reactive capability at voltage limit
    - May adopt a standard range here too, like with pf
      - Spread the settings across a range: 1.02, 1.03, and 1.04.

Sample of Controller Configurations

- active power control – reactive power control (watt-var)
    - Baseline options
        - Use a pf control
        - IEEE default A and B
    - Continue the Boundary cases
        - Full compensation (offset voltage change at Prated)
        - Overvoltage compensation (offset overvoltage at Prated)
    - Consider variations that delay reactive compensation until higher active power levels

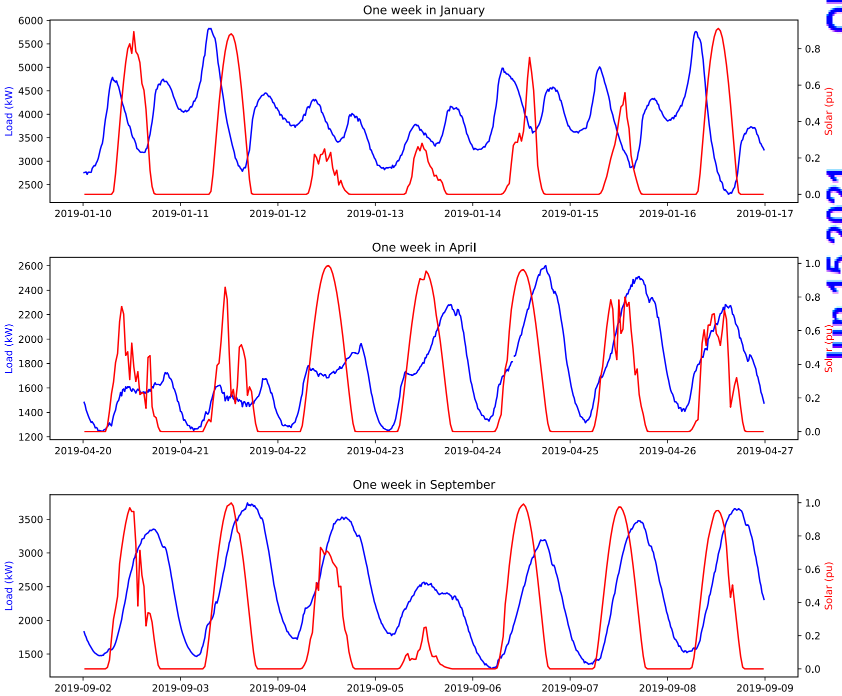
- voltage – active power control (v-watt)
    - Settings from first study: 1.06 puV, 0 puQ : 1.09puV, -0.312 puQ
    - Expect to use it as a secondary to the primary controller, except for
    - May use at feeder head DER locations where reactive power is not effective

Metrics

- Site specific (fixed)
  - Rated Pgen, Qgen at PCC and inverter
  - SCC at Station, PCC
  - X, from PCC back to source
  - R, from PCC back to source
  - PCC Voltage, Basecase (P=Q=0)
  - PCC Voltage, Initial (P=Prated, Q=0)
  - Min load kva/Peak load kva
  - Feeder head power flow, kW and kVAR
  - ΔV/ΔP (Presp, derivative of voltage variation to real power injection)
  - ΔV/ΔQ (Qresp, derivative of voltage variation to reactive power injection)
  - Qresp/Presp = (dV/dQ) / (dV/dP)
  - ΔV/ΔPrated (total voltage change at rated active power)
  - ΔV/ΔQrated (total voltage change at rated reactive power)
- Controller specific
  - Overvoltage Magnitude, PCC, Feeder, Inverter (V)
  - Overvoltage Occurrences, PCC, Feeder, Inverter
  - Feeder Active Power Max, Min (kW)
  - Feeder Reactive Power, Max, Min (kVAR)
  - Total MWh, MVARh, at PCC, Inverter
  - Tradeoff MW, MWh

Quasi-Static Time Series (QSTS) Model

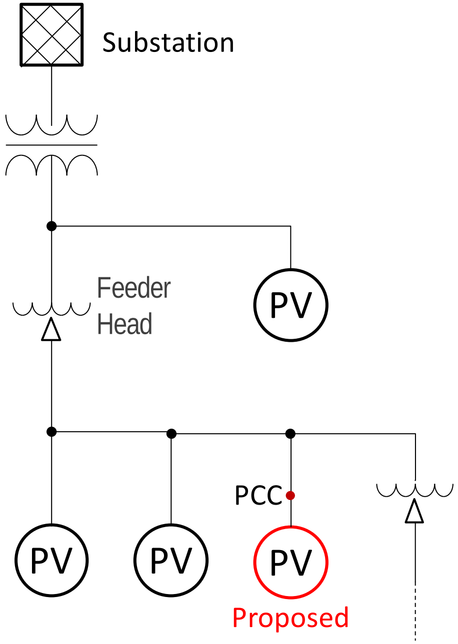
- 8760-hour load profile developed from DEC and DEP measurements (for year 2019)
- Solar taken from the NREL NSRDB database (at each feeder zip code and for year 2019)
- Feeder voltage regulation (e.g., LTC, VR, CB)
  - Local control as in the original CYME models
- Inverter control
  - Q priority (i.e., active power restricted if needed)
  - Q cut-in power level = 5% of inverter rating
- Baseline case definition
  - No injection from the PV under study while all other existing PVs generate power
- Smart Inverter functions in evaluation
  - Constant Power Factor
  - Volt-Var
  - Watt-Var



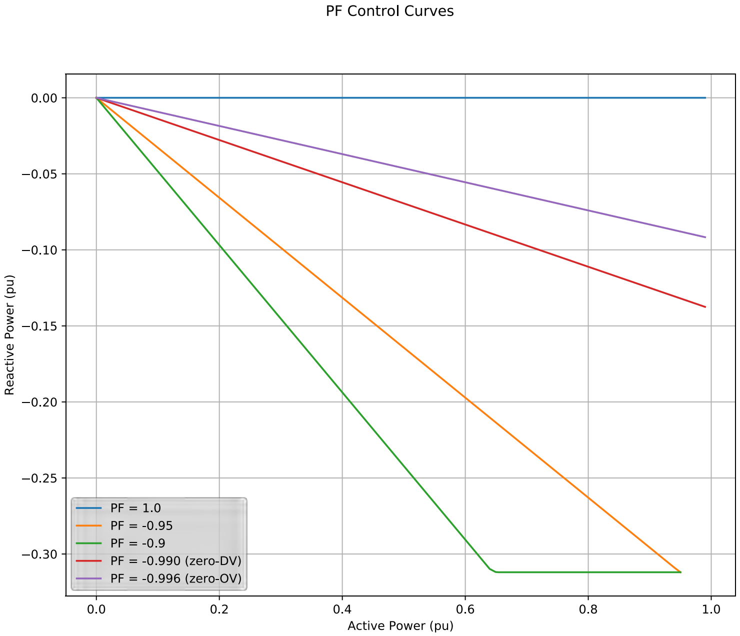
Time Series Preliminary Results

Feeder A Characterization Table

Parameter	Value
Feeder peak load	6.85 MW (PF = 0.995)
Connected DERs	Three existing and one proposed (5.5MVA each)
R_PCC (pu @ 1MVA)	0.0018
X_PCC (pu @ 1MVA)	0.011
∂V / ∂P (puV / 1MW)	0.0014 (-0.0005 ~ 0.0014 depending on load/gen levels)
∂V / ∂Q (puV / 1MVAr)	0.0110 (0.0105 ~ 0.0110 depending on load/gen levels)



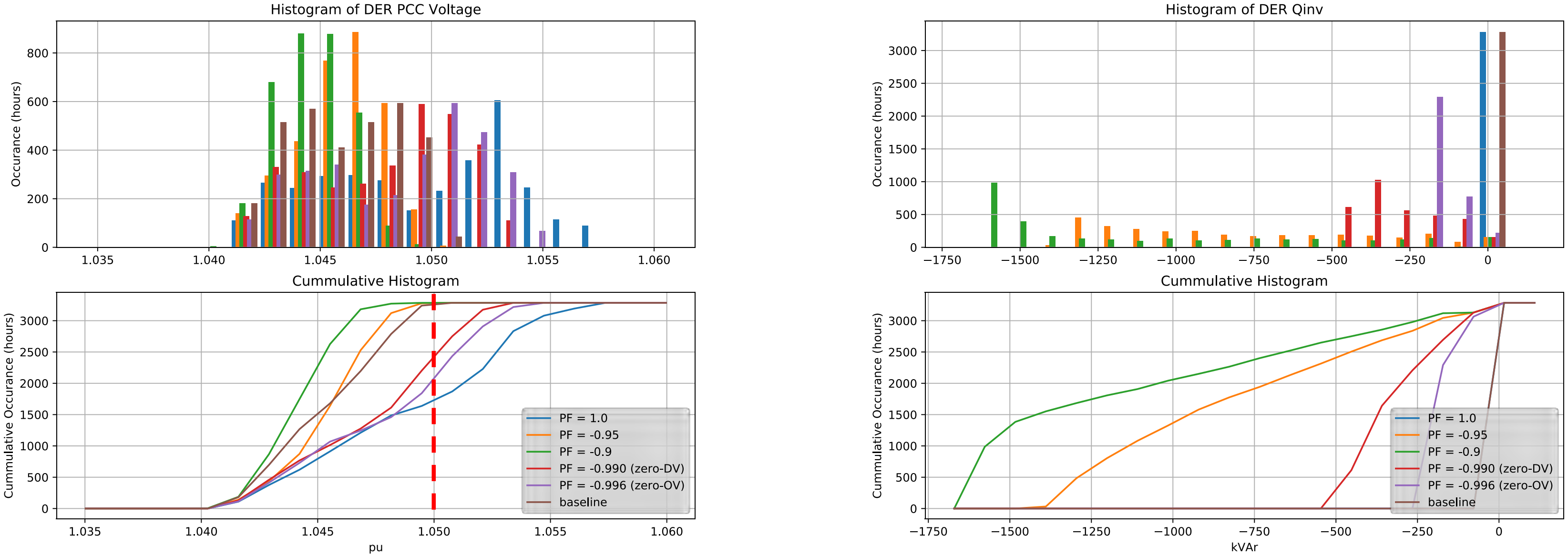
Constant Power Factor Control Mode Comparison



	PF=1.0	PF=-0.95	PF=-0.9	PF=-0.990 (zero-DV)	PF=-0.996 (zero-OV)
Max V_PCC (pu)	1.058	1.050	1.049	1.054	1.055
DER MWh	8472	8465	8459	8472	8472
DER MVArh	0	-2775	-3798	-1173	-782
Max Tradeoff MW	0.0	0.2	0.3	0.0	0.0
Tradeoff MWh	0.2	7.6	14.7	0.4	0.2
Feeder Loss MWh	268 +179	268 +176	268 +178	268 +176	268 +177
Feeder Loss MVArh	2517 +1573	2517 +1596	2517 +1625	2517 +1569	2517 +1568

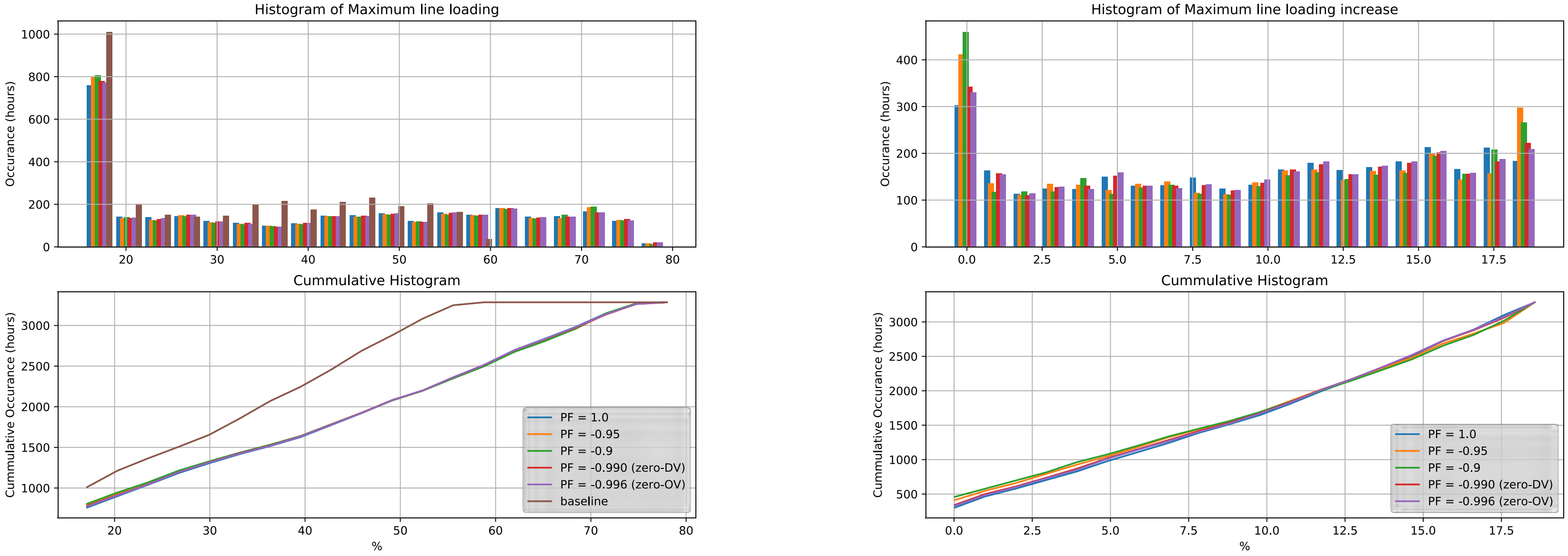
- Inverter clamps Q at 31.2% as its specified limit (equivalent to 0.95 power factor)
- The worst-case (PF=-0.9) tradeoff MWh is 0.17% (i.e., 14.7MWh/8472MWh) of the total generation yield
- The difference between control modes on feeder loss is insignificant

Constant Power Factor Control Mode (Continue)



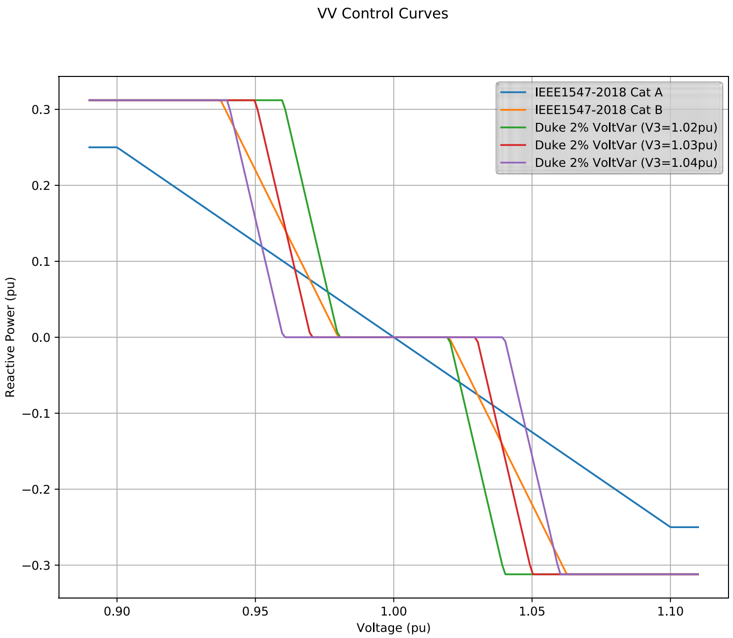
- Only 9AM to 5PM daily hours for 365 days
- Baseline case means no power output from the proposed DER
- Zero-DV power factor still sees over-voltage due to the operation of line voltage regulator
- As power factor becomes more inductive, so does the absorbed Q increase

Constant Power Factor Control Mode (Continue)



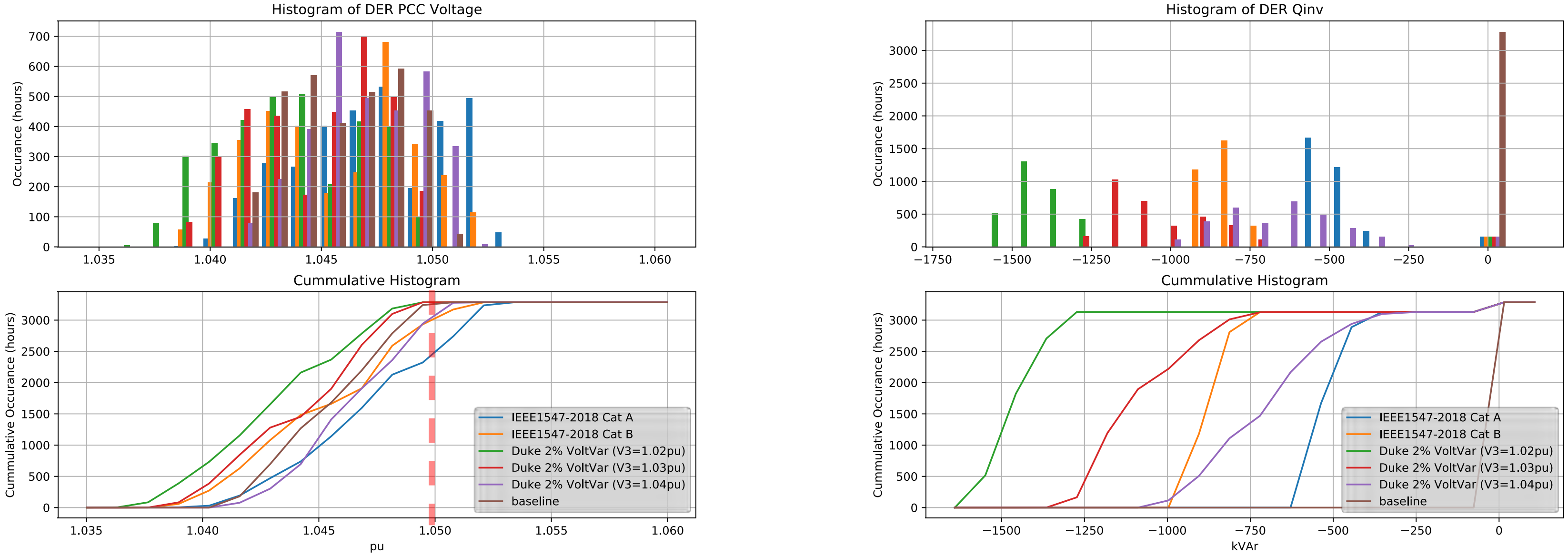
- All power factor modes show similar increase (~17%) to the maximum line loading
- No over-loading is observed in this feeder due to the proposed DER

Volt-Var Control Mode



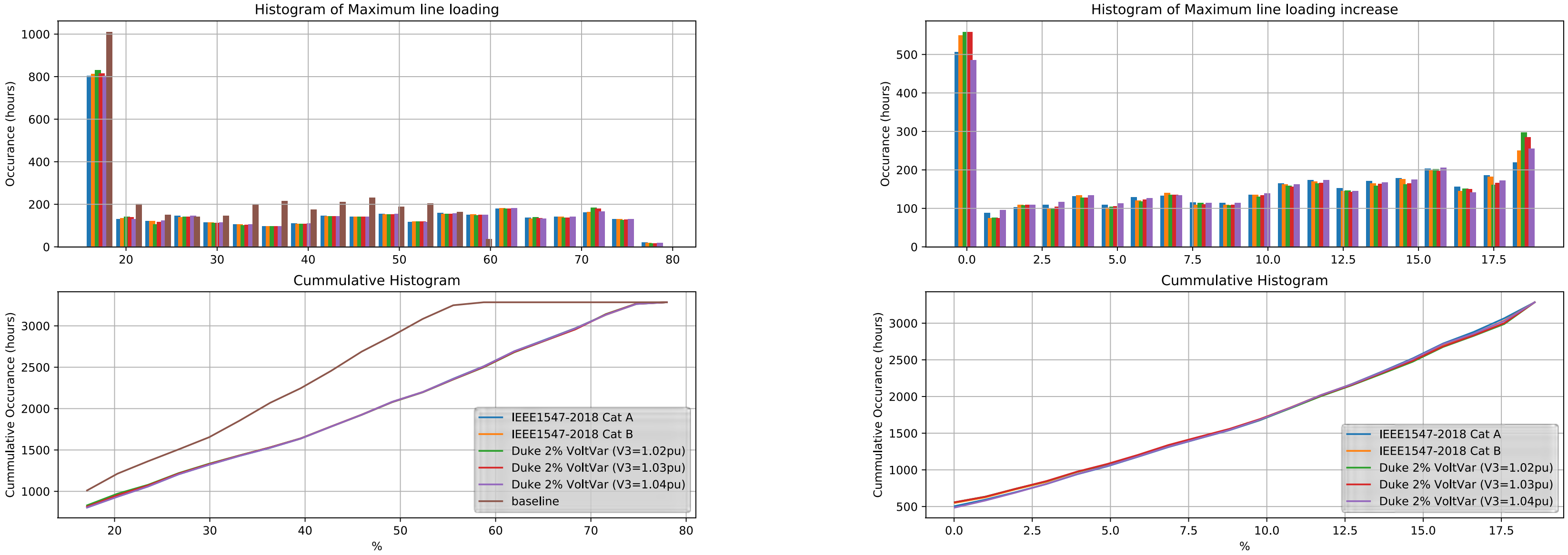
	1547 A	1547 B	2% V3=1.02	2% V3=1.03	2% V3=1.04
Max V_PCC (pu)	1.053	1.052	1.049	1.050	1.052
DER MWh	8472	8471	8466	8468	8472
DER MVArh	-1862	-2956	-4831	-3614	-1869
Max Tradeoff MW	0.0	0.1	0.2	0.2	0.1
Tradeoff MWh	0.3	1.6	7.1	4.4	0.8
Feeder Loss MWh	268 +174	268 +174	268 +177	268 +175	268 +175
Feeder Loss MVArh	2517 +1557	2517 +1571	2517 +1617	2517 +1591	2517 +11566

Volt-Var Control Mode (Continue)



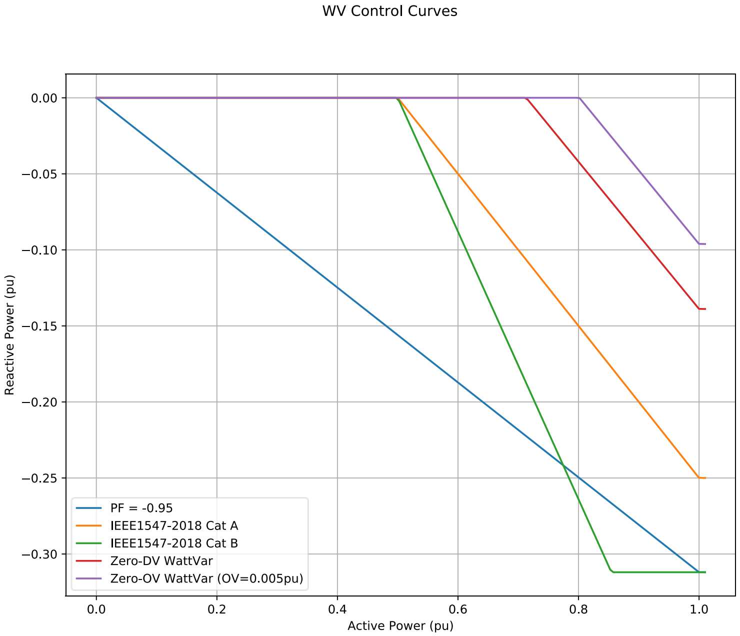
- Most options show lower number of over voltage hours as compared to power factor mode
- Earlier voltage regulation (V3=1.02 or 1.03) helps mitigate over voltage violation
- Steeper volt-var slope helps mitigate over voltage violations (1547-B vs. 2%-V3=1.02)

Volt-Var Control Mode (Continue)



- All options show similar increase (~17%) to the maximum line loading
- No over-loading is observed in this feeder due to the proposed DER

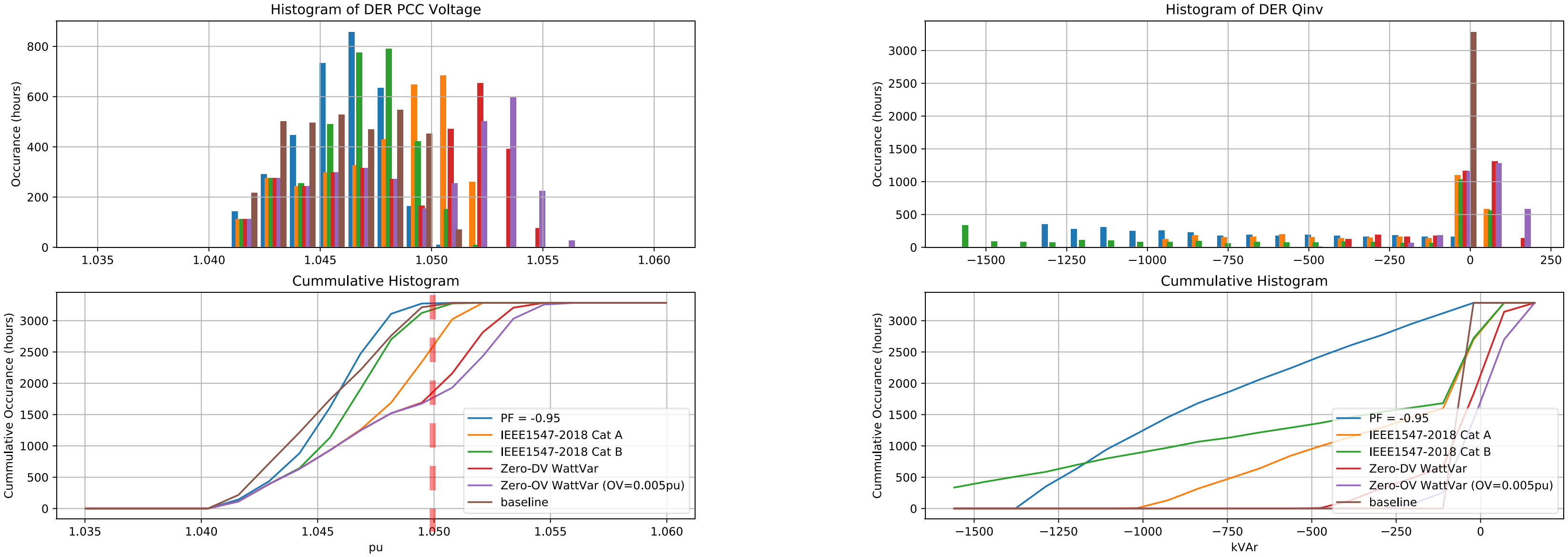
Watt-Var Control Mode



	PF=-0.95	1547 A	1547 B	Zero-DV	Zero-OV
Max V_PCC (pu)	1.050	1.053	1.052	1.055	1.056
DER MWh	8465	8470	8457	8472	8472
DER MVArh	-2775	-1112	-1914	-344	-155
Max Tradeoff MW	0.2	0.1	0.3	0.0	0.0
Tradeoff MWh	7.6	2.3	16.1	0.3	0.2
Feeder Loss MWh	268 +176	268 +178	268 +179	268 +178	268 +178
Feeder Loss MVArh	2517 +1596	2517 +1587	2517 +1615	2517 +1578	2517 +1575

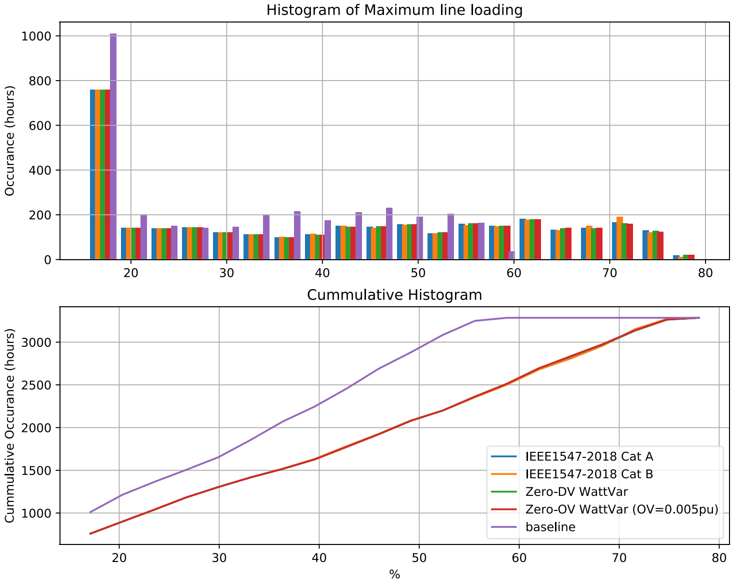
- Watt-var is a non-linear version of constant power factor control
- With same Qmax at full power, watt-var 1547-B results in lower total DER MVArh than that of PF=-0.95 or PF=-0.9

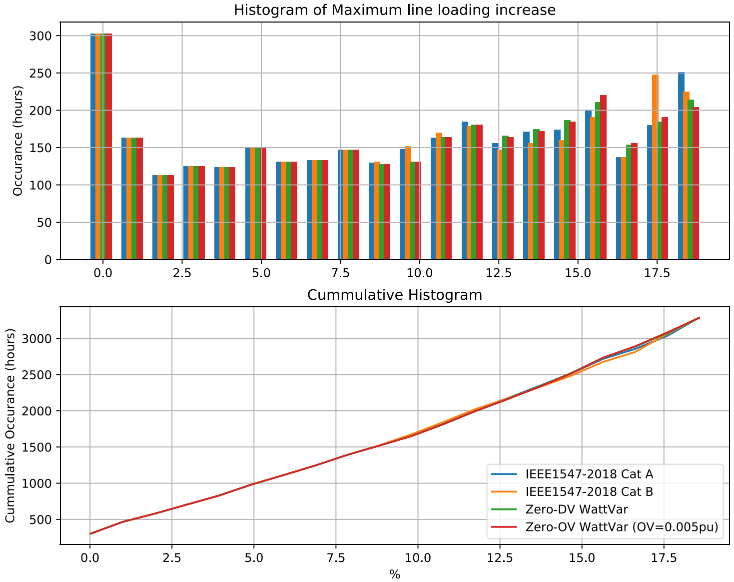
Watt-Var Control Mode (Continue)



- All options present over voltage hours in the simulated year
- Steeper watt-var slope and higher Q value help mitigate over voltage violations (as expected)

Watt-Var Control Mode (Continue)

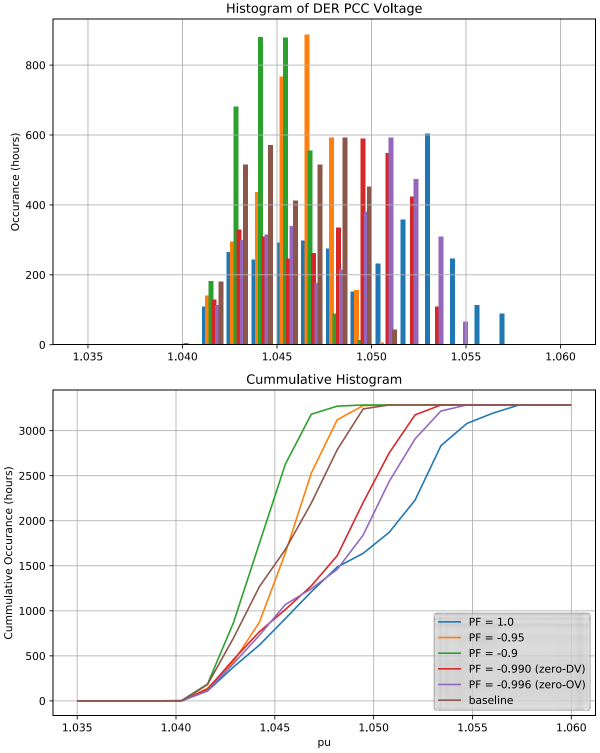




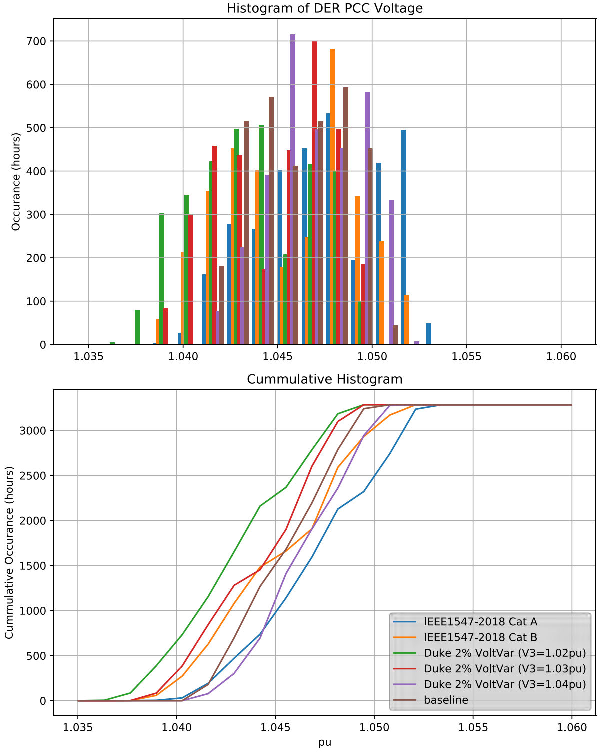
- All options show similar increase (~17%) to the maximum line loading
- No over-loading is observed in this feeder due to the proposed DER

Comparison of Control Options

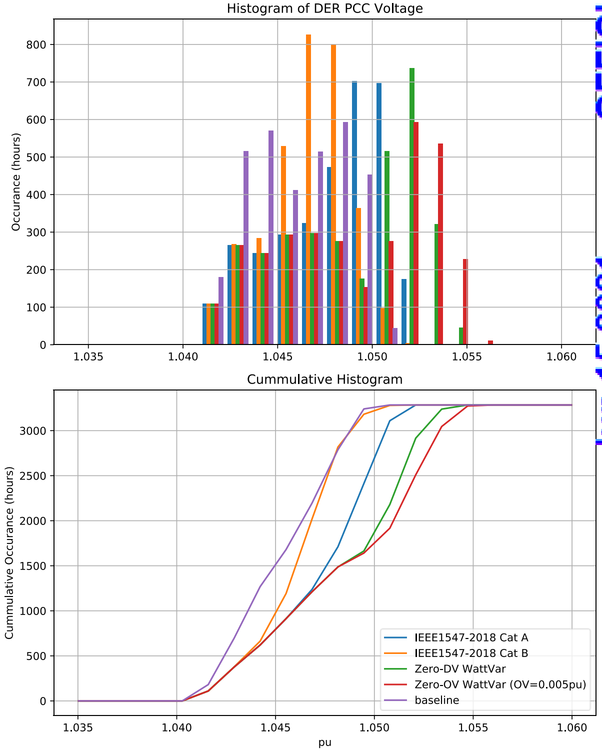
Constant PF



Volt-Var

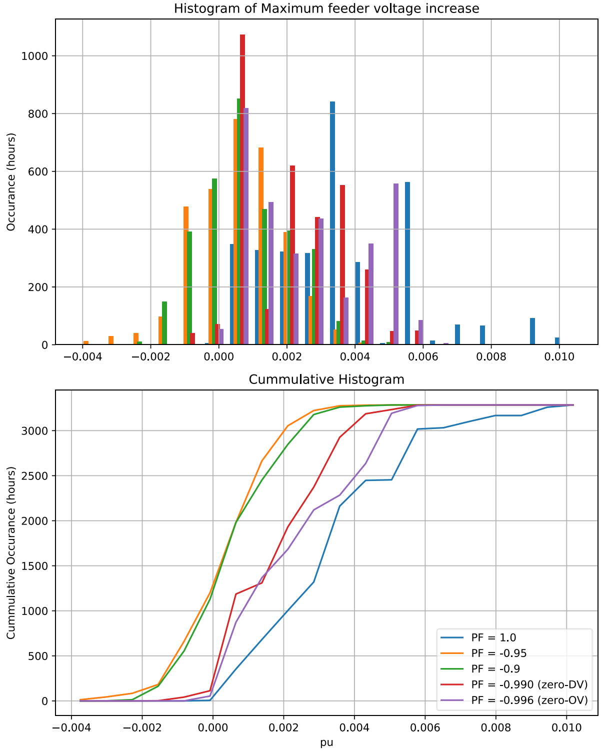


Watt-Var

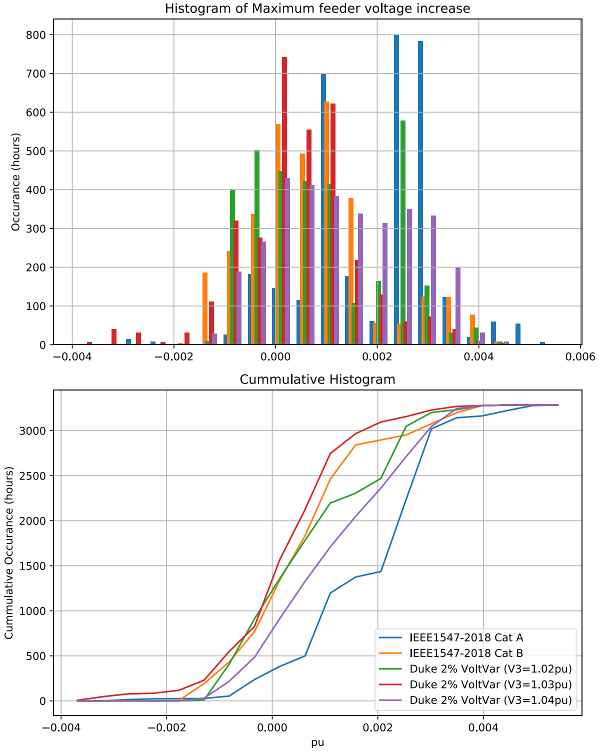


Comparison of Control Options (Continue)

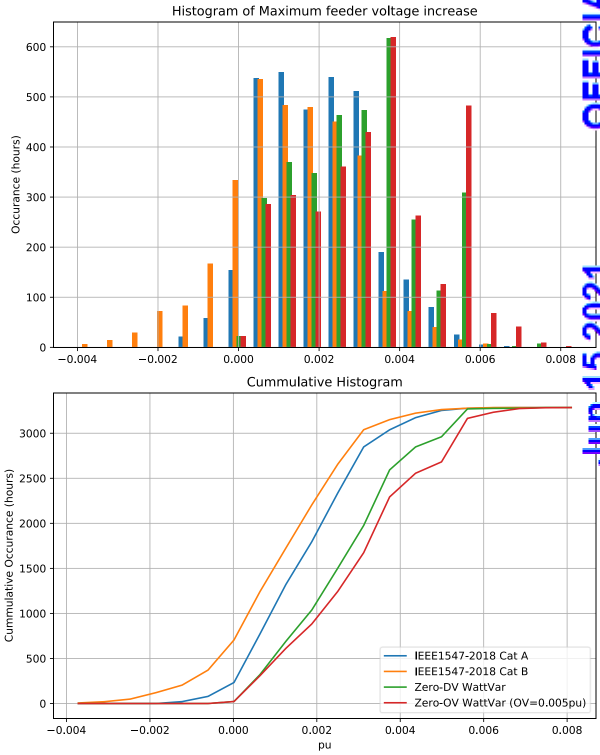
Constant PF



Volt-Var



Watt-Var



- Plots here show the maximum voltage increase on the feeder versus the baseline case

Jennings Exhibit No. 7
Docket No. E-2, Sub 1276

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TSRG: Inverter Volt-VAR Study Update

Anthony C Williams, DER Technical Standards

January 20, 2021

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Second Study Overview

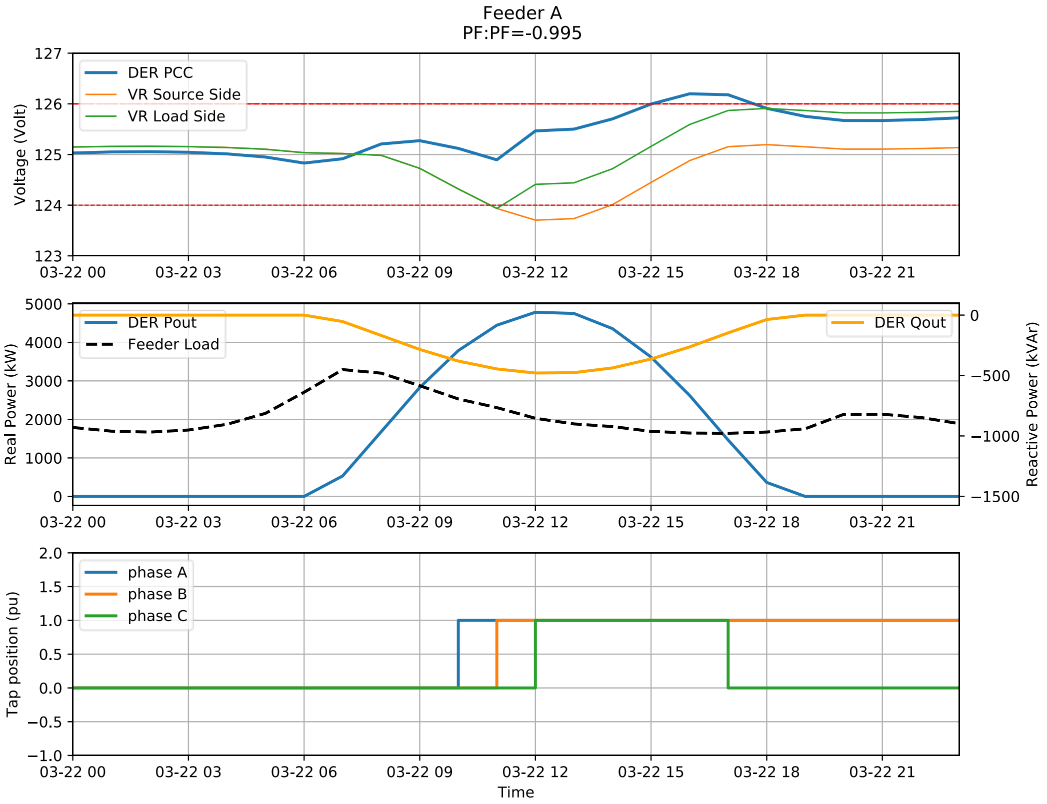
- More emphasis on higher voltage feeders so that less DER forces the overvoltage
- Calculate P and Q responses
- Consider a broader variety of controller types
  - Limited controller setting variations: approximately 6 volt-var, 8 pf, 5 watt-var
  - Continued use of volt-watt to backup the primary controller
- Expand the attributes monitored during the study; to inform conclusions
- Quasi-Static Time Series (QSTS) simulation using 8760 hourly load and solar profile
- Compare monitored attributes across the feeders for the various controller types
  - Inform policy development to guide application of DER voltage and reactive power controls, and
  - Develop methods to a) provide a quick assessment of reactive power control effectiveness at a potential UDER interconnection point, and b) indicate the most appropriate type of control
- Final report February, presentation at the following TSRG

Recent Methodology Improvements

- Yukon capacitor control logic modeled for DEP
    - Provides more reasonable statistics of substation Q demand
- Long term dynamic simulation methods
    - Time dependency (sequencing) of each time step being modeled
    - Next state dependent on last state, not initial state
- Interaction and setting coordination between reactive power controlled DER on the same feeder
- Impact of voltage regulator (upstream to DERs) included in optimal control development

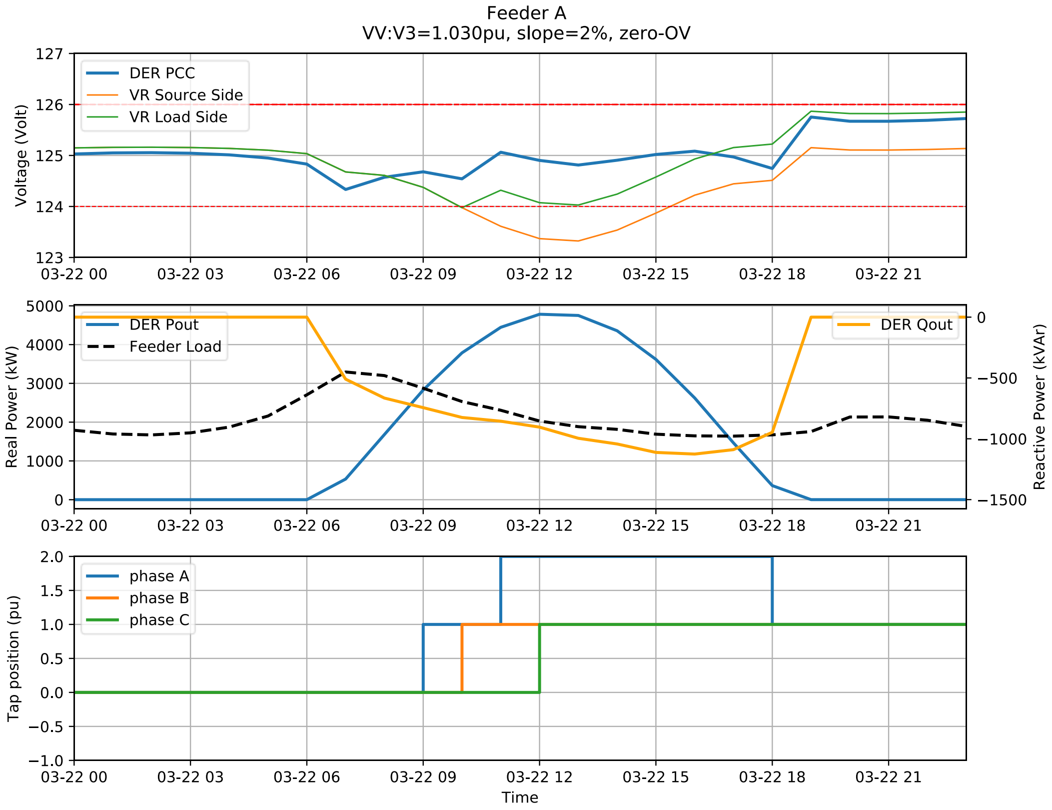
VR + DER Case with Violation

- Station regulator interaction with DER reactive power injection
- DER without VR tap changes resolves the overvoltage
- If conditions cause the voltage at the VR to be near the lower bandwidth
- Reactive injection causes VR to raise taps
- Typically causes violation because voltage limit harder to maintain



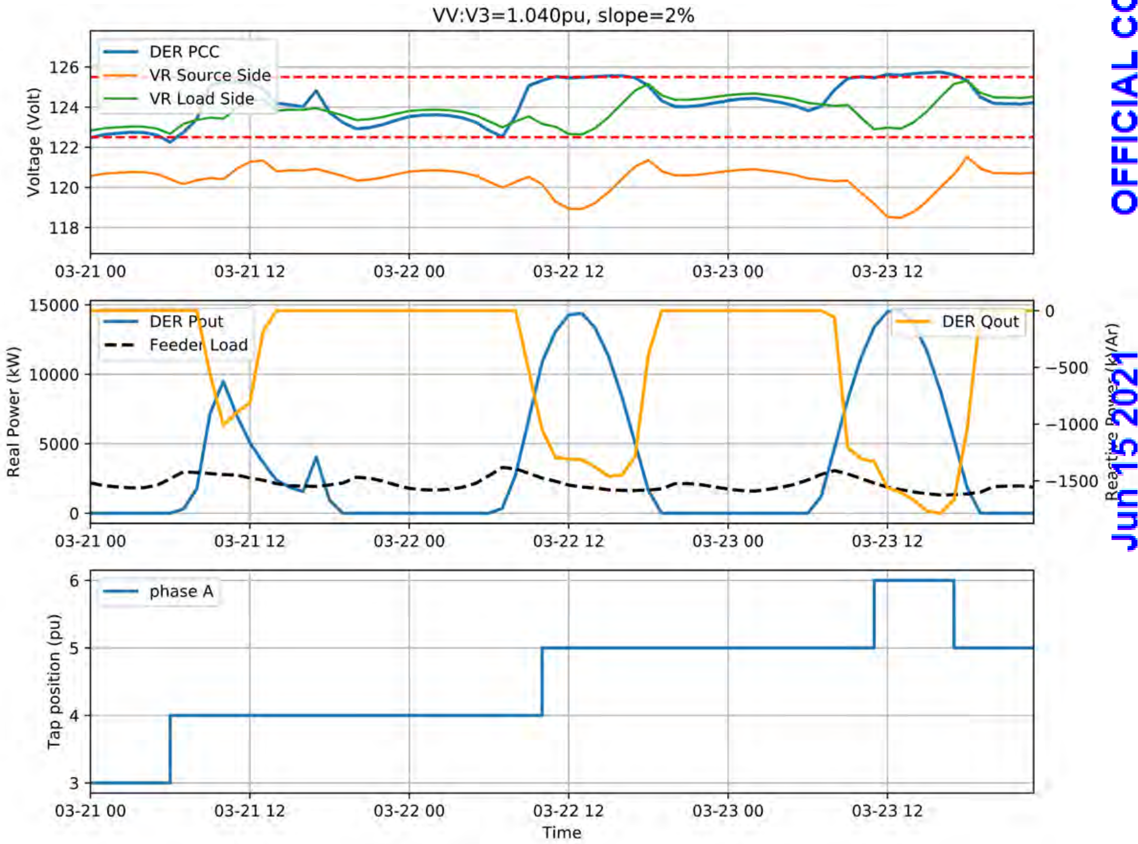
VR + DER Case without Violation

- Same issue, different outcome
- Reactive injection still causes VR to raise taps
- There is enough margin to voltage limit in this case to absorb the rise
- This unacceptable operation is less observable in the field
- The DER and VR are working against each other; creating unnecessary reactive power flow



Coordinated VR + DER Case

- Refined Objective:
  Use DER reactive power to maintain voltage below limit with no VR tap increases
- Use a 3-day response to initialize the tap position and evaluate interaction
- Unknown if balanced solutions can be found for each location

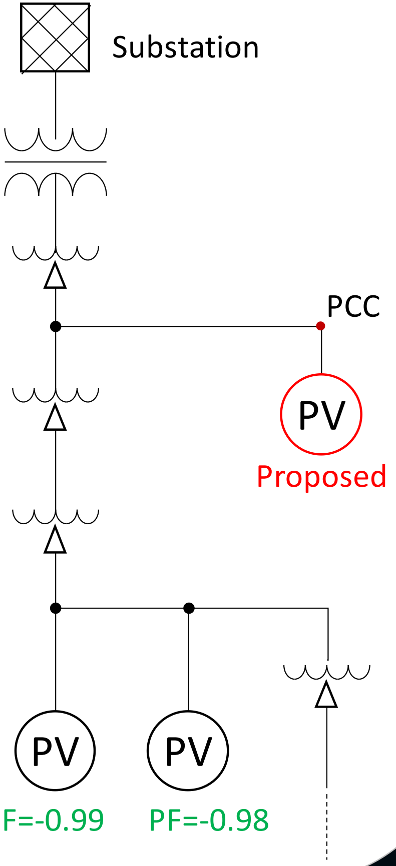


Overview of the Feeder Under Study

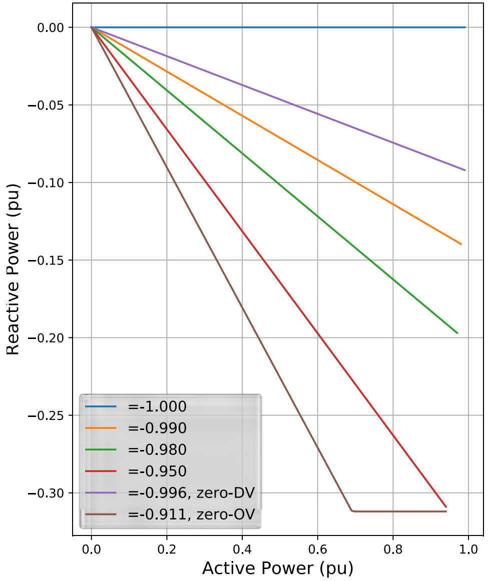
Feeder B Characterization Table

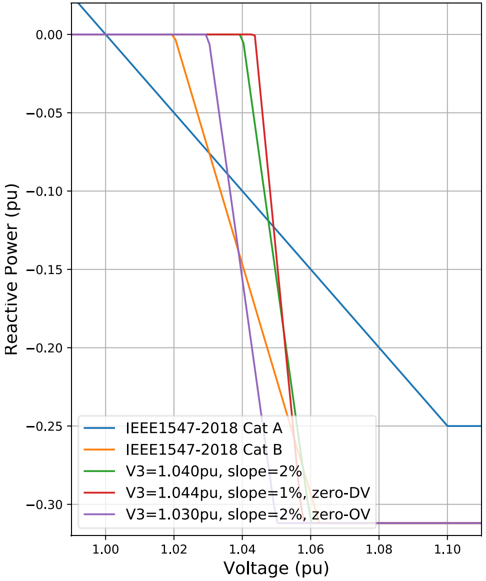
Parameter	Value
Feeder peak load	2.51 MW (PF = 0.966)
Connected DERs	Two existing PV (5.5MW each) One proposed PV (5.0MW, 5.25MVA)
Short Circuit Capacity	231 MVA @ Sub (secondary), 153MVA @ PCC
Z_REG (pu @ 1MVA)	0.0002 + j0.0043
Z_PCC (pu @ 1MVA)	0.0008 + j0.0065
Z_PCC2REG (pu @ 1MVA)	0.0006 + j0.0022 (= Z_PCC - Z_REG)
∆V_Full (pu)	0.0033
∂V / ∂P (puV / MVAr)	0.00066 (= ∆V_Full / Rated_P)
∂V / ∂Q (puV / MVAr)	0.0071
Regulator Control Setting	Vref = 124V, BW = 2V
∆V_Other_PCC2REG_Max (pu)	0.0139

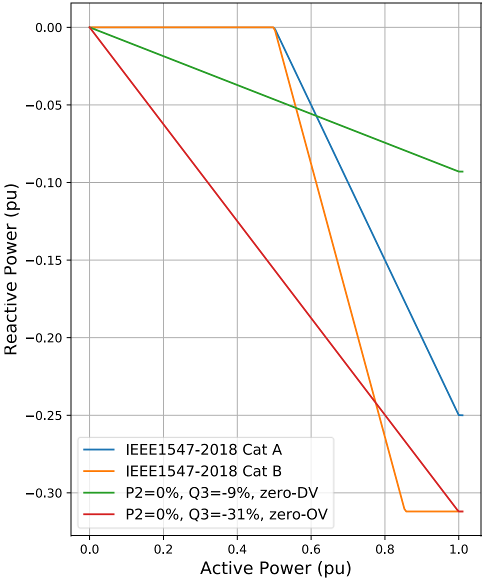
- Values in this table are used to determine the settings for the reactive power controls



Evaluated Control Options

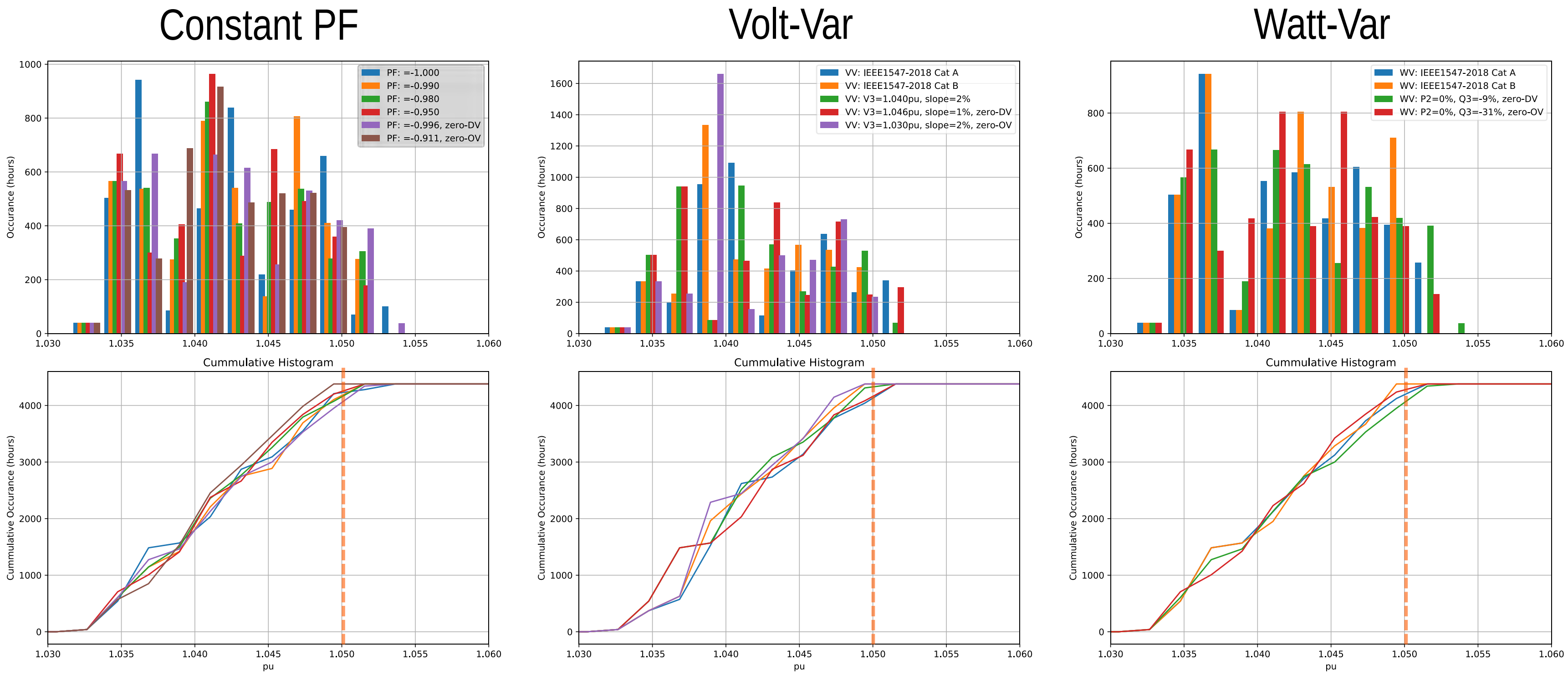

Constant PF


Volt-Var


Watt-Var

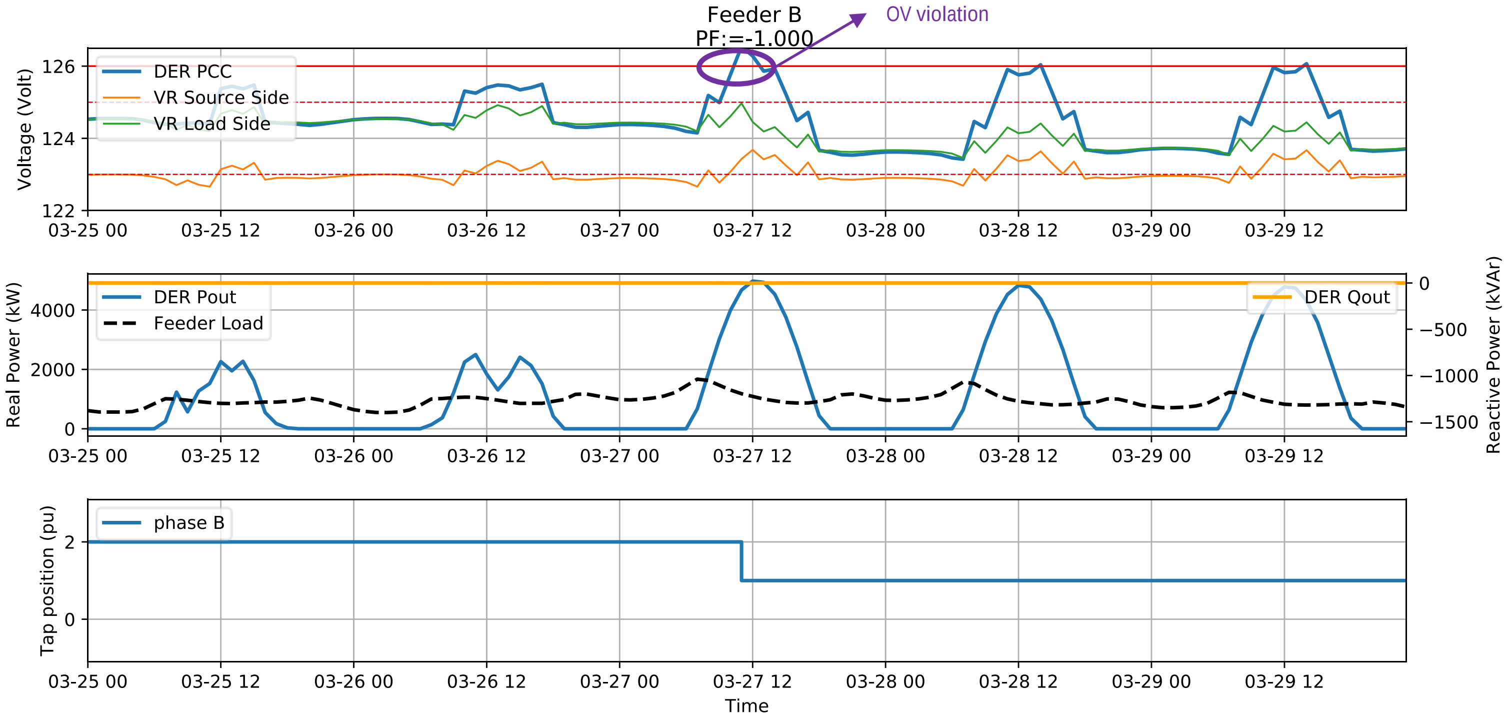
- zero-OV options are more aggressive than zero-DV options to correct the voltage rise from existing DERs

Histogram of PCC Voltage in One Year



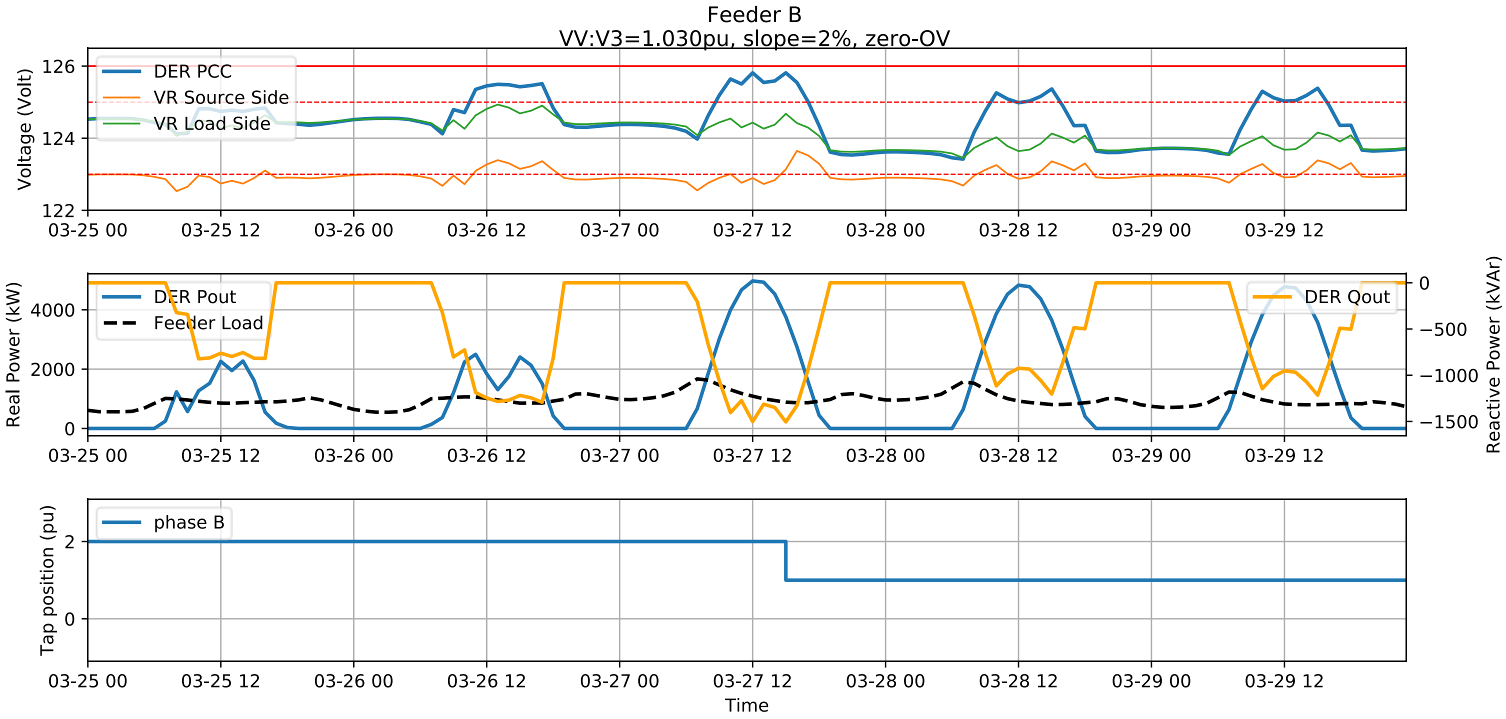
- All control options are clustered due to proximity of PCC to the voltage regulator
- Zero-OV options work well as they considers the impact of voltage regulator

Long Term Dynamic Simulation (Unity PF Mode)



- Five-day (two cloudy and three sunny days) time series simulation
- With unity power factor, DER PCC voltage gets higher than the 105% threshold (i.e., 126V)

Long Term Dynamic Simulation (Volt-Var Mode)



- With the selected Volt-Var control, PCC voltage is always lower than the 105% threshold
- Additional over-voltage margin is required to cover the worst case when VR terminal voltage reaches the top of the BW, 125V, for excursions within the 60 minute time step, and for unanalyzed worse operating conditions

Detailed Summary Tables of All Evaluated Control Options

	PF =-1.000	PF =-0.990	PF =-0.980	PF =-0.950	PF =-0.996, zero-DV	PF =-0.911, zero-OV	VV IEEE1547-2018 Cat A	VV IEEE1547-2018 Cat B	VV V3=1.040pu, slope=2%	VV V3=1.046pu, slope=1%, zero-DV	VV V3=1.030pu, slope=2%, zero-OV	WV IEEE1547-2018 Cat A	WV IEEE1547-2018 Cat B	WV P2=0%, Q3=-9%, zero-DV	WV P2=0%, Q3=-31%, zero-OV
Max V_PCC (pu)	1.055	1.052	1.053	1.051	1.054	1.051	1.052	1.051	1.051	1.052	1.051	1.053	1.05	1.054	1.051
hours_(Vpcc>1.05)	264	363	356	253	507	103	379	148	208	446	0	591	45	507	179
min_Vpcc	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033
hours_(Vpcc<0.95)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
hours_(Volt-Watt ON)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
max_Vinv	1.06	1.05	1.049	1.043	1.054	1.04	1.05	1.044	1.047	1.051	1.039	1.05	1.048	1.054	1.043
hours_(Vinv>1.05)	1295	86	0	0	532	0	0	0	0	304	0	116	0	532	0
min_Vinv	1.033	1.033	1.033	1.032	1.033	1.03	1.032	1.03	1.033	1.033	1.031	1.033	1.029	1.033	1.033
hours_(Vinv<0.95)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
max_Vfdr	1.061	1.062	1.062	1.062	1.061	1.061	1.062	1.061	1.062	1.061	1.061	1.062	1.061	1.061	1.062
hours_(Vfdr>1.05)	2514	2645	2759	2869	2547	2861	3122	3503	2614	2514	3510	2514	2514	2547	2802
min_Vfdr	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033	1.033
hours_(Vfdr<0.95)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
max_sub_kW	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513	2513
min_sub_kW	-14847	-14831	-14795	-14698	-14847	-14698	-14837	-14793	-14826	-14841	-14687	-14755	-14605	-14847	-14687
max_sub_MVAr	1	1	2	2	1	2	1	2	1	1	2	2	2	1	2
min_sub_MVAr	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1
max_sub_Amps	357	358	357	356	358	356	358	357	358	358	356	357	355	358	356
max_fdr_loading (%)	57	57	57	56	57	56	57	57	57	57	56	57	56	57	56
hours_(fdr_loading>100%)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DER MWh	9114	9112	9108	9096	9114	9096	9113	9109	9112	9114	9096	9103	9084	9114	9094
DER MVArh	1	-1298	-1849	-2979	-846	-3744	-2068	-3200	-1045	-435	-3822	-1096	-1889	-847	-2844
total_INV_MWh	9138	9137	9133	9122	9138	9123	9138	9135	9137	9138	9124	9128	9110	9138	9121
total_INV_MVArh	304	-989	-1534	-2645	-542	-3394	-1753	-2869	-736	-131	-3477	-786	-1562	-542	-2513
Max Increased_INV_Loss kW *	0	1	1	3	0	4	1	2	1	1	4	2	5	0	3
Increased_INV_Loss MWh	0	1	2	5	0	8	2	5	1	0	7	1	4	0	4
Max Tradeoff kW	6	20	55	157	4	157	14	67	25	11	167	97	250	4	167
Tradeoff MWh	1	2	7	19	1	19	2	6	2	1	18	12	30	1	20
max_fdr_loss_kW	457	458	459	454	457	454	458	459	458	457	454	457	454	457	454
Feeder Loss MWh	502	506	508	512	504	515	511	517	505	502	519	504	506	504	512
max_fdr_loss_kVAr	2869	2877	2881	2861	2871	2861	2875	2882	2878	2874	2861	2878	2859	2871	2861
Feeder Loss MVArh	3161	3173	3181	3208	3166	3230	3186	3210	3173	3163	3226	3171	3193	3166	3204

* Assuming 1% conduction loss for DER inverter

- This table is used to compare and select the optimal control options

Simplified Table to Focus on those Optimal Options

	PF =-1.000	PF =-0.996, zero-DV	PF =-0.911, zero-OV	VV V3=1.040pu, slope=2%	VV V3=1.046pu, slope=1%, zero-DV	VV V3=1.030pu, slope=2%, zero-OV	WV P2=0%, Q3=-9%, zero-DV	WV P2=0%, Q3=-31%, zero-OV
Max V_PCC (pu)	1.055	1.054	1.051	1.051	1.052	1.051 ↓	1.054	1.051
hours_(Vpcc>1.05)	264	507	103	208	446	0 ↓	507	179
DER MWh	9114	9114	9096	9112	9114	9096 ↓	9114	9094
DER MVArh	1	-846	-3744	-1045	-435	-3822 ↑	-847	-2844
Max Increased_INV_Loss kW	0	0	4	1	1	4 ↑	0	3
Increased_INV_Loss MWh	0	0	8	1	0	7 ↑	0	4
Max Tradeoff kW	6	4	157	25	11	167 ↑	4	167
Tradeoff MWh	1	1	19	2	1	18 ↑	1	20
Feeder Loss MWh	502	504	515	505	502	519 ↑	504	512
Feeder Loss MVArh	3161	3166	3230	3173	3163	3226 ↑	3166	3204

- Although different control options result in different levels of DER reactive power absorption (i.e., “DER MVArh”), the impact to DER energy yield (i.e., “Tradeoff MWh”) and feeder losses (i.e., “Feeder Loss MWh” and “Feeder Loss MVArh”) is limited

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Metrics

- Site specific (fixed)
  - Rated Pgen, Qgen at PCC and inverter
  - SCC at Station, PCC
  - X, from PCC back to source
  - R, from PCC back to source
  - PCC Voltage, Basecase (P=Q=0)
  - PCC Voltage, Initial (P=Prated, Q=0)
  - Min load kva/Peak load kva
  - Feeder head power flow, kW and kVAR
  - ΔV/ΔP (Presp, derivative of voltage variation to real power injection)
  - ΔV/ΔQ (Qresp, derivative of voltage variation to reactive power injection)
  - Qresp/Presp = (dV/dQ) / (dV/dP)
  - ΔV/ΔPrated (total voltage change at rated active power)
  - ΔV/ΔQrated (total voltage change at rated reactive power)
- Controller specific
  - Overvoltage Magnitude, PCC, Feeder, Inverter (V)
  - Overvoltage Occurrences, PCC, Feeder, Inverter
  - Feeder Active Power Max, Min (kW)
  - Feeder Reactive Power, Max, Min (kVAR)
  - Total MWh, MVARh, at PCC, Inverter
  - Tradeoff MW, MWh

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Docket No. E-2, Sub 1276

NAVIGANT
A Guidehouse Company

Draft Report: 3/23/2020

Impact of Enabling Inverter Based Resource Reactive Power Controls

Prepared for:

DUKE ENERGY®

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Disclaimer

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Executive Summary

The North Carolina Utilities Commission (NCUC) tasked Duke to evaluate the software-based controls of advanced inverters according to the IEEE 1547-2018 standard. This report is an initial study that evaluates voltage-reactive power and voltage-active power control functions for six different feeders. In IEEE 1547 2018 these functions are better known as Volt-Var and Volt Watt capabilities of the smart inverter. The study analyzed multiple distributed Volt-Var and Volt-Watt control settings for the inverters and the mitigation necessary for higher DER penetration levels. As directed by the Commission, Duke also leveraged the Technical Standards Working Group (TSRG) to begin a collaborative stakeholder process for analyzing smart inverter control functionalities consistent with IEEE 1547-2018.

The study included industry benchmarking and technical modeling. The industry scan helped Duke understand current practices to inform what technical studies could best assess the IEEE 1547-2018 functionality. This formed the basis for an initial study to evaluate voltage-reactive power and voltage-active power control functions for multiple inverter-based distributed energy resources on six different feeders. The study evaluated multiple distributed voltage-reactive (Volt-Var) and active power (Volt-Watt) control settings for the inverters and identified how to enable inverter reactive power and active power-based voltage control for DER integration.

The results of the industry benchmarking are summarized as follows:

- Benchmarked utilities include Xcel Energy (Minnesota), Ameren (Illinois), National Grid (Massachusetts) and Dominion Energy (South Carolina). Most of the utilities acknowledged that ride-through requirements should be implemented. Xcel Energy and Ameren prioritized ride-through and voltage – reactive functionalities as the highest priority. National Grid implemented an interim solution by adapting to California Rule 21 and Hawaii standards. PJM suggested that the local distribution companies set the requirements. Pilot studies conducted by various utilities verified Volt-Var and Volt-Watt functionalities.
- Volt-Var pilot studies conducted by utilities with high penetration of DER indicated that curtailment of customer generation was minimal when Volt-Var and Volt-Watt functions were activated. Key observations from these studies were that Volt-Watt functionality, when combined with constant power factor (CPF) and Volt-Var control, relies on voltage regulation from CPF and Volt-Var control before it reduces power output to protect against voltage excursions. Deadband[1] plays an important role in reactive power absorption and response time[2] plays an important role in the number of transformer load tap changer (LTC) operations. For effective Volt-Var control coordination, automated capacitor control is needed. Most studies indicated that due to the increase in reactive power demand across the system, Bulk Power System (BPS) impacts should also be evaluated where there is significant Volt-Var control capability.
- The North America Electric Reliability Corporation (NERC) published reliability guidelines for the BPS offering a perspective on the adoption of IEEE 1547-2018. “The timely adoption and implementation of IEEE 1547-2018 for DER connected to the distribution system across North America is strongly encouraged. The specifications for DER in IEEE 1547-2018 include performance capability categories and allowable ranges of functional settings, which provide flexibility to align with specific system needs. However, these flexibilities require coordination between distribution and transmission entities for effective adoption[3]”. The guidelines indicate that any deviation from the category assignments and

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[1] Deadband constitutes a range of input values in a control system where the output is zero. Deadband regions are used in control systems to prevent oscillation or repeated activation-deactivation cycles.

[2] Also referred to as “slope”.

[3] Reliability Guideline, Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018, December 2019.

settings, should be communicated to the location's Reliability Coordinator (RC) to ensure the DER are accurately modeled in reliability studies.

Secondly, Volt-Var studies were carried out on six representative feeders, three feeders on the Duke Energy (DEC) system and three feeders studied on the Duke Energy Progress (DEP) system. The studies on Feeders A, C, D indicated that, although Volt-Var control significantly improves voltages, it cannot be used on a stand-alone basis to mitigate voltage issues under all loading conditions and all penetrating levels. Studies indicate a 2% Volt-Var controller from 1.04-1.06 per unit (pu) can reduce certain overvoltage conditions but may not fully eliminate the issue by itself., For higher DER penetration level Volt-Var control with a lower slope, that provides a more pronounced voltage change, could be a solution and would benefit from further study. These configurations must be studied further to rule out any adverse impacts from excessive reactive power consumption.

Furthermore, in this study we analyzed the use of Volt-Watt as a secondary controller to Volt-Var. Duke's studies indicated that a 2% Volt-Var control, from 1.04-1.06 pu, in combination with a Volt-Watt controller could better manage high levels of DER penetration. As seen in the cases studied, a Volt-Watt controller would have an impact on voltage only when the voltages are close to the higher bound in the 3% voltage range (1.06-1.09 pu). At its lower bound, the active power reduction appears minimal; therefore, may not impact voltages significantly. Thus, at high levels of DER penetration, a Volt-Watt controller with the lower bound shifted left to 1.05 pu voltage could improve the voltages. Duke will continue to analyze Volt-Var and Volt-Watt joint controller.

Lastly, more analysis of the substation and line regulator settings with time series power flow studies are necessary. The benchmarking studies highlight the importance of system impedance or the X/R ratio at the point of interconnection. X/R ratio is a critical characteristic that determines the effectiveness of voltage and reactive power control on a feeder. This was confirmed in the Duke study in that DER located near the end of the feeder causes the most voltage rise, and thus requires the most aggressive voltage control or mitigation strategy.

Greater detail is provided in the study results captured below. Section 1 of this report introduces the need for Duke to conduct the study along with results from industry benchmarking. Section 1 also touches on the current status of IEE 1547 as of this filing. A more detailed benchmarking of Volt-Var activity in California and Idaho is presented in Section 1, along with NERC guidance related to IEEE 1547. Section 2 describes how the models were developed, the study methodology, the approach to modelling and important model assumptions. Section 2 additionally provides geographical and electrical overviews of each of the six feeders analyzed in the study. Most importantly, Section 2 captures the results of each study conducted for the six feeders identified as case studies. Finally, Sections 3 and 4 provide a summary conclusion of study results, and recommendations and next steps for implementing IEEE 1547-2018 on the Duke system.

1. Introduction

The North Carolina Utilities Commission (NCUC) tasked Duke to evaluate the software-based controls of advanced inverters according to the IEEE 1547-2018 standard. This report evaluates the use of autonomous voltage-reactive power (IEEE 1547-2018 section 5.3) and voltage-active power (IEEE 1547-2018 section 5.4.2) control functions for multiple inverter-based DER connected to the same feeder. This initial study was conducted on six feeders to understand how these controls impact feeder voltages and reactive power absorption at the feeder level. The study also evaluated multiple control setpoints and identified the benefits and disadvantages of Volt-Var and Volt-Watt advanced control setting options. Furthermore, the study considered reactive power mitigation at substation and the feeder head to minimize the impact on the transmission system to meet transmission system voltage and reactive power requirements. As direct by the NCUC, Duke began a stakeholder process to consider the IEEE 1547-2018 "…technical standards that could allow for higher penetrations of DER on the distribution grid…" In addition, to understand the practices on implementing the IEEE 1547-2018 a benchmarking of the industry is included in Section 1.1.

1.1 Benchmarking

1.1.1 Industry Status of IEEE 1547 2018 and Practices of Utilities

The IEEE 1547-2018 DER specifications include performance capability categories and allowable ranges of functional settings to align with specific system needs. Utility benchmarking focused on understanding the prioritization and implementation of the standard functionalities is surveyed and summarized in this section.

Industry Status of IEEE 1547 - The IEEE Standard 1547-2018, *IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces*, was published in April 2018. This standard requires DER to have new grid-support functionalities and interoperability features. The IEEE Standard 1547.1-2020, *Standard Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces* was approved by IEEE Standards Association Standards Board (IEEE SASB) in March 2020 and is yet to be published (expected June 2020). 1547.1-2020 defines the conformance test procedures for DER systems that are required to be compliant with IEEE 1547-2018.Thus the two standards complement each other.

After the publication of IEEE 1547.1-2020, Underwriters Laboratories (UL) is expected to update its product certification standard UL 1741, *Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources*, to which all DER equipment must be tested and certified as UL compliant. The UL 1741 update is expected to be completed in late 2020 or early 2021 depending on Underwriters Laboratory timelines. Once Underwriters Laboratory is complete with its certification work, then the Nationally Recognized testing Laboratories (NRTL) will be able to test and certify DER equipment as IEEE 1547 compliant. Given the timeline provided above, we would expect to see UL 1741 listed and IEEE 1547-2018 compliant DER equipment being available on market in late 2021.

Minnesota became the first state[4] to integrate some functionalities of the updated IEEE Standard 1547-2018 into its interconnection regulations. The Minnesota Public Service Commission (MPSC) adopted new technical standards document, known as the Technical Interconnection and Interoperability Requirements

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[4] https://www.utilitydive.com/news/minnesota-pioneers-integration-of-new-interconnection-standard-expected-to/568560/

(TIIR)[5]. TIIR addressed an array of technical settings and functionalities that DER must have when connecting to the grid. The MPSC's January 22, 2020 Order required utilities to reconvene the Distributed Generation Workgroup (DWG) to draft a guidance document. This guidance document is required to clarify the TIIR interim provisions for inverter-based systems (IBS) until newly certified equipment is available[6]. Based on the TIIR document, interim guidance[7] and the DWG proceedings, the prioritization and implementation of IEEE 1547-2018 functionalities by the utilities is interpreted and included in Appendix Table B.1. The TIIR specifies that for voltage and reactive control the DER should be installed with constant power factor mode enabled and with 0.98 power factor, absorbing reactive power. For voltage and reactive power control a set of default settings were specified.

Ameren, Illinois operates as a Local Balancing Authority in Midcontinent Independent System Operator (MISO). MISO provided guidelines[8] on the IEEE 1547-2018 functionalities that impact transmission system reliability. MISO indicated in the guideline the functionalities that are "strongly recommended" and "recommended" which were interpreted to rank the functionality implementation. MISO's guideline strongly recommended voltage and reactive power controls along with frequency and voltage disturbance ride-through for implementation by Ameren and other utilities in its jurisdiction. The prioritization matrix for Ameren based on MISO guideline is included in Appendix Table B.1.

National Grid and ISO-New England (ISO-NE) with the help of the Massachusetts Technical Standards Review Group (TSRG) developed the Source Requirement Document[9] (SRD) as an interim solution before implementing the complete IEEE 1547-2018 requirements. The SRD included guidance on voltage and frequency trip settings and laid out the following requirements applicable to DER. All applicable inverter-based resources shall:

- be certified per the requirements of UL 1741 SA with either CA Rule 21 or Hawai'ian Rule 14H as the SRD
- have the voltage and frequency trip settings as specified in the SRD developed by ISO-NE and National Grid
- have the ride-through capability per abnormal performance category II of IEEE 1547-2018 and includes additional performance requirements
- comply with status of other grid support utility interactive inverter functions

In addition, National Grid implemented changes to Electric System Bulletin 756 (ESB 756)[10] which has the requirements for parallel generation connected to National Grid owned Electric Power System (EPS). The key changes implemented to Appendix C of the ESB 756 are:

- National Grid may specify values within the allowable ranges of IEEE 1547, subject to the limitations on voltage and frequency trip settings, specified by the Reliability Coordinator (RC) that consider bulk power system impacts of affected aggregate DER capacity. Where Regional ISO voltage and frequency requirements apply, the Interconnection Customer (IC) shall refer to the Company's ESB 756 Appendix

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[5] https://mn.gov/puc/assets/TIIR_tcm14-418483.pdf

[6] https://mn.gov/puc/assets/DRAFT%2016-521%20SLIDES%20for%20TSG%20Mtg%20on%20Interim%20Guidance%201-24-20_tcm14-421174.pdf

[7] https://mn.gov/puc/assets/MREA%20--%20Proposed%20MN%20Implemetation%20Addendum%20v2%20011920_tcm14-421175.pdf

[8] https://cdn.misoenergy.org/MISO%20Guideline%20for%20IEEE%20Std%201547388042.pdf

[9] https://www9.nationalgridus.com/non_html/ISO%20New%20England%20Source%20Requirement%20Document-2018-02-06.pdf

[10] https://www9.nationalgridus.com/non_html/shared_constr_esb756.pdf

A for specific requirements related to North American Electric Reliability Corporation (NERC) Protection and Control (PRC) standards.

- For fault current, short circuit protection, and relay settings, current values are based on the full volt-Ampere (VA) nameplate rating of the equipment, which may be greater than the kW rating of the equipment.
- If two utility grade relays are used to provide the required functions for sufficient redundancy, the failure of both relays, being out of service shall trip the interrupting device.
- Incorporated IEEE 1547-2018 widening of trip settings for voltage and frequency and require Category II inverters for consistency.
- Incorporated IEEE 1547-2018 for voltage and frequency ride through trip requirements complying with ISO-NE's Source Requirement Document (SRD) document.
- The DER shall not connect or return to service following a trip (including any ground fault current sources) until five minutes of healthy utility voltage and frequency are detected.

Dominion Energy, in the PJM Utility Members Working Group[11], acknowledged that there are several new additions to IEEE 1547-2018 including requirements to have ride-through capabilities on all DER. The PJM group, including Dominion, concluded that "every EDC (Electric Distribution Companies) electric distribution system is different, in term of need, size, stiffness and possibly statutory requirements, thus impacting operating practices".

1.1.2 Benchmarking of Volt-Var Functionalities

Based on publicly available information Navigant benchmarked pilot studies conducted by various utilities to implement the IEEE 1547-2018 standard. Table 1.1 summarizes the studies that were conducted by utilities while testing smart inverter functionalities for voltage regulation capabilities. The following are the key takeaways from the studies:

- **Southern California Edison (SCE)** - Inverters linearly absorb vars more than the specified dQ/dV gradient during voltage ramp up, but during ramp down the inverters provided vars as per specified dQ/dV gradient. The inverters there provide var support after voltage drops below 98% and draws vars after voltage goes above 102% of nominal voltage.
- **San Diego Gas and Electric (SDG&E)** study evaluated six different constant power factor settings, three leading and three lagging, and three different Volt-Var curves to quantify the impact on feeder voltage. The results from the study indicated that constant power factor setting of 0.85 resulted in voltage change of just over 1% on the primary. This voltage change from a localized 700 kW of controllable PV was comparable to the voltage impact of the 1,200 kVAR switched capacitor at the substation. Voltage range was reduced by up to 11% and the standard deviation in voltages was reduced by up to 23%. With reactive power priority, the impact to the voltage profile could be greater.
- **Pacific Gas and Electric** conclusions from the pilot study are that smart inverters with Volt-Watt/Volt-Var controls resulted in fewer voltage violations. Volt-Var curve sets with greater reactive power absorption had a larger effect on secondary voltage reduction. Optimal performance and configuration require further testing and development to ensure that manufacturers comply with standards and smart inverter certification procedures. Individual smart inverters occasionally reported incorrect curve settings, largely due to synchronization and command verification issues. Curtailment of customer generation due to activation of Volt-Var and Volt-Watt functions was minimal.

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[11] https://www.pjm.com/-/media/committees-groups/task-forces/derrttf/20190115/20190115-item-06-dominion-presentation-at-pjm-der-ridethrough.ashx

- **Idaho Power** tailored Volt-Var to balance reactive power absorption with LTC operations. The study applied several pre-defined settings and performed simulation using Open DSS to examine system impacts on minimum and maximum voltage and maximum delta voltage, reactive power at the point of interconnection, substation and coordination with capacitors, and LTC operations. The study results indicate that some inverters ignore volt-var curves at "high" voltage. Deadband plays an important role in reactive power absorption and response time plays an important role in the number of LTC operations. For effective Volt-Var control coordination automated capacitor control is needed.

Table 1.1. Summary of pilot Studies

Subcategory	PG&E	SCE	SDG&E	Idaho Power
Constant Power Factor Mode	YES	YES	YES	YES
Voltage-Reactive Power (Volt-Var)	YES	YES	YES	YES
Active Power – Reactive Power (Watt-var or P-Q)	NO	NO	NO	NO
Constant Reactive Power	NO	NO	NO	NO
Voltage Active Power (Volt-Watt)	YES	YES	YES	YES

1.1.3 NERC Bulk Power System Guidance

In December 2019, NERC published the Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018. The NERC guidelines offered NERC's perspective on the adoption of IEEE 1547-2018, stating, "…[t]he timely adoption and implementation of IEEE 1547-2018 for DER connected to the distribution system across North America is strongly encouraged. The specifications for DER in IEEE 1547-2018 include performance capability categories and allowable ranges of functional settings, which provide flexibility to align with specific system needs[12]". NERC also states that IEEE 1547-2018 is intended to apply only to distribution system connected DER and is generally not suited for higher voltage interconnections (i.e., resources connecting to the sub transmission or transmission systems). The reliability guideline encouraged the timely adoption and implementation of IEEE 1547-2018 for DER connected to the distribution system across North America. NERC highlights the need for coordination between distribution and transmission entities to effectively implement the standard.

The guidelines identify reactive power-voltage regulation during normal operations, abnormal voltage and frequency ride-through performance categories, regional voltage and frequency regulation settings, and communication protocols for RC coordination. Abnormal performance category assignment and specification of regional settings for any active power-related functions (e.g., frequency-droop and voltage-active power) should be coordinated with the RC. The RC should be informed of any deviation from the category assignments and settings to ensure that DER are accurately modeled in reliability studies.

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[12] Reliability Guideline, Bulk Power System Reliability Perspectives on the Adoption of IEEE 1547-2018, December 2019.

2. Model Development and Study Methodology

Voltage management refers to control of voltage and reactive power levels on a distribution feeder or group of feeders for the purpose of maintaining system voltage within permissible operating limits (usually +/-5% of 1 per unit). The standard functionality of smart inverters with IEEE 1547-2018 standard includes the capability to participate in voltage management via active and reactive power control. Some of the inverter modes that can be modeled according to IEEE 1547-2018 include the following voltage management modes:

- Voltage - Reactive Power (Volt-Var)
- Active Power – Reactive Power (watt-var)
- Voltage-Active Power (Volt-Watt)
- Fixed Power Factor

The study methodology evaluates the performance and impact of inverters with the control modes above enabled under various setpoints configurations and feeder conditions. The modeling approach and assumptions are stated in the section below.

2.1 Modeling Approach and Assumptions

This study focuses on the smart inverter IEEE 1547 2018 functions for active and reactive power control to test and demonstrate useful autonomous control modes and settings. These control modes monitor voltage at the point of common coupling (PCC) and manage active and reactive power output of the DER. The goal of the study is to evaluate the impact of Volt-Var, Volt-Watt and watt-var control for large utility scale DER (> 1 MW) on distribution system voltage. Feeders were selected that represented a variety of topologies, including existing generation, capacitor bank locations, location of line voltage regulators (LVRs), and LTCs. Representative feeders under study were identified based on Duke operating and design experience and stakeholder comments in the January 21, 2020 TSRG meeting. The table below summarizes the cases selected for the Volt-Var study.

Table 2.1. Cases selected for the Volt-Var study

	DEC feeders			DEP feeders		
	Feeder A	Feeder B	Feeder C	Feeder D	Feeder E	Feeder F
LTC or Bank regulator	No	Yes	No	No	Yes	No
Feeder head regulator	Yes	No	Yes	No	No	Yes
Line regulator	No	No	Yes	Yes	No	Yes
Line Capacitor	Yes	Yes	No	No	No	No
Existing generation (KVA)	336	No	No	10000	No	No
peak load (KVA)	13736	6739	7054	7104	5627	6679

There is at least one feeder with each type of voltage regulator. A heuristic method was used to segment the test feeders into different sections based on the feeder strength at different locations along the feeder and X/R ratio. The effectiveness of Volt-Var, Volt-Watt and watt-var control for large utility scale DER (> 1 MW) was evaluated[13].

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[13] CYME version 8.2 was used to conduct the analysis.

2.1.1 Base Case Modeling

Duke's distribution models were used to conduct the studies to evaluate a range of DER control functions. A total of six feeders were evaluated, three in each system that is DEP and there in DEC respectively. The feeders selected were chosen in areas where DER interconnections are more active and with a variety of feeder voltage control devices. The studies were conducted at two load levels, off-peak load (minimum) and shoulder load. The off-peak load case was expected to have the highest voltage and require the most reactive power absorption by the DER. To test this assumption, the shoulder load case was also checked. The next highest load was expected to be shoulder load and then peak load, but those cases were not expected to create high voltage in all but the most unusual cases. The base case modeled existing DER at unity power factor (UPF) only.

These base cases contained existing loads, controls for switched devices (e.g. capacitor banks and voltage regulators), power factor, and pu voltage. This set a clear baseline to compare the current performance of the feeder with that after adding DER with the advanced inverter controls enabled.

A critical aspect of evaluating the performance of advanced inverter controls with respect to Volt-Var evaluation is accurate feeder loading and resource profiles. For this study loading conditions extracted from the 15-minute real and reactive power interval data were used in the analysis. To capture the impact on feeder voltages, off peak and shoulder cases were analyzed for the six feeders to demonstrate DER control performance variations. Feeder B, which had a bank regulator with a high resistive drop compensation, was also evaluated for system peak load conditions.

In order to test the controllers, voltage must exceed the controller settings so that it signals the inverter to provide compensation. Therefore, generation was added along the feeders, and especially at the end, in such a way as the voltage was pushed above 1.05 pu. In most cases, a 2 MW DER was used as the test configuration. If more than 2 MW of active power injection was required to increase the voltage, then additional 2 MW units or a 5 MW unit was added at that location. Each 2 MW or 5 MW DER has a +/- 0.9 power factor (pf) capability, therefore it is rated 2.22 MVA and 5.55 MVA respectively. This method is common and electrically equivalent to a single larger MW site, but without the additional modeling of multiple unique DER sizes. The DER is connected to the feeder with a single step-up transformer with a %Z = 5.75 and an X/R ratio of 8.24. A 0.9 power factor was chosen based on IEEE 1547-2018 normal performance Category B. Because 0.95 power factor is also a common power factor rating, that was also monitored.

2.2 Study Methodology

To evaluate the performance several smart inverters with active power, reactive power, and voltage control schemes enabled, the capacity was deployed to each feeder until voltage violations were observed and thermal loading were within reason. Power flow principles and electrical parameters like system strength and electrical impedance between smart inverters and the substation dictate how the voltage will vary. Based on this, the generation was sited in such locations where maximum voltage change would be observed by adding DER. Such locations were chosen by considering low short circuit MVA and low X/R ratio. As stated by Chalmers University of Technology[14] evaluating electrical limiting factors for wind energy installations, "*If the grid is mainly resistive (X/R-ratio low) then the magnitude of the voltage depends mainly on the active power and if the grid is mainly inductive (X/R ratio high) it depends mainly on the reactive power. If the grid is strong (higher Short Circuit MVA/stiffness factor) the voltage is not much affected by power produced*". In general distribution feeder and system strength is characterized by short circuit MVA.

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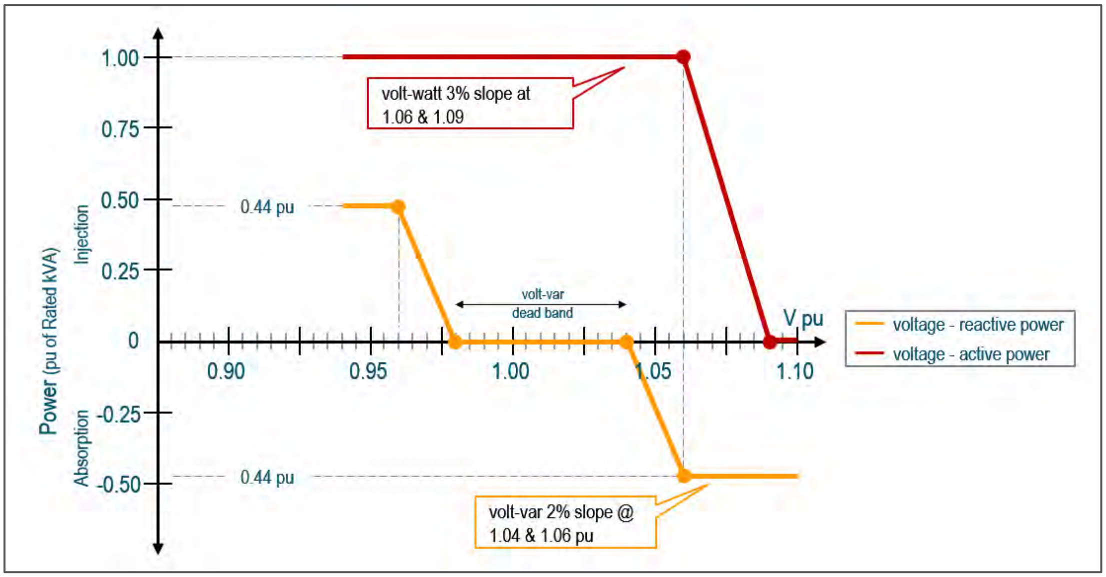
[14] Lundeberg, S. (2000). Electrical limiting factors for wind energy installations. Chalmers University of Technology, Gothenburg, Sweden

Thus, both feeder strength and short circuit MVA magnitude decrease as the DER location moves further away from the substation. These interactions were considered during the study.

To evaluate the impact of active and reactive power injections and the relationship with feeder characteristics, change in voltage with respect to change in reactive power (dV/dQ) and change in voltage with respect to change in active power (dV/dP) impact response curves were developed for each feeder. These response curves for DER located at different points along the feeder served as heuristics to indicate whether real or reactive power control is more effective at managing feeder voltage, determine the effectiveness of each control, and assess which control configurations may be more effective.

Multiple control methods and control setpoints were considered during the study. The most common Volt-Var and Volt-Watt control settings used across all the feeders are shown in Figure 2.0.

Figure 2.0 Most Common Control Settings



2.3 DER Volt-Var Power Flow Results

The study was carried out on the six feeders listed in Table 2.1, three each on the DEC and DEP system respectively. Feeders A, B, and C (analyzed in Section 2.3.1 to section 2.3.3) summarize the studies on the feeders on the DEC system. Feeders D, E, and F (Section 2.3.4 to 2.3.6) summarize the studies on the feeders on the DEP system. It should be noted too that Feeders A and D were performed first chronologically, so those two feeders have many more permutations of control options than the others. Based on the results of the first two feeders, fewer control options were reviewed for the remaining feeders.

2.3.1 Feeder A overview

The feeder layout is shown in Figure 2.1. A large portion of the feeder backbone consists of 2 AWG conductor. The feeder has 3 cap banks (highlighted with blue markers in Figure 2.1) with two capacitor banks rated 900 kVAR each, and the capacitor just north of the substation is also connected to the backbone and is rated 600kVAR. The feeder currently has 336 kW of existing DER generation (highlighted with cyan marker in Figure 2.1). The feeder also models a station regulator with a 121 Volt setpoint.

To evaluate active and reactive power controls, Feeder A was modeled with a total of 10 MW of DER with smart inverter capability (highlighted with green markers in Figure 2.1) to push end of line voltages above 1.05 pu. Additional DER are added at specific locations to cover the length of the feeder and where maximum voltage change is expected.

Figure 2.1. Feeder A layout

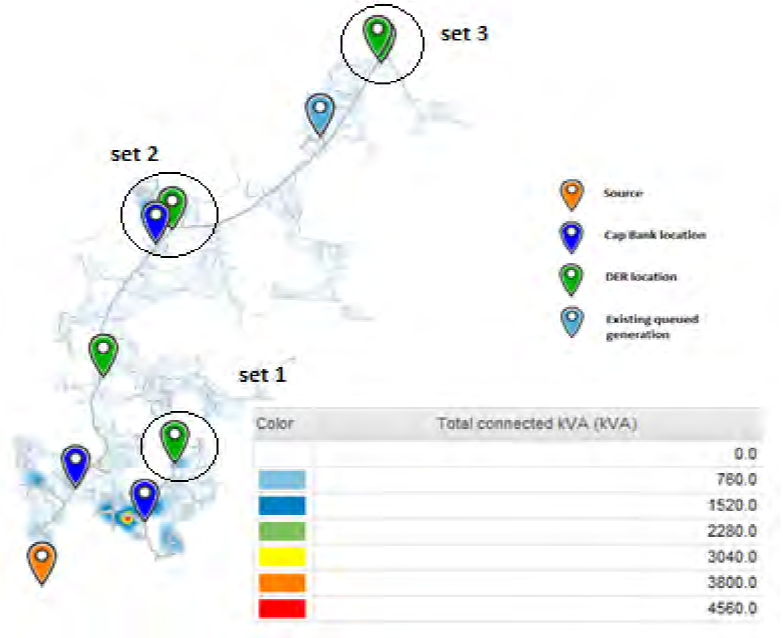


Table 2.2. Feeder Generation Modeling

Generation	Value
Existing generation (end of feeder)	336 kW/336 kVA
Generation with smart inverter capability – set 1	4 MW/4.44 MVA
Generation with smart inverter capability – set 2	2 MW/2.22 MVA
Generation with smart inverter capability – set 3	4 MW/4.44 MVA

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 10 MW of DER at UPF. These cases are referred to as case #0 and case #1 respectively.

To evaluate the locational impacts of injecting or absorbing active and reactive powers on voltage, dV/dP and dV/dQ response curves were computed. These curves give an indication of what control strategy might be most suitable for each location. ***Figure 2.2*** and Table 2.3 show the impact response curves and slopes for Feeder A under off-peak conditions (see section 2.3.1.2 for more details on off-peak case modeling).

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Figure 2.2. Response Curves

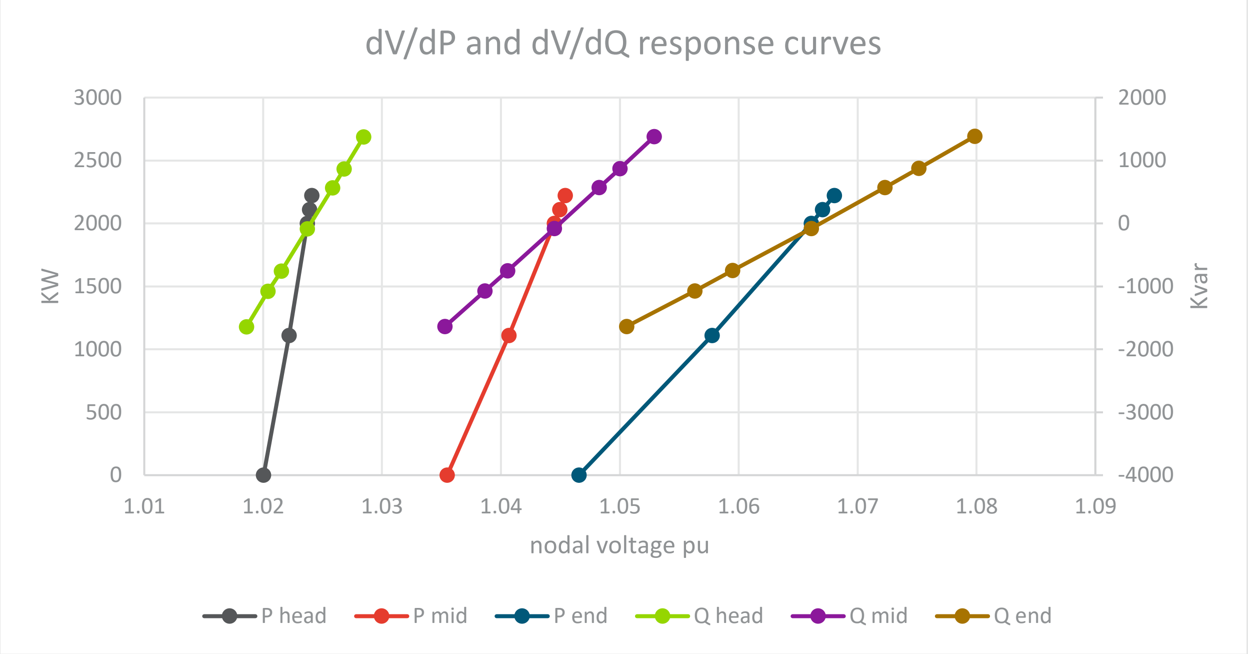

Table 2.3. dV/dP and dV/dQ response curves and feeder characteristics

Feeder Characteristic	DER location set 1	DER location set 2	DER location set 3
dV/dP	0.41%	1.00%	2.17%
dV/dQ	0.32%	0.57%	0.96%
Qresp/Presp	0.79	0.57	0.44
SCMVA	125	86	54
X/R	3.25	1.83	1.22

The dV/dQ and dV/dP responses are the percent voltage change for the rated DER capability. The response curve slopes show that the set 3 DER units have a noticeably higher dV/dP value as opposed to set 1 and set 2. These study results indicate the set 3 location, at the end of the feeder, will have a larger voltage variation due to any addition of DER capacity. Also, set 3 DER units have a significantly higher dV/dQ value, indicating voltage at this location is most sensitive to changes in reactive power as compared to other locations. For example, Table 2.3 indicates that the 2 MW DER in set 3, is required to absorb approximately 969 kVAR of reactive power (the 0.90 pf rating) in order to change the voltage 0.96%. The set 1 location where dV/dP and dV/dQ values are low, Volt-Var and Volt-Watt control are less helpful for mitigating voltage issues as compared to set 2 and set 3 locations.

The Q response and the P response ratio shows the portion of the voltage change caused by active power injection that can be compensated with reactive power. A ratio less than 1 indicates there is not enough reactive capability available to compensate for the voltage rise caused by the rated active power injection. The response curves also indicate visually that it is difficult at the rated reactive power level to mitigate the entire voltage change caused by active power injection. Additionally, only set 3 location exceeds 1.05 pu voltage at unity power factor. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.1.1 Off-Peak Load Study Results

Feeder A was first studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in Table 2.4.

Table 2.4. Feeder off-peak load characteristics

Feeder load characteristics	Value
Total load kW	1606.9
Total load kVAR	425.6
load PF	96.7%
Total load kVA	1662.3
Total KVA (peak load)	13735.6
Feeder Load Factor	41.0%
Total load as a % of peak load	12.1%

From case #0 and case #1 developed, the next set of cases model DER with either Volt-Var, Volt-Watt, watt-var or a combination of those to evaluate which control function provides the most optimal response. These cases are summarized in Table 2.5 for off-peak loading conditions. Figure 2.3 plots the voltages for each of the cases in Table 2.5.

Table 2.5. Cases description – off peak[15]

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter (kW)	kVAR absorption at the PCC (head, middle and end)	Total_kVAR absorption at the PCC
#1	900 kVAR (head)	5	set 1, set 2, set 3	UPF	100%	No	2000	-170,-82,-158	-410
#2	900 kVAR (head), 900 kVAR (middle)	3	set 1, set 2	Volt-Var	3% from 1.06 to 1.09	No	2000	-170,-82	-982
#2	900 kVAR (head), 900 kVAR (middle)	2	set 3	Volt-Var	3% from 1.06 to 1.09	No	2000	-730	
#3	900 kVAR (head)	3	set 1, set 2	Volt-Var	3% from 1.06 to 1.09	No	2000	-170,-82	-759
#3	900 kVAR (head)	2	set 3	Volt-Var	3% from 1.06 to 1.09	No	2000	-507	

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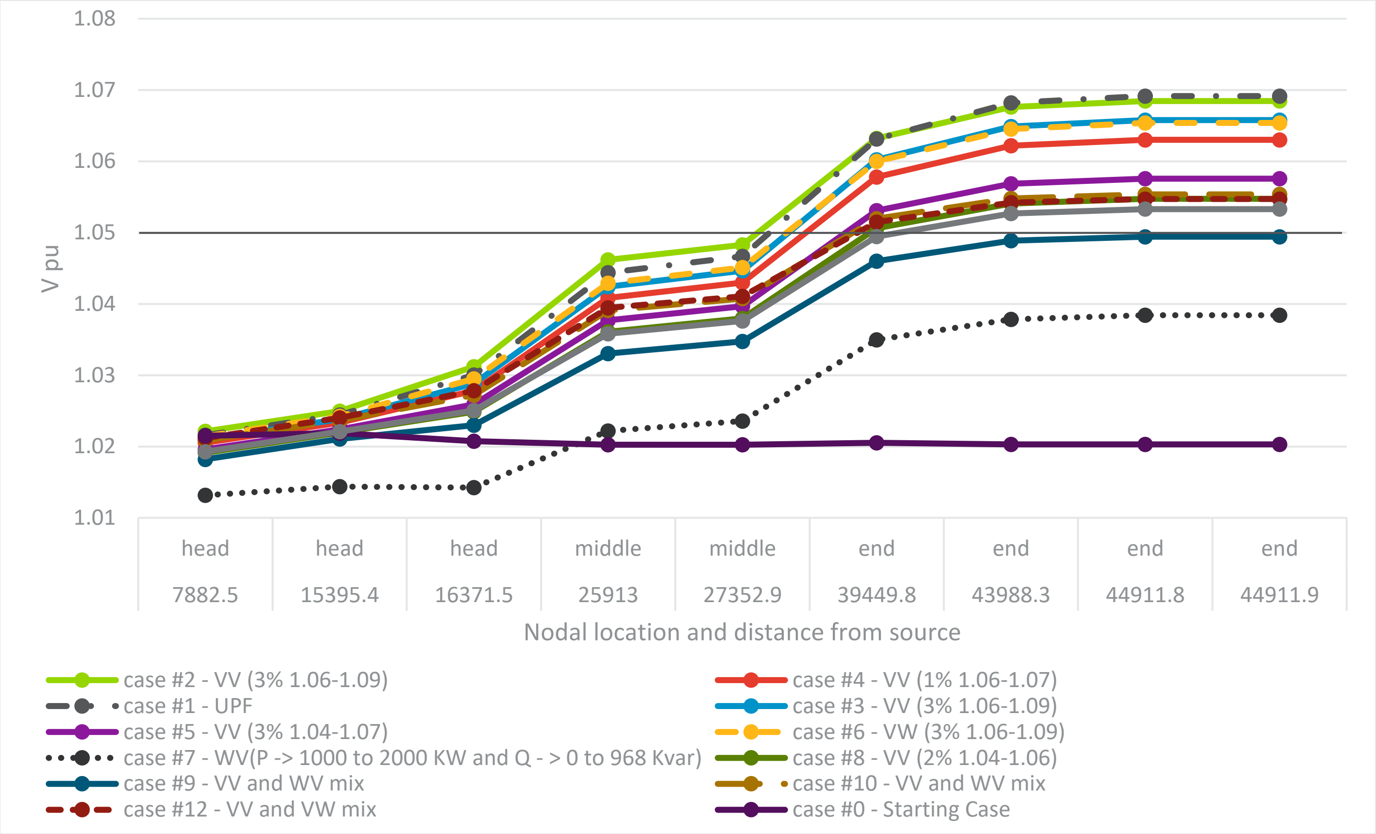
[15] Volt-Var control was modeled with “watts precedence over vars”

#4	900 kVAR (head)	3	set 1, set 2	Volt-Var	1% from 1.06 to 1.07	No	2000	-170,-82	-1036
#4	900 kVAR (head)	2	set 3	Volt-Var	1% from 1.06 to 1.07	No	2000	-784	
#5	900 kVAR (head)	2	set 1	Volt-Var	3% from 1.04 to 1.07	No	2000	-170	-1696
#5	900 kVAR (head)	1	Set 2	Volt-Var	3% from 1.04 to 1.07	No	2000	-190	
#5	900 kVAR (head)	2	set 3	Volt-Var	3% from 1.04 to 1.07	No	2000	-1336	
#6	900 kVAR (head)	3	set 1, set 2	Volt-Watt	3% from 1.06 to 1.09	No	2000	-170,-82	-379
#6	900 kVAR (head)	2	set 3	Volt-Watt	3% from 1.06 to 1.09	No	1793	-127	
#7	900 kVAR (head)	5	set 1, set 2, set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	-2162,-1079,-2150	-5391
#8	900 kVAR (head)	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-170	-1938
#8		1	Set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-148	
#8	900 kVAR (head)	2	set 3	Volt-Var	2% from 1.04 to 1.06	Yes	2000	-1620	
#9	900 kVAR (head)	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-172	-2412
#9		1	Set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-97	
#9		2	set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	-2143	
#10	2400 kVAR (head), 900 kVAR (middle)	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-170	-2432
#10		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-115	
#10		2	set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	-2147	
#11	900 kVAR (head)	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-170	-1671
#11		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-122	

#11		2	set 3	Volt-Var and Volt-Watt	Volt-Var: 2% 1.04 to 1.06 and Volt-Watt - 2% 1.05 to 1.07	No	1816	-1379	
#12	1700 kVAR (head), 900 kVAR (middle)	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-186	-1929
#12		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-195	
#12		2	set 3	Volt-Var and Volt-Watt	Volt-Var: 2% 1.04 to 1.06 and Volt-Watt - 2% 1.05 to 1.07	Yes	1702	-1548	

Table 2.5 above indicates if DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.07 pu. Case #7 with watt-var control and Case #9 with a combination of Volt-Var and watt-var control both successfully mitigate overvoltage's seen in Case #1. However, with these control functions especially involving watt-var, there is a significant reactive power consumption that needs to be supplied by the transmission system. Case #7 results indicate the units consume a total of ~5400 kVAR respectively requiring reactive power compensation to provide the additional reactive power consumption created by the DERs. Based on these results, case #9 and case #11 were evaluated for reduced reactive power consumption.

Figure 2.3. Nodal Voltages – Off Peak



Case #12 modeled new shunt capacitors at the feeder head to compensate for the reactive power absorbed that was calculated in case #11. This maintains a constant reactive power consumed from the transmission system. The shunt capacitors were modeled at locations where both SC MVA and system X/R ratio was noticeably higher. This ensured voltages were not negatively impacted by the addition of shunt capacitors.

An important takeaway from this analysis is that although Volt-Var control does help control voltages, it cannot be used on a standalone basis to mitigate voltage issues under all loading conditions for Feeder A. Adding Volt-Watt to Volt-Var control or watt-var could work when Volt-Var alone is not sufficient but requires more evaluation. Another option, as a possibility to avoid watt-var, is to increase the volt-var control ramp rate and absorb more reactive power for a given voltage change. However, other concerns, such as stability of the inverter voltage control, are concerns as well. If the inverter injects more reactive power at a rate higher than the Q response of the feeder, the voltage may not remain stable. This study did not go below 2% because that seemed to be a lower rate of change than the Q response of the feeders.

2.3.1.2 Shoulder Peak Load Study Results

Feeder A was also studied for shoulder peak loading conditions. This analysis was carried out to verify the control selected for the off-peak loading condition also worked for the shoulder peak loading condition. The same feeder model used for the off-peak was used for evaluating the shoulder peak loading condition. Feeder load was modified and is shown in Table 2.6.

Table 2.6. Feeder Shoulder-peak Load Characteristics

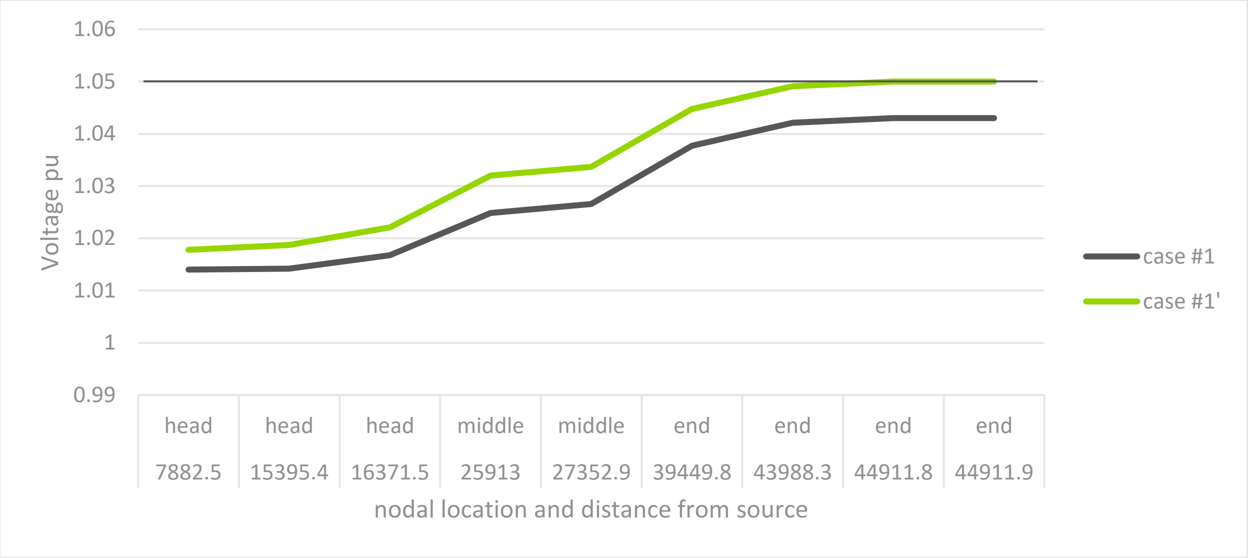
Feeder load characteristics	Value
Total load KW	8879.7
Total load kVAR	2105.4
load PF	97.3%
Total load KVA	9125.9
Total KVA (peak load)	13735.6
Total load as a % of peak load	66.4%

A "current system base case" was created which represented the existing system topology (no DER with smart inverter capability modeled). A "base case with smart inverter capability enabled DERs" was created which modeled 10 MW of DER at unity pf (UPF). These cases are referred to as case #0 and case #1 respectively. It should be noted that with the loading conditions as identified in Table 2.6, voltages along the feeder were less than 1.05 pu. Therefore, a capacitor bank was switched in to get the voltages above 1.05 pu. This was done to increase the voltage without adding more generation because several facilities were near their thermal limits and that would only be made worse by more generation. The main objective is to consider the effectiveness of the controls for higher voltages, so this configuration is acceptable for performing the test.

Table 2.7. Case Description 1 and 1' - shoulder peak

Case #	Caps	Regulator	Location	Control Type	Control Outline
#1	offline	-5,-6,-4	head, middle and end	UPF	UPF
#1'	900 kVAR (head), 600 kVAR (head), 900 kVAR (middle)	-5,-6,-4	head, middle and end	UPF	UPF

Figure 2.4. Nodal Voltages - shoulder peak



Using Case #1', the next set of cases model DER with either Volt-Var, Volt-Watt, watt-var or a combination to evaluate which control function provides the most optimal response. These cases are summarized in **Error! Not a valid bookmark self-reference.** for shoulder peak loading condition. Figure 2.5 plots the voltages for each of the studied cases in **Error! Not a valid bookmark self-reference.**.

Table 2.8. Case description - shoulder peak[16]

Case #	Caps	Number of DER units	Location	Control type	Control description	gen outside 0.95 pf limit	Each Inverter_KW	kVAR absorption at the PCC	Total_kVAR absorption at the PCC
#1'	1500 kVAR (head), 900 kVAR (middle)	5	set 1, set 2, set 3	UPF	100%	No	2000	-170,-82,-158	-410
#2, #3, #4	1500 kVAR (head), 900 kVAR (middle)	3	set 1, set 2, set 3	Volt-Var	3% from 1.06 to 1.09	No	2000	-170,-82,-158	-410
#5	1500 kVAR (head), 900 kVAR (middle)	3	set 1, set 2	Volt-Var	3% from 1.04 to 1.07	No	2000	-170,-84	-826

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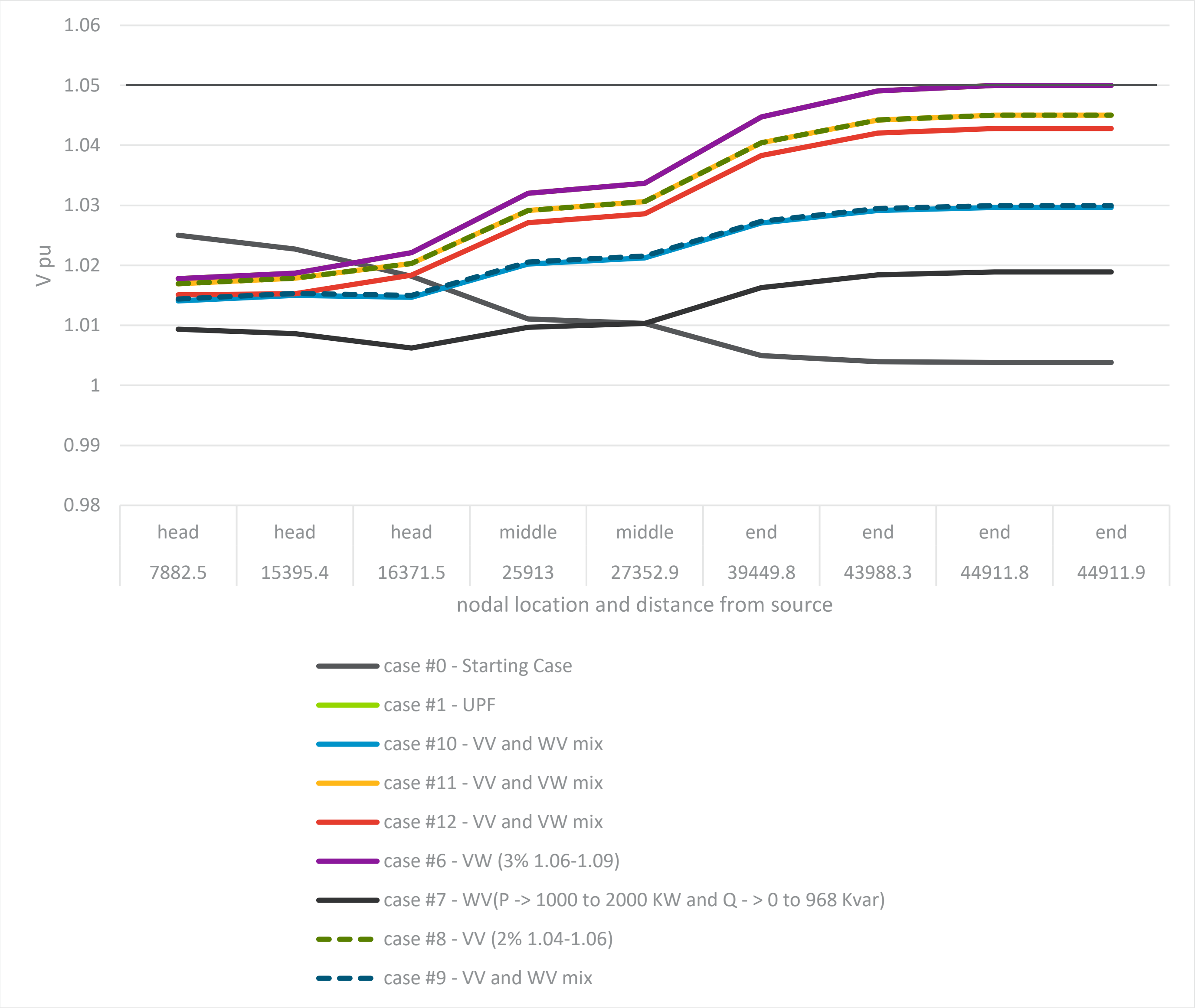
[16] Volt-Var control was modeled with "watts precedence over vars"

Case #	Caps	Number of DER units	Location	Control type	Control description	gen outside 0.95 pf limit	Each Inverter_KW	kVAR absorption at the PCC	Total_kVAR absorption at the PCC
#5	1500 kVAR (head), 900 kVAR (middle)	2	Set 3	Volt-Var	3% from 1.04 to 1.07	No	2000	-572	
#6	1500 kVAR (head), 900 kVAR (middle)	5	set 1, set 2, set 3	Volt-Watt	3% from 1.06 to 1.09	No	2000	-170,-82,-158	-410
#7	1500 kVAR (head), 900 kVAR (middle)	5	set 1, set 2, set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	--2162,-1079,-2158	-5399
#8	1500 kVAR (head), 900 kVAR (middle)	3	set 1, set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-170,-148	-978
#8	1500 kVAR (head), 900 kVAR (middle)	2	set 3	Volt-Var	2% from 1.04 to 1.06	No	2000	-660	
#9	1500 kVAR (head), 900 kVAR (middle)	3	set 1, set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-172,-86	-2412
#9	1500 kVAR (head), 900 kVAR (middle)	2	Set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	-2154	

Case #	Caps	Number of DER units	Location	Control type	Control description	gen outside 0.95 pf limit	Each Inverter_KW	kVAR absorption at the PCC	Total_kVAR absorption at the PCC
#10	3900 kVAR (head), 900 (middle)	3	set 1, set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-172,-86	-2412
#10	3900 kVAR (head), 900 (middle)	2	Set 3	Watt-Var	P->1000 to 2000 KW and Q->0 to 968 kVAR	Yes	2000	-2154	
#11	1500 kVAR (head), 900 kVAR (middle)	3	set 1, set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-170,-148	-978
#11	1500 kVAR (head), 900 kVAR (middle)	2	Set 3	Volt-Var and Volt-Watt	Volt-Var: 2% 1.04 to 1.06 and Volt-Watt - 2% 1.05 to 1.07	No	2000	-660	
#12	2500 kVAR (head), 900 (middle)	3	set 1, set 2	Volt-Var	2% from 1.04 to 1.06	No	2000	-170,148	-1030
#12	2500 kVAR (head), 900 (middle)	2	Set 3	Volt-Var and Volt-Watt	Volt-Var: 2% 1.04 to 1.06 and Volt-Watt - 2% 1.05 to 1.07	No	2000	-712	

Figure 2.5. Nodal voltages - shoulder peak



Based on the plots in Figure 2.5, the control functions that work for off-peak can also work for shoulder peak conditions indicating the off-peak case alone could be used to determine the selection of control function. Because the reactive power absorbed is higher in the off-peak case than for shoulder loading conditions, the off-peak compensation remains the limiting case.

2.3.2 Feeder B overview

The feeder layout is shown in Figure 2.6. Much of the backbone consists of size 556 MCM conductor. The feeder has a cap bank (highlighted with blue marker in Figure 2.6) rated 900 kVAR. The feeder currently has no existing generation.

To evaluate active/reactive power controls, Feeder B modeled a total of 8.88 MVA of DER with smart inverter capability and 6.66 MVA of DER at UPF (highlighted with green markers in Figure 2.6). The DER are added at locations to cover the length of the feeder and where maximum voltage change is expected. Also note that following stakeholder discussion, Duke modified the model to ensure the inverters were operating in reactive power priority. This option allows active power to exceed the 0.9 pf rating when the maximum reactive power is not required for voltage compensation, but then reduce active power to provide reactive power when required.

Figure 2.6. Feeder B layout

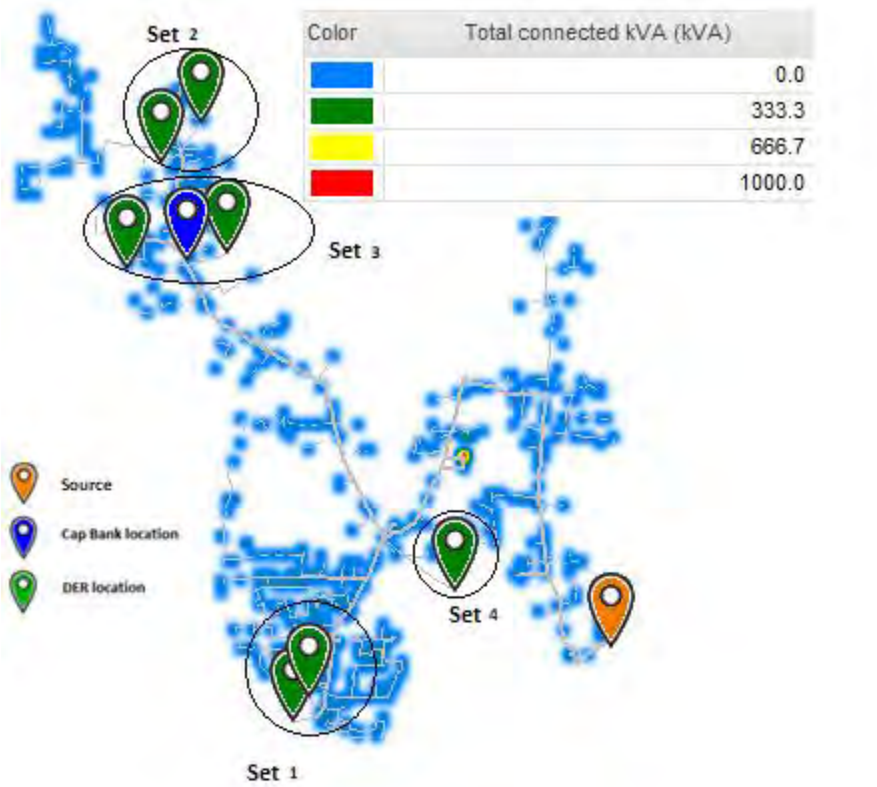
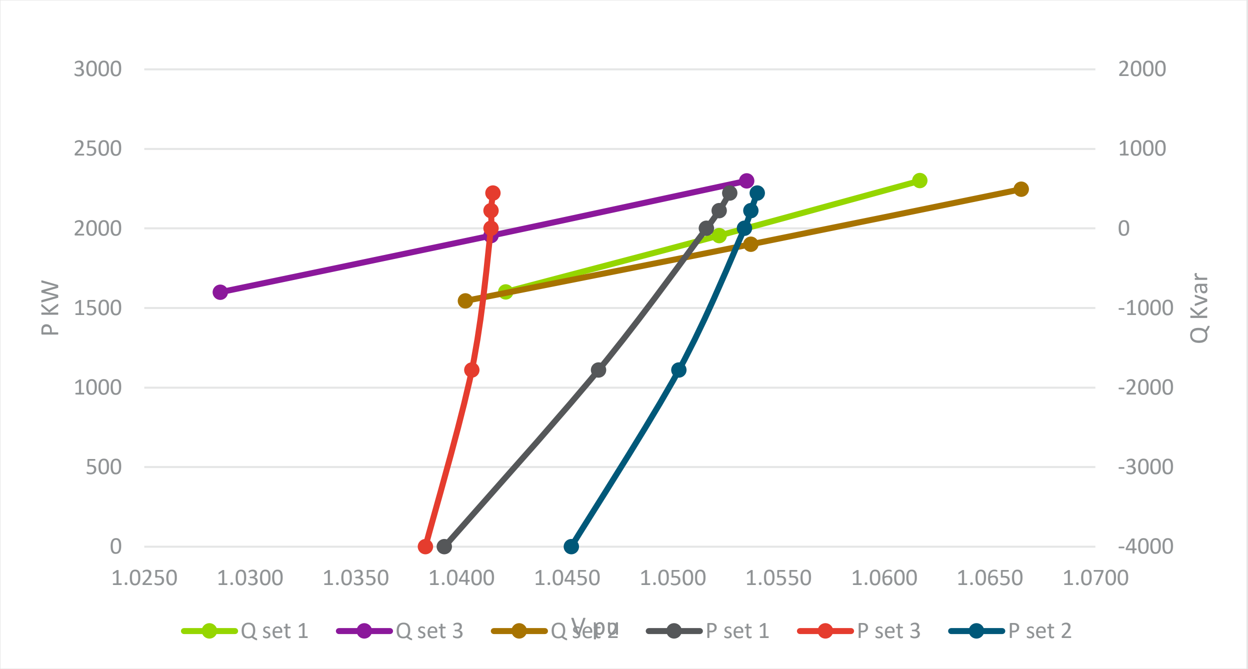


Table 2.9. Feeder B generation modeling

Generation	Value
Existing generation (end of feeder)	0 KVA
Generation with smart inverter capability modeled in set 1	4.44 MVA
Generation with smart inverter capability modeled in set 2	4.44 MVA
Generation modeled in set 3 (UPF)	4.44 MVA
Generation modeled in set 4 (UPF)	2.22 MVA

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 15.54 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively.

Figure 2.7. Feeder B Response Curves – off peak conditions



As with Feeder A, to evaluate the locational impacts of injecting/absorbing active and reactive powers on votlage, dV/dP and dV/dQ response curves were computed. These curves give an indication of what control strategy might be most suitable for each location. Figure 2.7 and Table 2.10. dV/dP and dV/dQ response curves and feeder characteristics show the response curves and slopes for Feeder A under off-peak conditions (see section 2.3.2.2 for more details on off-peak case modeling).

Table 2.10. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1	DER location – set 2	DER location – set 3
dV/dP	1.38%	0.91%	0.34%
dV/dQ	1.38%	1.84%	1.75%
Presp/Qresp	1.00	2.02	5.07
SCMVA	44	38	41
X/R	2.15	2.91	4.22

The response curve slopes show that the set 1 DER units have a higher dV/dP value as opposed to DER units set 2 and set 3. This indicates set 1 location will have a larger voltage variation due to addition of DERs. Set 1, set 2 and set 3 locations have somewhat similar dV/dQ value (albeit set 1 has a lower value), indicating Volt-Var control could work at these locations, but would be limited to approximately 1.3% to 1.8% voltage change. Additionally, at the location of each set of DER, the voltage exceeds 1.05 pu voltage at UPF. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.2.1 Off-Peak Load Study Results

Feeder B was first studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in Table 2.11.

Table 2.11. Feeder B off-peak load characteristics

Feeder load characteristics	Value
Total load KW	713.8
Total load kVAR	121.4
load PF	98.6%
Total load KVA	724
Total KVA (peak load)	6738.6
Feeder Load Factor	31.4%
Total load as a % of peak load	10.7%

From case #0 and case #1 developed, the next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate which control function provides the most optimal response. These cases are summarized in Table 2.12 for off-peak loading condition. Figure 2.8 plots the voltages for each of the studied cases in Table 2.12.

Table 2.12. Cases description – off peak[17]

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
#0	N/A	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	N/A	7	set 1 - 4	UPF	100%	No	2222	-198,-196,-202,-103	-699
#8	N/A	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2209	-547	-1420
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2211	-558	
		2	set 3	UPF	100%	No	2222	-210	
		1	set 4	UPF	100%	No	2222	-105	
#13	N/A	2	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2209	-547	-1420

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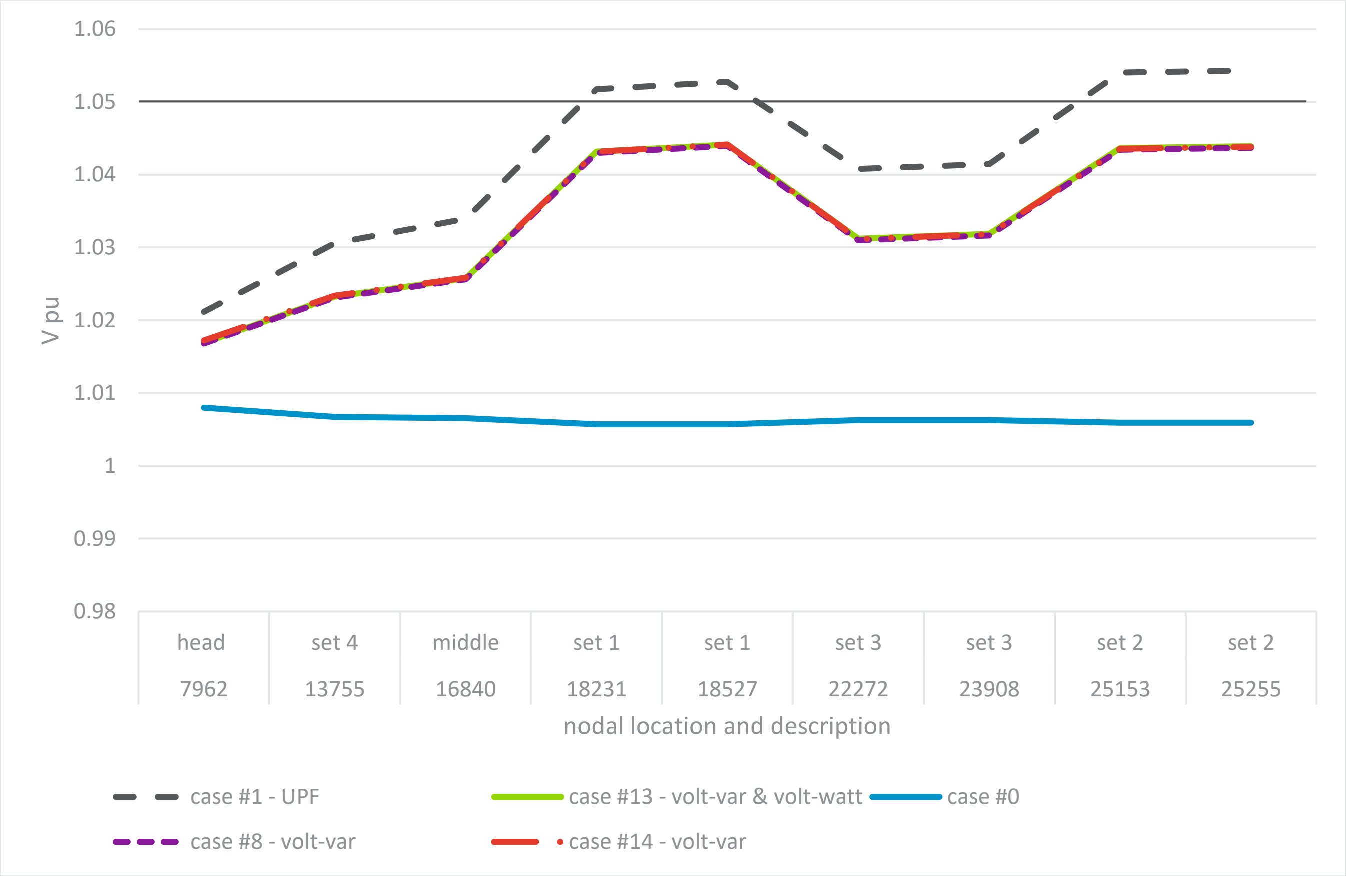
[17] Volt-Var control was modeled with “vars precedence over watts”

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
		2	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2211	-558	
		2	set 3	UPF	100%	No	2222	-210	
		1	set 4	UPF	100%	No	2222	-105	
#14	1110 kVAR	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2208	-566	-1454
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2208	-573	
		2	set 3	UPF	100%	No	2222	-210	
		1	set 4	UPF	100%	No	2222	-105	

Figure 2.8. Nodal Voltages – off peak



If DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.055 pu. Case #8 with Volt-Var control mitigates overvoltages seen in Case #1. Case #14 modeled new shunt capacitors in case #8 to compensate for reactive power consumption from the transmission system. The shunt capacitors were modeled at locations where both SC MVA and system X/R ratio was higher. This ensured voltages were not negatively impacted by the addition of shunt capacitors. Case #13 demonstrated that Volt-Watt control was not needed for this feeder because the results were the same as Case #8.

2.3.2.2 Shoulder Peak Load Study Results

Feeder B was later studied for shoulder peak loading conditions. This analysis was carried out to verify if the control selected for the off-peak loading condition also worked for the shoulder peak loading condition. The feeder shoulder peak loading characteristics are shown in Table 2.13.

Table 2.13. Feeder B shoulder-peak load characteristics

Feeder load characteristics	Value
Total load KW	3873.0
Total load kVAR	1139.6
load PF	95.9%
Total load KVA	4037.2
Total KVA (peak load)	6738.6
Total load as a % of peak load	60.0%

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 15.5 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. The next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate the control function selected for off-peak also worked for shoulder peak. These cases are summarized in Table 2.14**Error! Reference source not found.** for shoulder peak loading condition. Figure 2.9 plots the voltages for each of the studied cases in **Error! Reference source not found.**.

Table 2.14. Case description - shoulder peak[18]

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
#0	900 kVAR	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	900 kVAR	7	set 1 - 4	UPF	100%	No	2222	-198,-196,-202,-103	-699
#8	900 kVAR	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2205	-681	-1971
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2173	-981	
		2	set 3	UPF	100%	No	2222	-204	
		1	set 4	UPF	100%	No	2222	-105	

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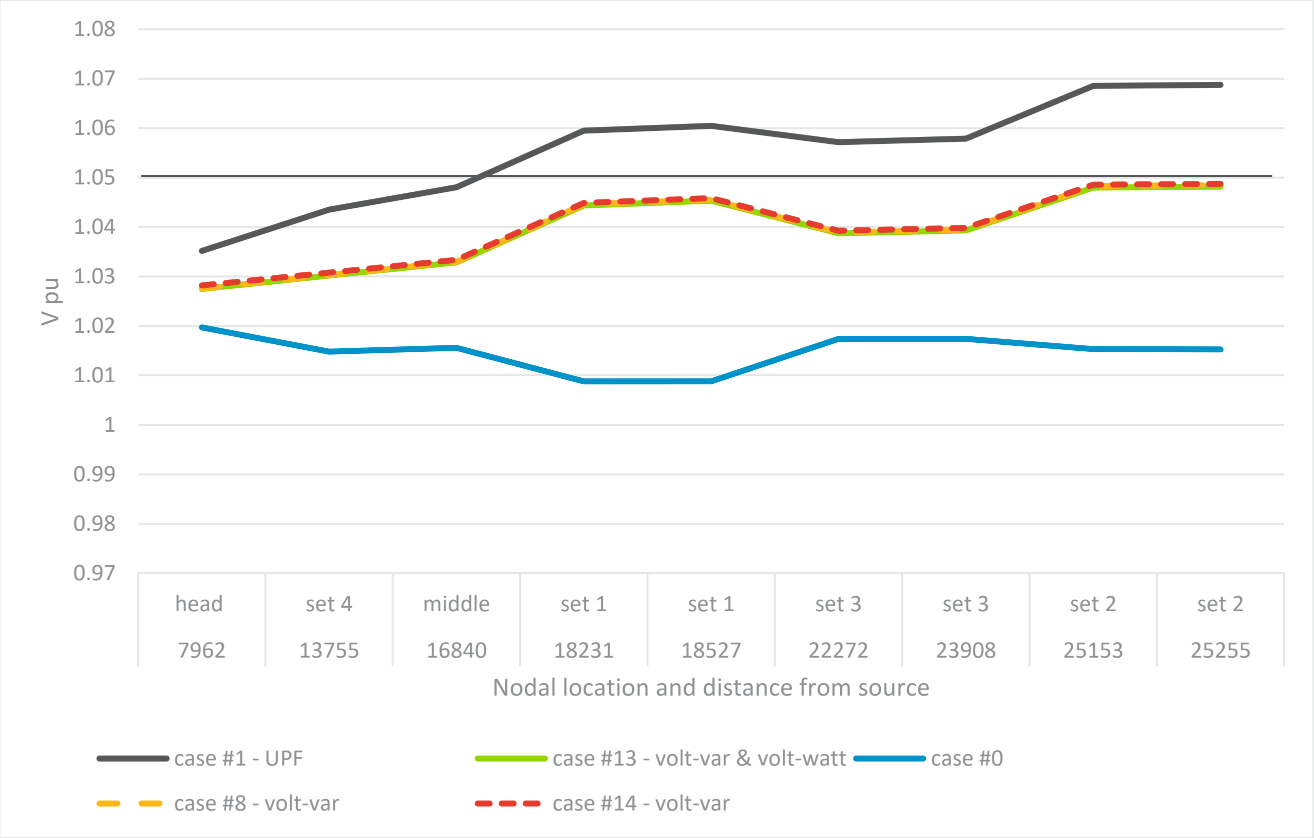
[18] Volt-Var control was modeled with “vars precedence over watts”

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
#13	900 kVAR	2	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2205	-681	-1971
		2	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2173	-981	
		2	set 3	UPF	100%	No	2222	-204	
		1	set 4	UPF	100%	No	2222	-105	
#14	900 kVAR, 1650 kVAR	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2202	-710	-2017
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2171	-1000	
		2	set 3	UPF	100%	No	2222	-203	
		1	set 4	UPF	100%	No	2222	-104	

Based on the plots in Figure 2.9, the control functions that work for off-peak conditions would also work for shoulder peak conditions.

It should be noted that the voltages seen in shoulder peak case #1 exceed the voltages in the off-peak case. This is attributed to the station regulator which has a high value of resistive compensation. This moves the effective setpoint higher for higher load levels. Therefore, based on these results, it was determined that an evaluation of system peak is also required for this feeder.

Figure 2.9. Nodal voltages - shoulder peak



2.3.2.3 System Peak Load Study Results

As with the off-peak, dV/dP and dV/dQ response curves were computed to evaluate the locational impacts of injecting/absorbing active and reactive powers on voltage at peak load. Table 2.15 shows the response characteristics for the feeder under peak load conditions.

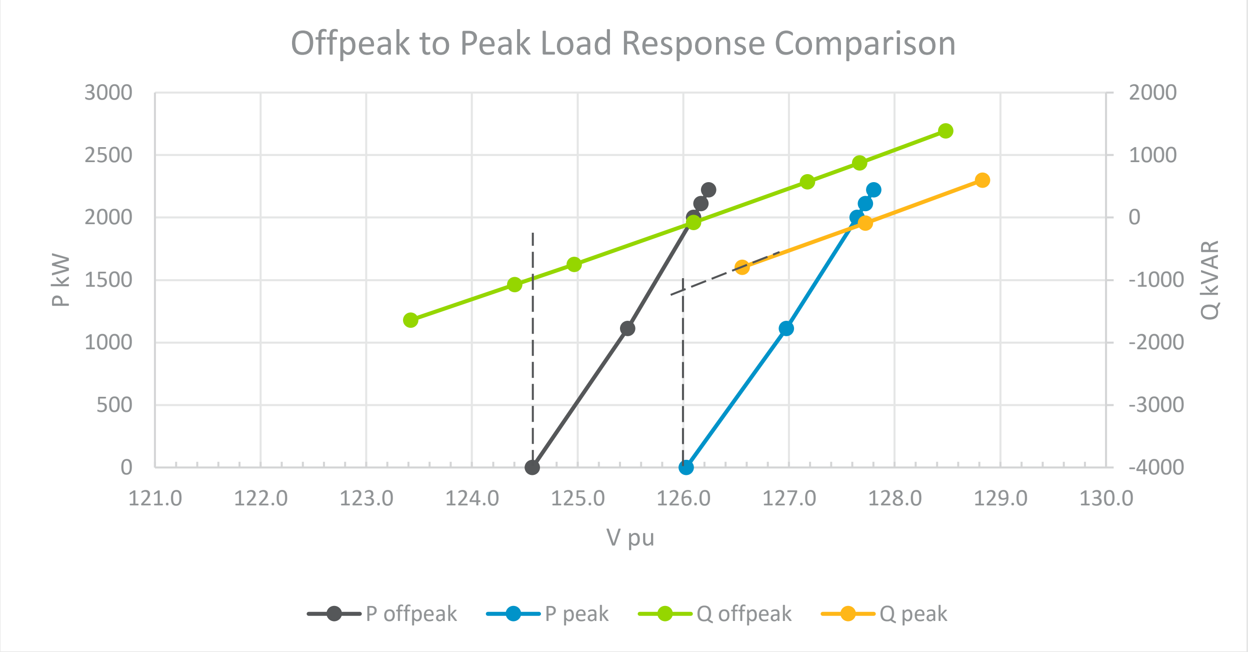
Table 2.15. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1	DER location – set 2	DER location – set 3
dV/dP	1.50%	1.09%	Not computed
dV/dQ	1.33%	1.79%	Not computed
Qresp/Presp	0.89	1.65	Not computed
SCMVA	44	38	41
X/R	2.15	2.91	4.22

Comparing the off-peak responses to the system peak, there are some differences, but they are small. The active power responses changed by approximately 0.20% and the reactive response changed by 0.05%. Comparing the response curves for set 1 and adjusting for the base case change in voltage, as shown in

Figure 2.10, the responses are practically identical. This is only one comparison, but it may indicate that these values do not change significantly for various load levels

Figure 2.10. Off-peak to Peak load response comparison



For illustration purposes, the vertical dashed lines provide an estimate of the reactive compensation needed to return the PCC voltage to the state prior to injecting active power. In the off peak case, there is enough capability before reaching the 0.9 pf limit and more than enough to bring the voltage below 1.05 pu. At peak, it seems the reactive power comes very close to bringing the voltage close to the base case voltage, but it may not be enough to get below 1.05 pu.

Peak loading condition for Feeder B was further studied. This analysis was carried out to verify if the control selected for the off-peak, and shoulder peak loading condition also worked for the system peak loading condition as it was expected the peak case would have the highest voltages. The feeder peak loading characteristics are shown in Table 2.16.

Table 2.16. Feeder B peak load characteristics

Feeder load characteristics	Value
Total load KW	6646.6
Total load kVAR	1109.6
load PF	98.6%
Total load KVA	6738.6
Total KVA (peak load)	6738.6
Total load as a % of peak load	100.0%

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 15.5 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively.

The next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate the control function selected for off-peak and shoulder peak also worked for system peak. The cases are summarized in Table 2.17 for shoulder peak loading condition. Figure 2.11 plots the voltages for each of the studied cases in Table 2.17.

Table 2.17. Case description - peak[19]

Cases #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
#0	900 kVAR	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	900 kVAR	7	set 1 - 4	UPF	100%	No	2222	-198,-196,-202,-103	-699
#8	900 kVAR	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2195	-806	-2219
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2173	-1108	
		2	set 3	UPF	100%	No	2222	-202	
		1	set 4	UPF	100%	No	2222	-103	
#13	900 kVAR	2	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2195	-806	-2219
		2	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2173	-1108	

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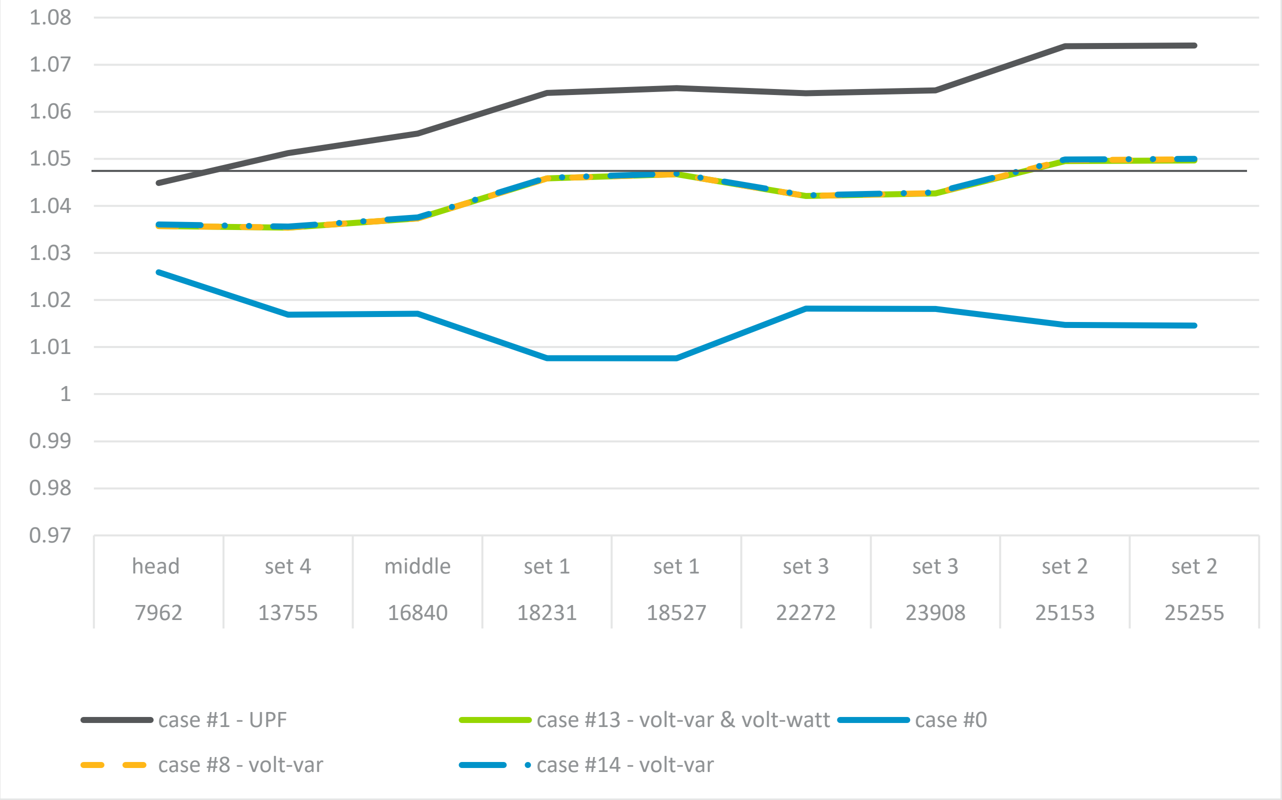
[19] Volt-Var control was modeled with “vars precedence over watts”

Cases #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3 and set 4)	Total_kVAR absorption at the PCC
		2	set 3	UPF	100%	No	2222	-202	
		1	set 4	UPF	100%	No	2222	-103	
#14	900 kVAR, 1800 kVAR	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	2190	-818	-2242
		2	set 2	Volt-Var	2% from 1.04 to 1.06	No	2153	-1117	
		2	set 3	UPF	100%	No	2222	-203	
		1	set 4	UPF	100%	No	2222	-104	

Figure 2.11. Feeder B Nodal voltages - peak



Based on the plots in Figure 2.11, the control functions that work for off-peak and shoulder peak also work for system peak conditions. As seen in the shoulder peak case where voltages exceeded the off-peak case, voltage seen in peak case #1 exceeded the voltage in the off-peak and shoulder peak cases. As stated before, this is because the station regulator has a high value of resistive compensation. This moves the setpoint higher for higher loads. This calls for an adjustment of the “R” compensation values after further analysis.

2.3.3 Feeder C overview

The feeder layout is shown in Figure 2.12. Much of the backbone consists of size 336 MCM conductor. The feeder currently has no existing generation. The feeder models a regulator at the feeder head with a 125 V voltage setpoint, and reverse operating mode set to “Co-generation”. The feeder also models a line regulator with a 125 V voltage setpoint, and no reverse operating mode.

To evaluate active/reactive power controls, feeder C modeled a total of 6.66 MVA of DER with smart inverter capability (highlighted with green markers in Figure 2.12). The DER are added at locations to cover the length of the feeder and where maximum voltage change is expected. As per Duke’s interconnection guidelines, generation can interconnect between the source and the first line regulator.

Figure 2.12. Feeder C layout

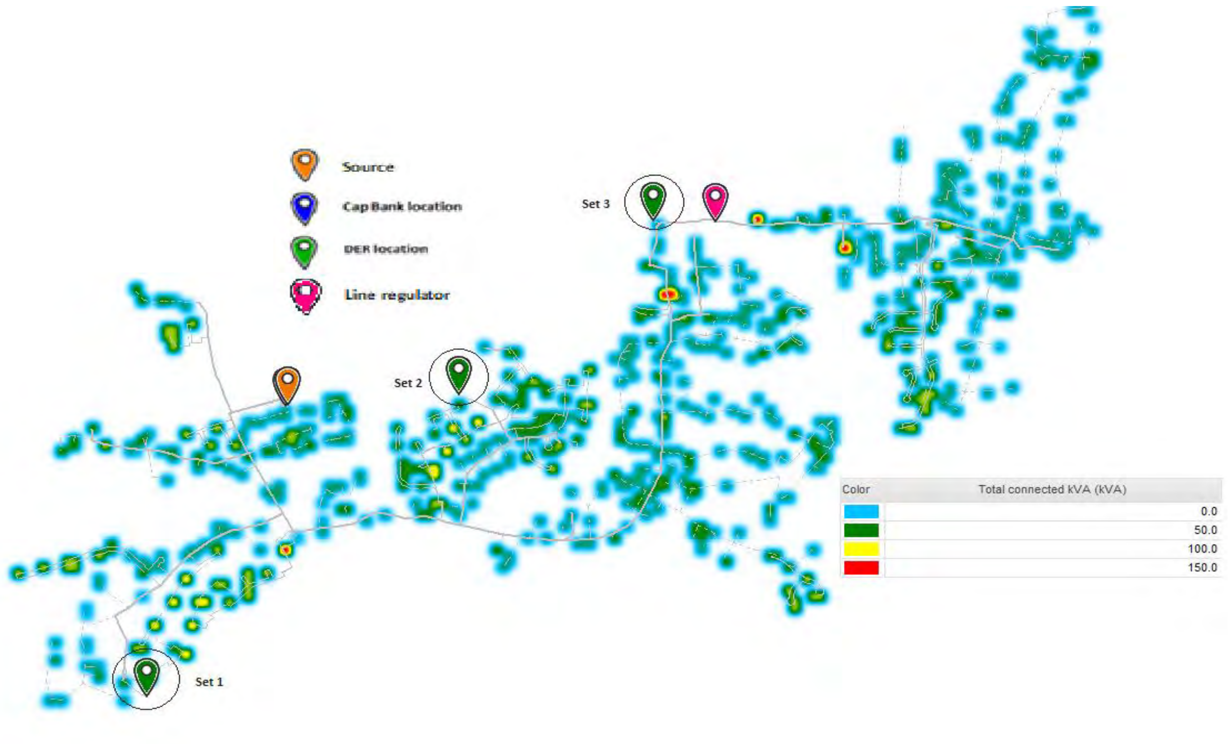


Table 2.18. Feeder C generation modeling

Generation	Value
Existing generation (end of feeder)	0 KVA
Generation with smart inverter capability modeled in set 1	2.22 MVA
Generation with smart inverter capability modeled in set 2	2.22 MVA
Generation with smart inverter capability modeled in set 3	2.22 MVA

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 15.5 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. As in the previous feeders, dV/dP and dV/dQ response curves were computed under off-peak conditions.

Figure 2.13 shows the response curves for Feeder C under off-peak conditions (see section 2.3.3.1 for more details on off-peak case modeling).

Figure 2.13. Response Curves – off peak conditions

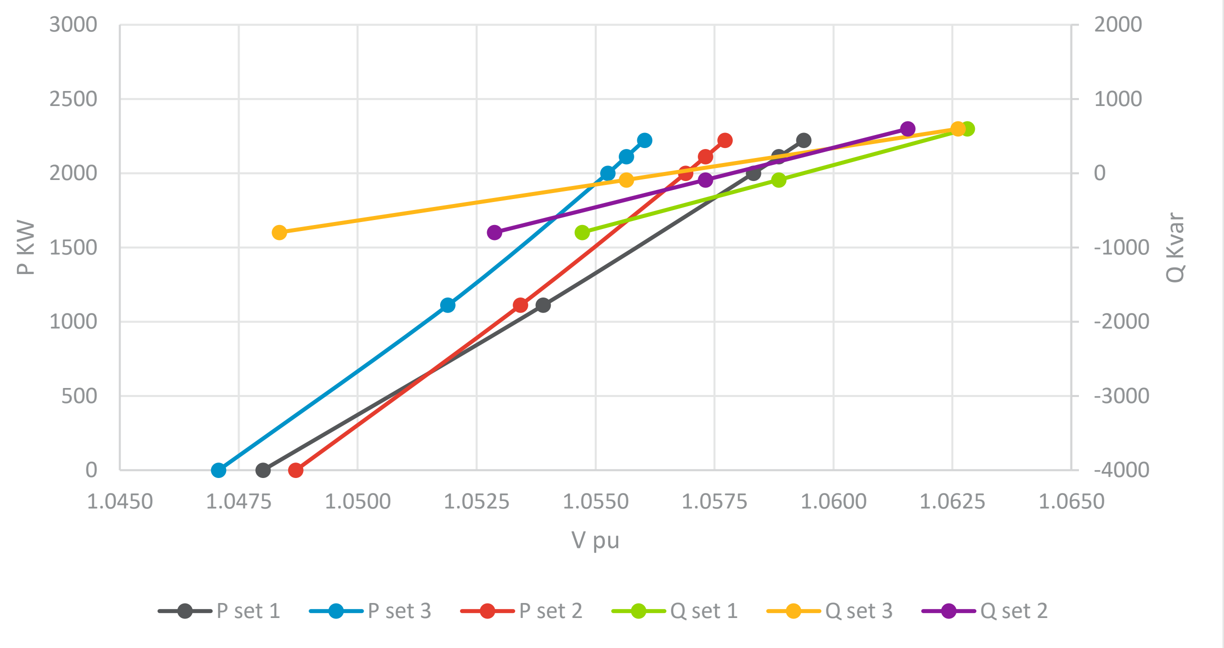


Table 2.19. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1	DER location – set 2	DER location – set 3
dV/dP	1.15%	0.91%	0.91%
dV/dQ	0.57%	0.61%	1.00%
Qresp/Presp	0.49	0.67	1.01
SCMVA	62	62	50
X/R	2.01	2.44	3.04

The response curve slopes show that all three sets of DER have similar and low dV/dP values. This indicates that adding generation at any of the locations will have a similar voltage variation due to addition of DERs. Moreover, the set 1 to set 2 locations have low dV/dQ value (set 3 is about double). Although Volt-Var control will have somewhat of a muted impact in mitigating voltage violations, the voltage violations would themselves be low as the dV/dP values are also lower. It is clear from the charts that only set 3 has the potential to reduce voltage below 1.05 pu using reactive power. Therefore, as in previous cases, Volt-Var control or a combination of Volt-Var and Volt-Watt control could work for this feeder. Additionally, all location sets exceed 1.05 pu voltage at UPF. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.3.1 Off-Peak Load Study Results

Feeder C was first studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in Table 2.20.

Table 2.20. Feeder C off-peak load characteristics

Feeder load characteristics	Value
Total load KW	1237.3
Total load kVAR	225.8
load PF	98.4%
Total load KVA	1257.7
Total KVA (peak load)	7053.9
Feeder Load Factor	38.0%
Total load as a % of peak load	17.8%

From case #0 and case #1 developed, the next set of cases model DER with either Volt-Var, Volt-Watt, watt-var or a combination to evaluate which control function provides the most optimal response. These cases are summarized in Table 2.21 for off-peak loading condition.

Figure ***2.14*** plots the voltages for each of the studied cases in Table 2.21.

Table 2.21. Cases description – off peak[20]

Case #	Caps	Resgulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3)	Total_kVAR absorption at the PCC
#0	N/A	-3,-2,-2/-1,-1,0	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	N/A	-3,-2,-2/-2,-1,-1	3	set 1 - 3	UPF	100%	No	2222	-99,-99,-99	-297
#8	N/A	-3,-2,-2/-1,-1,0	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2155	-638	-1877
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2184	-498	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2127	-741	

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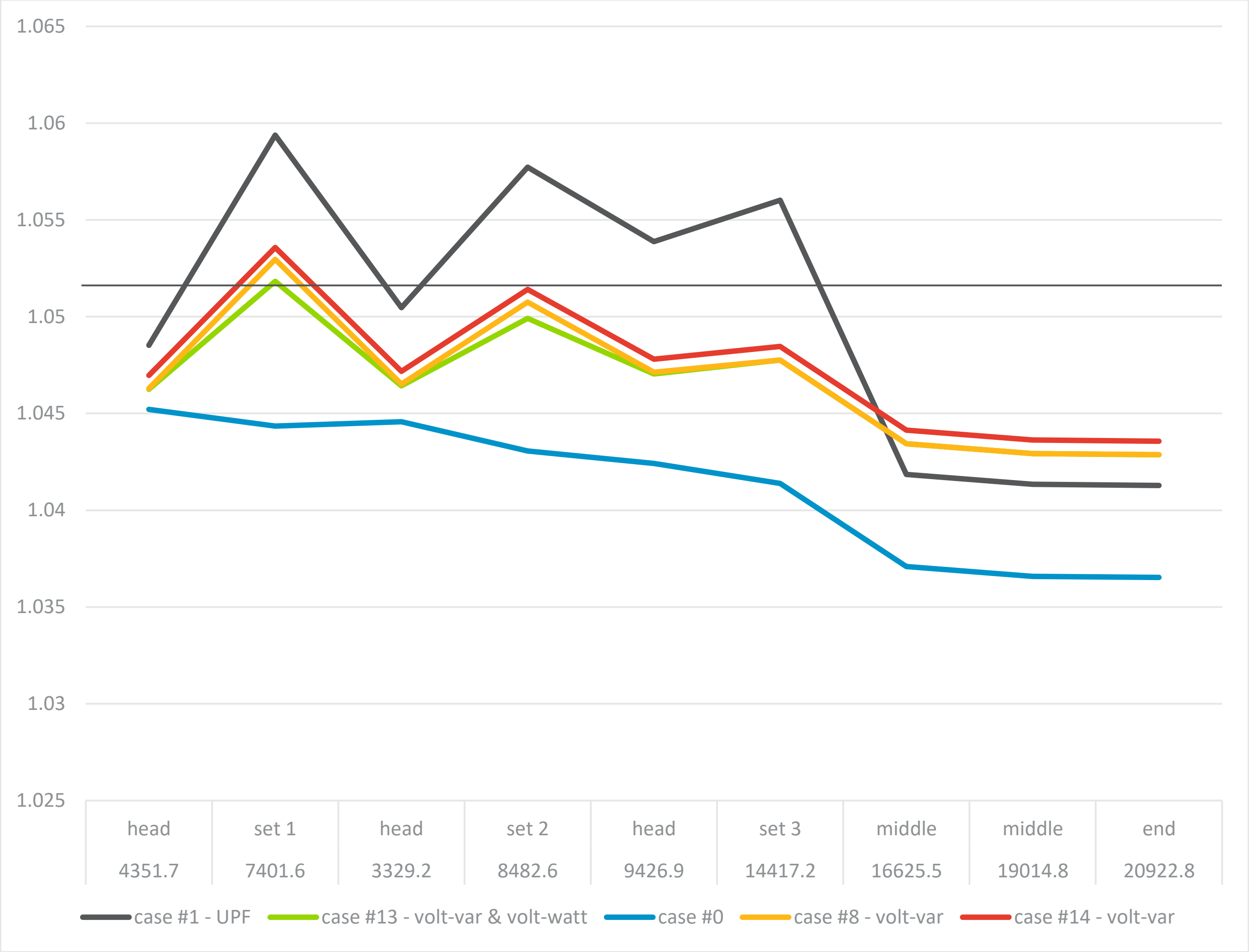
[20] Volt-Var control was modeled with “vars precedence over watts”

Case #	Caps	Resgulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3)	Total_kVAR absorption at the PCC
#13	N/A	-3,-2,-2/-1,-1,0	1	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2155	-638	-1877
			1	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2184	-498	
			1	set 3	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	Yes	2127	-741	
#14	1900 kVAR	-3,-2,-2/-1,-1,0	1	set 1	Volt-Var	2% from 1.04 to 1.06	Yes	2126	-751	-1889
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2157	-643	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2189	-495	

From Table 2.21 we see that if DER were to interconnect under existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.06 pu. Case #8 with Volt-Var control mitigates overvoltages seen in Case #1 (although there is a small overvoltage of 1.051 pu at set 2 location). From Case 8, the DER units consume a total of ~1900 kVAR requiring reactive power compensation to offset the additional reactive power consumption from the transmission system. Therefore, Case #14 models new shunt capacitors to compensate the transmission system for reactive power consumed on the feeder. As noted above, only set 3 brought the voltage within limits. More aggressive settings that provide more reactive power absorption are needed for the controllers to absorb more reactive power, which may or may not correct voltage at the other locations. More aggressive settings must be balanced with the concerns for controller stability. Such concerns are currently under evaluation by EPRI, but there is minimal information at this time. These results continue to indicate that Volt-Watt would be another possible controller that could be added with the Volt-Var.

The new shunt capacitors were modeled at locations where both SC MVA and system X/R ratio is higher which is a node very near to the substation.

Figure 2.14. Feeder C Nodal Voltages – off peak



2.3.3.2 Shoulder Peak Load Study Results

Feeder C was later studied for shoulder peak loading conditions. The analysis was carried out to verify if the control selected for the off-peak loading condition also worked for the shoulder peak loading condition. The feeder shoulder peak loading characteristics are shown in Table 2.22**Error! Reference source not found.**.

Table 2.22. Feeder C shoulder-peak load characteristics

Feeder load characteristics	Value
Total load KW	4019.0
Total load kVAR	1281
load PF	95.2%
Total load KVA	4218.2
Total KVA (peak load)	7053.9
Total load as a % of peak load	59.8%

As in the off-peak case, a “current system base case” was created for shoulder peak which represented the existing system topology (no DER modeled). A “base case with DER” was created which modeled 6.66 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively.

The next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate the control function selected for off-peak also worked for shoulder peak. These cases are summarized in

Table 2.23 for shoulder peak condition.

Table 2.23. Case description - shoulder peak[21]

Case #	Caps	Regulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3)	Total_kVAR absorption at the PCC
#0	N/A	'-2,0,0/2,0,3	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	N/A	'-2,0,0/0,0,1	3	set 1 - 3	UPF	100%	No	2222	-99,-99,-99	-297
#8	N/A	'-2,0,0/0,0,1	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2213	-302	-931
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2222	-103	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2181	-526	

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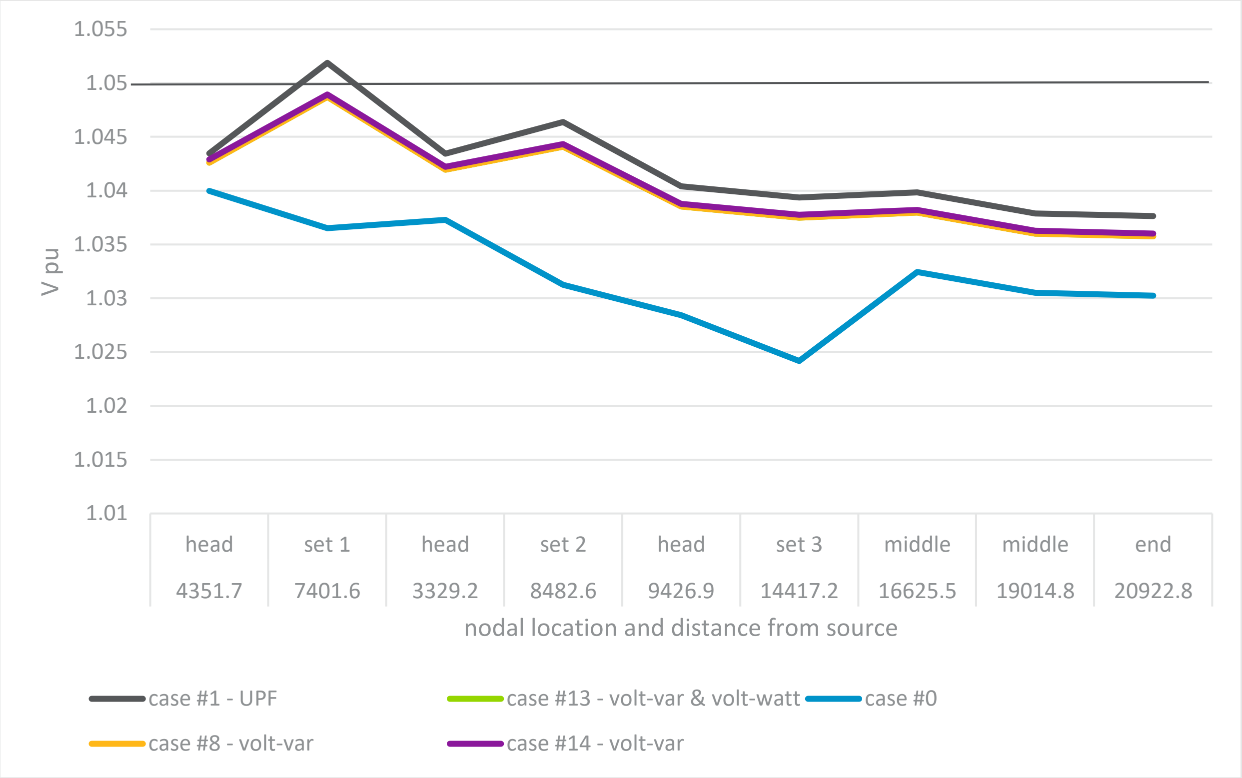
[21] Volt-Var control was modeled with “vars precedence over watts”

Case #	Caps	Regulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter _KVA	kVAR absorption at the PCC (set 1, set 2, set 3)	Total_kVAR absorption at the PCC
#13	N/A	'-2,0,0/0,0,1	1	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2213	-302	-931
			1	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2222	-103	
			1	set 3	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2181	-526	
#14	900 kVAR	'-2,0,0/0,0,1	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2179	-537	-953
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2212	-313	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2222	-103	

Figure 2.15. Feeder C Nodal voltages - shoulder peak

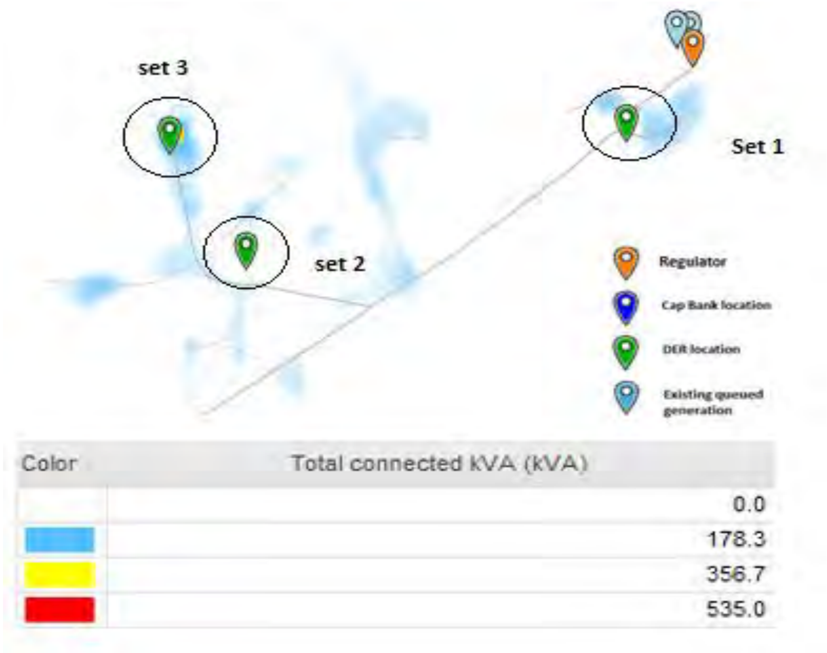


Based on the plots in Figure 2.15**Error! Reference source not found.**, the control functions are better able to maintain voltage with limits for shoulder load conditions. Off-peak remains the worse reactive power absorption case.

2.3.4 Feeder D overview

The feeder layout is shown in Figure 2.16 The feeder currently has 10 MW of existing generation (highlighted with cyan marker in Figure 2.16). The feeder also models a feeder head regulator with a 125 V voltage setpoint, and operating mode set to “bi-directional”. To evaluate active/reactive power controls, feeder A modeled a total of 6 MW of DER with smart inverter capability (highlighted with green markers in (Figure 2.16). The DER are added at locations to cover the length of the feeder and where maximum voltage change is expected.

Figure 2.16. Feeder D layout



Color	Total connected kVA (kVA)
	0.0
🟦	178.3
🟨	356.7
🟥	535.0

Table 2.24. Feeder D generation modeling

Generation	Value
Existing generation (end of feeder)	10 MW/10 MVA
Generation with smart inverter capability modeled in set 1 location	2 MW/2.22 MVA
Generation with smart inverter capability modeled at the middle section	2 MW/2.22 MVA
Generation with smart inverter capability modeled at the end section	2 MW/2.22 MVA

dV/dP and dV/dQ response curves show the impact of injecting active and reactive power. These curves give an indication of what control strategy might be most suitable for each location. Figure 2.17 shows the response curves for Feeder D under off-peak conditions (see section 2.3.4.1 for more details on off-peak case modeling).

Figure 2.17. Response Curves

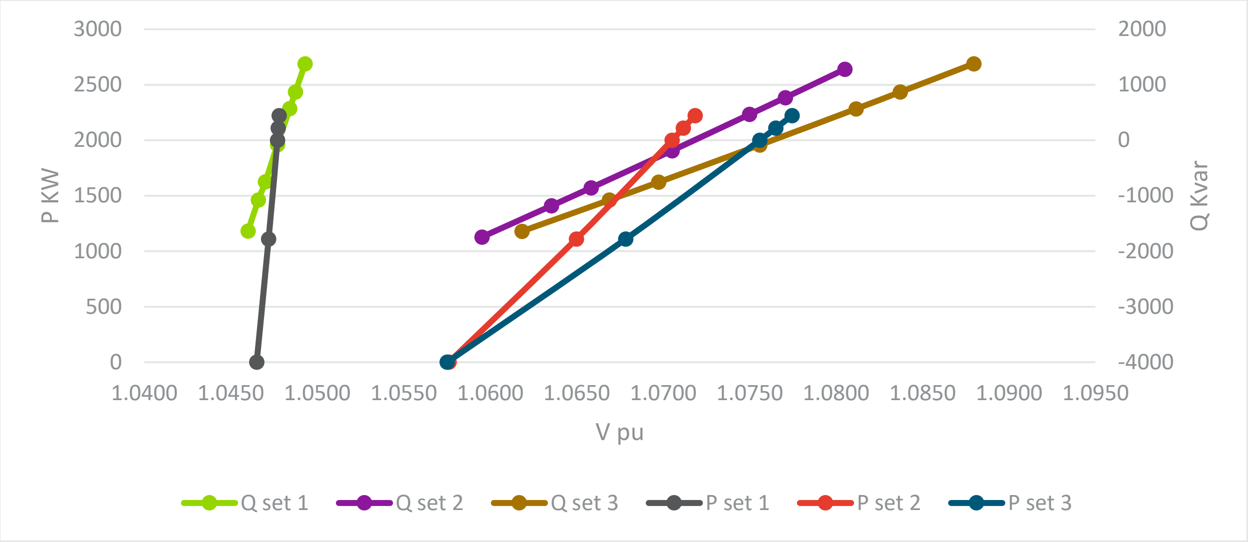


Table 2.25. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1	DER location – set 2	DER location – set 3
dV/dP	0.13%	1.43%	2.01%
dV/dQ	0.11%	0.68%	0.85%
Qresp/Presp	0.81	0.47	0.42
SCMVA	129	62	52
X/R	5.80	1.72	1.43

The response curve slopes show that, the set 3 location has a higher dV/dP value as opposed to set 1 and set 2 locations. This indicates that adding generation at set 3 location will have a larger voltage variation due to addition of DERs. The charts also show there is not enough var capability to reduce voltage below 1.05 pu. Also, the dV/dQ value is low and indicates that some of the voltage rise cannot be mitigated. At set 1 location, neither active or reactive power impact the voltage significantly and this is represented by the very low response values. Sets 2 and 3 exceed 1.05 pu voltage at UPF. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.4.1 Off-Peak Load Study Results

Feeder D was first studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in the Table 2.26 below.

Table 2.26. Feeder D off-peak load characteristics

Feeder load characteristics	Value
Total load KW	252.2
Total load kVAR	94.7
load PF	94.0%
Total load KVA	269.4
Total KVA (peak load)	7103.8
Total load as a % of peak load	3.8%

From case #0 and case #1 developed, the next set of cases model DER with either Volt-Var, Volt-Watt, watt-var or a combination to evaluate which control function provides the most optimal response. These cases are summarized in Table 2.27 for off-peak loading condition. Figure 2.18. Feeder D Nodal Voltages – off peak plots the voltages for each of the studied cases in Table 2.27.

Table 2.27. Cases description – off peak[22]

Case #	Caps	Number of DER units	Location	Control type	Control outline	Gen outside 0.95 pf limit	Inverter_KW	kVAR absorption at the PCC	total kVAR
#1	none	3	set 1,set 2,set 3	UPF	UPF	No	2000	-82,-78,-86	-246
#5	none	1	set 1	Volt-Var	3% from 1.04 to 1.07	No	2000	-276	-1897
#5	none	1	set 2	Volt-Var	3% from 1.04 to 1.07	Yes	1999	-744	
#5	none	1	set 3	Volt-Var	3% from 1.04 to 1.07	Yes	1999	-877	
#6	none	1	set 1	Volt-Watt	3% from 1.06 to 1.09	No	2000	-82	-198
#6	none	1	set 2	Volt-Watt	3% from 1.06 to 1.09	No	1769	-63	
#6	none	1	set 3	Volt-Watt	3% from 1.06 to 1.09	No	1490	-53	

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[22] Volt-Var control was modeled with “watts precedence over vars”

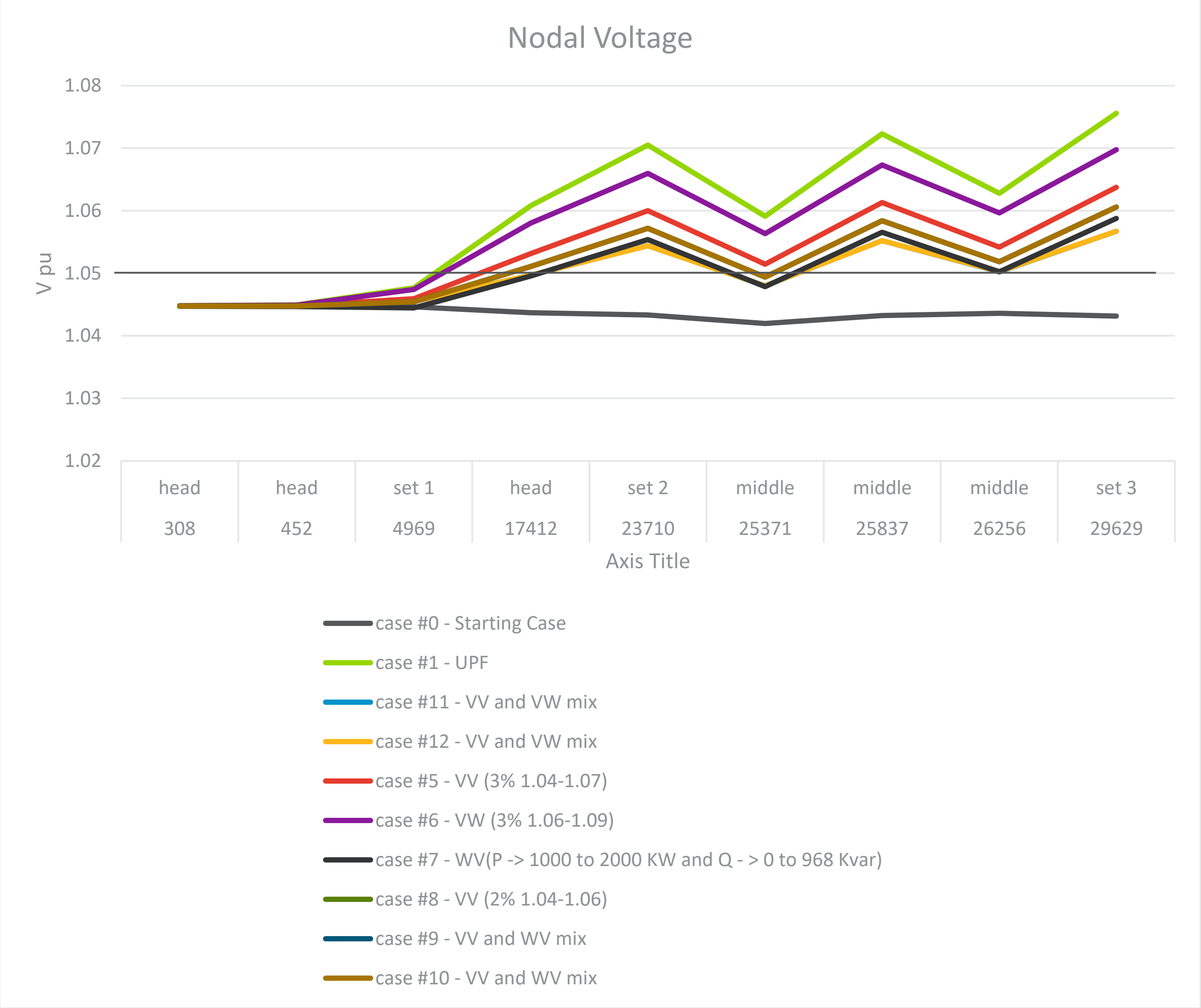
Case #	Caps	Number of DER units	Location	Control type	Control outline	Gen outside 0.95 pf limit	Inverter_KW	kVAR absorption at the PCC	total kVAR
#7	none	3	set 1,set 2,set 3	watt-var	P_1000->2000kW Q_0-928kvar or 0.9 pf	Yes	2000	-1075,-1072,-1078	-3225
#8	none	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-347	-2341
#8	none	1	set 2	Volt-Var	2% from 1.04 to 1.06	Yes	1999	-923	
#8	none	1	set 3	Volt-Var	2% from 1.04 to 1.06	Yes	1999	-1071	
#9	none	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-346	-2341
#9	none	1	set 2	Volt-Var	2% from 1.04 to 1.06	Yes	1999	-923	
#9	none	1	set 3	watt-var	P_1000->2000kW Q_0-928kvar or 0.9 pf	Yes	1999	-1072	
#10	2400 kVAR (set 1)	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-346	-2341
#10	2400 kVAR (set 1)	1	set 2	Volt-Var	2% from 1.04 to 1.06	Yes	1999	-923	
#10	2400 kVAR (set 1)	1	set 3	watt-var	P_1000->2000kW Q_0-928kvar or 0.9 pf	Yes	1999	-1072	
#11	none	1	set 1	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	No	2000	-352	-1934

Case #	Caps	Number of DER units	Location	Control type	Control outline	Gen outside 0.95 pf limit	Inverter_KW	kVAR absorption at the PCC	total kVAR
#11	none	1	set 2	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	Yes	1679	-752	
#11	none	1	set 3	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	Yes	1449	-830	
#12	2000 kVAR (set 1)	1	set 1	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	No	2000	-352	-1934
#12	2000 kVAR (set 1)	1	set 2	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	Yes	1679	-752	
#12	2000 kVAR (set 1)	1	set 3	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 2% from 1.05 to 1.07	Yes	1449	-830	

If DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.075 pu. Case #7 with watt-var control which utilized the maximum reactive capability of the DER units still could not mitigate overvoltages seen in Case #1. Therefore, it is not possible to integrate 6 MW of new DER on this feeder at UPF.

Case #9 and Case #11 results indicate the units consume a total of ~2350 and ~1950 kVAR respectively requiring reactive power compensation to compensate for the additional reactive power consumption by the DERs. Therefore, Case #10 and Case #12 modeled new shunt capacitors to compensate for reactive power consumption from the transmission system. The shunt capacitors were modeled at locations where both SC MVA and system X/R ratio is higher. This would ensure voltages are not negatively impacted by the addition of shunt capacitors.

Figure 2.18. Feeder D Nodal Voltages – off peak



2.3.4.2 Shoulder Peak Load Study Results

Feeder D was later studied for shoulder peak loading conditions. This analysis was carried out to verify if the control selected for the off-peak loading condition also worked for the shoulder peak loading condition. The feeder shoulder peak loading characteristics are shown in Table 2.28.

Table 2.28. Feeder D shoulder-peak load characteristics

Feeder load characteristics	Value
Total load KW	4241.2
Total load kVAR	314.2
load PF	99.7%
Total load KVA	4253.0
Total KVA (peak load)	7103.8
Total load as a % of peak load	59.8%

A "current system base case" was created which represented the existing system topology (no DER with smart inverter capability modeled). A "base case with smart inverter capability enabled DERs" was created which modeled 6 MW of DER added at UPF. These cases are referred to as case #0 and case #1 respectively. The next set of cases model DER with either Volt-Var, watt-var or a combination of Volt-Var and Volt-Watt to evaluate the control function selected for off-peak also worked for shoulder peak. These cases are summarized in Table 2.29 for shoulder peak loading condition.

Figure 2.19 shows the plots of voltages for each of the studied cases in Table 2.29.

Table 2.29. Case description - shoulder peak[23]

Case #	Caps	Number of DER units	Location	Control type	Control outline	Gen outside 0.95 pf limit	Inverter_KW	kVAR absorption at the PCC	total kVAR
#1	none	3	set 1,set 2,set 3	UPF	UPF	No	2000	-83,-82,-82	-247
#8	none	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2000	-124	-791
#8	none	1	set 2	Volt-Var	2% from 1.04 to 1.06	Yes	2000	-287	
#8	none	1	set 3	Volt-Var	2% from 1.04 to 1.06	Yes	2000	-380	
#14	1000 kVAR	1	set 1	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 3% from 1.06 to 1.09	No	2000	-125	-794

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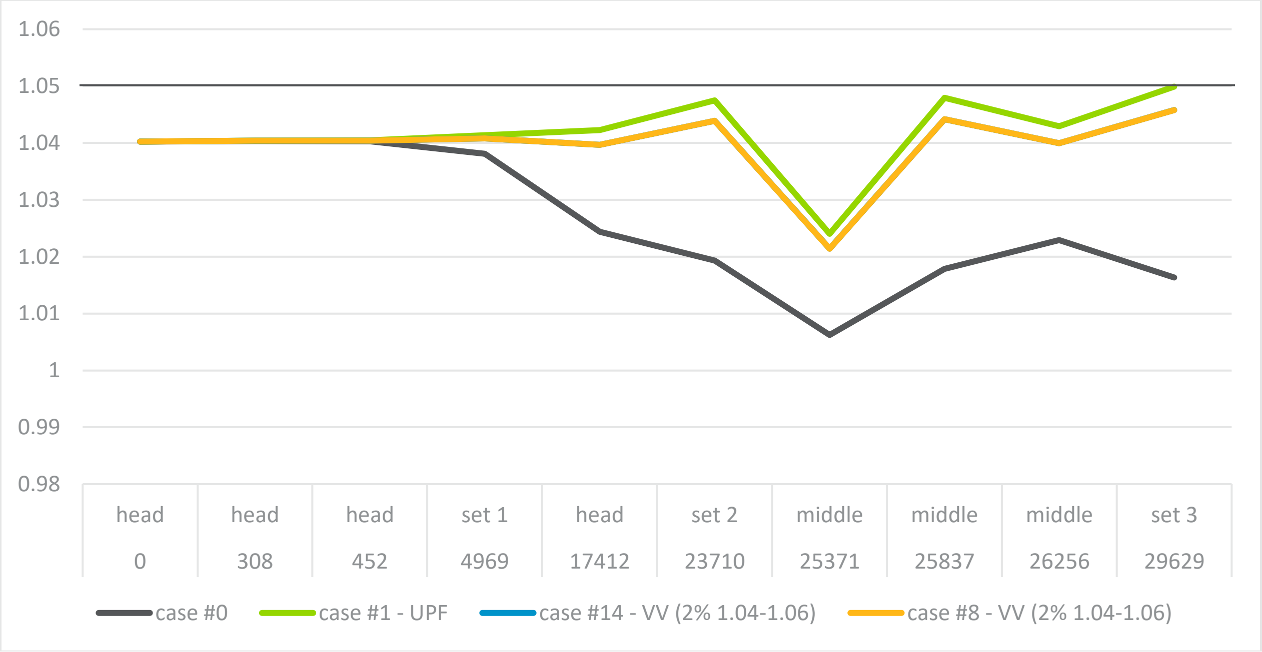
[23] Volt-Var control was modeled with "watts precedence over watts"

Case #	Caps	Number of DER units	Location	Control type	Control outline	Gen outside 0.95 pf limit	Inverter_KW	kVAR absorption at the PCC	total kVAR
#14	1000 kVAR	1	set 2	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 3% from 1.06 to 1.09	Yes	2000	-288	
#14	1000 kVAR	1	set 3	Volt-Var and Volt-Watt	Volt-Var: 2% from 1.04 to 1.06 and Volt-Watt - 3% from 1.06 to 1.09	Yes	2000	-381	

Figure 2.19. Feeder D Nodal voltages - shoulder peak



Based on the plots in

Figure 2.19, voltages for case #8 with Volt-Var control mitigates voltage issues seen in case #1. Off-peak remains the worse reactive power absorption case.

2.3.5 Feeder E overview

The feeder layout is shown in Figure 2.20. Much of the backbone consists of size 477 MCM conductor. The feeder has three cap banks (highlighted with blue marker in Figure 2.20) rated 600 kVAR each. The feeder currently has no existing generation. To evaluate active/reactive power controls, feeder A modeled a total of 17.76 MVA of DER with smart inverter capability (highlighted with green markers in Figure 2.20). The DER are added at locations to cover the length of the feeder and where maximum voltage change is expected.

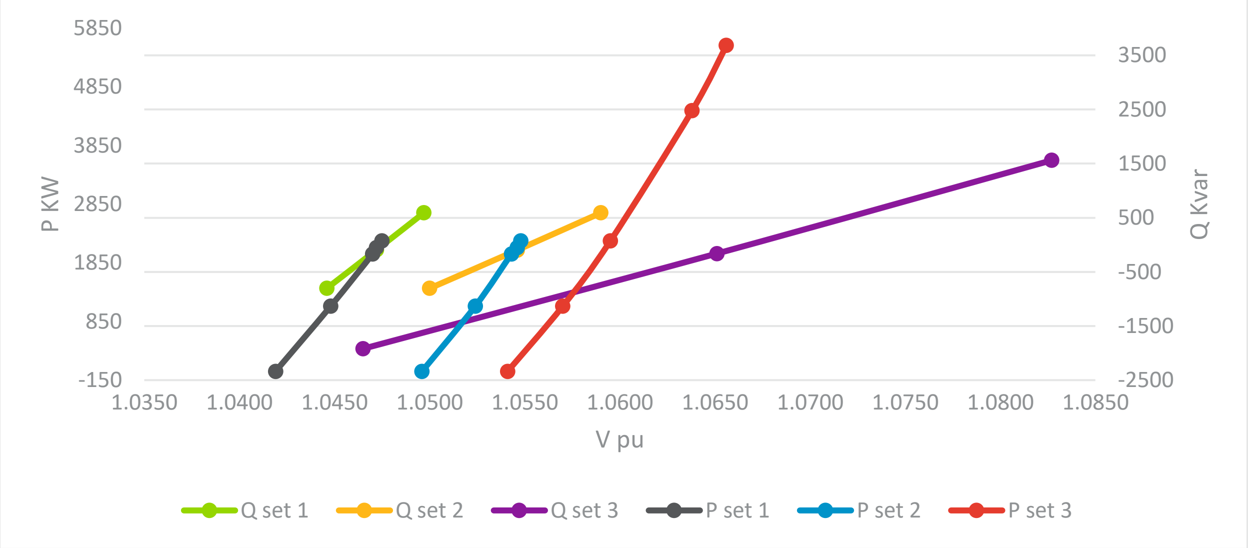
Table 2.30. Feeder E generation modeling

Generation	Value
Existing generation	0 KVA
Generation with smart inverter capability modeled in set 1	2.22 MVA
Generation with smart inverter capability modeled in set 2	2.22 MVA
Generation with smart inverter capability modeled in set 3	5.55 MVA
Generation with smart inverter capability modeled in set 4	2.22 MVA
Generation with smart inverter capability modeled in set 5	5.55 MVA

Figure 2.20. Feeder E layout

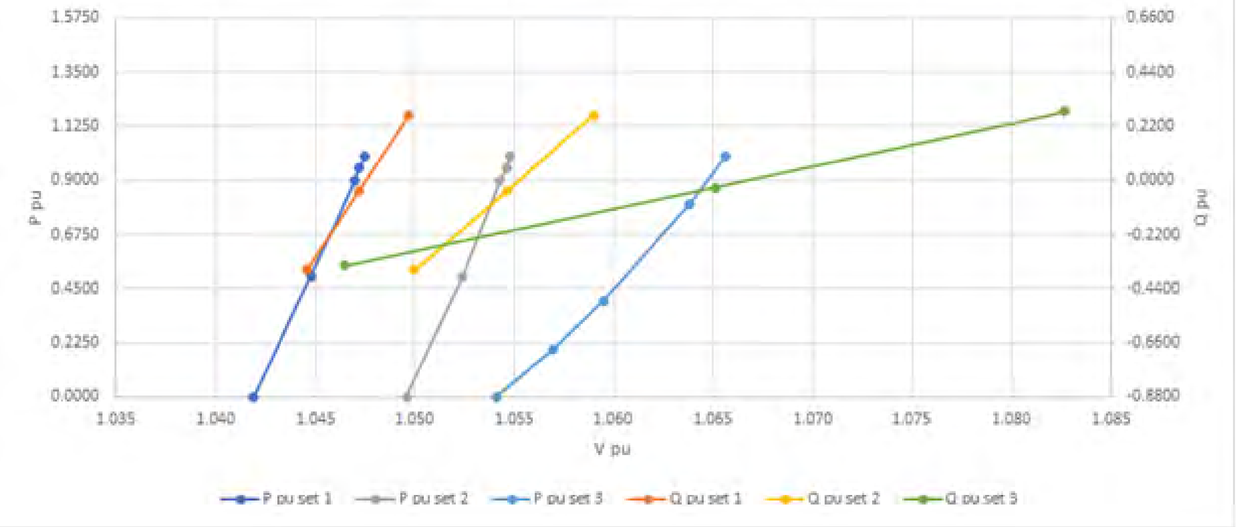
A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 17.76 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. As in previous feeders, dV/dP and dV/dQ response curves were computed under off-peak conditions. Figure 2.21 and Table 2.32 show the response curves and feeder characteristics for Feeder E under off-peak conditions (see section 2.3.5.1 for more details on off-peak case modeling).

Figure 2.21. Feeder E Response Curves (kW and kVar) – off peak conditions



This chart does look different from the others because this feeder has various sizes of DER. In such cases, the chart must be normalized by converting to a pu basis, which gives the more uniform curves. Figure 2.22 is the same as Figure 2.21 but in pu to develop more uniform curves for analysis. However, that change can make it a little more difficult to relate to the actual active and reactive magnitudes. The reactive power for 0.95 pf, the maximum magnitude represented by the reactive lines shown below, is much larger for the 5 MW DER than the 2 MW DER (although they both stop at 0.31 pu Q. This difference in magnitude can be lost on charts formatted this way.

Figure 2.22. Feeder E Response curves pu - off-peak conditions



One point of application: The Q line for the 5 MW DER can be moved graphically down along the dP line and that is the reactive power response for a DER at that kW value (the line will grow shorter because the rated reactive power decreases with the size of the DER, but the slope remains the same).

Table 2.31. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1	DER location – set 2	DER location – set 3
dV/dP	0.57%	0.52%	1.35%
dV/dQ	0.36%	0.63%	2.56%
Qresp/Presp	0.63	1.21	1.90
SCMVA	93	74	57
X/R	2.71	3.25	4.06

The response curve slopes show that, set 1 and set 2 locations have a high slope, or stated another way, that the voltage change is low for both active and reactive power injections. The high SC MVA at these locations directly impacts this and it translates to low dV/dP and dV/dQ values. Set 3 stands out as a good candidate for reactive power control because there is almost twice the reactive capability available to correct the voltage rise from the power injection. Therefore, as in previous cases, Volt-Var control or a combination of Volt-Var and Volt-Watt control is most applicable for locations further down the feeder. Sets 2 and 3 locations exceed 1.05 pu voltage at UPF. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.5.1 Off-Peak Load Study Results

Feeder E was first studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in Table 2.33.

Table 2.32. Feeder E off-peak load characteristics

Feeder load characteristics	Value
Total load KW	1505
Total load kVAR	593.5
load PF	93.0%
Total load KVA	1617.8
Total KVA (peak load)	5627.4
Feeder Load Factor	47.5%
Total load as a % of peak load	28.7%

From case #0 and case #1 developed, the next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate which control function provides the most optimal response. These cases are summarized in Table 2.33 for off-peak loading condition. plots the voltages for each of the studied cases in Figure 2.23.

Table 2.33. Cases description – off peak[24]

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set 4 and set 5)	Total_kVAR absorption at the PCC
#0	600 kVAR	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	600 kVAR	7	set 1,2,4	UPF	100%	No	2222	-101,-100,-98	-660
			set 3,5	UPF	100%	No	5555	-181,-180	
#8	600 kVAR	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2220	-174	-2770
		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2216	-256	
		1	set 3	Volt-Var	2% from 1.04 to 1.06	No	5466	-1012	
		1	set 4	Volt-Var	2% from 1.04 to 1.06	No	2184	-440	
		1	set 5	Volt-Var	2% from 1.04 to 1.06	No	5489	-888	
#13	600 kVAR	1	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2220	-174	-2770
		1	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2216	-256	
		1	set 3	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	5466	-1012	

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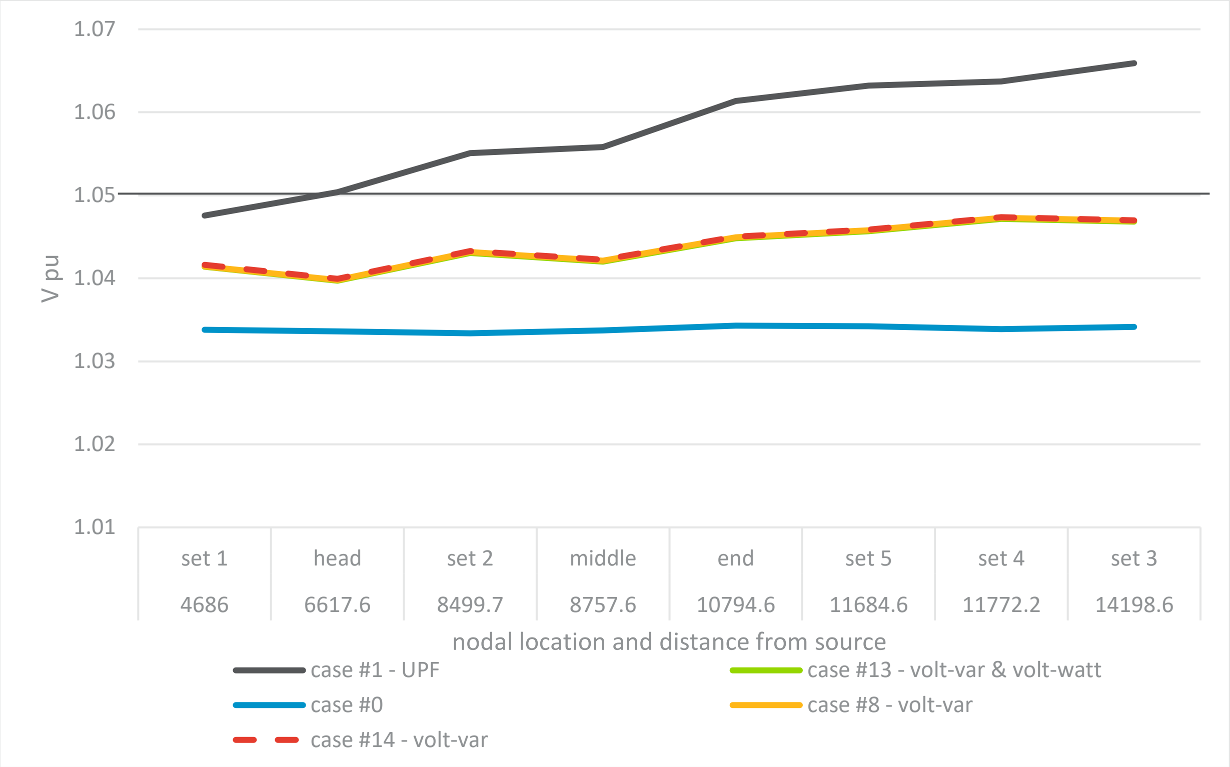
[24] Volt-Var control was modeled with "vars precedence over watts"

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set 4 and set 5)	Total_kVAR absorption at the PCC
		1	set 4	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2184	-440	
		1	set 5	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	5489	-888	
#14	600 kVAR , 2800 kVAR	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2220	-183	-2803
		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2216	-261	
		1	set 3	Volt-Var	2% from 1.04 to 1.06	No	5466	-1018	
		1	set 4	Volt-Var	2% from 1.04 to 1.06	No	2184	-444	
		1	set 5	Volt-Var	2% from 1.04 to 1.06	No	5464	-897	

Figure 2.23.Feeder E Nodal Voltages – off peak



If DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.065 pu. Case #8 with Volt-Var control mitigate overvoltages seen in Case #1. The DER consume a total of ~2800 kVAR requiring reactive power compensation to compensate for the additional reactive power consumption from the transmission system. Case #14 modeled new shunt capacitors in case #8 to compensate for reactive power consumption from the transmission system. The shunt capacitors were modeled at locations where both SC MVA and system X/R ratio was higher. This ensured voltages were not negatively impacted by the addition of shunt capacitors.

As shown in the voltage chart above, the middle of the feeder has a slight voltage decrease. Having a large DER at the end of the feeder may require the compensating capacitor(s) to be located at other feeder locations than at the feeder head. It may cause other issues to provide significant reactive power at the feeder head because of transferring the power, interactions with the intermediate DER, or line segment loading along the feeder. These additional aspects were not included in this study.

2.3.5.2 Shoulder Peak Load Study Results

Feeder E was later studied for shoulder peak loading conditions. This analysis was carried out to verify if the control selected for the off-peak loading condition also worked for the shoulder peak loading condition. The feeder shoulder peak loading characteristics are shown in Table 2.34.

Table 2.34. Feeder E should peak load characteristics

Feeder load characteristics	Value
Total load KW	3357.4
Total load kVAR	1148.2
load PF	94.6%
Total load KVA	3548.3
Total KVA (peak load)	5627.4
Total load as a % of peak load	63.1%

Table 2.35 Case description - shoulder peak[25]

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set 4 and set 5)	Total_kVAR absorption at the PCC
#0	1200 kVAR	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
#1	1200 kVAR	7	set 1,2,4	UPF	100%	No	2222	-101,-100,-98	-660
			set 3,5	UPF	100%	No	5555	-181,-180	
#8	1200 kVAR	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2216	-255	-3008
		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2212	-299	
		1	set 3	Volt-Var	2% from 1.04 to 1.06	No	5455	-1051	
		1	set 4	Volt-Var	2% from 1.04 to 1.06	No	2179	-458	
		1	set 5	Volt-Var	2% from 1.04 to 1.06	No	5477	-945	
#13	1200 kVAR	1	set 1	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2216	-255	-3008

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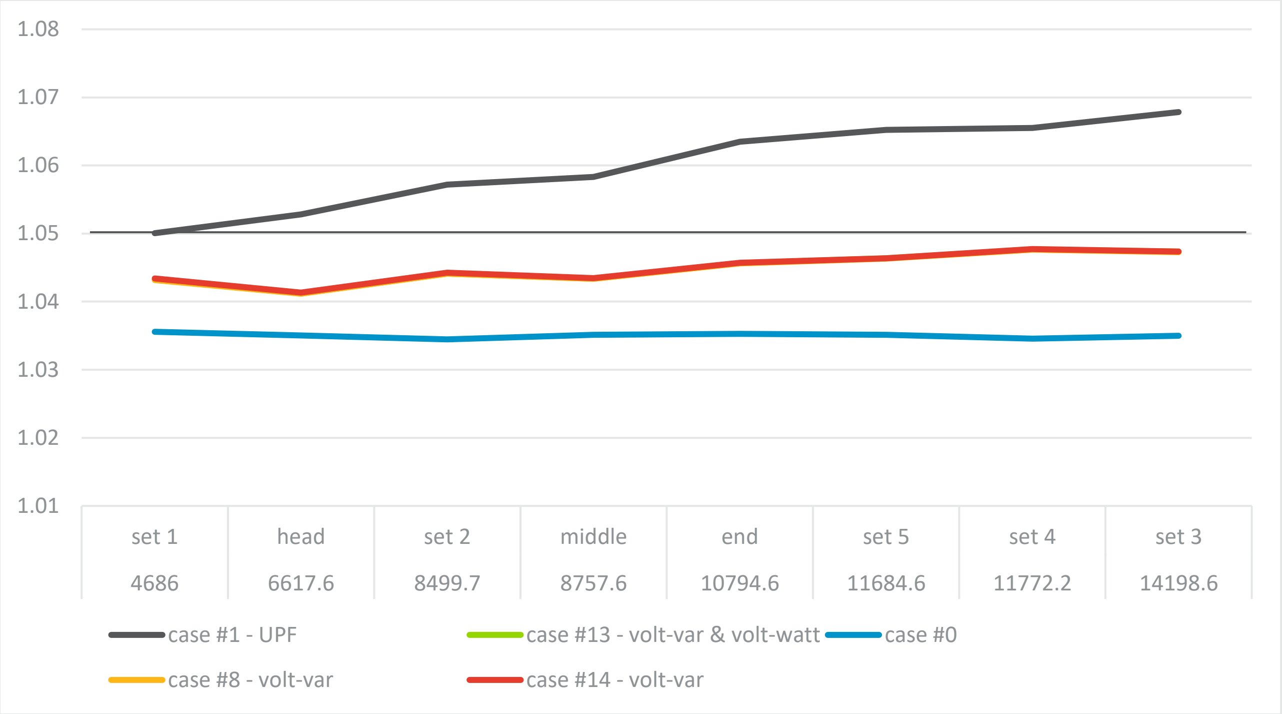
[25] Volt-Var control was modeled with “vars precedence over watts”

Case #	Caps	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter_KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set 4 and set 5)	Total_kVAR absorption at the PCC
		1	set 2	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2212	-299	
		1	set 3	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	5455	-1051	
		1	set 4	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	2179	-458	
		1	set 5	Volt-Var and Volt-Watt	2% from 1.04 to 1.06 and 3% from 1.06 to 1.09	No	5477	-945	
#14	1200 kVAR , 3000 kVAR	1	set 1	Volt-Var	2% from 1.04 to 1.06	No	2216	-265	-3046
		1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2212	-306	
		1	set 3	Volt-Var	2% from 1.04 to 1.06	No	5453	-1059	
		1	set 4	Volt-Var	2% from 1.04 to 1.06	No	2178	-462	
		1	set 5	Volt-Var	2% from 1.04 to 1.06	No	5475	-954	

As in the off-peak case, a “current system base case” was created for shoulder existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 17.76 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. The next set of cases model DER with either Volt-Var or a combination of Volt-Var and Volt-Watt to evaluate the control function selected for off-peak also worked for shoulder peak. Figure 2.25 plots the voltages for each of the studied cases in Table 2.35.

Figure 2.24. Feeder E Nodal voltages - shoulder peak



Based on the plots in Figure 2.24, the control functions that work for off-peak conditions would also work for shoulder peak conditions. It should be noted that shoulder peak case has a slightly higher reactive power requirement than the off-peak case. This is a concern because this implies that the DER would consume reactive power much of the time and the reactive compensation will be connected for extended periods. The potential of higher absorption for longer periods creates more concerns for feeder voltage management and should be investigated further if this condition could be likely.

2.3.6 Feeder F Overview

The feeder layout is shown in Figure 2.25. Much of the backbone consists of size 477 MCM conductor. The feeder has four cap banks (highlighted with blue marker in Figure 2.25) rated 600 kVAR each. The feeder currently has no existing generation. The feeder models a line regulator with a 125 V voltage setpoint, and operating mode set to “bi-directional”. To evaluate active/reactive power controls, feeder F modeled a total of 17.76 MVA of DER with smart inverter capability (highlighted with green markers in Figure 2.25). The DER are added at locations to cover the length of the feeder and where maximum voltage change is expected. As per Duke’s interconnection guidelines, generation can interconnect between the source and the first line regulator.

Figure 2.25. Feeder F layout

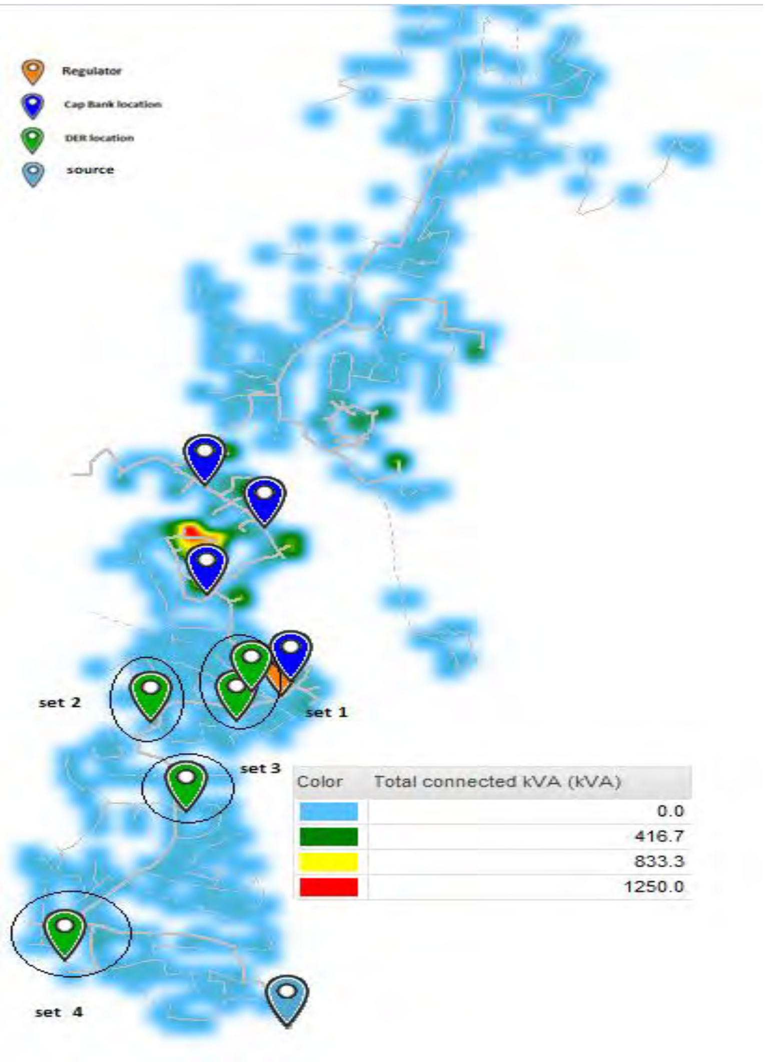


Table 2.36. Feeder F generation modeling

Generation	Value
Existing generation	0 KVA
Generation with smart inverter capability modeled in set 1	11.11 MVA
Generation with smart inverter capability modeled in set 2	2.22 MVA
Generation with smart inverter capability modeled in set 3	2.22 MVA
Generation with smart inverter capability modeled in set 4	2.22 MVA

A “current system base case” was created which represented the existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 17.76 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. dV/dP and dV/dQ response curves were computed under shoulder peak conditions as shoulder peak represented higher system voltages than off-peak. Figure 2.26 and Table 2.37 show the response curves and feeder characteristics for Feeder F under shoulder peak conditions (see section 2.3.6.1 for more details on shoulder peak case modeling). There are two different sizes of DER and the charts are formatted more for the 2 MW DER, so the reactive line for the 5 MW DER does not align with the active power line.

Figure 2.26. Feeder F Response Curves – shoulder peak conditions

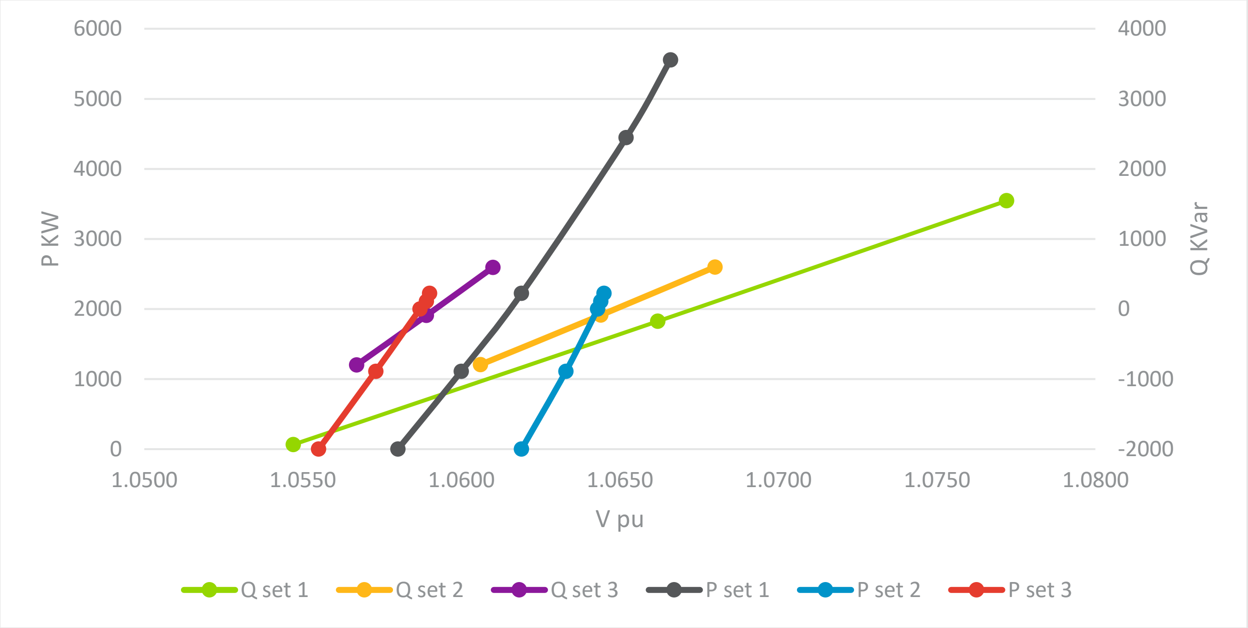


Table 2.37. dV/dP and dV/dQ response curves and feeder characteristics

	DER location – set 1[26]	DER location – set 2	DER location – set 3
dV/dP	0.98%	0.27%	0.36%
dV/dQ	1.58%	0.52%	0.30%
Qresp/Presp	1.62	1.95	0.85
SCMVA	80	88	109
X/R	4.25	4.39	3.34

The response curve slopes show that the SC MVA for all the three location sets is high indicating changes in active power and reactive power will have less impact on nodal voltages. This is also represented by the low response ratios. The 2 MW DER of set 3 does not even move the voltage ½%. This demonstrates that even when adding 17.76 MVA of generation the voltage impacts are much less when the DER are located close to the station. It reduces the voltage concerns, reduces the reactive power flow, and maintains the normal station to load power flow direction. Although SC MVA for all three location sets is high, location

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[26] Set 1 location has 5.55 MVA +/- 0.9 PF capability DER. The response curves were calculated for this configuration.

set 1 and 2 have a high X/R ratio indicating the feeder is more sensitive to reactive power than active power. Therefore, Volt-Var could work at these locations but would be limited up to 1.6% voltage change.

Additionally, at all location sets, the voltage exceeds 1.05 pu voltage at UPF, however the chart and responses indicate that no single inverter can bring the node voltage within limit using only reactive power. Therefore, the study would focus on controls that would reduce this voltage below 1.05 pu.

2.3.6.1 Shoulder Peak Load Study Results

Feeder F was studied for shoulder peak loading condition. The feeder shoulder peak loading characteristics are shown in Table 2.38.

Table 2.38. Feeder F should peak load characteristics

Feeder load characteristics	Value
Total load KW	4030.5
Total load kVAR	802.9
load PF	98.1%
Total load KVA	4110.4
Total KVA (peak load)	6678.7
Feeder Load Factor	57.1%
Total load as a % of peak load	61.5%

A “current system base case” was created for shoulder existing system topology (no DER with smart inverter capability modeled). A “base case with smart inverter capability enabled DERs” was created which modeled 17.76 MVA of DER at UPF. These cases are referred to as case #0 and case #1 respectively. The next set of cases model DER with either Volt-Var to evaluate the control function for shoulder peak. Figure 2.27 plots the voltages for each of the studied cases in Table 2.39

Table 2.39 Case description - shoulder peak[27]

Cases	Caps	Regulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter _KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set4)	Total_kVAR absorption at the PCC
	N/A	-1, 0, 1	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	600 kVAR	-4, -3, -2	2	set 1	UPF	UPF	No	5555	-203,-203	-700
			1	set 2	UPF	UPF	No	2222	-98	
			1	set 3	UPF	UPF	No	2222	-98	

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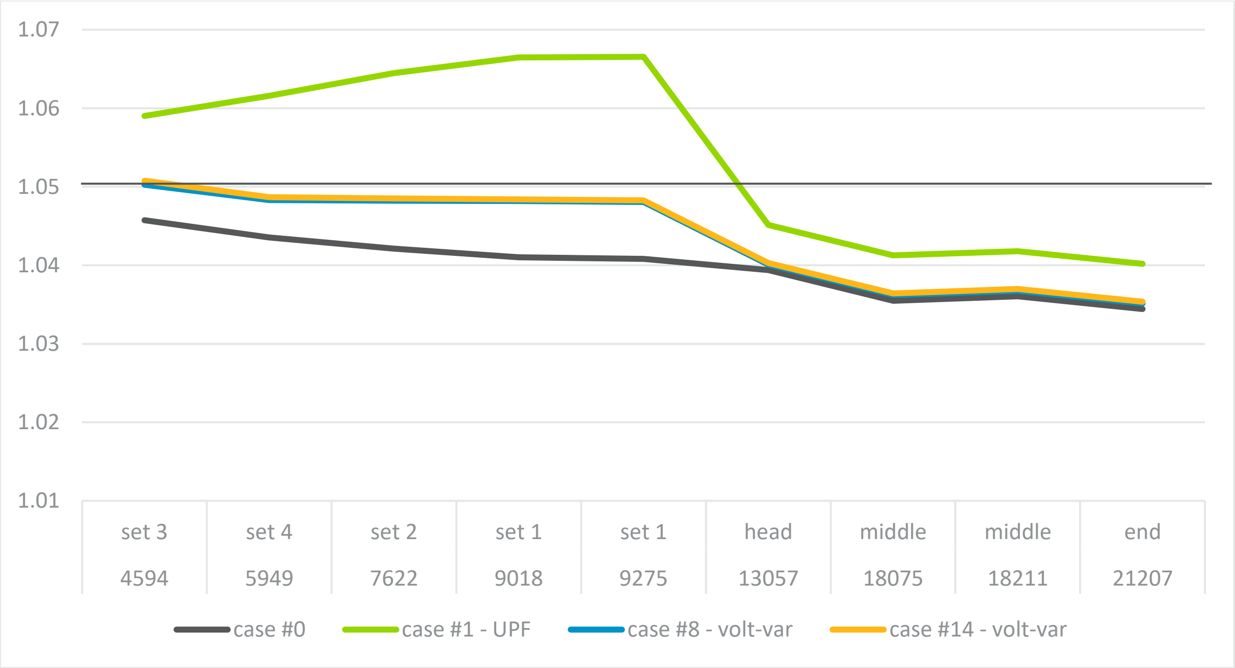
[27] Volt-Var control was modeled with “vars precedence over watts”

			1	Set 4	UPF	UPF	No	2222	-98	
	600 kVAR	-2, -1, 0	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	5431	-1205,-1205	-3982
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2173	-496	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2163	-589	
			1	Set 4	Volt-Var	2% from 1.04 to 1.06	No	2177	-487	
	600 kVAR , 1400 kVAR	-2, -1, 0	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	5426	-1232,-1232	-4106
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2171	-508	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2157	-620	
			1	Set 4	Volt-Var	2% from 1.04 to 1.06	No	2174	-514	

Figure 2.27. Feeder F Nodal voltages - shoulder peak



If the DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be as high as 1.067 pu. Case #8 with Volt-Var control mitigates overvoltages seen in Case #1. Case #14 modeled new shunt capacitors in case #8 to compensate for reactive power consumption from the transmission system. The shunt capacitors were modeled at locations where both SC MVA and system X/R ratio was higher. This ensured voltages were not negatively impacted by the addition of shunt capacitors.

Because of the bus regulation, past data indicates that the feeder head voltage is higher at shoulder load than at off peak. This helps maintain the feeder load voltages closer to the same voltage, but it results in more voltage violations under higher load conditions. Possibly peak load would require even more DER reactive compensation.

The shoulder voltage profile requires more DER compensation than the off-peak case, nearly double. More analysis and evaluation are required for such large DER reactive absorption at the DER and also the large compensation that is required to balance the feeder at the station. Note that while active power was reduced to provide the reactive power, all units remained above the rated active power for the 90% pf.

2.3.6.2 Off-Peak Load Study Results

Feeder F was studied for off-peak loading conditions. The feeder off-peak loading characteristics are shown in Table 2.40.

Table 2.40. Feeder F off-peak load characteristics

Feeder load characteristics	Value
Total load KW	517.4
Total load kVAR	135.9
load PF	96.7%
Total load KVA	535.0
Total KVA (peak load)	6678.7
Total load as a % of peak load	7.74%

From case #0 and case #1 developed, case #8 which models Volt-Var control is evaluated. These cases are summarized in Table 2.41**Error! Reference source not found.** for off-peak loading condition. Figure 2.28 plots the voltages for each of the studied cases in Table 2.41.

Table 2.41. Cases description – off peak[28]

Cases	Caps	Regulator	Total number of DER units	Location	Control type	Control description	Gen outside 0.95 pf limit	Each Inverter _KVA	kVAR absorption at the PCC (set 1, set 2, set 3, set4)	Total_kVAR absorption at the PCC
case #0	N/A	-1, 0, 1	0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
case #1	N/A	-4, -3, -2	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	5555	-203,-203	-709
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2222	-101	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2222	-101	
			1	Set 4	Volt-Var	2% from 1.04 to 1.06	No	2222	-101	
case #8	N/A	-4, -3, -2	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	5511	-790,-790	-2087
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2215	-251	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2222	-105	
			1	Set 4	Volt-Var	2% from 1.04 to 1.06	No	2218	-151	
case #14	2000 kVAR	-4, -3, -2	2	set 1	Volt-Var	2% from 1.04 to 1.06	No	5511	806,-806	-2138
			1	set 2	Volt-Var	2% from 1.04 to 1.06	No	2215	-259	
			1	set 3	Volt-Var	2% from 1.04 to 1.06	No	2222	-106	
			1	Set 4	Volt-Var	2% from 1.04 to 1.06	No	2218	-161	

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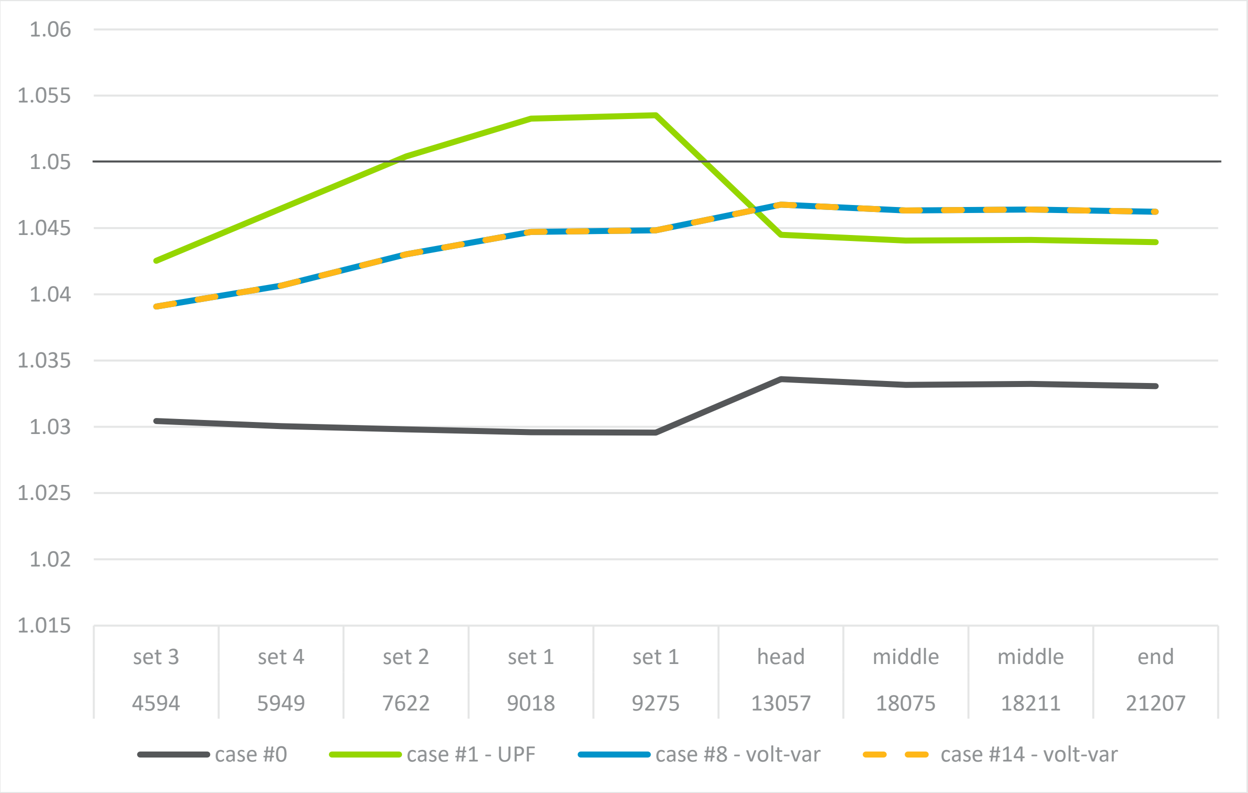
[28] Volt-Var control was modeled with "vars precedence over watts"

If DER were to interconnect following existing guidelines requiring interconnection at UPF, case #1 results indicate nodal voltages would be just above 1.05 pu. Case #8 with Volt-Var control mitigate overvoltages seen in Case #1. Although the response chart indicates that no inverter can bring the voltage within limit using only reactive power, what is seen here is a combined impact. While no single DER can bring the voltage down, the compound effect of all the units does control the voltage. This highlights the variation between a study with multiple new DER added at once rather than an interconnection study that only considers one new generator at the time. Both studies are helpful because one focuses on the impact of one DER and one considers the impact over time of multiple DER.

Figure 2.28. Feeder F Nodal Voltages – off peak



3. Conclusions

The studies were conducted on six indicative feeders, three feeders on the Duke Energy Carolina (DEC) system and three feeders studied on the Duke Energy Progress (DEP) system. Each feeder was pushed to a higher penetration level in order to get the voltage profile over 1.05 pu so the voltage control could be tested. The study results indicate that, although Volt-Var control significantly improves voltages, it cannot always be relied on as the only control to mitigate voltage issues under all loading conditions and all penetration levels. Several controller variations were considered with the main constraints including the reactive system response (dV/dQ), the normal and reduced voltage operating ranges for the Distribution System Demand Reduction (DSDR) and voltage optimization systems, along with the desire to use reactive power before actuating the volt-watt control. Multiple cases for each of the six feeders were modeled and analyzed at off peak and shoulder load conditions, with sensitivities around some cases. The following conclusions are derived from case studies and analysis:

1. **Voltage Controller –** Overall, the study results indicate a Volt-Var controller with 2% voltage slope between 1.04-1.06 pu, in combination with a Volt-Watt controller with 3% voltage slope between 1.06-1.09 pu will reduce overvoltage conditions. The setpoints were chosen to give Volt-Var priority over Volt-Watt and provide some coordination between the two controls. The goal was to reduce active power after the reactive power was exhausted at 1.06 pu.
2. **Category A or Category B** - Given the only two choices in IEEE 1547-2018 of Category A and Category B normal performance categories, Category A would provide limited voltage control. As a general specification for the entire system, Category B provides the most flexibility and margin for system changes over time.
3. **Location of DER on Feeder** - The results reiterated that DER near the station reduces the voltage concerns, reduces the reactive power flow, reduces the inverter control and reactive capability requirements, and maintains the normal station to load power flow direction.
4. **Active and Reactive Power Response to Off Peak and Peak Load Conditions –** TSRG Stakeholders were interested in a comparison of active and reactive power response for load variations. The results from Feeder B showed that the response levels were very similar and the voltage change was very consistent across the load levels. This should be verified with more feeders, but the general thought that the voltage response to power injections is rather consistent between load levels still seems valid.
5. **Persistence of the Voltage Increase** - While only looking mainly at two load conditions, it seems that once the voltage increases from DER interconnection, it remains elevated instead of returning to a lower level as load increases. Given that the controls must be active in the range of 1.04 to 1.06 pu, then there tends to be reactive power absorption all the time.
6. **Autonomous Versus Central Control of DERs** - Management of dynamic sources and higher levels of reactive power may not be possible with several local autonomous controls. Alternative controls were not considered in this study, but two possible options are:
    a. A centrally controlled voltage and reactive power management system; this would be something like those functions included with a distribution management system.
    b. A reference voltage (Vref) control that can adjust the setpoint to track along with the inherent system voltage. The purpose of the tracking function would be to adjust the setpoint so that compensation is not provided all the time.

4. Recommended Next Steps

An important positive result from this initial study is that generally a 2% Volt-Var controller from set at 1.04-1.06 pu reduces overvoltage conditions in many instances. However, as captured in the first conclusion of Section 3, these settings alone may not eliminate overvoltage conditions at high DER penetration levels. To further explore ways to integrate more DERs, and further explore many of the conclusions in 2-9 of Section 3, Duke is prepared to work collaboratively with TSRG stakeholders on the following recommended next steps:

- Present the findings and results of this study to the TSRG in second quarter of 2020
- Conduct time series power flow studies to look at system response over many hours
- Work with TSRG stakeholders to identify a pilot DER site to implement the 2% Volt-Var controller in first quarter 2021
- Further analyze the impact of Volt-Var on regulator settings and switched capacitor settings and assess the ability of existing controls to work properly with reactive power injection from DER.
- Consider the impact of incremental DER interconnections in addition to the higher penetration scenario
- Based on these results, consider other controls methods that could be effective (e.g. constant power factor based on system response or reference voltage)
- Analyze substation transformer bank level studies in addition to feeder level impacts
- Consider stability impacts and interactions with other DER and voltage control devices

Duke is committed to working with the TSRG to implement 1547 2018 and taking full advantage of the advanced smart controls features of the inverter based resources provided by IEEE 1547-2018. The UL 1741 update is expected to be completed in late 2020 or early 2021. Once certification work is complete and NRTL has tested and certified DER equipment as IEEE 1547 compliant, such equipment will be available in the marketplace. Duke anticipates that it will take some time for IEEE, UL and NRTL to take action. In the interim working with the TSRG to address the recommended steps above will put Duke in a place to adopt many aspects of 1547-2018 while ensuring that the new technology does not have a negative impact on reliability and safety of the distribution system.

Appendix A. Glossary of Terms

Term	Definition
Distributed Energy Resource (DER)	A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Electric System (BES)
Distributed Generation (DG)	Distributed generation is the term used when electricity is generated from sources, often renewable energy sources, near the point of use instead of centralized generation sources from power plants[29]
IEEE 1547 - 2018	A standard of the Institute of Electrical and Electronics Engineers meant to provide a set of criteria and requirements for the interconnection of distributed generation resources into the power grid.
KV	Kilo volts is unit for Voltage
Load Tap Changer (LTC)	A Load Tap Changer regulates the output voltage of a transformer by altering the number of turns in one winding and thereby changing the turns ratio of the transformer.
Power Factor (PF)	The ratio of real power in the electric circuit to the apparent power (Voltage multiplied by Current)
VAR	Kvar is unit for Reactive Power
Voltage Control	Control of voltage in the distribution system downstream from substation transformers using hardware and software in order to accomplish something
Volts (V)	This is unit of Voltage
Volt-Var functionality	Management of system-wide voltage levels and reactive power flow to achieve efficient distribution grid operation.
Volt-Watt functionality	Management of system-wide voltage levels and active power flow to achieve efficient distribution grid operation.

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[29] https://www.energy.gov/eere/slsc/renewable-energy-distributed-generation-policies-and-programs

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Docket No. E-2, Sub 1276

Carbon-Free Resource Integration Study

Reiko Matsuda-Dunn, Michael Emmanuel, Erol Chartan, Bri-Mathias Hodge, and Gregory Brinkman

National Renewable Energy Laboratory

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Office of Energy Efficiency & Renewable Energy
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January 2020

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Technical Report
NREL/TP-5D00-74337
January 2020

National Renewable Energy Laboratory
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Cover Photos by Dennis Schroeder: (clockwise, left to right) NREL 51934, NREL 45897, NREL 42160, NREL 45891, NREL 48097, NREL 46526.

List of Acronyms

DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
NREL	National Renewable Energy Laboratory
PV	photovoltaic
WIND	Wind Integration National Dataset

Foreword

This report covers the results of a preliminary phase 1 analysis conducted by the National Renewable Energy Laboratory (NREL) with Duke Energy, who funded this work and whose expertise, specialist knowledge, and diligence has helped guide the process. This initial effort is a net load analysis which compares estimated hourly solar, wind, net load, and system minimum generation time series for different scenarios. It aims primarily to set up a baseline for more detailed modeling as part of a larger effort between Duke Energy and NREL expected to last multiple years. The full analysis will provide a broader insight into the costs, challenges, and opportunities of renewable energy integration in the Duke Energy service territory in the Carolinas. This report and the full analysis are not financial plans and are not intended to replace Duke Energy's integrated resource planning process. Rather, they examine the operational considerations of integrating additional carbon-free resources onto the Duke Energy Carolinas and Duke Energy Progress system.

Executive Summary

This report presents a net load analysis, geospatial analysis, and a web application for the Duke Energy Carbon-Free Resource Integration Study. In this collaborative engagement, the National Renewable Energy Laboratory (NREL) provides research support to Duke Energy to analyze the impacts of integrating significant amounts of new solar photovoltaic (PV) power into its service territory under a variety of scenarios. This analysis covers Duke Energy's territories in North Carolina and South Carolina, including two balancing authorities—Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC)—with detailed assessments and discussions of the operations of the existing fleet, particularly nuclear generation, under high-penetration scenarios of solar PV. In addition to quantifying the solar potential, NREL is working with Duke Energy to identify possible opportunities for wind, storage, demand-side resources, and other technologies.

Scenario Analysis

This analysis looks at a variety of solar power penetration levels in Duke Energy's service territory in the Carolinas—compared to load and system-wide minimum generation levels—that best represent potential challenges and opportunities for renewable generation integration. An example of this includes an analysis of balancing solar and load for typical days during different seasons and extreme days, such as minimum and peak net load days. Net load is defined as the customer load less wind power and solar power generation. This analysis is performed by comparing estimated hourly solar, wind, net load, and system minimum generation time series for the different scenarios. The overall aim is to help Duke Energy understand initial estimates of possible curtailment, key periods of ramping, and load-following requirements. Further, this analysis captures net load impacts across different seasons and operational issues related to generation flexibility limit during periods of low load with high penetrations of solar energy.

Key Findings

Table ES-1 shows the results of the annual metrics, including annual percentage of load met by carbon-free generation, annual percentage of curtailed energy, annual hours of curtailment, and annual maximum instantaneous curtailment for all scenarios. For scenarios 1 through 11, both balancing authorities (DEC and DEP) are modeled as a single region, whereas Scenario 12 models DEP and DEC separately with an interconnection limit between them.

In scenarios 1 through 7, as solar energy penetration increases, the percentage of load met by carbon-free generation increases, until the flexibility limit is reached, when PV production must be curtailed, and additional solar power has a marginal impact. The average annual percentage of load met by carbon-free generation ranges from 60% to 77%, for these aforementioned scenarios, as shown in Table ES-1. As the PV penetration level increases, the marginal contribution to carbon-free generation suffers diminishing returns, due to the inability to shift the timing of PV generation to match the early and late hour net demand, especially from 20% through 35% PV energy penetration.

Table ES-1. Annual Metrics Evaluation for All Scenarios in the Net Load Analysis

Scenario	DEP and DEC Modeled as a Single Region or Separately	Definition	Annual Load Met by Carbon-Free Generation (%)	Annual Curtailed Renewable Energy (%)	Annual Hours of Curtailment	Annual Maximum Instantaneous Curtailment (MW)
1. Solar energy penetration 5%	Single region	4,109 MW, 5.5% of total solar is rooftop	60.4%	0%	6	530
2. Solar energy penetration 10%	Single region	8,219 MW, 5.5% of total solar is rooftop	65.5%	1%	179	3,323
3. Solar energy penetration 15%	Single region	12,328 MW, 5.5% of total solar is rooftop	69.7%	8%	882	6,618
4. Solar energy penetration 20%	Single region	16,438 MW, 5.5% of total solar is rooftop	72.5%	17%	1,506	10,003
5. Solar energy penetration 25%	Single region	20,547 MW, 5.5% of total solar is rooftop	74.4%	27%	2,016	13,504
6. Solar energy penetration 30%	Single region	24,656 MW, 5.5% of total solar is rooftop	75.6%	35%	2,355	17,207
7. Solar energy penetration 35%	Single region	28,766 MW, 5.5% of total solar is rooftop	76.5%	42%	2,587	20,909
8. Higher ratio of distributed to utility solar added to the system	Single region	Based on the 25% solar energy penetration scenario, 18.91% of PV is uncurtailable rooftop	74.4%	27%	2,017	13,548

Scenario	DEP and DEC Modeled as a Single Region or Separately	Definition	Annual Load Met by Carbon-Free Generation (%)	Annual Curtailed Renewable Energy (%)	Annual Hours of Curtailment	Annual Maximum Instantaneous Curtailment (MW)
9. Additional storage	Single region	Based on the 25% solar energy penetration scenario, addition of 1,000 MW of 4-hour storage, 1,000 MW of 6-hour storage, and 2,000 MW of 8-hour storage	77.1%	12%	1,239	11,073
10. Nuclear retirement	Single region	Based on the 25% solar energy penetration scenario, assume a 10% nuclear reduction	70.2%	22%	1,804	12,551
11. Additional wind energy at 5% penetration	Single region	Based on the 30% solar energy penetration scenario, an additional 5% wind energy penetration is added	79.4%	32%	2,486	17,486
12—DEC 5%	Separate regions	Based on scenarios 1–3 inclusive, DEP and DEC are analyzed separately with an interconnection limit between	70%	0%	5	246
12—DEC 10%	Separate regions		75%	1%	213	1,886
12—DEC 15%	Separate regions		80%	7%	912	3,418
12—DEP 5%	Separate regions		50%	0%	5	246
12—DEP 10%	Separate regions		54%	1%	205	1,600
12—DEP 15%	Separate regions		58%	10%	905	3,418

For scenarios 2 through 7 (solar energy penetration levels of 10% to 35% inclusive), analysis shows that the annual percentage curtailment ranges from 1% to 42% of total solar energy as PV penetration increases from 10% to 35%. The majority of the solar energy curtailment occurs during the spring and fall seasons, which are characterized with low load and high renewable energy production. Also, Scenario 7, which has a solar energy penetration level of 35% and models both balancing authorities as one region, experienced the highest maximum instantaneous curtailment and hours of curtailment: 20,909 MW and 2,587 hours, respectively.

The increased proportion of private solar PV analyzed in Scenario 8 does not materially affect the curtailment required. This does not infer that significant amount of rooftop will have no impact on system balancing. Given the assumptions of this study, with increasing penetration of rooftop solar from 5.5% of the total to 18.9% of the total, there is still sufficient curtailable solar to balance load and generation. Annual curtailment is 33% of utility solar and 27% of the total solar, which is the same as the baseline in Scenario 5.

The additional storage (26,000 MWh)[1] modeled in Scenario 9 results in a 3% increase in the amount of load met by carbon-free generation compared with the baseline in Scenario 5, which has 25% PV penetration. Also, the percentage of renewable energy curtailed decreases by 15%, whereas the 10% nuclear retirement scenario leads to a 4% decrease in the amount of load met by carbon-free generation and curtailed solar energy.

Further, the addition of 5% wind energy penetration to 30% solar energy in Scenario 11 results in a 2% increase in carbon-free energy production compared with the 35% solar energy penetration case. Also, the renewable energy curtailed decreases by 10% of the total renewable energy production. Thus, this shows that a balanced mix of renewable resources might reduce curtailment and the overall system cost compared to a similar penetration of PV-only generation

When DEC and DEP are modeled as individual balancing authorities with existing limited interconnection between them, Scenario 12 shows that DEP experiences a lower average percentage of load met by carbon-free generation, ranging from 50% to 58%, compared to DEC, which ranges from 70% to 80%. A production cost optimization would enable simulation of the interconnection and other transmission constraints in a more realistic manner.

Figure ES-1 (below) shows the annual contribution to carbon-free energy from all the scenarios considered in this study. The largest contribution resource to carbon-free energy is the nuclear power plant, followed by the increasing penetration of PV. Also, Figure ES-1 shows the impact of resource diversity with wind integration in the amount of carbon-free energy contribution with DEP and DEC modeled as a single balancing authority. Scenario 11, with 30% PV and 5% wind energy penetration, results in the highest contribution: 79%.

Another important metric used to assess the diminishing returns of increasing levels of variable generation resources added to the system is marginal curtailment.[2] As PV penetration levels increase, marginal curtailment increases more rapidly than total curtailment, as shown in Figure ES-2. This indicates that an increasing proportion of solar energy capacity will be curtailed as the system approaches high penetration levels of variable solar generation without adding sufficient system flexibility; however, solutions such as the addition of storage and wind power instead of additional solar power result in the marginal curtailment being reduced, as shown in Figure ES-2.

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[1] This study did not consider the value stacking of storage units (i.e., using storage for other ancillary services, such as frequency regulation, voltage support, spinning and nonspinning reserves); therefore, the load-shifting and flexibility benefit presented in this report cannot be used solely for the economic assessment of storage deployment in the grid.

[2] The marginal curtailment rate refers to the curtailment from an additional unit of variable generation capacity added to the system. For example, when increasing the variable generation penetration level from 10% to 15%, the marginal curtailment is the curtailment rate of the additional 5% of variable generation.

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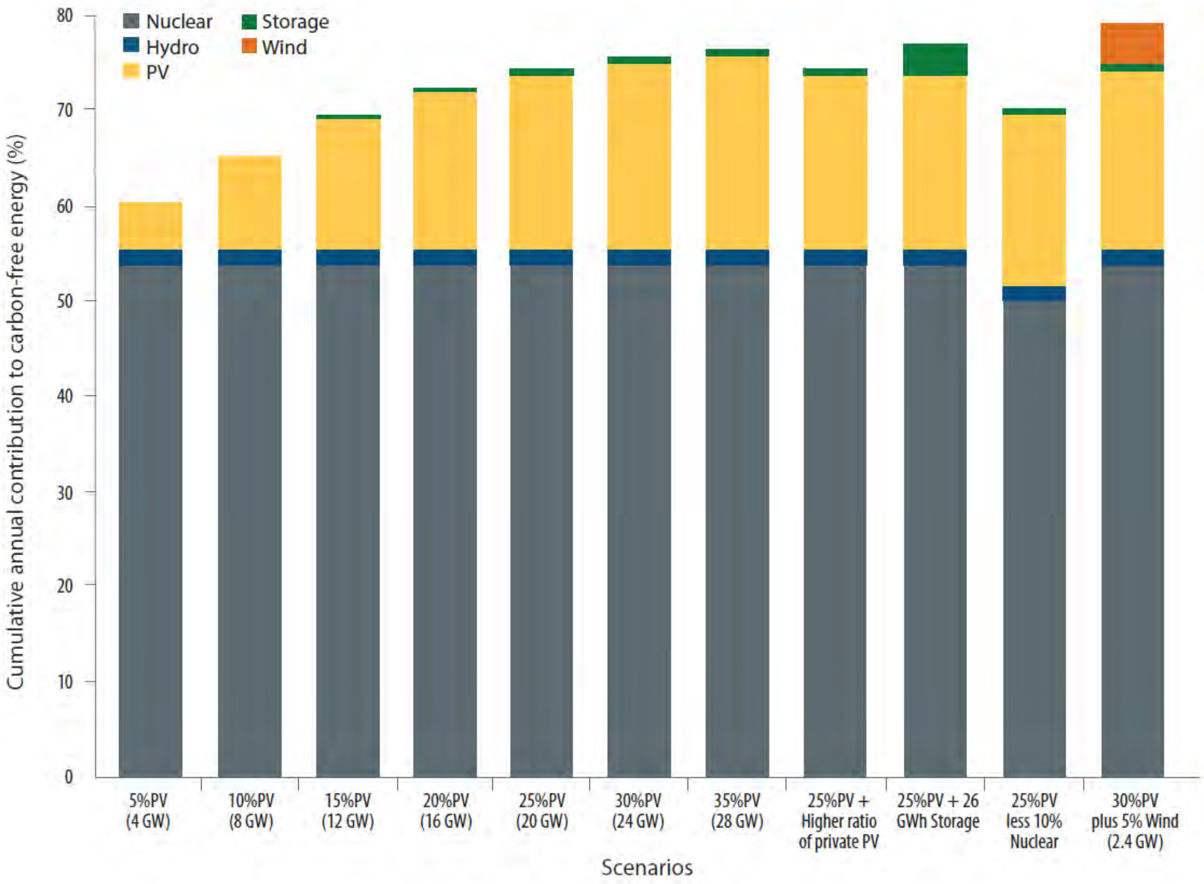

Figure ES-1. Percentage of annual carbon-free energy and contribution from each energy resource with increasing PV penetration, generation retirement, storage, and wind integration

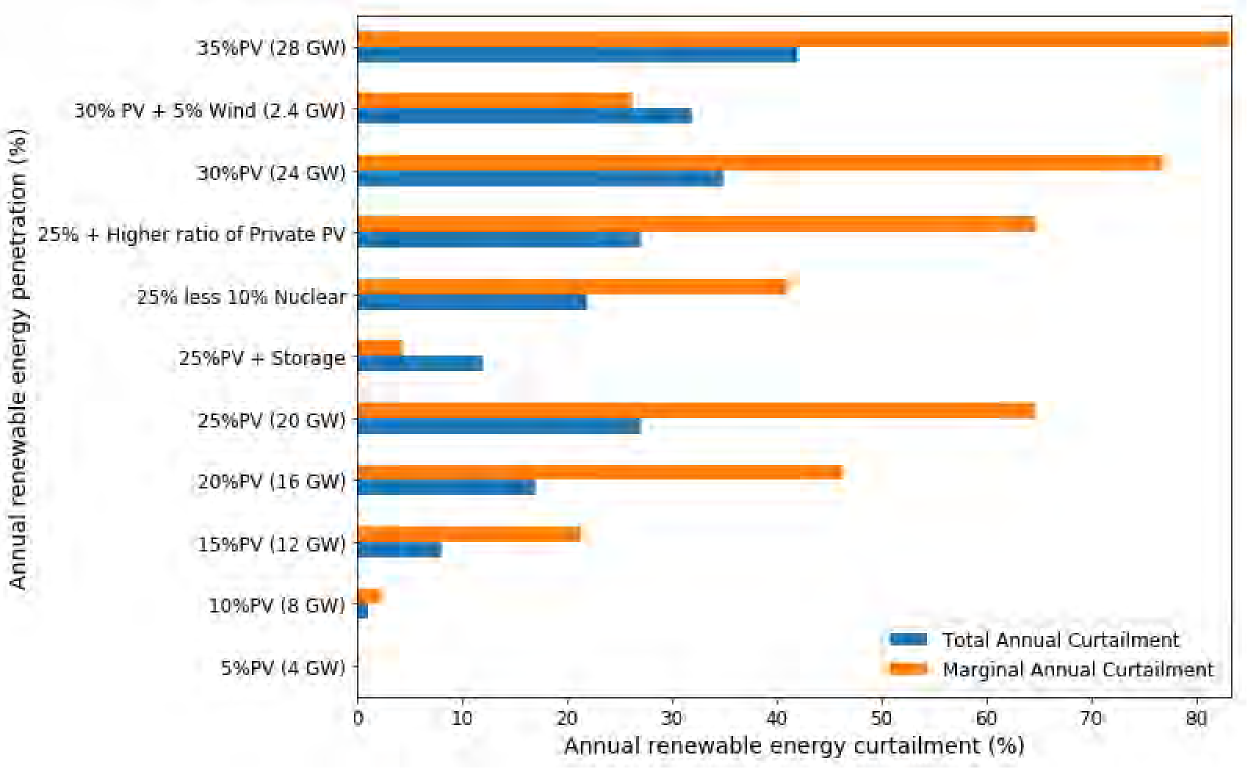

Figure ES-2. Marginal and total curtailment with increasing PV penetration, generation retirement, storage, and wind integration

Conclusions

The results and analysis of Phase 1 of the Carbon-Free Resource Integration Study presented in this report will help NREL and Duke Energy scope future work in this area to examine and address the identified grid integration challenges in greater technical detail. Further analysis with more advanced models—such as unit commitment and economic dispatch, capacity expansion planning, and dynamic analysis models—will be required to more fully assess system impacts with increasing variable generation penetration levels as well as flexibility opportunities to accommodate variable renewable energy sources to achieve the carbon-free goals of Duke Energy.

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1 Introduction

Duke Energy is one of the largest electric power holding companies in the United States. It has more than 30,000 distributed energy resource facilities, with a combined capacity of more than 3,700 MW operating across all Duke Energy jurisdictions. More than 90% of this capacity is in the Carolinas, where more than 16,000 distributed energy resource sites generate more than 3,200 MW on the transmission and distribution systems, making the Duke Carolinas a national leader for integrating utility-scale solar generation. Duke Energy continues to strengthen its commitment toward carbon-free electricity generation, and during the next several years the capacity of solar generation across Duke Energy is expected to at least double. The incentivization of commercial solar by Duke Energy coupled with the recently launched proposal for 6800 MW under the North Carolina House Bill 589, as well as plans to add 700 MW of solar facilities in Florida, continue to drive the rapid adoption of solar generation across Duke Energy's service territory (Duke Energy, 2018).

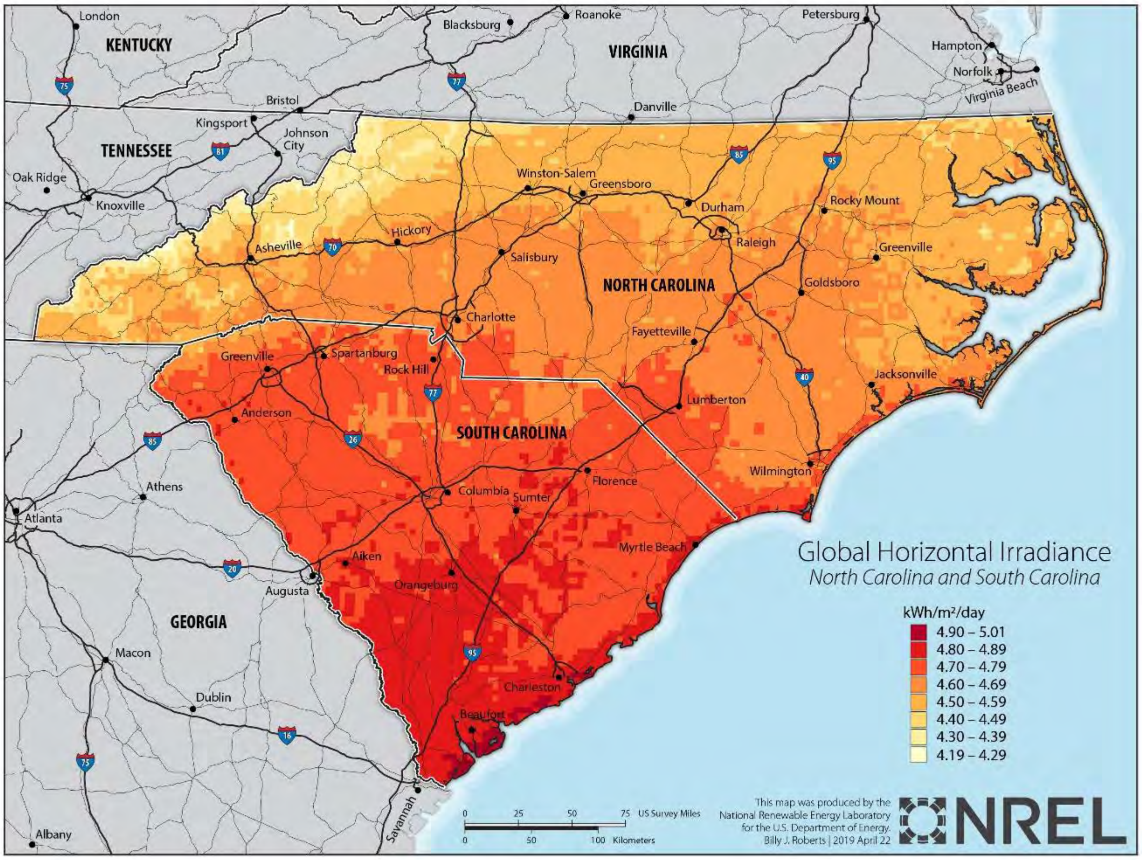


Figure 1. Solar energy resource in the Carolinas region

Duke Energy is seeking to analyze the impacts of integrating significant amounts of new carbon-free power sources into the Duke Energy power system under a variety of penetrations levels. This report focuses on investigating the addition of solar power along with understanding how the integration of variable generation sources, especially at high penetration levels, comes with potential challenges to reliable power system operations. The variability and uncertainty of renewable energy sources are two major constraints to integrating them into the power system. In power network operations, generation planners will always need to ensure that there is enough capacity to serve load at any given time. Characterizing variable generation resources in planning operations becomes a challenge because of their tendency to disrupt the balance of the generation portfolio. Consequently, thermal and hydro generators are operated differently to accommodate the variability and uncertainty of renewable electricity generators (Lew, 2013).

Additionally, the integration of variable and uncertain power generation from wind and solar units at high penetration levels introduces another pivotal variable: net load (normal load less wind power and solar power). This creates a new set of requirements for integrated and reliable power system planning operations. The net load variability has created a further need to evaluate system flexibility because of its impacts on system operating costs. The ability of the power system to integrate additional renewable resources is largely a function of its flexibility, which is chiefly driven by the ability of individual plants to change their output to serve these variations in net electricity consumption (Ela, 2014). The key to managing the variability and uncertainty of variable generation sources is to increase the system-wide flexibility in the power system (Mai, et al., 2012).

Duke Energy is committed to creating a carbon-free power system of the future. Currently, the large nuclear fleet contributes to load greatly as carbon-free generation. With the current cost of solar power, it makes sense to investigate increasing solar power capacity to meet higher carbon-free goals. This will likely increase the requirement for Duke's thermal generation sources to be flexible, which will be limited by their nuclear power plants, which typically run only at full output. A detailed understanding of power system flexibility characteristics has become critical because high levels of variable generation will have significant impacts on the operation of the traditional thermal generation fleet.

This report analyzes the net load and presents the impact of high penetration levels of variable generation on the operation of Duke Energy's power system given the flexibility limits set by a combination of the must-run units, hydro schedules, nuclear generators, and storage. These limits dictate curtailing excess solar power during times when there is a greater amount of solar photovoltaic (PV) generation than can be accommodated.

To contextualize subsequent discussions in this report, it is important to define variable generation penetration levels. One power-based definition considers the ratio of variable generation nameplate capacity to system peak load. The definition of penetration level by energy often estimates the amount of renewable energy (pre-curtailment) injected into the grid during a period of time and helps to quantify the amount of displaced fossil-fueled generation, fuel consumption savings, and avoided carbon emissions. The energy-based definition is useful when considering very large systems and long time frames, and it has been adopted in many renewable portfolio standards (Bebic, 2008). Therefore, the analysis presented in this report uses the energy-based definition of penetration level on an annual basis.

In scoping Phase 1 of this collaborative engagement, the National Renewable Energy Laboratory (NREL), in consultation with Duke Energy, designed the scenarios to be considered, as shown in Table 1. These scenarios are analyzed and documented in this report. Note that the penetration levels used in naming the scenarios are approximate numbers based on annual energy before curtailment.

Table 1. Scenarios for Net Load Analysis

Scenario	Definition
1. Solar energy penetration 5%	4,109 MW, 5.5% of total solar is rooftop
2. Solar energy penetration 10%	8,219 MW, 5.5% of total solar is rooftop
3. Solar energy penetration 15%	12,328 MW, 5.5% of total solar is rooftop
4. Solar energy penetration 20%	16,438 MW, 5.5% of total solar is rooftop
5. Solar energy penetration 25%	20,547 MW, 5.5% of total solar is rooftop
6. Solar energy penetration 30%	24,656 MW, 5.5% of total solar is rooftop
7. Solar energy penetration 35%	28,766 MW, 5.5% of total solar is rooftop
8. Higher ratio of distributed to utility solar added to the system	Based on the 25% solar energy penetration scenario, 18.91% of PV is uncurtailable rooftop
9. Additional storage	Based on the 25% solar energy penetration scenario, addition of 1,000 MW of 4-hour storage, 1,000 MW of 6-hour storage, and 2,000 MW of 8-hour storage
10. Nuclear retirement	Based on the 25% solar energy penetration scenario, assumes a 10% nuclear reduction
11. Additional wind energy penetration 5%	Based on the 30% solar energy penetration scenario, an additional 5% wind energy penetration is added
12. Scenarios 1–3 modeled with two balancing authorities	Based on scenarios 1–3 inclusive, DEP and DEC are analyzed separately with an interconnection limit between, defined in the appendix

This report examines the amount of renewable energy curtailment as well as the particular hours of curtailment for these scenarios. This report also presents an evaluation of the daily percentage of carbon-free generation from carbon-free plants.

Note that there are some limitations to the net load analysis presented in this report. This analysis does not include unit commitment and economic dispatch models; interconnection to neighbors; market models; system stability metrics such as voltage and/or frequency; or costs—all of which would be essential in recommending a pathway to the future.

2 Characterizing the Net Load

As power system planning continues to move toward adopting an integrated planning approach caused by increasing variable generation integration, it is now critical to begin characterizing the net load. The net load—defined here as the total customer demand minus the variable generation—gives the demand that must be met by traditional dispatchable generation. For this analysis, solar PV is considered to be non-dispatchable, though the utility solar power can be curtailed down. Therefore, its contribution to meeting reserve margins is quantified by how it changes the net load.

The net load analysis can be of interest for several reasons, including:

- At high penetration levels, variable generation can cause a significant shift in the timing of both the minimum and peak net load relative to the system or gross load, which can impact the system generation scheduling, cost of generation, and daily unit commitment and dispatch.
- During low-load conditions, which typically occur during the spring, high penetrations of variable generation can violate the system flexibility limit and result in significant integration issues. Consequently, during such periods renewable generation must be curtailed, which can adversely impact variable generation project economics or contractual arrangements with renewable generators.
- Net load analysis can be a useful tool in assessing power system flexibility in the presence of varying penetration levels of variable generation. Because increasing variable generation penetration levels can lead to increases in net load variability, and thus required thermal unit ramp rates and ramping ranges, the need for the power system to become more flexible increases. This scenario demands that conventional power plants would need to change their output more frequently than traditionally. Situations when the system flexibility requirements are not met could impact the reliable and economic operations of the grid. Impacts could include variable generation curtailment, reserve shortfalls, and potential frequency violations as a result of over- and undergeneration (Milligan, 2015)
- Outputs from net load analysis such as maximum renewable curtailment and the number of hours of curtailment are important metrics that can be used to evaluate system flexibility. Detailed flexibility evaluation, however, requires further analysis using different modeling methods, such as production cost modeling, capacity expansion planning, and dynamic stability analysis.

3 Scenario Analysis

This net load analysis covers the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) balancing authorities, with 2019 hourly forecasted load data supplied by Duke Energy. Maintaining load and renewable resource coincident relationships is a primary consideration in net load analysis and assessing its impact on the system operational requirements, such as determining minimum generation levels (GE Energy, 2010). Spatial and temporal correlation of the load and variable generation sources are needed to accurately reflect the underlying weather patterns that drive both load and variable generation.

This report uses 2019 forecasted annual load and solar PV time-series profiles supplied by Duke Energy and based on the same weather period to ensure that the solar profiles are synchronized with the weather assumed in the load. For the net load analysis, thermal generation outside of nuclear, hydropower, and must-run units is considered to be entirely flexible—i.e., there are no constraints on minimum stable level, ramp rates, and outage rates. Rooftop solar is non-curtailable, utility solar is curtailable, and the must-run units are used for local voltage constraints. Table 8, in the appendix, shows a list of assumptions and definitions used for the net load analysis.

The generation flexibility limit consists of nuclear, hydropower units, and must-run units, offset by the hydropower pumped storage capacity (see Equation 1 in the appendix). Nuclear is assumed to run at 100% capacity for this analysis. From the data supplied by Duke Energy, note that the must-run units have hourly triggers and therefore could change intra-daily, whereas hydro schedules vary monthly. This explains why the generation flexibility limit line could change seasonally, and possibly daily, which is reflective of the inherent characteristics of the must-run units and hydro capacity considered in this analysis. The renewable energy curtailment per hour is the net load below the flexibility limit, which is calculated using Equation 2 in the appendix. The daily percentage of carbon-free generation includes solar power, wind power, hydropower, and nuclear (using storage), and it is calculated in Equation 3 in the appendix. The presented maximum up-ramp and down-ramp times are based on the ending times of each ramp.

An analysis of the average, minimum, and maximum net load days is performed to illustrate the varying impact of the net load variability across different seasons on key metrics, such as daily percentage of carbon-free generation, percentage of curtailed energy, maximum instantaneous curtailment, and hours of curtailment. The net load curves, as presented in this section, help capture the net load demand that the system must meet in real time for reliable operation of the grid.

3.1 Scenarios 1–7: 5%–35% Solar Energy Penetration

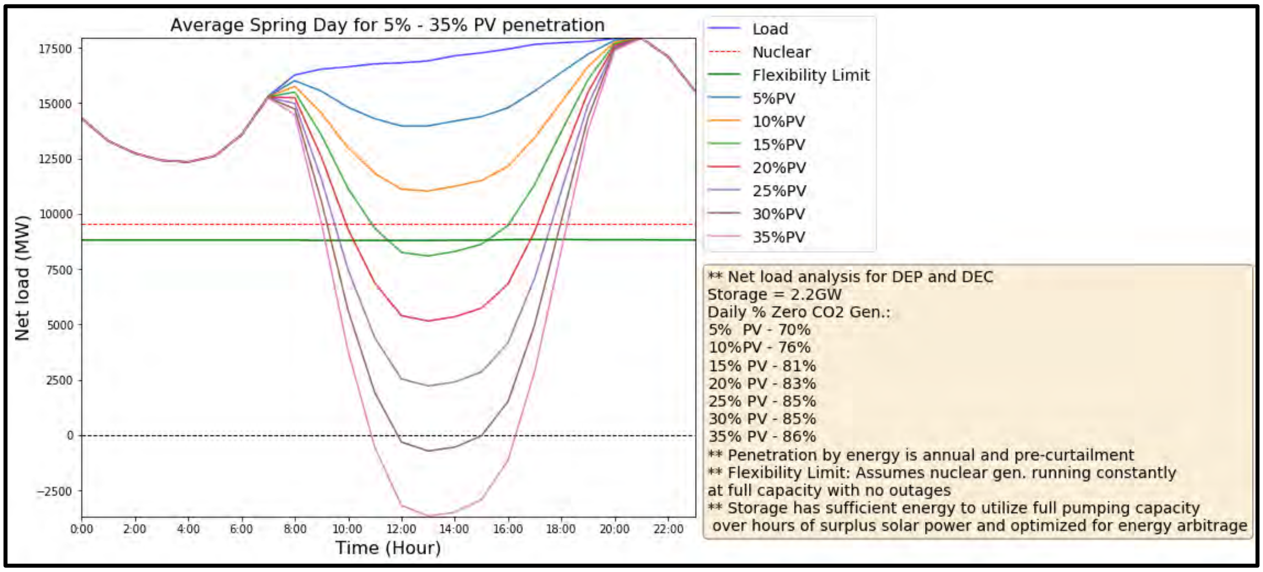
Seven different levels of solar energy penetration are explored, beginning with 5% penetration and increasing in 5% increments through 35% penetration. The solar output before curtailment is the 2019 PV time series provided by Duke Energy scaled to the specified percentage of the total load. The scalars used for each scenario are provided in Table 3 of the appendix and are calculated using Equation 4. Higher penetrations of solar power are expected to experience geographical smoothing, which the scalers do not account for and thus overestimate the variability. Ramp rates for all the scenarios are calculated as the difference between the net load at a given hour and the hour immediately prior.

Solar PV capacities for each level of solar penetration are shown in Table 2.

Table 2. PV Capacities for Penetration Levels Defined by Scenarios 1–7

PV penetration in terms of annual energy before curtailment (%)	5	10	15	20	25	30	35
PV capacity (MW)	4,109	8,219	12,328	16,438	20,547	24,656	28,766

Average daily values for load, generation flexibility limit, rooftop, and all PV plants are estimated across all seasons. Figure 2 shows these data for scenarios 1–7 in the spring season, which has the highest curtailment. Graphs for the three remaining seasons are available in the appendix. In low penetrations of PV, adding more PV increases the percentage of load met by carbon-free generation until the flexibility limit is reached, at which point curtailment increases and additional solar power has diminishing returns.



** Net load analysis for DEP and DEC
Storage = 2.2GW
Daily % Zero CO2 Gen.:
5% PV - 70%
10%PV - 76%
15% PV - 81%
20% PV - 83%
25% PV - 85%
30% PV - 85%
35% PV - 86%
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity over hours of surplus solar power and optimized for energy arbitrage

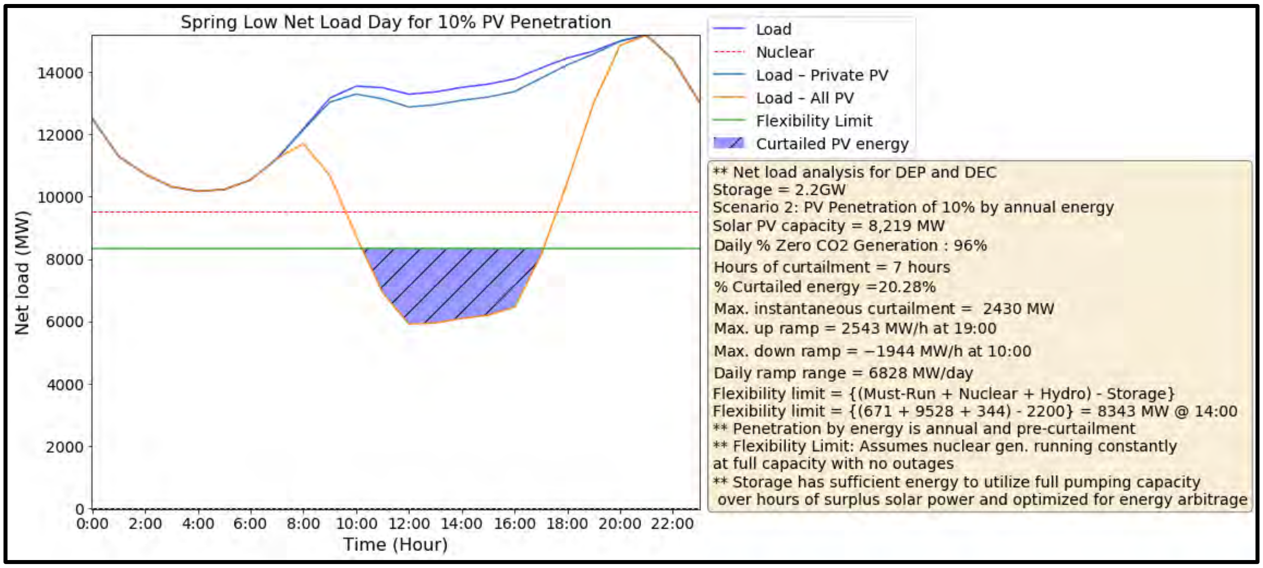
Figure 2. Average net load for all scenarios for spring

Annual average carbon-free generation ranges from 60% to 77% from the 5% PV penetration case to the 35% case, respectively. Seasonal values are shown in Table 3.

Table 3. Average Seasonal Percentage of Load Met by Carbon-Free Generation for Each Scenario

Scenario	Spring	Summer	Fall	Winter	Annual
1. Solar energy penetration 5%	69%	54%	65%	57%	60%
2. Solar energy penetration 10%	75%	59%	70%	61%	65%
3. Solar energy penetration 15%	80%	64%	74%	63%	70%
4. Solar energy penetration 20%	83%	68%	76%	65%	73%
5. Solar energy penetration 25%	84%	71%	78%	66%	74%
6. Solar energy penetration 30%	85%	73%	79%	67%	76%
7. Solar energy penetration 35%	86%	74%	80%	68%	77%
8. Increase proportion of distributed solar	84%	71%	78%	66%	74%
9. Additional storage	88%	73%	81%	68%	77%
10. Nuclear retirement	80%	67%	73%	62%	70%
11. Additional wind energy penetration 5%	90%	76%	83%	71%	79%
12. Two balancing authorities: DEC 5%	80%	61%	76%	66%	70%
12. Two balancing authorities: DEC 10%	87%	66%	82%	70%	75%
12. Two balancing authorities: DEC 15%	93%	71%	87%	73%	80%
12. Two balancing authorities: DEP 5%	56%	45%	53%	47%	50%
12. Two balancing authorities: DEP 10%	62%	50%	57%	50%	54%
12. Two balancing authorities: DEP 15%	65%	55%	60%	53%	58%

With the current flexibility limit, curtailment is necessary at PV penetration levels of 10% and more. Duke Energy will first experience significant curtailment at the 10% PV penetration level, at an annual average of 1.1%. Figure 3 shows a low net load day in spring, during which 20% curtailment will occur. With 10% PV energy, 65% of the annual load is met by carbon-free generation, indicating that in this case nearly 65% of energy from carbon-free sources could be achieved before any curtailment is needed. In Scenario 12, where DEP and DEC are modeled separately with a total PV penetration of 15%, DEC in spring achieves a carbon-free contribution of more than 100%. This is because we assume that existing storage can charge with energy that would otherwise be curtailed and then release the corresponding energy within the same day. This value suggests that this operation would result in a surplus of generation.



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 96%
Hours of curtailment = 7 hours
% Curtailed energy =20.28%
Max. instantaneous curtailment = 2430 MW
Max. up ramp = 2543 MW/h at 19:00
Max. down ramp = −1944 MW/h at 10:00
Daily ramp range = 6828 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 344) - 2200} = 8343 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Figure 3. Minimum net load day for spring with 10% PV penetration

Annual percentage of curtailment ranges from 1.1% to 42% of total solar energy for scenarios 2–7. Seasonal and annual percentages of curtailment are shown in Table 4, and hours of curtailment are shown in Table 5. Seasonal maximum instantaneous curtailment is given in Table 13 in the appendix. Generally, the highest curtailment occurs in spring and the lowest in summer.

Table 4. Average Percentage Curtailed Energy

Scenario	Spring	Summer	Fall	Winter	Annual
1. Solar energy penetration 5%	0%	0%	0%	0%	0%
2. Solar energy penetration 10%	2%	0%	1%	2%	1%
3. Solar energy penetration 15%	12%	1%	10%	10%	8%
4. Solar energy penetration 20%	25%	4%	22%	22%	17%
5. Solar energy penetration 25%	36%	12%	32%	31%	27%
6. Solar energy penetration 30%	44%	21%	40%	39%	35%
7. Solar energy penetration 35%	50%	29%	46%	45%	42%
8. Increase proportion of distributed solar	36%	12%	32%	31%	27%
9. Additional storage	19%	2%	15%	14%	12%
10. Nuclear retirement	30%	8%	27%	26%	22%
11. Additional wind energy penetration 5%	40%	20%	36%	34%	32%
12. Two balancing authorities: DEC 5%	0%	0%	0%	0%	0%
12. Two balancing authorities: DEC 10%	2%	0%	1%	1%	1%
12. Two balancing authorities: DEC 15%	11%	1%	9%	10%	7%
12. Two balancing authorities: DEP 5%	0%	0%	0%	0%	0%
12. Two balancing authorities: DEP 10%	2%	0%	1%	1%	1%
12. Two balancing authorities: DEP 15%	15%	1%	13%	13%	10%

Table 5. Hours of Curtailment per Season

Scenario	Spring	Summer	Fall	Winter	Annual
1. Solar energy penetration 5%	0	0	0	6	6
2. Solar energy penetration 10%	76	0	45	58	179
3. Solar energy penetration 15%	351	36	275	220	882
4. Solar energy penetration 20%	533	216	403	354	1,506
5. Solar energy penetration 25%	636	458	494	428	2,016
6. Solar energy penetration 30%	707	598	562	488	2,355
7. Solar energy penetration 35%	752	700	610	525	2,587
8. Increase proportion of distributed solar	634	454	496	433	2,017
9. Additional storage	484	136	341	278	1,239
10. Nuclear retirement	593	363	457	391	1,804
11. Additional wind energy penetration 5%	746	650	584	506	2,486
12. Two balancing authorities: DEC 5%	0	0	0	5	5
12. Two balancing authorities: DEC 10%	91	2	54	66	213
12. Two balancing authorities: DEC 15%	358	53	278	223	912
12. Two balancing authorities: DEP 5%	0	0	0	5	5
12. Two balancing authorities: DEP 10%	90	1	51	63	205
12. Two balancing authorities: DEP 15%	361	45	282	217	905

In Duke Energy’s current system, low load days are important because of the lack of flexible thermal generation that can be relied on to reduce power output, if needed. In the case of high solar power penetration, such as the 25% case shown in Figure 4, the minimum net load days are more important because the system becomes more sensitive to solar power forecasting errors and causes greater ramps and variability. In this case, the average curtailment for this season is 25%; however, this particular day shows a sunny low load day reaching 62.9% curtailment.

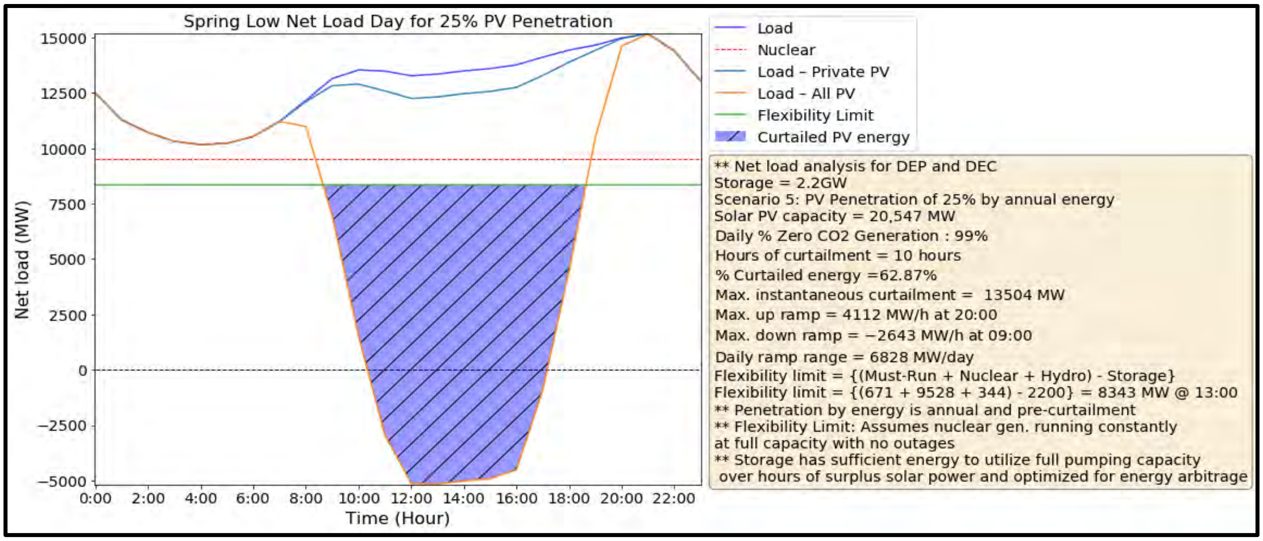


Figure 4. Minimum net load day for spring, the highest curtailment season, with 25% solar energy penetration

At higher loads, such as the peak load day of summer, which has 25% PV penetration, shown in Figure 5, flexible thermal generation needs to increase output, and therefore the system has a greater ability to reduce generation to be replaced with solar power during the day, and less curtailment is required. This is evident in Table 4, which shows that the curtailment during the summer is the minimum of all the values of seasonal curtailment across all scenarios.

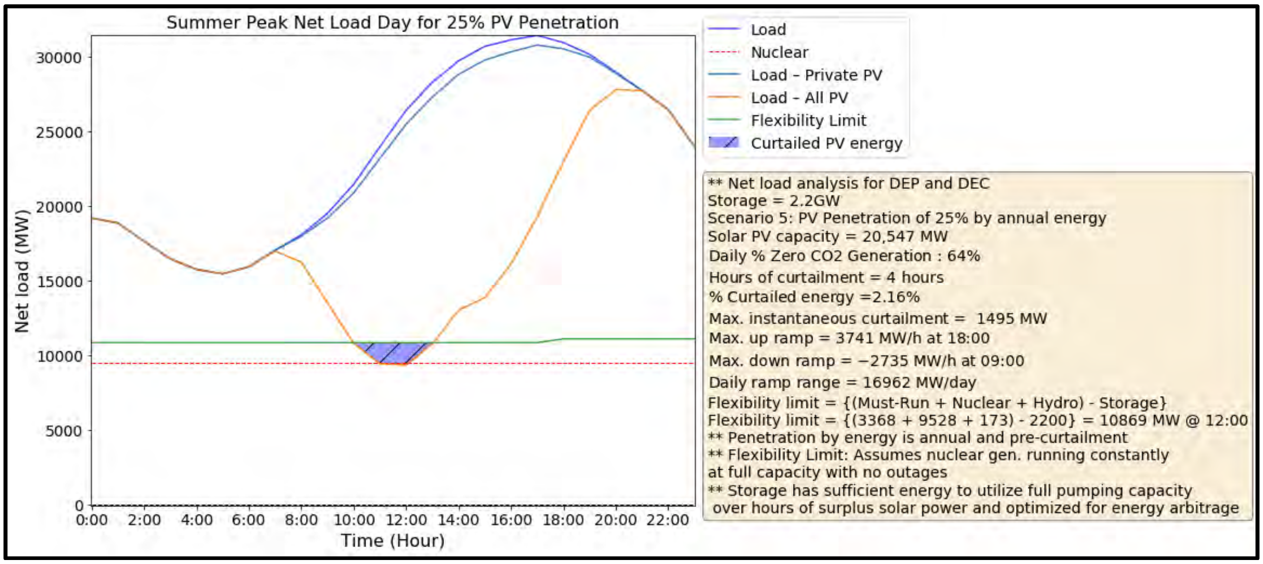


Figure 5. Max net load day for lowest curtailment season, summer, with 25% solar energy penetration

Marginal curtailment is defined as the percentage of the additional renewable energy that would be curtailed as the penetration level is increased by 5% of the load. The curtailment of each scenario is compared to that of the scenario with 5% less solar. Or, in the case of Scenario 11, which has 5% wind and 30% solar penetration, the curtailment is compared to that of Scenario 6, which has 30% solar. The marginal curtailment for all applicable scenarios is shown in Table 6.

Table 6. Percentage Marginal Curtailment

Scenario	% Marginal Curtailment
2. Solar energy penetration 10%	2.2%
3. Solar energy penetration 15%	21.4%
4. Solar energy penetration 20%	46.3%
5. Solar energy penetration 25%	64.6%
6. Solar energy penetration 30%	76.7%
7. Solar energy penetration 35%	83.2%
9. Additional storage	4.3%
10. Nuclear retirement	41.0%
11. Additional wind energy penetration 5%	26.3%
12. Two balancing authorities: 10% penetration	2.5%
12. Two balancing authorities: 15% penetration	22.9%

The load duration curve can also be a useful tool to illustrate the impact of variable generation penetration on the system peak and light loads. Load duration curves for the total system load and net load with 25% PV penetration are shown in Figure 6. The annual peak load is insignificantly reduced by the integration of solar PV because it occurs in winter before sunrise. During certain periods (1,947 hours), however, this penetration level reduces the annual minimum load to less than the minimum generation level set by the nuclear line. This implies that as PV penetration increases, solar PV will start to offset baseload generation or must be curtailed. This effect could vary based on the generation flexibility limit line imposed by the must-run units, hydro schedules, and energy storage systems.

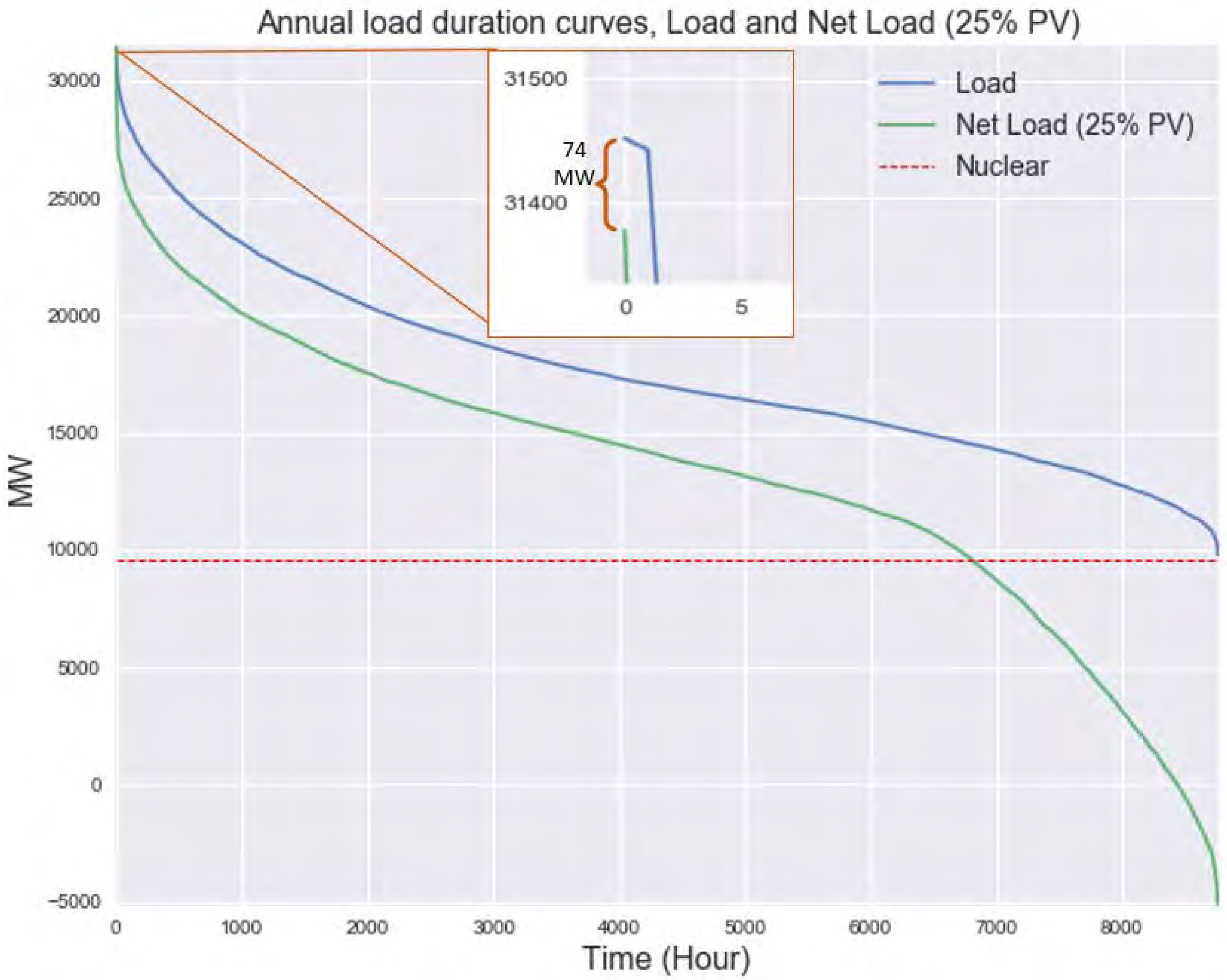


Figure 6. Annual load duration curves, load, and net load with 25% PV penetration

3.2 Scenario 8: Increased Proportion of Distributed Solar Energy

A portion of the PV generation, rooftop PV, is not curtailable by Duke Energy. Scenario 8 examines a relatively high solar penetration scenario of 25%, with the maximum expected proportion of the solar energy from rooftop solar. A model with such a large percentage of rooftop PV for the 25% solar power penetration by energy case will improve understanding of how the requirements for curtailment of additional PV might change with increased adoption of behind-the-meter solar PV. The PV time series provided by Duke includes separate profiles for rooftop and utility-scale solar energy, so the rooftop time series and utility time series are both scaled to forecast a higher proportion of rooftop solar generation. The scalars and equations used to calculate these profiles are shown in the appendix.

To capture an increase in rooftop PV by 2030, the maximum percentage of total solar PV that might be rooftop PV was assumed to be 18.91%. This percentage was obtained using the NREL-developed standard scenarios of the U.S. power sector tool,[3] which models 42 different scenarios to capture the impacts of fuel prices, demand growth, retirements, technology and financing costs, transmission and resource restrictions, and policy considerations on possible power system capacity expansion futures. The scenario predicting the largest ratio of rooftop solar to utility solar in the Carolinas in 2030 accounts for extended lifetimes of current generation facilities. This Extended Lifetimes Scenario assumes that coal power plant lifetimes are increased by 10 years, there are no retirements of underused coal power plants, and all nuclear power plants have 80-year lifetimes.

Using Scenario 5 (25% solar energy penetration) as a baseline, the effect of an increased proportion of distributed PV energy to utility PV energy is modeled. The PV time series corresponding to 25% solar penetration was scaled by the projected percentage of utility PV energy and the percentage of distributed PV energy to calculate the two projected time series.

The analysis assumes that rooftop PV cannot be curtailed, so an increase in the percentage of rooftop PV results in an increase in utility PV that must be curtailed. Comparing the results of Scenario 8 to Scenario 5 (25% PV penetration) shows that 33.2% of utility solar would be curtailed provided a maximum increase in the proportion of rooftop PV versus utility PV, whereas 28.5% of utility PV would be curtailed if this proportion remains unchanged from the assumptions used in scenarios 1–7.

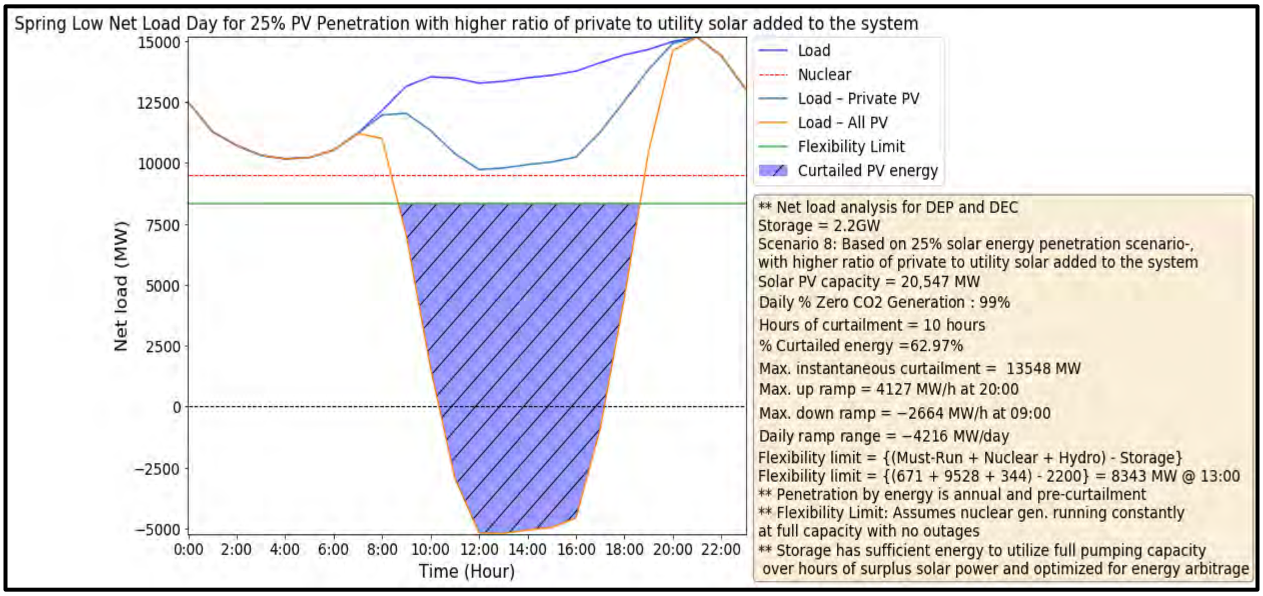


Figure 7. Minimum net load day with an increase in rooftop PV

As shown in Figure 7, even with a maximum increase in rooftop PV to 18.91%, the difference between load and solar as a result of rooftop generation never crosses the flexibility limit at 25% solar penetration.

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[3] https://openei.org/apps/reeds/#

3.3 Scenario 9: Additional Storage Capabilities

Scenario 9 captures the effect of an increase in storage with 25% solar energy penetration and demonstrates how this additional technology resource might reduce the curtailment required in a high solar penetration scenario. The hypothetical storage is charged entirely with surplus renewable energy sources and is assumed to discharge throughout the remainder of the day with a round-trip efficiency of 80%. The storage stores energy only during hours of surplus generation. In addition to the existing storage consisting of 2,200 MW of pumped storage hydropower, the additional storage modeled is 1,000 MW of 4-hour storage, 1,000 MW of 6-hour storage, and 2,000 MW of 8-hour storage. This is a total of 26,000 MWh of storage.

The storage is given a hierarchy of use preferences: for each modeled day, the 8-hour storage is used to capacity first, followed by the 6-hour storage, and finally the 4-hour storage is used. The generation flexibility limit line is then adjusted to incorporate the additional used storage, and curtailment is adjusted to fit the new flexibility limit.

The addition of such storage results in an improvement in the percentage of renewable energy curtailed from 26.9% (Scenario 5) to 14.8%. The greatest improvement is seen in the winter, during which time the curtailment decreases from 31.3% to 14%. The minimum net load day in the winter of Scenario 9 is shown in Figure 6, and that of Scenario 5 is shown in Figure 9.

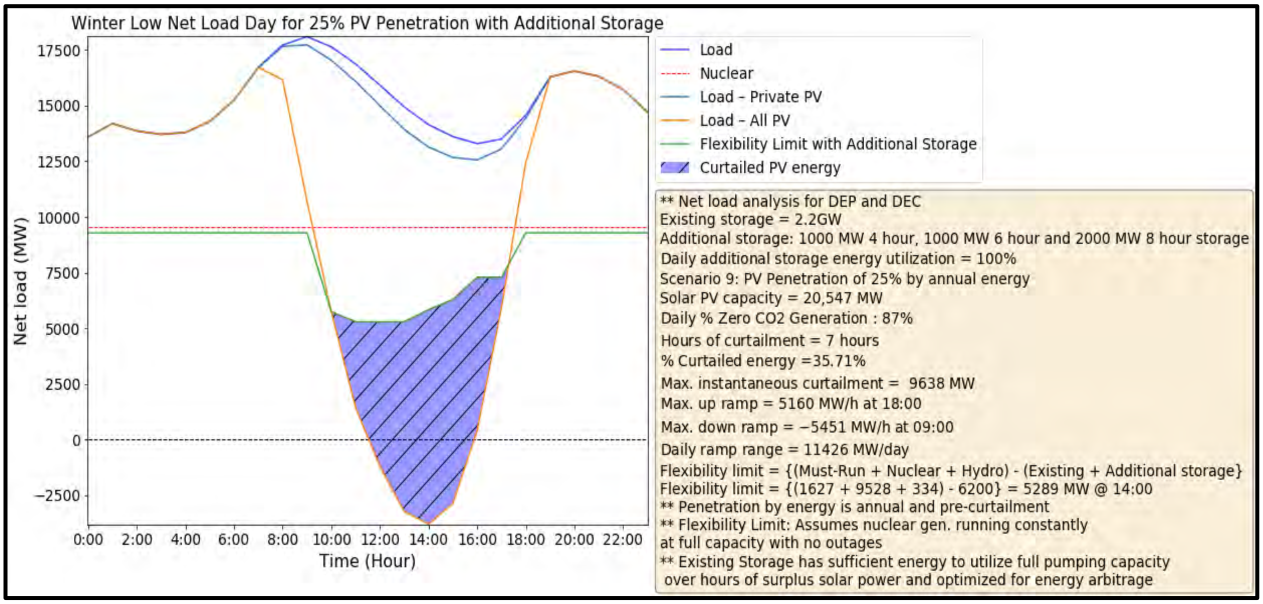
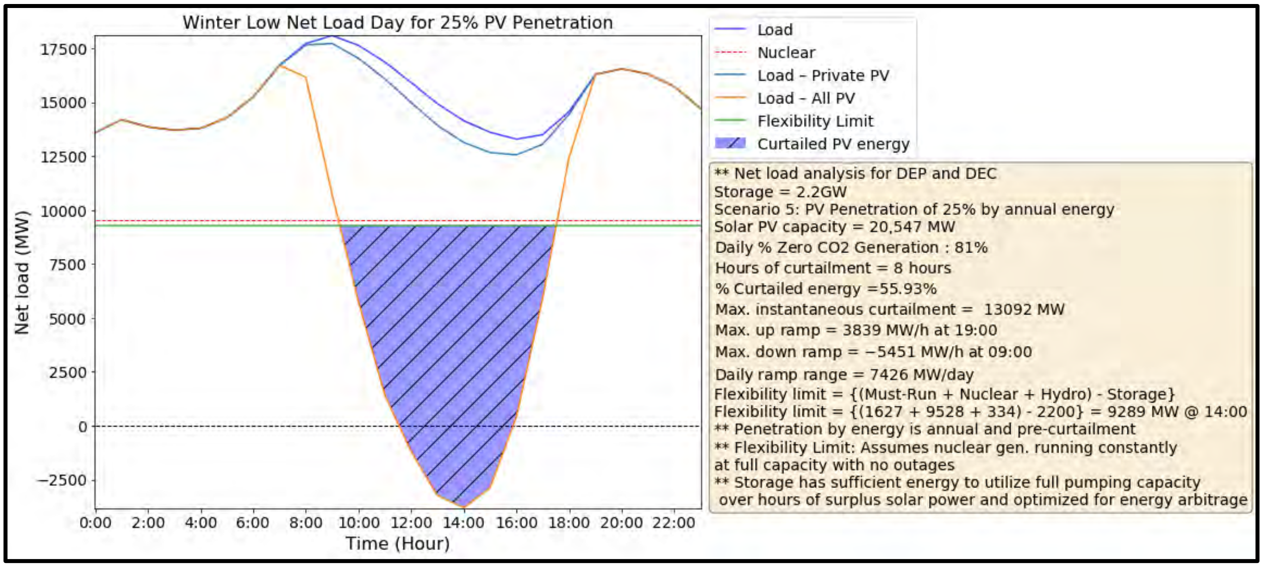


Figure 8. Minimum net load day in winter with additional storage

The additional storage modeled accounts for 7% of the load on this day. The annual contribution to this additional storage amounts to 3.7% of annual load.



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 81%
Hours of curtailment = 8 hours
% Curtailed energy =55.93%
Max. instantaneous curtailment = 13092 MW
Max. up ramp = 3839 MW/h at 19:00
Max. down ramp = −5451 MW/h at 09:00
Daily ramp range = 7426 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Figure 9. Minimum net load day in winter without additional storage

The smallest impact occurs in the summer, with an improvement from 11.8% curtailment to 2.3%. For this analysis, storage is assumed to be used exclusively for load-shifting. In reality, storage could also potentially provide ancillary services, such as regulation reserves, especially in the summer seasons, when the load-shifting requirement is minimal. Further, if transmission constraints were considered, the total contribution of storage to saving renewable energy curtailment could be higher.

In this model, energy storage devices are charging only during times of overgeneration. The additional storage modeled results in an annual average of 77% carbon-free energy, whereas the carbon-free percentage of Scenario 5 is 74%. The additional storage yields a greater percentage of the carbon-free energy resource than that of Scenario 7, the 35% solar energy penetration model (77%).

Further analysis should examine a unit commitment and economic dispatch model, which could help understand the most economical and effective storage solutions to meet the proposed extra flexibility here, including the potential to use controllable electric vehicle charging. Further, such detailed analysis would quantify the economic value and system stability benefits of the additional storage through such examples as additional capacity, enabling higher penetrations of low-cost solar power and providing ancillary services.

3.4 Scenario 10: Generation Retirement

The portion of energy from nuclear sources is unique in the Duke Energy Carolinas region, contributing to a large amount of carbon-free generation. For this analysis, the possibility of ramping down nuclear is excluded (see assumptions in Table 8). The flexibility of nuclear is limited, and therefore it impacts the amount of variable energy that must be curtailed, particularly at high penetrations of solar. As current nuclear generation facilities are retired, the generation flexibility limit could decrease, especially if the energy is replaced with flexible thermal sources, allowing for larger contributions from solar and wind energy resources. Scenario 10 looks at the required curtailment resulting from the retirement of 10% of the nuclear generation, again using 25% solar penetration. A new generation flexibility limit is calculated with the nuclear generation reduced to 90% to reflect the nuclear retirement. It is assumed that the generation is replaced with flexible thermal generation. The other components of the flexibility limit are the same as those used in scenarios 1–7, including inflexible hydropower units and must-run units, with additional flexibility provided by hydropower pumped storage.

This reduction in the nuclear generation of the system with 25% solar penetration reduces the necessary curtailment from 26.9% of total renewable energy to 22.2%. Despite greater quantities of carbon-free solar power contributing to load, however, the percentage of carbon-free energy is reduced from 74% to 70%, which is to be expected because nuclear energy is carbon-free and generates consistently throughout the day.

3.5 Scenario 11: Additional Wind Energy Penetration

Duke Energy will work toward the goal of carbon-free energy generation primarily by incorporating solar power because solar is a plentiful resource in the Carolinas regions (see Figure 1). As the penetration of solar power increases, however, the imbalance in the availability of solar during a day—with increased power during daylight hours and a complete lack of power otherwise—becomes more problematic. It is therefore beneficial to consider an additional renewable source that can generate at different times of the day, such as wind. Scenario 11 examines the incorporation of 5% of the annual load generated by wind energy in addition to 30% solar energy penetration. A map of the wind resource is shown in Figure 10.

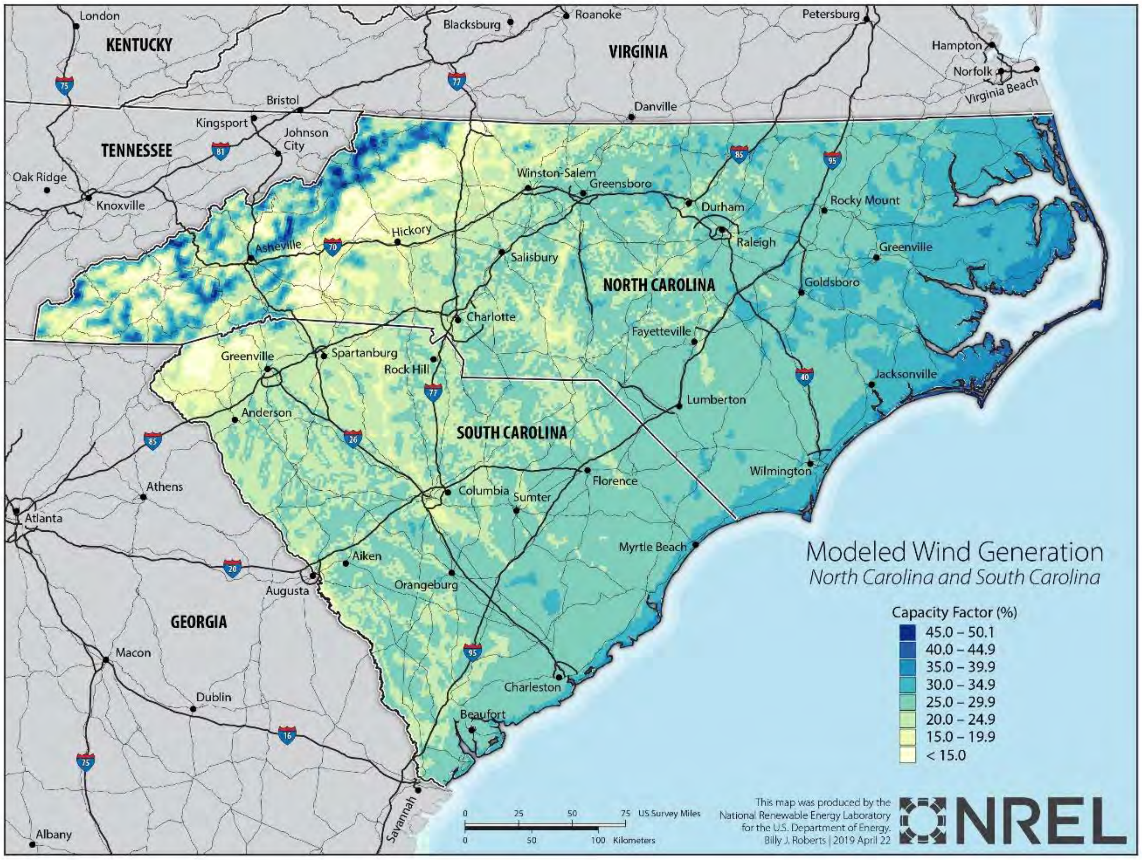


Figure 10. Wind capacity factors in the Carolinas

The wind time series is a simulated power output from NREL's Wind Integration National Dataset (WIND) Toolkit (Draxl, et al., 2015) based on the 2006 meteorological year. The 5% wind is calculated in a manner similar to the percentage of solar penetration levels (see Equation 5 in the appendix). The wind power profiles were taken from offshore profiles where the wind resource is high. Further, because the profiles are offshore, we assume that they are insignificantly correlated with load. The wind energy profile was scaled to match 5% of the load. The net load for this scenario is calculated as the remaining load after the contribution of the 5% wind and 30% solar penetration. The curtailment of wind and solar is proportional to the generation of wind and solar, respectively.

Building off of the 30% PV scenario (Scenario 6), there is an interesting comparison between adding another 5% of PV (to get 35% PV, Scenario 7)) or adding 5% wind (Scenario 11). Adding another 5% PV (to get to a total of 35% PV) leads to 83.2% of that additional 5% of solar being curtailed, while adding 5% wind (to 30% PV) requires only 26.3% of that additional wind to be curtailed. Looking at the total renewable curtailment of Scenario 11 compared to Scenario 7 (35% PV), adding wind improves the total renewable energy curtailment from 42% to 33.9%.

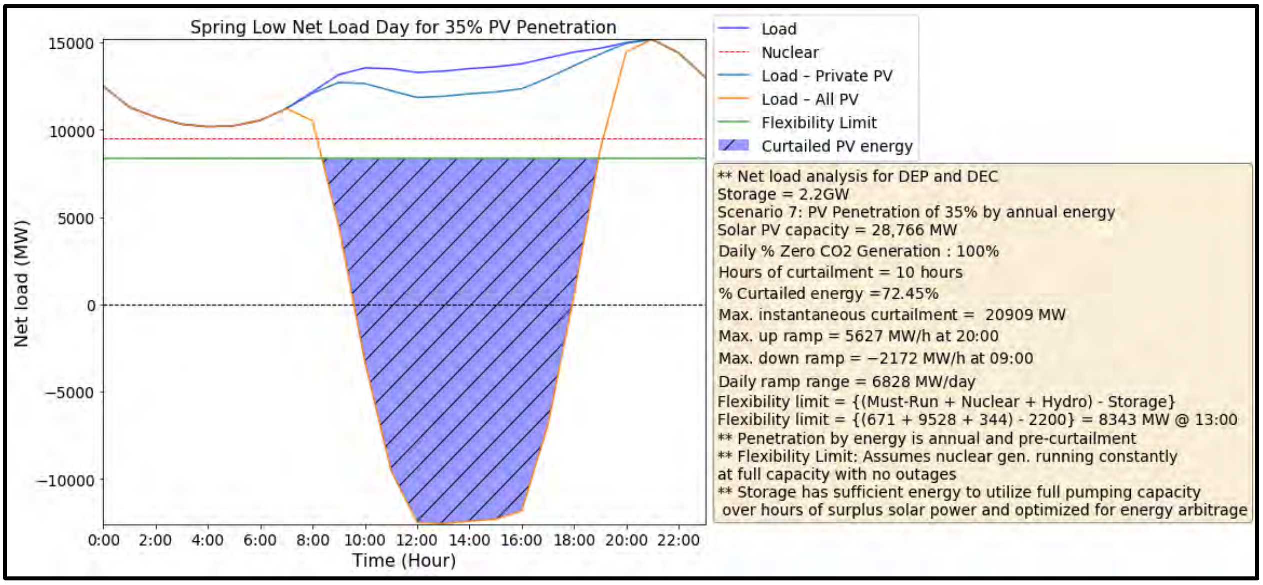


Figure 11. Minimum net load day in spring with 35% PV energy penetration

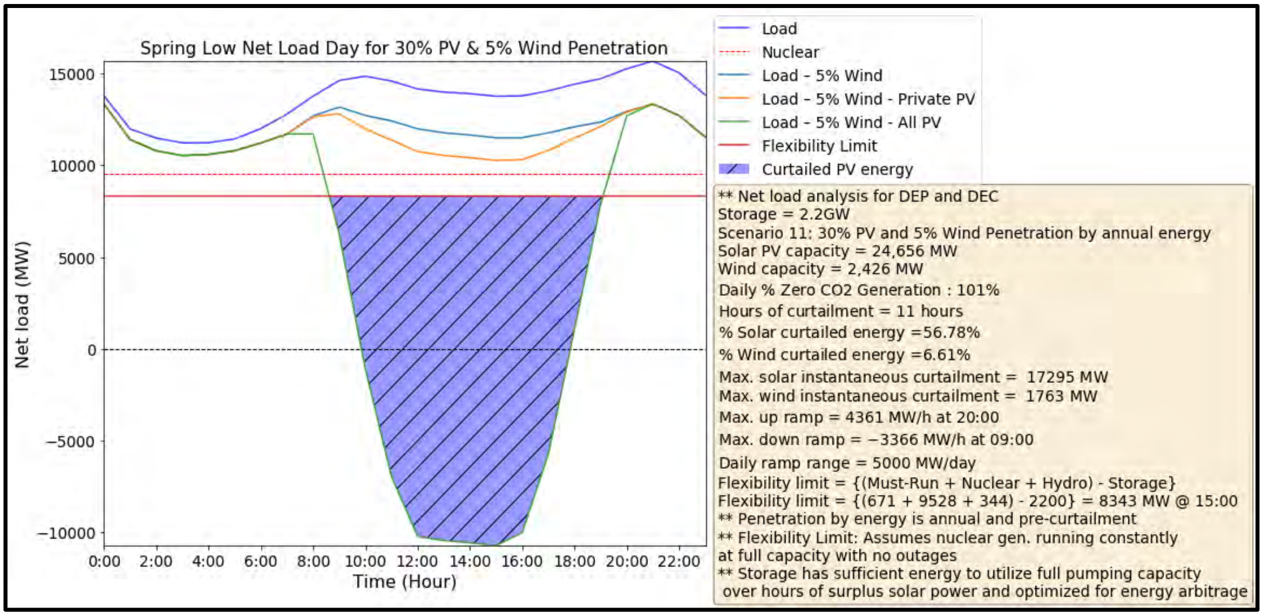


Figure 12. Minimum net load day in spring with 30% PV plus 5% wind energy penetration

And, since curtailment is reduced, that also means energy from carbon-free sources improves compared to Scenario 7. The average annual percentage of carbon-free energy in a 35% PV penetration scenario is 77%, whereas the percentage of carbon-free energy in a 30% PV, 5% wind penetration scenario is 79%, the greatest of all examined scenarios.

3.6 Scenario 12: DEC and DEP Modeled as Individual Balancing Authorities with a Limited Interconnection

All prior scenarios assume unlimited transfer capability in the Carolinas region. Scenario 12 separates DEC and DEP into separate regions with Duke Energy's existing transfer capability to observe the effect on the net load and curtailment given 5%, 10%, and 15% solar penetration levels by energy. The interconnection limit is provided by Duke Energy. It is directional and has different values for nighttime (0 h–7 h) and daytime (8 h–23 h). The separate loads are also provided by Duke Energy (all loads in prior analyses are the sum of these two loads). The generation totals of the must-run units for all prior scenarios are also calculated first for DEC and DEP and then summed, so the isolated values are used in Scenario 12. The generation flexibility limit is parsed between the two balancing authorities by separating must-run units, hydropower (see appendix for hydro assignments to DEC and DEP), nuclear (hourly generation values for DEC and DEP are provided by Duke Energy), and pumped storage (values also provided by Duke Energy). The equation for calculating each generation flexibility limit is the same as that used to calculate the generation flexibility limit for the total area (see Equation 1).

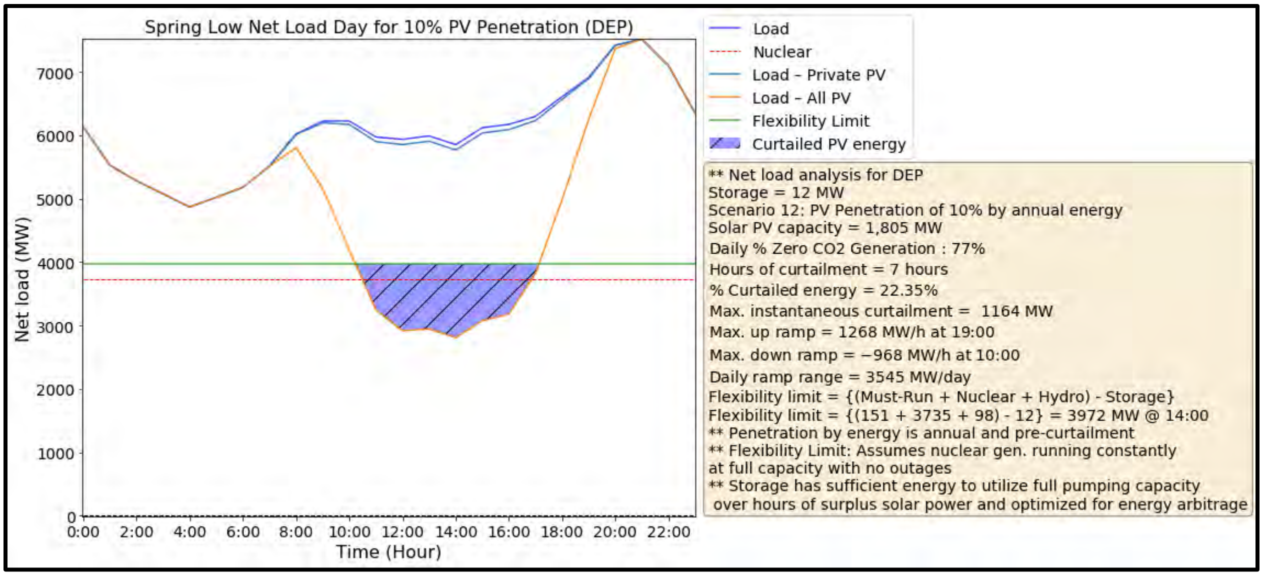
The interconnection is simulated to maintain the same difference between the net load and the flexibility limit of each balancing authority, provided that the transfer limit is not exceeded. This assumption of operating the interconnection to minimize the possibility of curtailment in high solar penetration scenarios was decided with Duke Energy. A production cost optimization would enable simulation of the interconnection and other transmission in a more realistic manner. If the difference between the net load of one balancing authority and its flexibility limit is less than that of the other, load is transferred until the difference is equal or the transfer limit in that direction, for that time of day, is met. This analysis uses 12 different equations to calculate 12 different scenarios resulting from variations in the calculations because of the sign and magnitude of the differences and the times of day (see appendix). The results of these 12 scenarios are then summed to produce a time series of load transfer, which is then used to calculate the net load of each balancing authority after the transfer. To calculate the transfer, load transfer to DEC is arbitrarily defined as negative, whereas load transfer to DEP is defined as positive. The resulting net loads of DEC and DEP are calculated with the transfer amount (see appendix).

The sum of the required solar power curtailment for both regions after the interconnection is modeled is greater than the curtailment that results when they are modeled as one balancing authority, or a region without transmission limitations. As shown in Table 7, an increase in transmission capabilities would support increased solar energy penetration. This benefit is minimal at low levels of PV penetration, but it increases at higher percentages.

Table 7. Comparison of Curtailment of the System Modeled With and Without Transmission Limitations

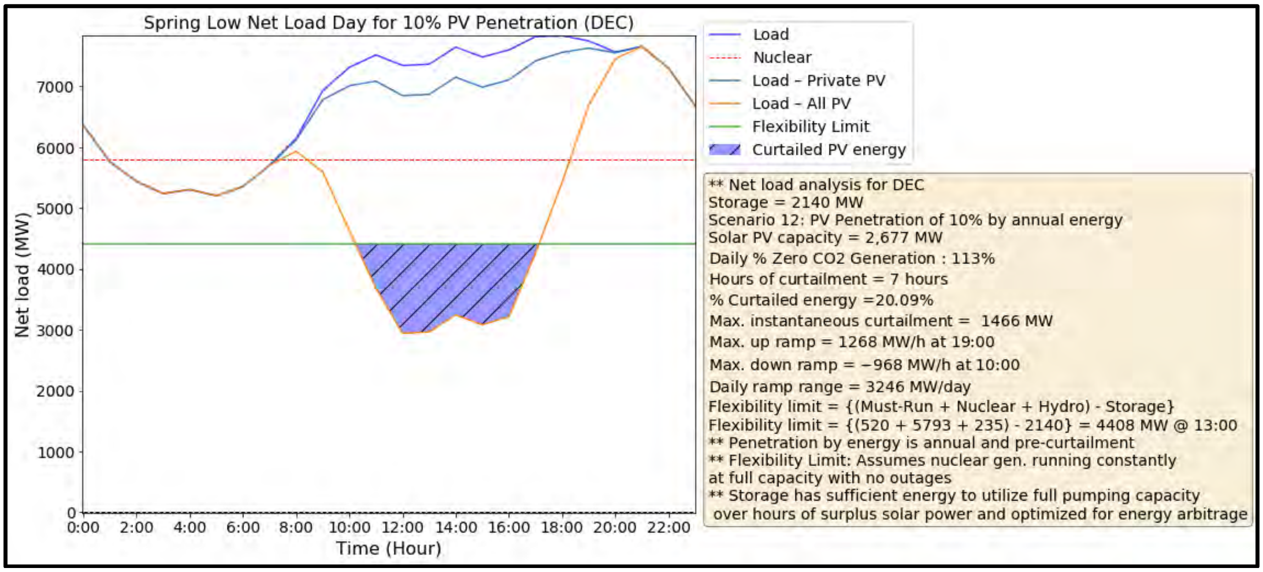
Percentage PV Penetration	Curtailment with Infinite Transmission (MWh)	Percentage Curtailment with Infinite Transmission	Curtailment with Limited Transmission (MWh)	Percentage Curtailment with Limited Transmission
5%	1,570	0.0%	1,361	0.0%
10%	172,444	1.1%	191,306	1.2%
15%	1,824,853	7.9%	1,928,162	8.3%

The minimization of curtailment with an increase in transmission capacity is illustrated when the minimum net load days to DEP and DEC, shown in Figure 13 and Figure 14, respectively, are compared to Figure 15. The first two figures of the separate balancing areas display 22% curtailed energy in DEP and 20% and DEC, whereas Figure 15 shows 20% curtailment on the minimum load day when DEP and DEC are modeled as one balancing area with unlimited transmission capabilities.



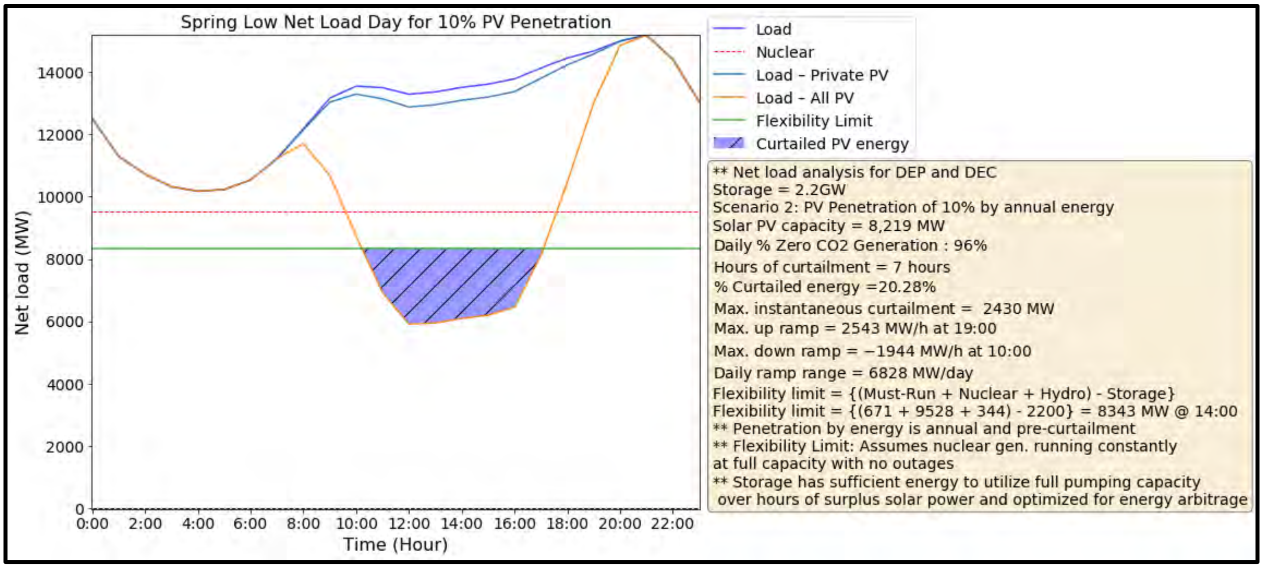
** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 77%
Hours of curtailment = 7 hours
% Curtailed energy = 22.35%
Max. instantaneous curtailment = 1164 MW
Max. up ramp = 1268 MW/h at 19:00
Max. down ramp = −968 MW/h at 10:00
Daily ramp range = 3545 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 98) - 12} = 3972 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Figure 13. Low net load day for the DEP balancing authority with 10% PV penetration in spring



** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 113%
Hours of curtailment = 7 hours
% Curtailed energy =20.09%
Max. instantaneous curtailment = 1466 MW
Max. up ramp = 1268 MW/h at 19:00
Max. down ramp = −968 MW/h at 10:00
Daily ramp range = 3246 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 235) - 2140} = 4408 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Figure 14. Low net load day for the DEC balancing authority with 10% PV penetration in spring



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 96%
Hours of curtailment = 7 hours
% Curtailed energy =20.28%
Max. instantaneous curtailment = 2430 MW
Max. up ramp = 2543 MW/h at 19:00
Max. down ramp = −1944 MW/h at 10:00
Daily ramp range = 6828 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 344) - 2200} = 8343 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Figure 15. Low net load day with 10% PV penetration in spring when the Duke Carolinas territory is modeled with unlimited transmission capabilities

There is a difference in solar power output between the two balancing areas, such that DEP currently has roughly twice the solar capacity of DEC. The location of additional solar capacity will affect transmission constraints.

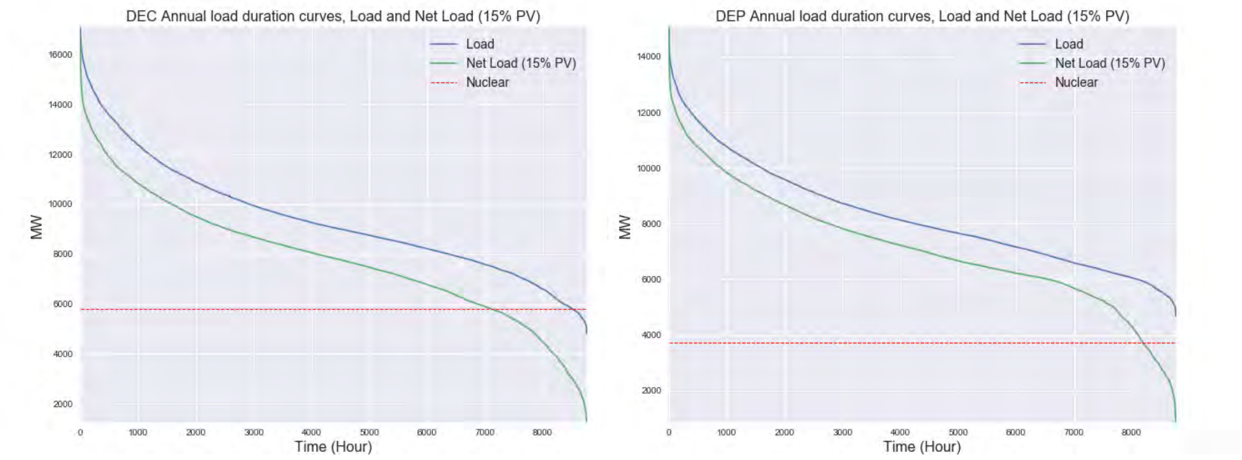


Figure 16. DEC and DEP load duration curves at 15% PV penetration

The load duration curves of the separate balancing authorities shown in Figure 16 show that at 15% PV energy penetration, there are 1,635 hours during which the net load dips below the nuclear generation limit in DEC and 577 hours in DEP, summing to 2,212 total hours. The load duration curve of the single balancing authority shown in Figure 17 shows an improvement, with 930 hours during which the net load is less than the nuclear limit.

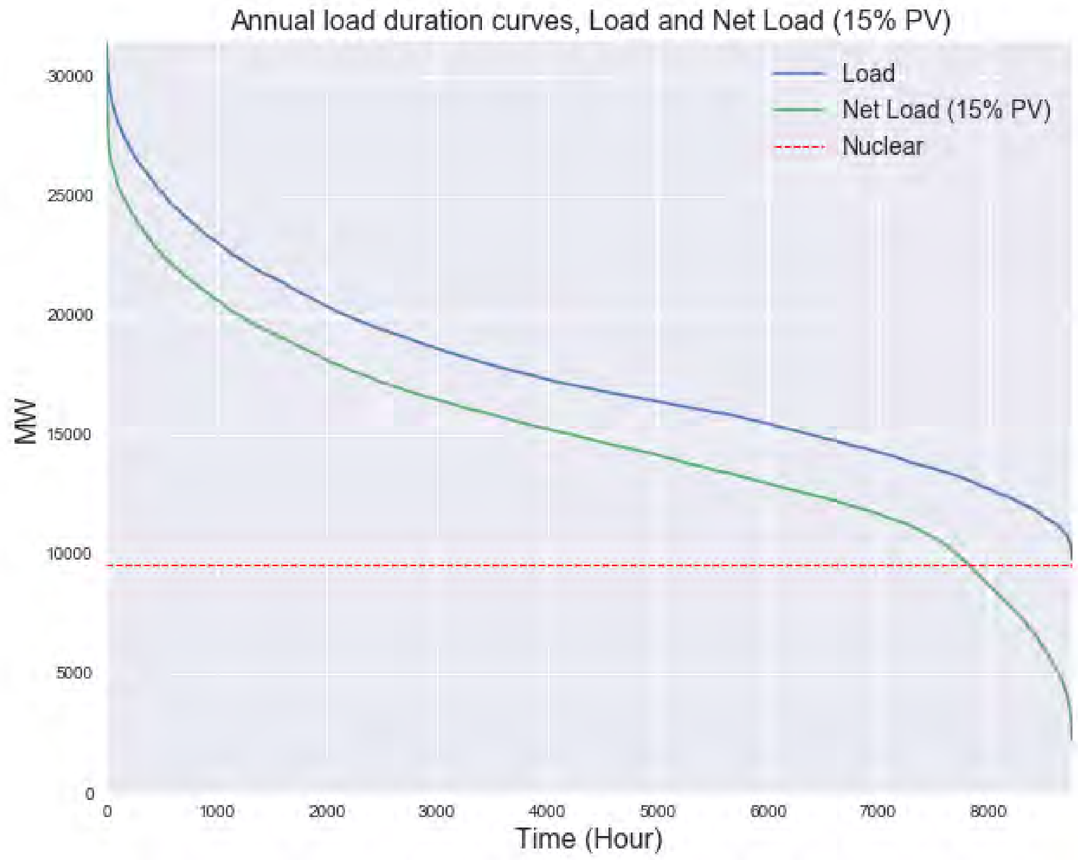


Figure 17. Load duration curve of the Duke Carolinas region modeled as one balancing area at 15% PV penetration

4 Geospatial Analysis

Several maps and an online application were created by the geospatial analysis team at NREL to visualize the solar and wind resources in the Duke Carolinas territory. The solar energy resource is characterized by global horizontal irradiance, and the wind energy resource is characterized by wind speed. Capacity factors were produced to visualize solar and wind generation, and exclusions[4] were made based on land categories and use type (see appendix for details). One such map is shown in Figure 18, which shows the capacity factors that are not in excluded areas of the region.

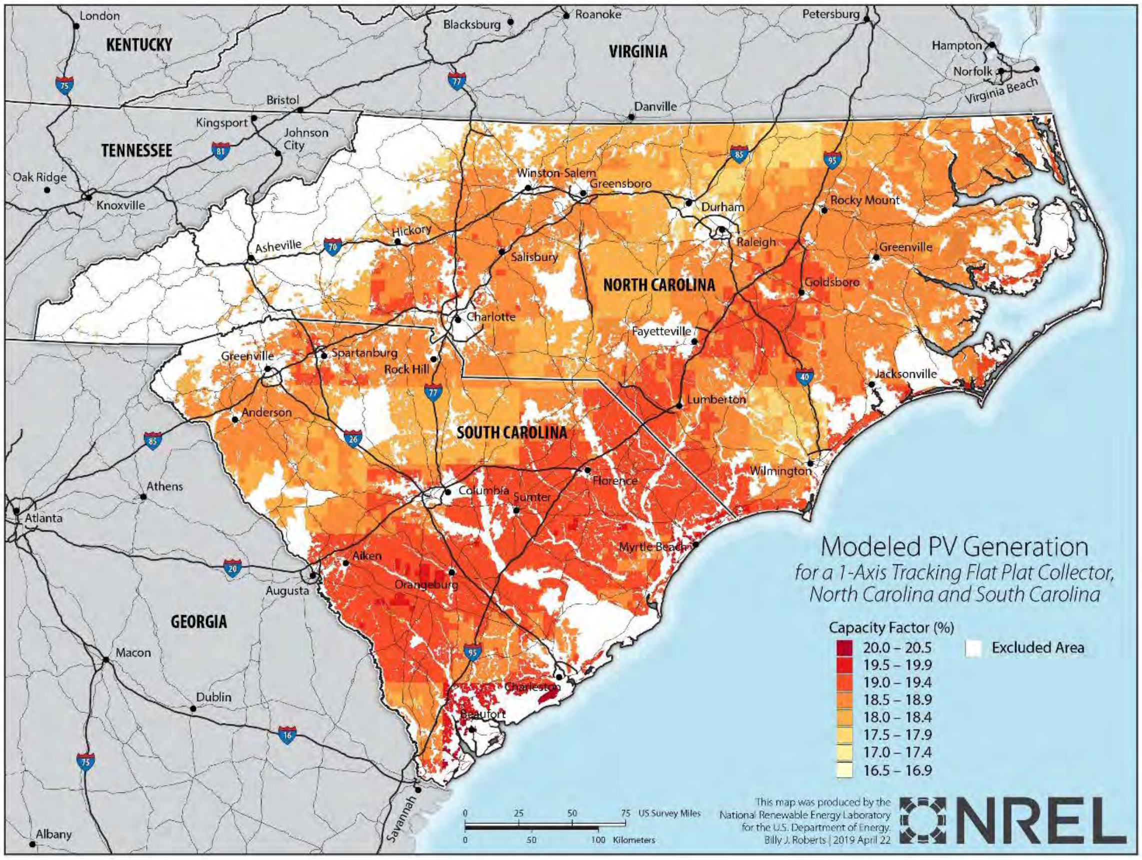


Figure 18. Multiyear mean capacity factors

The web application allows the user to examine these three layers of generation, energy resource, and exclusions for both wind and solar. The URL for the website is: https://maps.nrel.gov/duke. Note, please use Firefox, or Chrome for best results. The following layers are available on the web application:

- Solar exclusions: solar-categorized exclusions

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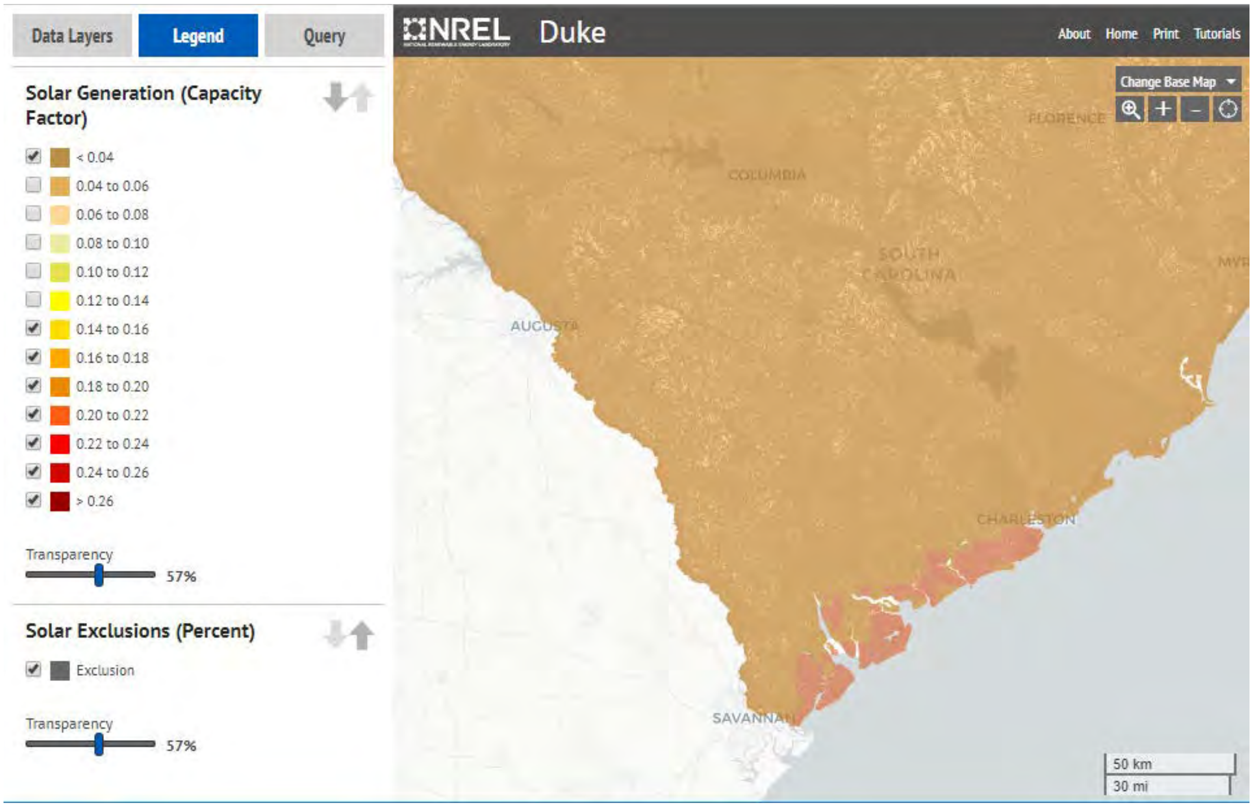
[4] Exclusions include a slope >5%, urban areas, water and wetlands, parks and landmarks, national parks, and other environmentally or culturally sensitive areas.

- Solar generation: multiyear mean PV capacity factors using the listed PV system configurations
- Solar energy resource: Multiyear mean global horizontal irradiance
- Wind exclusions: wind-categorized exclusions. Both 100% exclusions and 50% exclusions are listed in this layer, depicting locations that are 100% excluded and other locations that are 50% excluded. The decision for 50% exclusions is based on assumptions used in Lopez (2012).
- Wind generation: multiyear mean wind capacity factors using the listed wind system configurations
- Wind energy resource: multiyear mean wind speed.

The web application allows the user to navigate geospatially and zoom in and out of areas of interest. Any combination of data layers can be displayed at once, including exclusions, generation, and energy resource for solar power and wind power. The legend tab enables the user to filter for ranges of data within each layer and control the transparency to maintain visual clarity, depending on the number of layers selected. This is shown in Figure 19. The query tab enables the user to intuitively retrieve the data being visualized by one of the four following options: the user can (1) select an individual point on the map, (2) query an entire region, (3) draw a custom shape of interest, and (4) filter based on specific attributes. The data behind this web app make it a useful tool to explore future development in the form of production cost models for the continued study of carbon-free resource integration.



Solar Generation (Capacity Factor)

☑ < 0.04
☐ 0.04 to 0.06
☐ 0.06 to 0.08
☐ 0.08 to 0.10
☐ 0.10 to 0.12
☐ 0.12 to 0.14
☑ 0.14 to 0.16
☑ 0.16 to 0.18
☑ 0.18 to 0.20
☑ 0.20 to 0.22
☑ 0.22 to 0.24
☑ 0.24 to 0.26
☑ > 0.26

Transparency 57%

Solar Exclusions (Percent)

☑ Exclusion

Transparency 57%

Figure 19. Screenshot of geospatial web application

5 Conclusion

Duke Energy endeavors to increase the proportion of load met by carbon-free generation. With high quantities of nuclear power currently providing carbon-free generation, and given their great solar irradiance resource, Duke Energy seeks to analyze the impact of integrating significant amounts of new solar power into its power system under a variety of penetration levels. This additional solar power will help reach carbon-free goals; however, with the high minimum generation level of existing nuclear power, this net load analysis concludes that curtailment of solar is likely to begin at 10% solar energy penetration. Thus, the net load analysis becomes an important initial step in realizing this goal while maintaining a reliable and economically viable grid.

This net load analysis shows:

- The greatest curtailment occurs during the spring, which is usually characterized by low load and an oversupply of solar PV power output during the middle of the day.
- The largest ramps remain in winter, through all solar PV penetrations, and for all seasons the ramps increase as solar PV penetration increases.
- The largest maximum instantaneous curtailment, percentage of curtailed energy, and duration of curtailment occur during the spring.
- The system experiences the largest percentage of daily carbon-free generation during the spring, which is the highest compared with other seasons.
- The net load analysis shows a significant reduction in the peak net load and a shift in the timing of the minimum and peak net load. This effect is most significant during the summer because of the time-coincident correlation between the demand and solar output. Thus, solar PV can significantly contribute capacity value to the system during the summer peak load; however, the shift in timing minimum and peak net loads can affect generator outage and maintenance scheduling, and this should be investigated further using unit commitment and economic dispatch models.
- Even at high solar penetration levels of 25%, with the highest anticipated level of rooftop solar, curtailment rights of utility solar is sufficient to avoid an imbalance of supply and load. This net load analysis shows that building wind power after high levels of solar power curtailment are reached and building storage are two solutions that can aid in increasing the share of carbon-free emission generation in Duke Energy's system.
- The analysis of scenarios 12 and 10 show that transmission constraints and nuclear retirement both work against the goal of meeting load with carbon-free generation.

A key constraint in accommodating additional variable generation penetration is the ramping ability of conventional generators, to change their output in response to the fluctuating renewables. For instance, during the spring minimum net load day shown in Figure 4, the traditional generator fleet is required to increase the output rapidly as the sun sets. For Duke Energy, because the nuclear fleet has a high minimum generation limit, increasing system flexibility with technologies that provide fast ramp rates and control over load should be examined to accommodate higher PV penetrations.

In addition, managing system flexibility requires serious operational adjustments coupled with a resource mix that can quickly respond to the balance of electricity demand and net load variability. The result of this study further reveals that exceeding 15% PV penetration could lead to serious integration issues, especially during the spring, which is characterized by low load and a possible frequent overgeneration scenario.

Further analysis with more advanced models—such as unit commitment and economic dispatch, capacity expansion planning, and dynamic analysis models—will be required to more fully assess system impacts with increasing variable generation penetration as well as flexibility opportunities for accommodating variable renewable energy sources with conventional generation.

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Sengupta, M., Xie, Y., Lopez, A., Habte, A., Maclaurin, G., & Shelby, J. (2018). The National Solar Radiation Data Base (NSRDB). *Renewable and Sustainable Energy Reviews*, *89*, 51–60. https://doi.org/10.1016/j.rser.2018.03.003

Appendix

A.1 Data Sources and Assumptions

In the context of data and files provided by Duke Energy, for both Duke Energy Progress and Duke Energy Corporation, the capacity factors from the "Third Party Non-Curtailable" sheet are multiplied by the rooftop solar capacity for 2019. The capacity factors from the "Utility Owned" tab are multiplied by the sum of the utility nameplate capacities. "Net Metered (Rooftop) Solar" is assumed to be rooftop solar PV, whereas "D-Tied Universal Solar" and "T-Tied Universal Solar" are assumed to be utility. Hydro schedules are from "Carolinas Hydro Schedules_Capacity and Energy_Confidential.xlsx."

Table 8. Assumptions and Definitions for the Net Load Analysis

Assumptions for Scenarios 1 - 7
Penetration by energy is annual and pre-curtailment.
Storage is 2.2 GW, which represents the existing pumped hydro storage capacity.
Storage has sufficient energy capacity to use full pumping capacity during hours of surplus solar power and is optimized for energy arbitrage.
The percentage of curtailed energy is estimated as a percentage of total PV output energy.
Must-run units are defined relative to the highest load within the last week because the majority of must-run units have a weeklong minimum up time.
Nuclear runs consistently at full capacity and has no outages.
No contingency reserve is added to the flexibility limit line.
Interconnections to neighboring regions are not considered

A.2 Equations for Scenario Analysis

The inflexibility generation limit line, Gen_{inflex}, is given as:

$$Gen_{inflex} = \left\{(\text{MustRun units } + \text{ Nuclear capacity } + \text{ Hydro units}) - \text{ Storage}^{5}\right\} MW \quad (1)$$

Renewable energy curtailment is given as:

$$VG^{6}\ curtailment = \begin{cases} Gen_{inflex} - Net\ load, & Gen_{inflex} > Net\ load \\ 0, & Gen_{inflex} < Net\ load \end{cases} \quad (2)$$

Daily ratio of carbon-free generation is given as:

$$\sum_{n=1}^{24} \frac{(Nuclear_n + Hydro_n + 0.8 * Storage_n + VG\ precurtailment_n - VG\ curtailment_n)}{Total\ load_n} \quad (3)$$

Table 9. Scalars Used to Calculate PV Penetration

Scenario No.	Scalar
1	0.9642
2	1.9284
3	2.8926
4	3.8568
5	4.8210
6	5.7852
7	6.7494

The scalars to calculate the solar penetration required to meet the specified percentage of load were found with the following Equation:

$$\{(\text{Percent Penetration}) \cdot (AnnualLoad)/(AnnualPV)\} \quad (4)$$

---

[5] Storage represents the total pumped storage hydropower pumping capacity.

[6] *Variable generation* refers to solar and wind (where applicable) power plants.

The solar time-series was then multiplied by each scalar to produce the appropriate amount of annual solar to achieve the targeted penetration level for each Scenario. For example, to create the PV time-series for Scenario 1 with 5% solar penetration, the solar time-series was multiplied by 0.9642.

In Scenario 8 illustrates 25% solar energy penetration with 18.91% of solar due to rooftop solar generation. 18.91% of 25% of the load was calculated to find the amount of rooftop PV. A scalar to adjust the rooftop PV time-series was calculated similarly to the scalars used to calculate the time-series for Scenarios 1-7:

$$\{(\text{Percent Rooftop}) \cdot (25\% of AnnualLoad)/(AnnualRooftopPV)\} \tag{5}$$

The calculation for the remaining 89.09% of solar from utility is analogous:

$$\{(\text{Percent Utility}) \cdot (25\% of AnnualLoad)/(AnnualUtilityPV)\} \tag{6}$$

Additional storage in Scenario 9 is calculated according to the following rules:

If the curtailment is required, eight-hour storage is used to store as much of the curtailment required as possible, limited to 2000 MW inside of an hour. The maximum eight-hour storage over a 14-hour window is 2000 MW * 8 hours =16000 MWh, so any renewable generation beyond that must be stored by the six- or four-hour storage units. Next, the six-hour storage is used to store up to 1000 MW of excess energy in an hour, with the maximum storage over a 14-hour window of 6000 MWh. Finally, the four-hour storage is used to store up to 1000 MW of excess energy in an hour, with the maximum storage over a 14-hour window of 4000 MWh.

In Scenario 11, the wind time series is scaled by 0.6680 to match 5% of the total load, and is found with:

$$\{(0.05) \cdot (AnnualLoad)/(AnnualWind)\} \tag{7}$$

The wind time-series was then multiplied by 0.6680 to produce an annual generation equal to 5% of the load.

For Scenario 12, the location of hydropower units in each of the modelled BAs is as follows:

Table 10. Hydropower units corresponding to each region

DEC	DEP
Cowans Ford Hydro Keowee Hydro Lower Catawba Hydro Misc ROR Hydro Nantahala Hydro Upper Catawba Hydro	Blewett Hydro Marshall Hydro Tillery Hydro Walters Hydro

The Equations for calculating load transfer are listed in Table 11. “DEC” refers to the net load of DEC minus the flexibility limit of DEC, while “DEP” refers to the net load of DEP minus the flexibility limit of DEP.

Table 11. Equations to Calculate Load Transfer from DEC to DEP

(Net Load –Flexibility Limit)			**Time of Day**	**Equation**
DEC	**DEP**	**Comparison**		
<0	<0	|DEC|<|DEP|	8:00-23:00	*If*(|DEC-DEP|<1820): *If*($\text{DEP}_{\text{NetLoad}}$ +|DEC-DEP|> $\text{DEC}_{\text{NetLoad}}$ -|DEC-DEP|): *Average*(DEC,DEP)-*Min*(DEC,DEP) *Else:* |DEC-DEP| *Else If*($\text{DEP}_{\text{NetLoad}}$+1820> $\text{DEC}_{\text{NetLoad}}$-1820): *Average* (DEC,DEP)-*Min*(DEC,DEP) *Else:* 1820
<0	<0	|DEC|>|DEP|	8:00-23:00	*If*(|DEC-DEP|<1050): *If*($\text{DEC}_{\text{NetLoad}}$ +|DEC-DEP|> $\text{DEP}_{\text{NetLoad}}$ -|DEC-DEP|): -(*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:* -|DEC-DEP| *Else If*($\text{DEC}_{\text{NetLoad}}$+1050> $\text{DEP}_{\text{NetLoad}}$-1050): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* -1050
<0	>0		8:00-23:00	*If*(|DEC-DEP|>1050): *If*($\text{DEC}_{\text{NetLoad}}$+1050> $\text{DEP}_{\text{NetLoad}}$-1050): -(*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else: -1050* *Else If*($\text{DEC}_{\text{NetLoad}}$ +|DEC-DEP|> $\text{DEP}_{\text{NetLoad}}$ -|DEC-DEP|): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* -|DEC-DEP|
>0	<0		8:00-23:00	*If*(|DEC-DEP|>1820): *If*($\text{DEC}_{\text{NetLoad}}$+1820> $\text{DEP}_{\text{NetLoad}}$-18200): *Average*(DEC,DEP)-*Min*(DEC,DEP) *Else:* 1820 *Else If*($\text{DEC}_{\text{NetLoad}}$ +|DEC-DEP|> $\text{DEP}_{\text{NetLoad}}$ -|DEC-DEP|): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* |DEC-DEP|
>0	>0	|DEC|<|DEP|	8:00-23:00	*If*(|DEC-DEP|<1820): *If*($\text{DEP}_{\text{NetLoad}}$ +|DEC-DEP|> $\text{DEC}_{\text{NetLoad}}$ -|DEC-DEP|): -(*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:*- |DEC-DEP| *Else If*($\text{DEP}_{\text{NetLoad}}$+1820> $\text{DEC}_{\text{NetLoad}}$-1820): -(*Average* (DEC,DEP)-*Min*(DEC,DEP))

(Net Load –Flexibility Limit)			Time of Day	Equation
DEC	**DEP**	**Comparison**		
				Else: -1820
>0	>0	|DEC|>|DEP|	8:00-23:00	*If*(|DEC-DEP|<1050): *If*($DEC_{NetLoad}$ +|DEC-DEP|> $DEP_{NetLoad}$ -|DEC-DEP|): (*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:* |DEC-DEP| *Else If*($DEC_{NetLoad}$+1050> $DEP_{NetLoad}$-1050): (*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* 1050
<0	<0	|DEC|<|DEP|	0:00-7:00	*If*(|DEC`-DEP|<2933): *If*($DEP_{NetLoad}$ +|DEC-DEP|> $DEC_{NetLoad}$ -|DEC-DEP|): *Average*(DEC,DEP)-*Min*(DEC,DEP) *Else:* |DEC-DEP| *Else If*($DEP_{NetLoad}$+2933> $DEC_{NetLoad}$-2933): *Average* (DEC,DEP)-*Min*(DEC,DEP) *Else:* 2933
<0	<0	|DEC|>|DEP|	0:00-7:00	*If*(|DEC-DEP|<1036): *If*($DEC_{NetLoad}$ +|DEC-DEP|> $DEP_{NetLoad}$ -|DEC-DEP|): -(*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:* -|DEC-DEP| *Else If*($DEC_{NetLoad}$+1036> $DEP_{NetLoad}$-1036): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* -1036
<0	>0		0:00-7:00	*If*(|DEC-DEP|>1036): *If*($DEC_{NetLoad}$+1036> $DEP_{NetLoad}$-1036): -(*Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:* -1036 *Else If*($DEC_{NetLoad}$ +|DEC-DEP|> $DEP_{NetLoad}$ -|DEC-DEP|): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* -|DEC-DEP|
>0	<0		0:00-7:00	*If*(|DEC-DEP|>2933): *If*($DEC_{NetLoad}$+2933> $DEP_{NetLoad}$-2933): *Average*(DEC,DEP)-*Min*(DEC,DEP) *Else:* 2933 *Else If*($DEC_{NetLoad}$ +|DEC-DEP|> $DEP_{NetLoad}$ -|DEC-DEP|): -(*Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* |DEC-DEP|
>0	>0	|DEC|<|DEP|	0:00-7:00	*If*(|DEC-DEP|<2933): *If*($DEP_{NetLoad}$ +|DEC-DEP|> $DEC_{NetLoad}$ -|DEC-DEP|): -(*Average*(DEC,DEP)-*Min*(DEC,DEP))

(Net Load –Flexibility Limit)			Time of Day	Equation
DEC	DEP	Comparison		
				Else:- |DEC-DEP| *Else If*(DEP$_{NetLoad}$+2933> DEC$_{NetLoad}$-1820): -*(Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* -2933
>0	>0	|DEC|>|DEP|	0:00-7:00	*If*(|DEC-DEP|<1036): *If*(DEC$_{NetLoad}$ +|DEC-DEP|> DEP$_{NetLoad}$ -|DEC-DEP|): *(Average*(DEC,DEP)-*Min*(DEC,DEP)) *Else:* |DEC-DEP| *Else If*(DEC$_{NetLoad}$+1036> DEP$_{NetLoad}$-1036): *(Average* (DEC,DEP)-*Min*(DEC,DEP)) *Else:* 1036

Equations 8 and 9 show how the net load of each BA is changed by the interconnection after the load transfer is calculated.

$$\{(\text{DEC Net Load Before}) - (\text{Load Transfer}) = (\text{DEC Net Load After})\} \tag{8}$$

$$\{(\text{DEP Net Load Before}) + (\text{Load Transfer}) = (\text{DEP Net Load After})\} \tag{9}$$

A.3 Seasonal Metrics

The dates of each season are defined in Table 12.

Table 12. Season definitions

	Start Date	End Date
Spring	3/1/2019	5/31/2019
Summer	6/1/2019	8/31/2019
Fall	9/1/2019	11/30/2019
Winter	12/1/2019	2/28/2019

Table 13. Maximum instantaneous curtailment of each season (MW)

Scenario	Spring	Summer	Fall	Winter
1	0	0	0	530
2	2430	0	2752	3233
3	6113	2913	5897	6618
4	9801	6106	9183	10003
5	13504	9299	12560	13389
6	17207	12542	16023	16774
7	20909	16143	19689	20271
8	13548	9248	12568	13452
9	11073	5769	9185	9842
10	12551	8346	11607	12436
11	17486	13326	16273	17084
12 – DEC 5%	0	0	0	246
12 – DEC 10%	1466	252	1390	1886
12 – DEC 15%	3116	1878	2958	3418
12 – DEP 5%	0	0	0	246
12 – DEP 10%	1234	117	1390	1600
12 – DEP 15%	3116	1630	2958	3418

Table 14. Maximum up ramp of each season (MW/h)

Scenario	Spring	Summer	Fall	Winter
1	2927	2355	3839	4039
2	3244	2272	3839	4384
3	4539	3294	4412	5341
4	5443	4316	5474	6609
5	5964	5338	5960	7252

Scenario	Spring	Summer	Fall	Winter
6	6277	6360	6813	8362
7	6583	6360	7508	9472
8	5924	5408	5986	7278
9	6873	5338	6717	7876
10	6564	5338	6489	7481
11	6179	5943	6757	8401
12 – DEC 5%	1724	1369	1900	2594
12 – DEC 10%	1722	1539	2093	2594
12 – DEC 15%	2306	2242	2988	3030
12 – DEP 5%	1502	1130	1941	2003
12 – DEP 10%	1629	1754	1941	2309
12 – DEP 15%	2266	2385	2102	3068

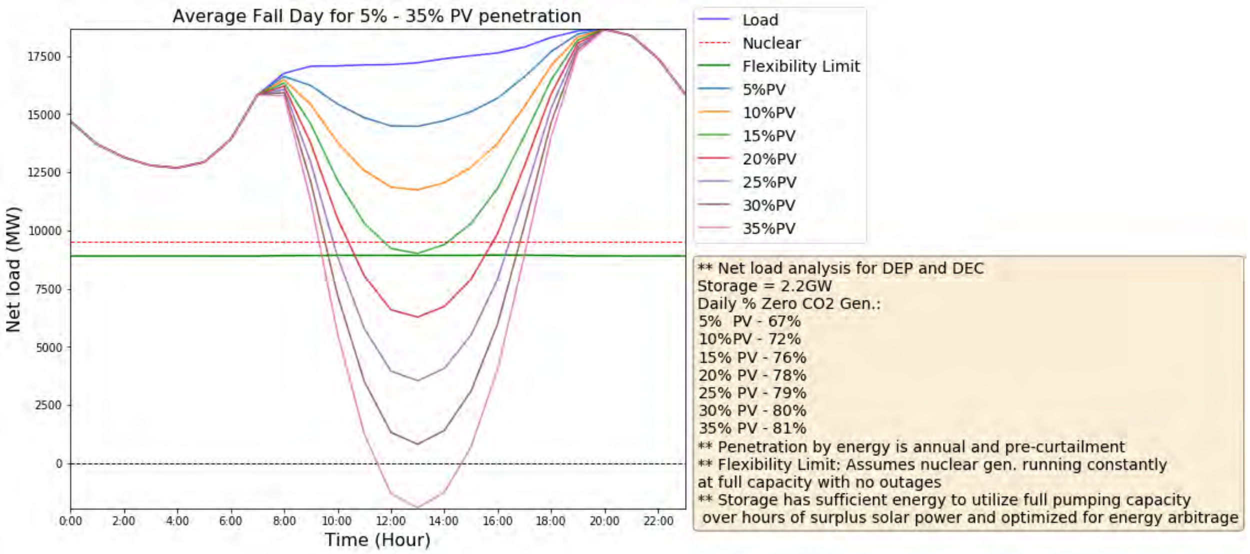
Table 15. Maximum down ramp of each season (MW/h)

Scenario	Spring	Summer	Fall	Winter
1	-3080	-4090	-2830	-5873
2	-3406	-4090	-3403	-5873
3	-4712	-4090	-4354	-5873
4	-6069	-4090	-5658	-6699
5	-7427	-4090	-6964	-7894
6	-8784	-4406	-8270	-9090
7	-9869	-4482	-9577	-10286
8	-7419	-4090	-6951	-7906
9	-7427	-4090	-6964	-7894
10	-7427	-4090	-6964	-7894
11	-8673	-4461	-8427	-9555
12 – DEC 5%	-2047	-2313	-1480	-3122
12 – DEC 10%	-2047	-2313	-1865	-3122
12 – DEC 15%	-2413	-2313	-2621	-3320
12 – DEP 5%	-1390	-1874	-1660	-2750
12 – DEP 10%	-1707	-1874	-1714	-2750
12 – DEP 15%	-2349	-1874	-2519	-2750

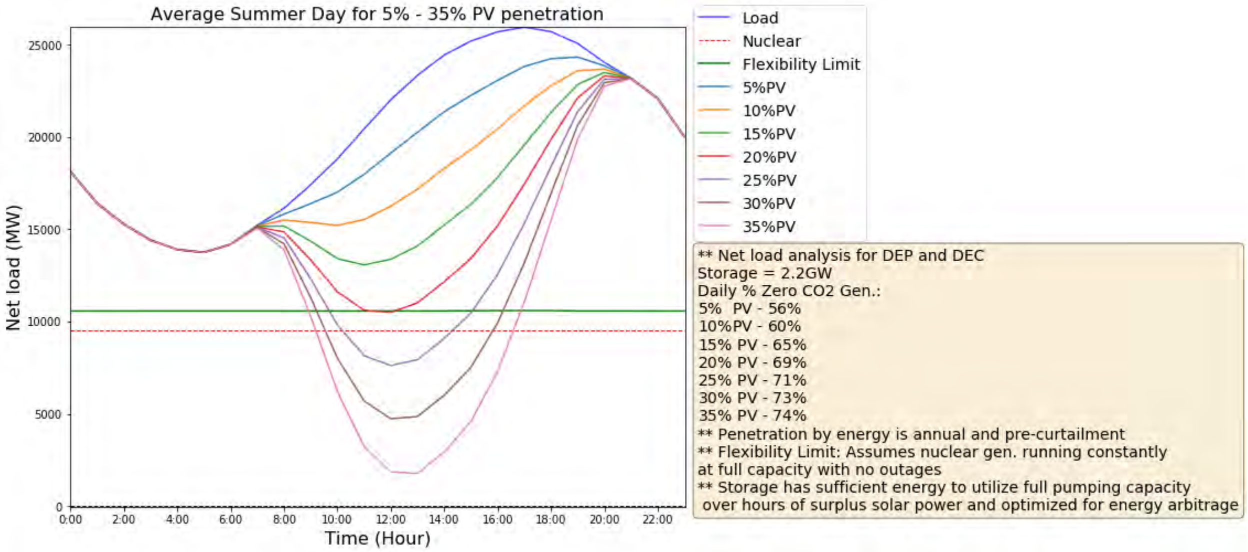
A.4 Additional Figures

Scenarios 1-7

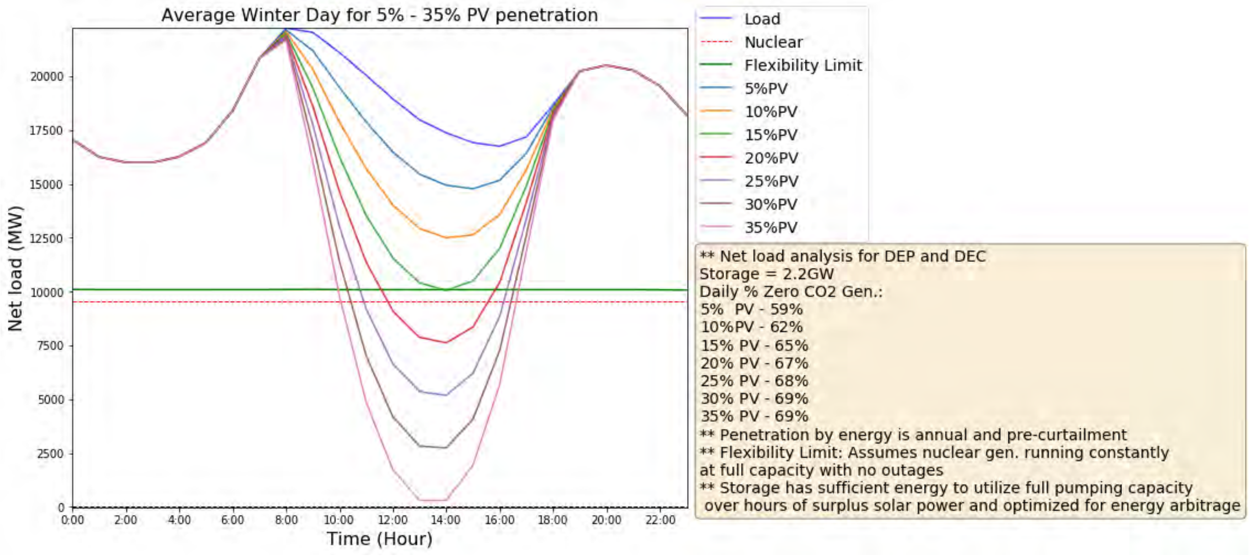
Seasonal Average for 5%-35% PV Penetration



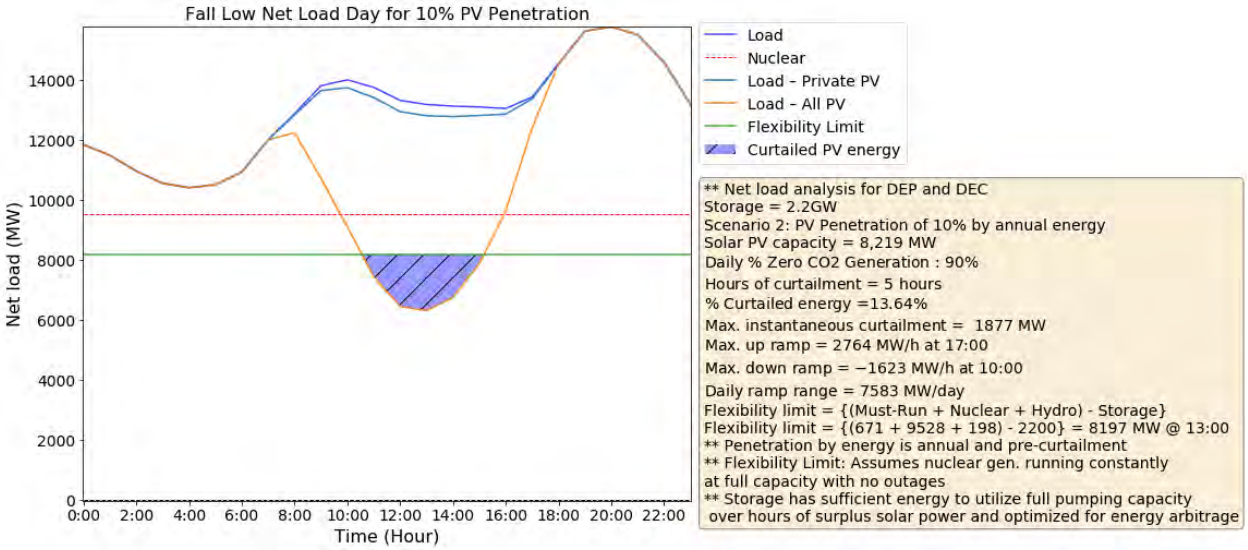
** Net load analysis for DEP and DEC
Storage = 2.2GW
Daily % Zero CO2 Gen.:
5% PV - 67%
10%PV - 72%
15% PV - 76%
20% PV - 78%
25% PV - 79%
30% PV - 80%
35% PV - 81%
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity over hours of surplus solar power and optimized for energy arbitrage



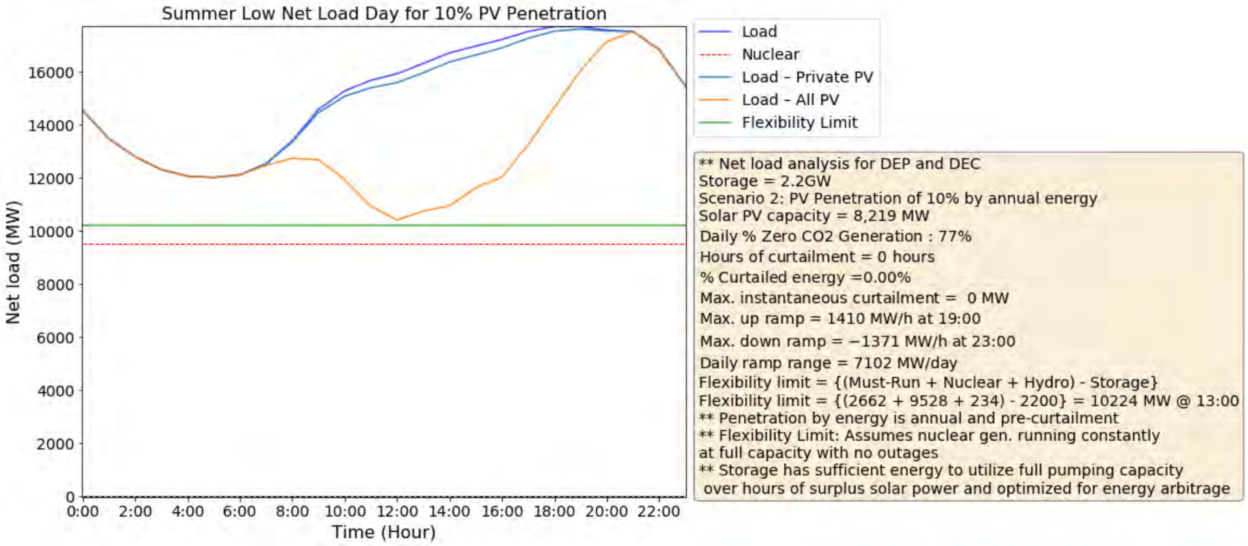
** Net load analysis for DEP and DEC
Storage = 2.2GW
Daily % Zero CO2 Gen.:
5% PV - 56%
10%PV - 60%
15% PV - 65%
20% PV - 69%
25% PV - 71%
30% PV - 73%
35% PV - 74%
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity over hours of surplus solar power and optimized for energy arbitrage


Average Winter Day for 5% - 35% PV penetration
Net load (MW)
20000
17500
15000
12500
10000
7500
5000
2500
0
0:00
2:00
4:00
6:00
8:00
10:00
12:00
14:00
16:00
18:00
20:00
22:00
Time (Hour)
Load
Nuclear
Flexibility Limit
5%PV
10%PV
15%PV
20%PV
25%PV
30%PV
35%PV
** Net load analysis for DEP and DEC
Storage = 2.2GW
Daily % Zero CO2 Gen.:
5% PV - 59%
10%PV - 62%
15% PV - 65%
20% PV - 67%
25% PV - 68%
30% PV - 69%
35% PV - 69%
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

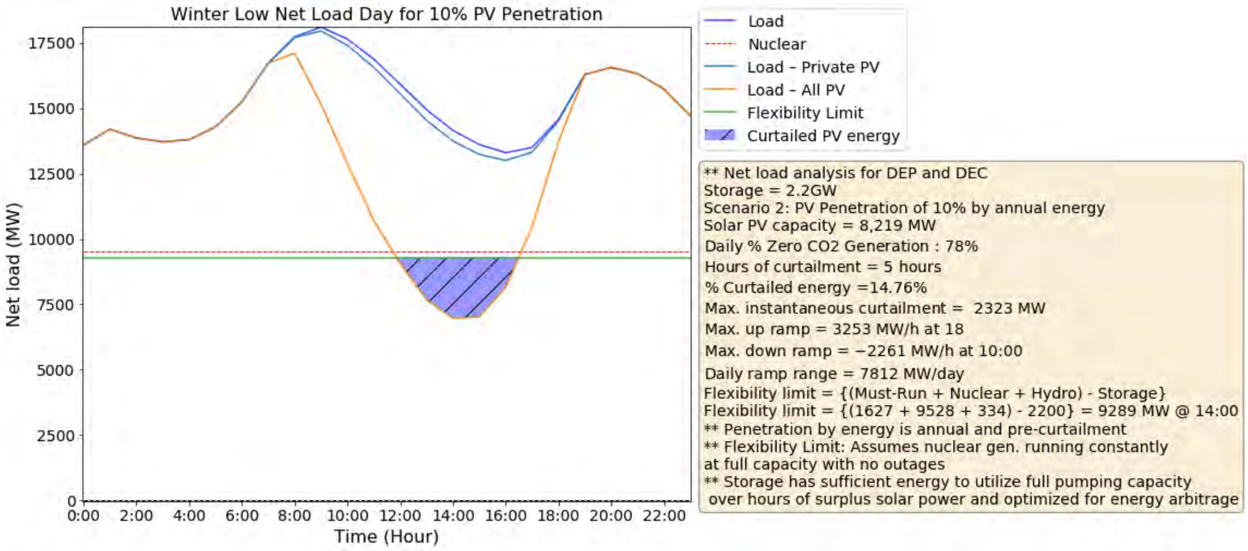
Seasonal Low Net Load Days: 10% PV Penetration



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 90%
Hours of curtailment = 5 hours
% Curtailed energy =13.64%
Max. instantaneous curtailment = 1877 MW
Max. up ramp = 2764 MW/h at 17:00
Max. down ramp = −1623 MW/h at 10:00
Daily ramp range = 7583 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 198) - 2200} = 8197 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 77%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1410 MW/h at 19:00
Max. down ramp = −1371 MW/h at 23:00
Daily ramp range = 7102 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 78%
Hours of curtailment = 5 hours
% Curtailed energy =14.76%
Max. instantaneous curtailment = 2323 MW
Max. up ramp = 3253 MW/h at 18
Max. down ramp = −2261 MW/h at 10:00
Daily ramp range = 7812 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

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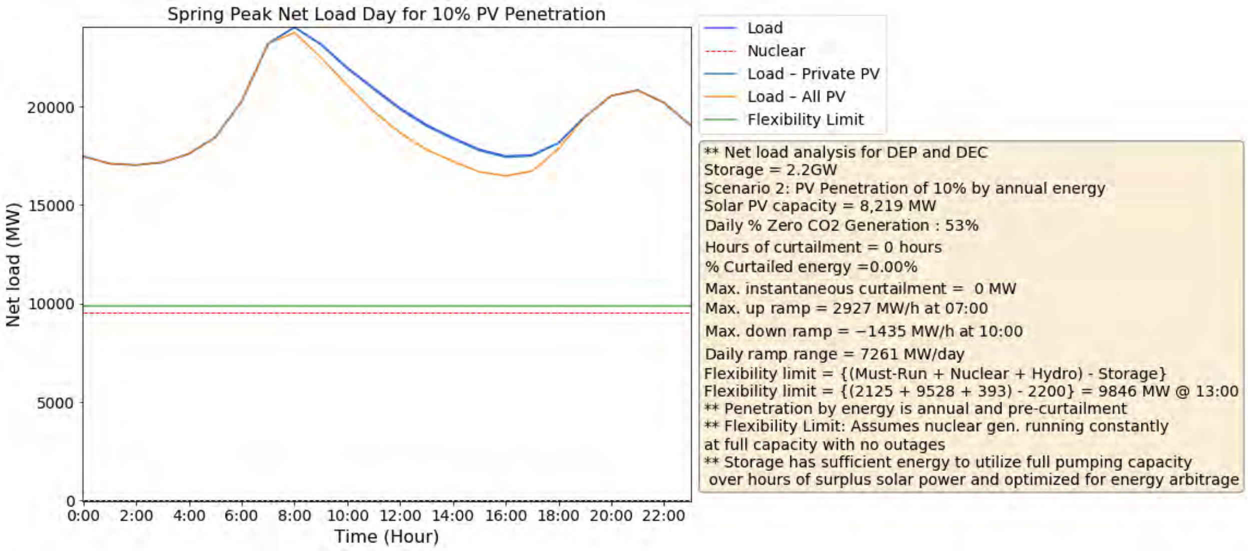
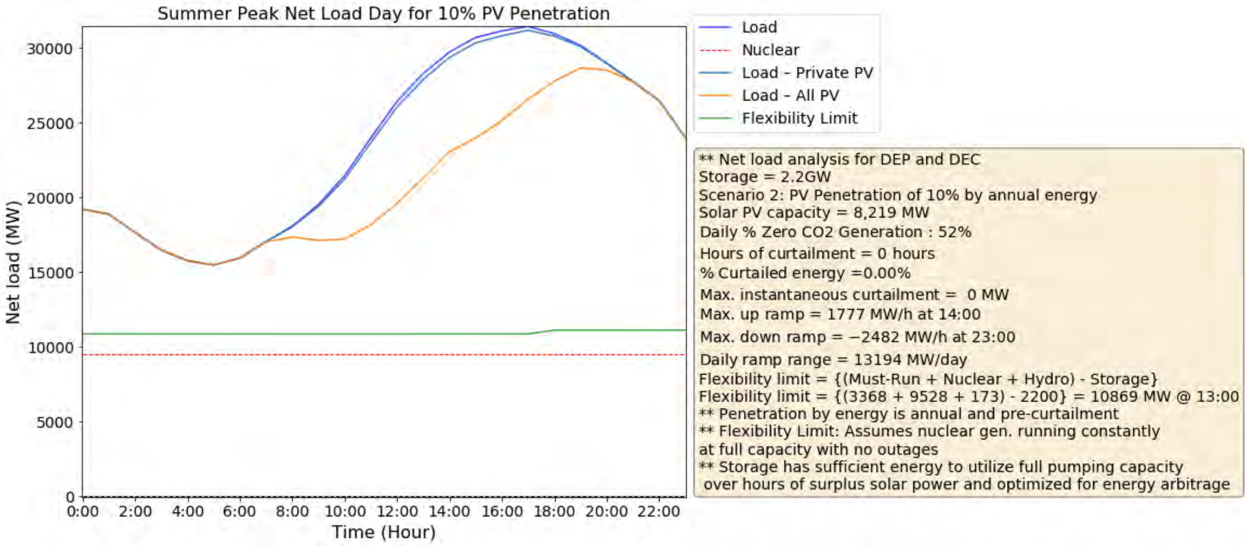
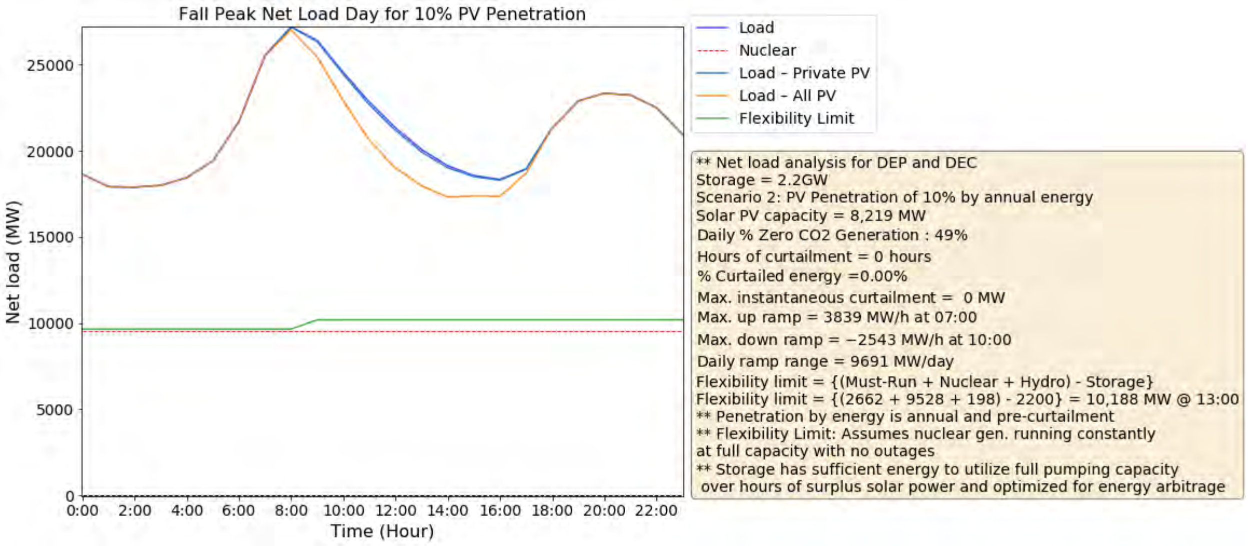
Seasonal Peak Net Load Days: 10% PV Penetration



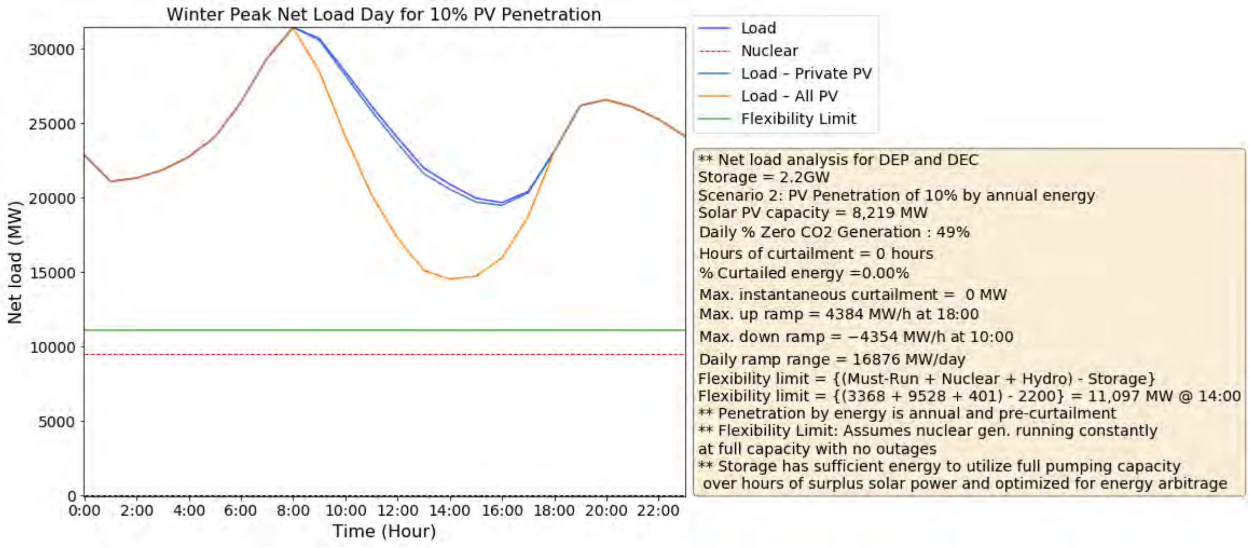
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1435 MW/h at 10:00
Daily ramp range = 7261 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 52%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1777 MW/h at 14:00
Max. down ramp = −2482 MW/h at 23:00
Daily ramp range = 13194 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

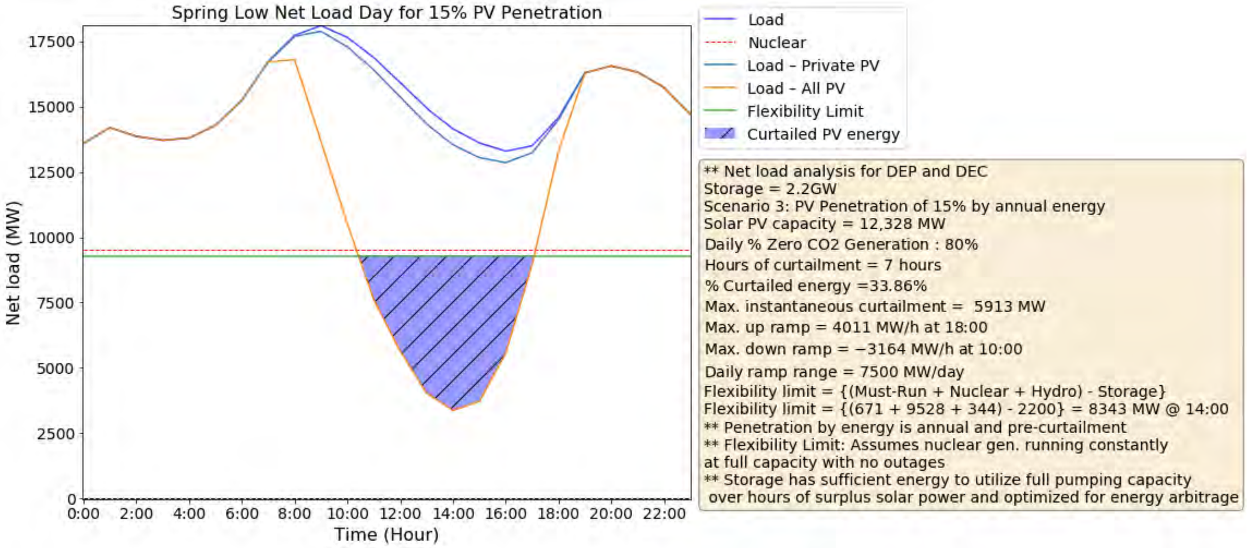


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 49%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −2543 MW/h at 10:00
Daily ramp range = 9691 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

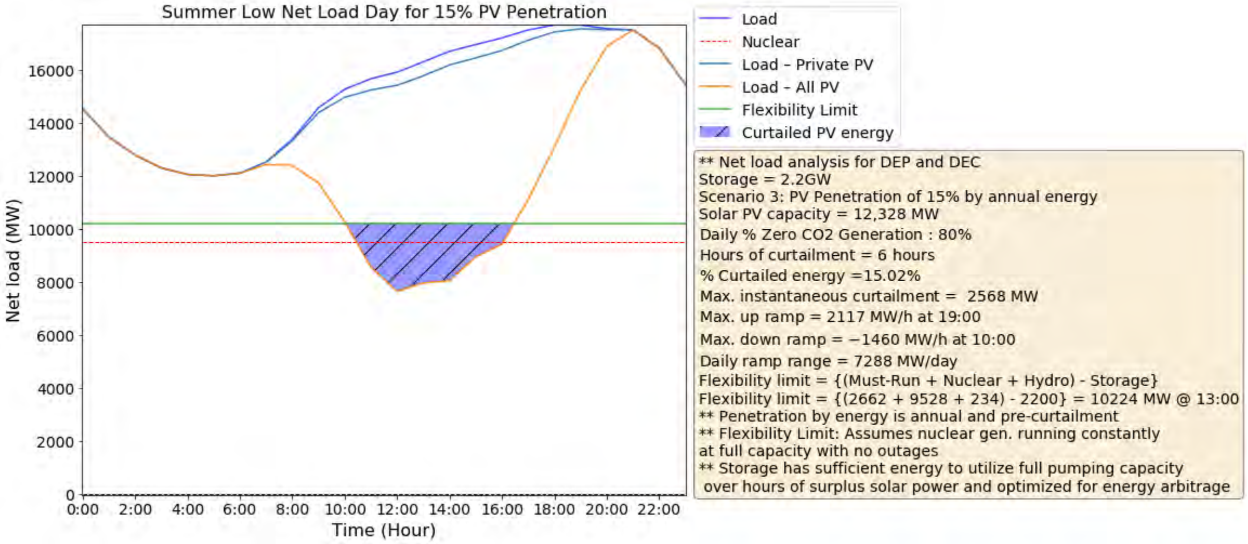


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 8,219 MW
Daily % Zero CO2 Generation : 49%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 4384 MW/h at 18:00
Max. down ramp = −4354 MW/h at 10:00
Daily ramp range = 16876 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

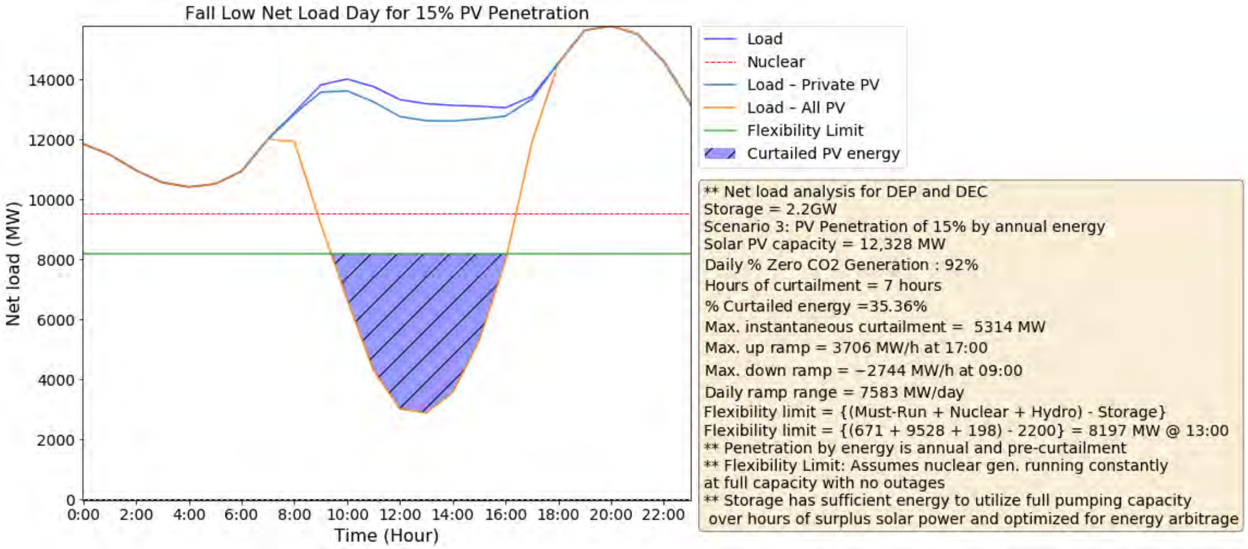
Seasonal Low Net Load Days: 15% PV Penetration



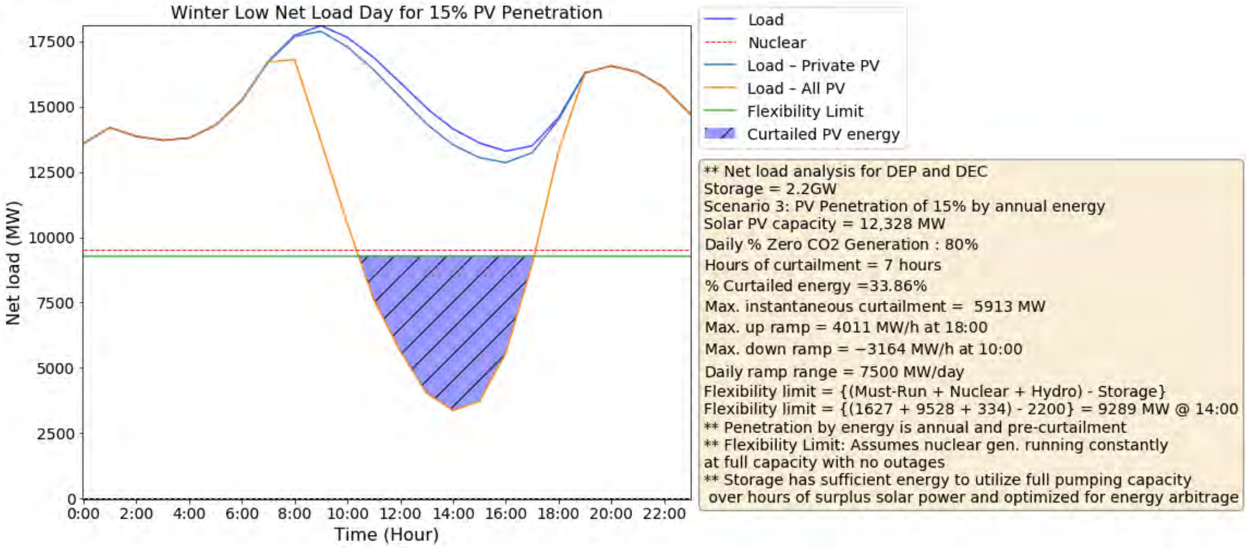
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 80%
Hours of curtailment = 7 hours
% Curtailed energy =33.86%
Max. instantaneous curtailment = 5913 MW
Max. up ramp = 4011 MW/h at 18:00
Max. down ramp = −3164 MW/h at 10:00
Daily ramp range = 7500 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 344) - 2200} = 8343 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 80%
Hours of curtailment = 6 hours
% Curtailed energy =15.02%
Max. instantaneous curtailment = 2568 MW
Max. up ramp = 2117 MW/h at 19:00
Max. down ramp = −1460 MW/h at 10:00
Daily ramp range = 7288 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

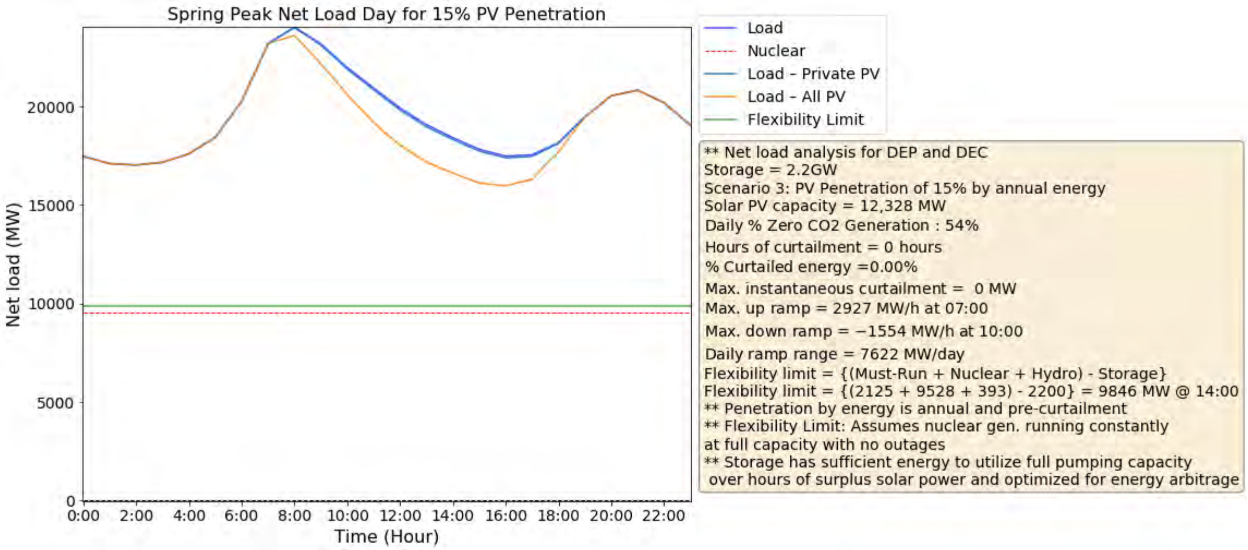


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 92%
Hours of curtailment = 7 hours
% Curtailed energy =35.36%
Max. instantaneous curtailment = 5314 MW
Max. up ramp = 3706 MW/h at 17:00
Max. down ramp = −2744 MW/h at 09:00
Daily ramp range = 7583 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 198) - 2200} = 8197 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

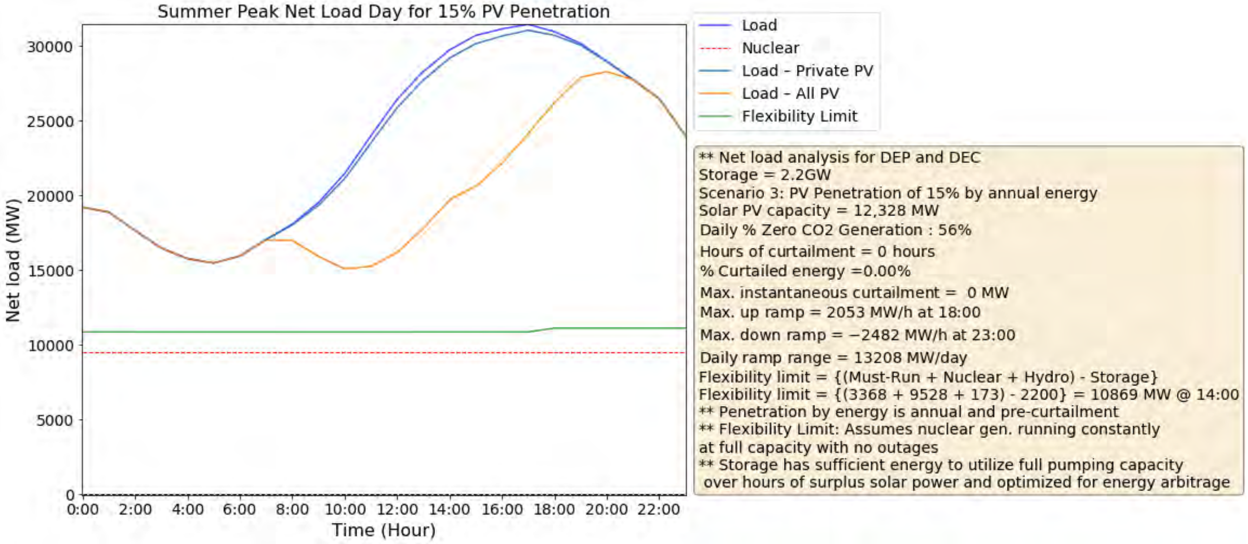


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 80%
Hours of curtailment = 7 hours
% Curtailed energy =33.86%
Max. instantaneous curtailment = 5913 MW
Max. up ramp = 4011 MW/h at 18:00
Max. down ramp = −3164 MW/h at 10:00
Daily ramp range = 7500 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

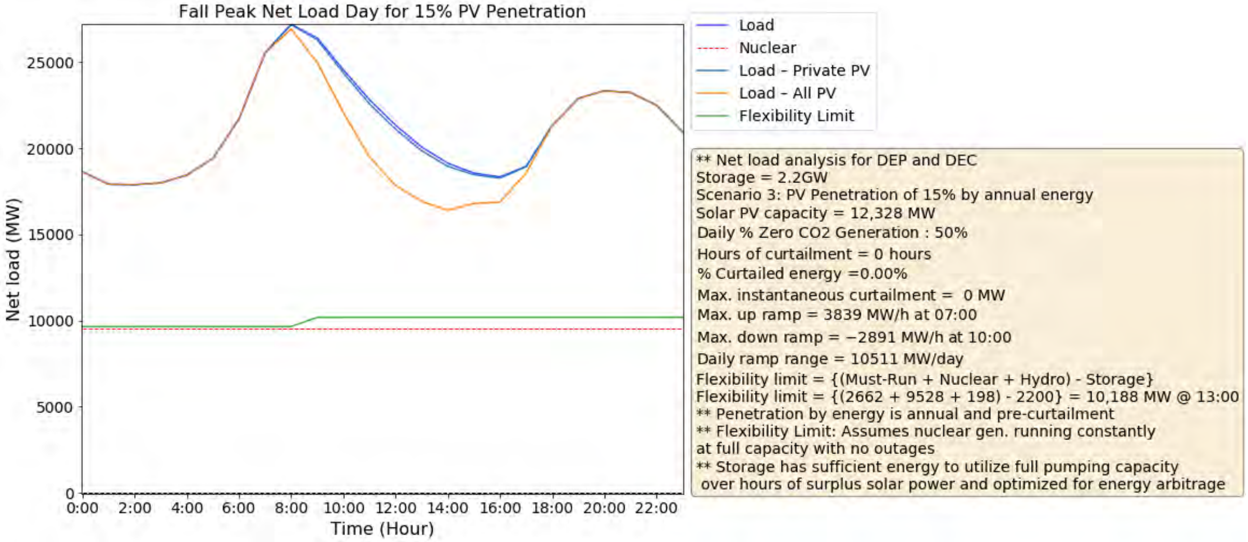
Seasonal Peak Net Load Days: 15% PV Penetration



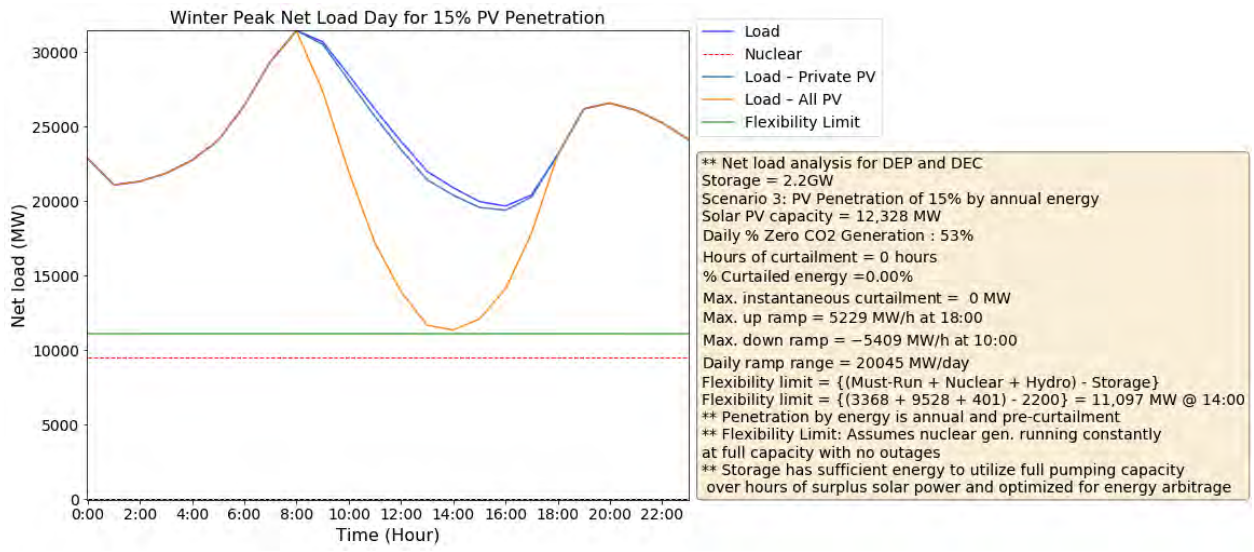
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 54%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1554 MW/h at 10:00
Daily ramp range = 7622 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2053 MW/h at 18:00
Max. down ramp = −2482 MW/h at 23:00
Daily ramp range = 13208 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

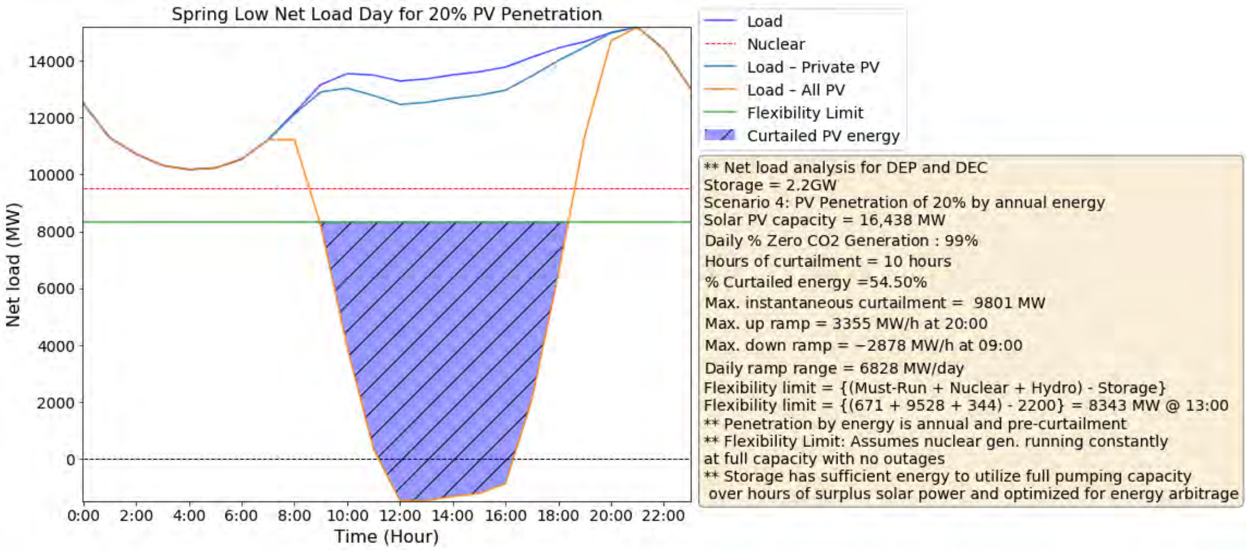


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 50%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −2891 MW/h at 10:00
Daily ramp range = 10511 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

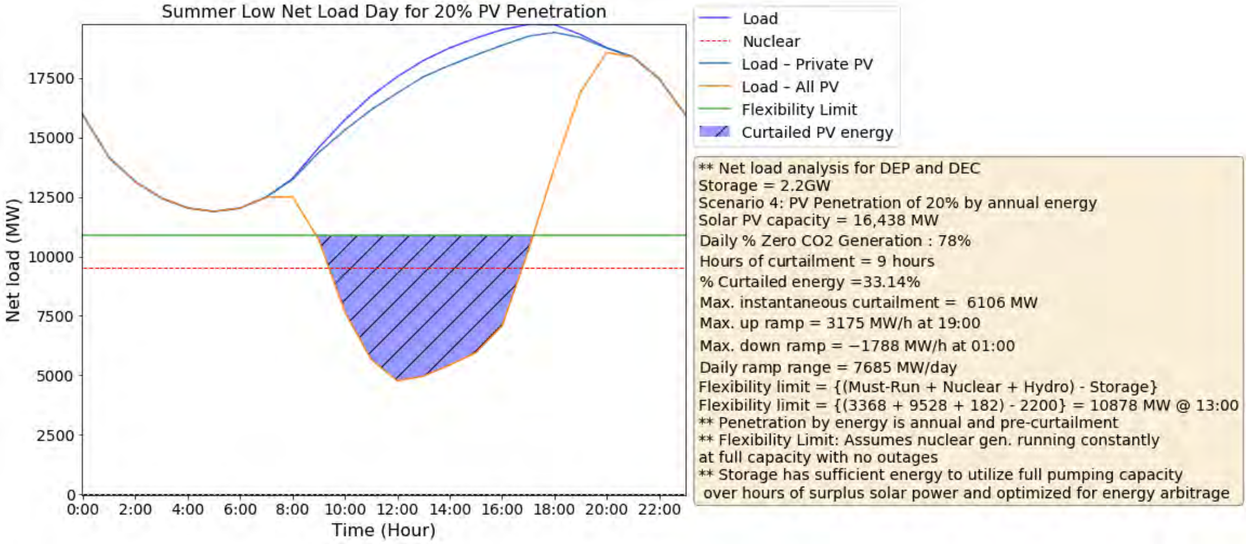


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 3: PV Penetration of 15% by annual energy
Solar PV capacity = 12,328 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 5229 MW/h at 18:00
Max. down ramp = −5409 MW/h at 10:00
Daily ramp range = 20045 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

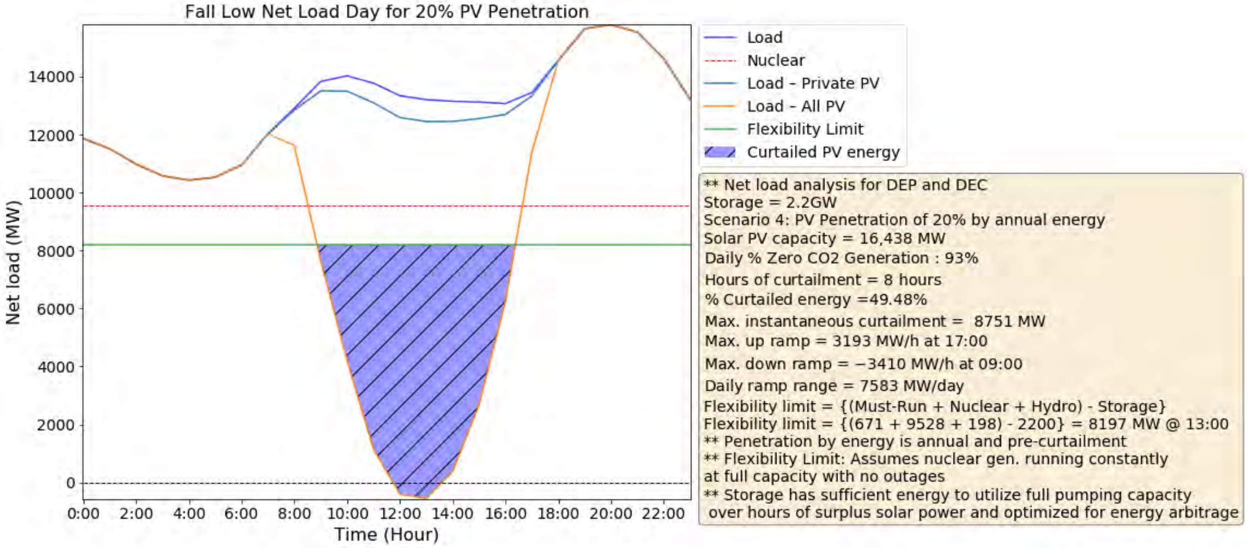
Seasonal Low Net Load Days: 20% PV Penetration



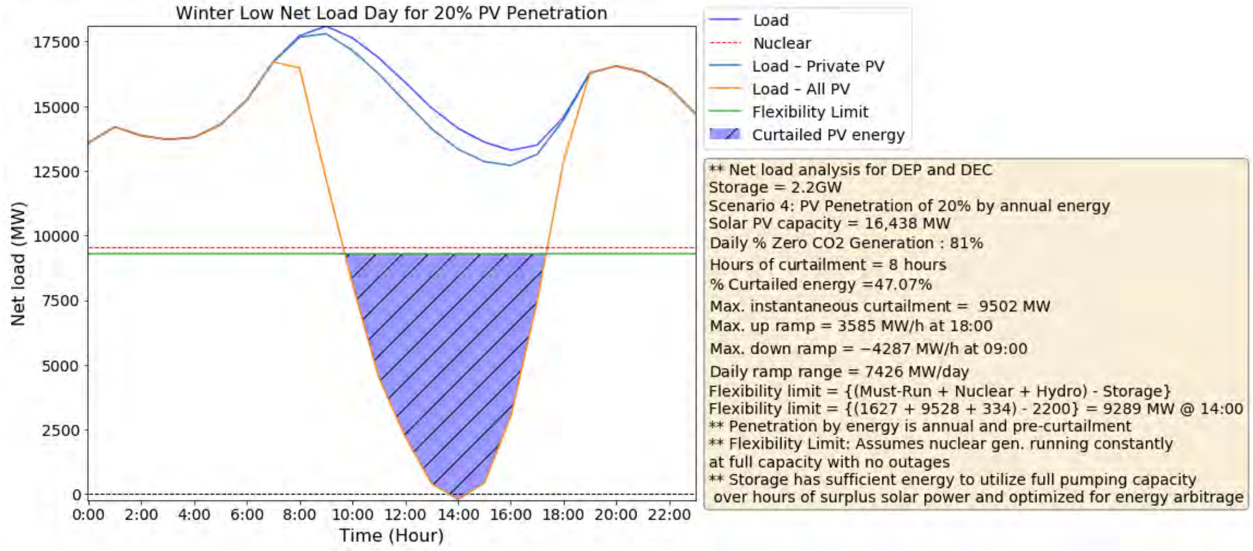
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 99%
Hours of curtailment = 10 hours
% Curtailed energy =54.50%
Max. instantaneous curtailment = 9801 MW
Max. up ramp = 3355 MW/h at 20:00
Max. down ramp = −2878 MW/h at 09:00
Daily ramp range = 6828 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 344) - 2200} = 8343 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 78%
Hours of curtailment = 9 hours
% Curtailed energy =33.14%
Max. instantaneous curtailment = 6106 MW
Max. up ramp = 3175 MW/h at 19:00
Max. down ramp = −1788 MW/h at 01:00
Daily ramp range = 7685 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 182) - 2200} = 10878 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

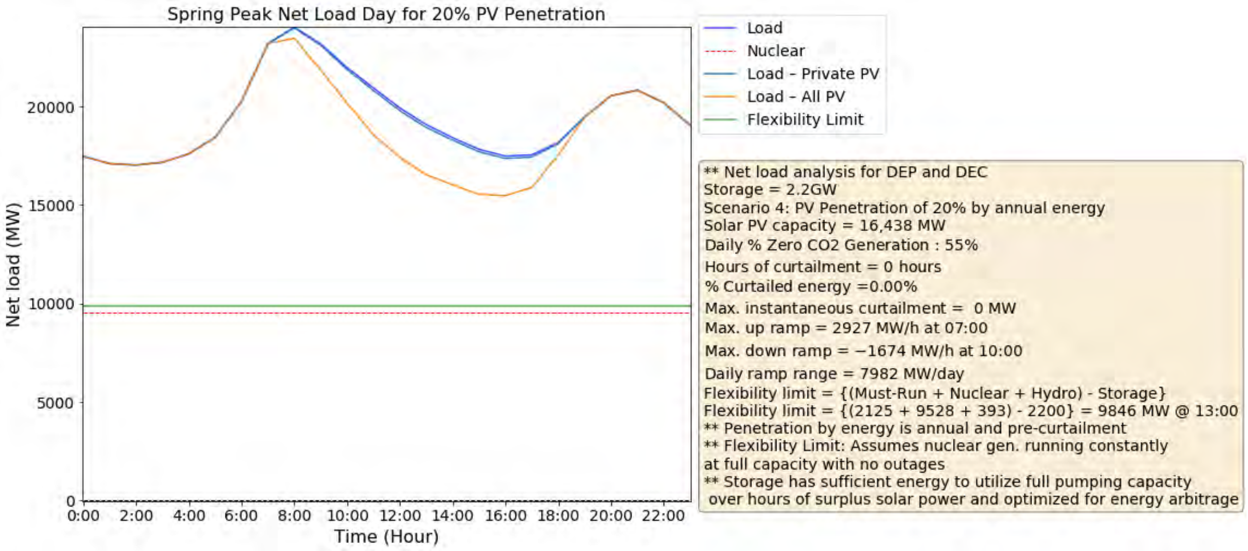


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 93%
Hours of curtailment = 8 hours
% Curtailed energy =49.48%
Max. instantaneous curtailment = 8751 MW
Max. up ramp = 3193 MW/h at 17:00
Max. down ramp = −3410 MW/h at 09:00
Daily ramp range = 7583 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 198) - 2200} = 8197 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

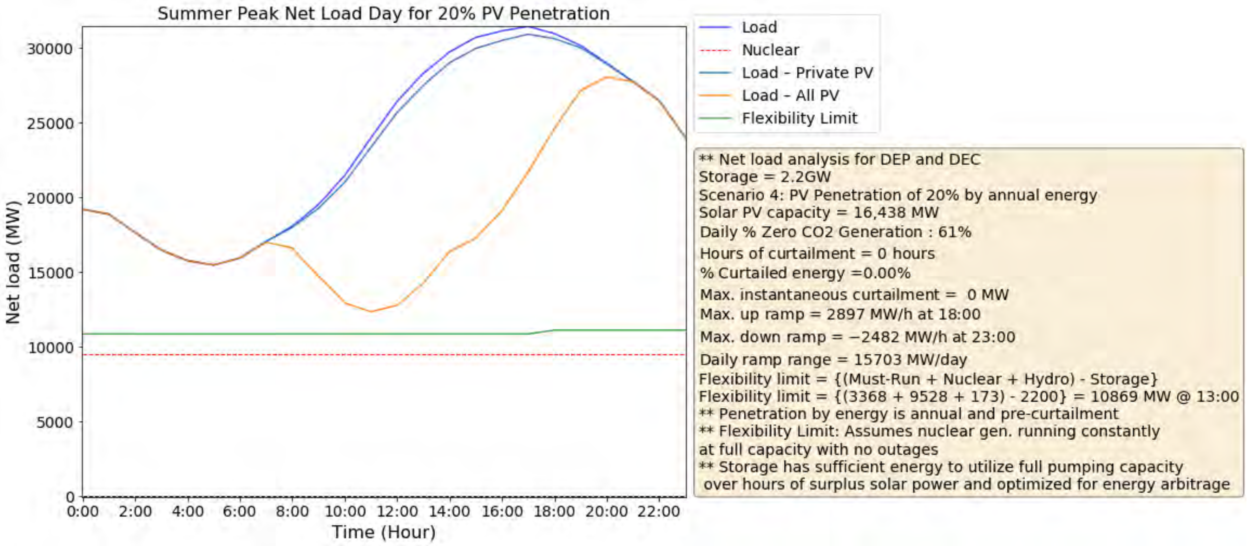


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 81%
Hours of curtailment = 8 hours
% Curtailed energy =47.07%
Max. instantaneous curtailment = 9502 MW
Max. up ramp = 3585 MW/h at 18:00
Max. down ramp = −4287 MW/h at 09:00
Daily ramp range = 7426 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

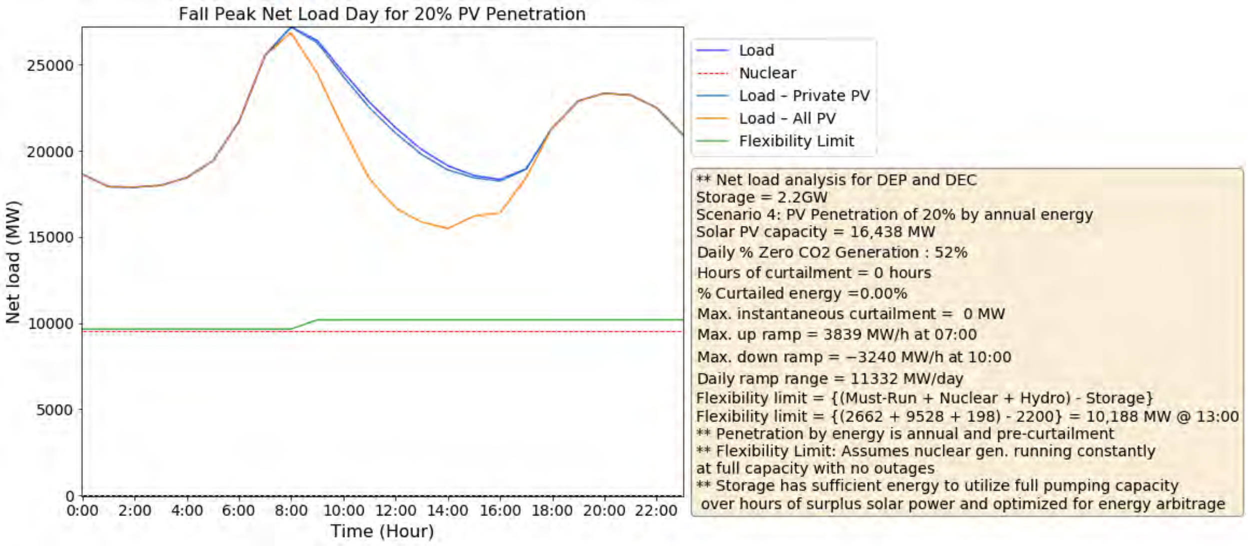
Seasonal Peak Net Load Days: 20% PV Penetration


Spring Peak Net Load Day for 20% PV Penetration

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 55%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1674 MW/h at 10:00
Daily ramp range = 7982 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Summer Peak Net Load Day for 20% PV Penetration

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 61%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2897 MW/h at 18:00
Max. down ramp = −2482 MW/h at 23:00
Daily ramp range = 15703 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Fall Peak Net Load Day for 20% PV Penetration

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 4: PV Penetration of 20% by annual energy
Solar PV capacity = 16,438 MW
Daily % Zero CO2 Generation : 52%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −3240 MW/h at 10:00
Daily ramp range = 11332 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

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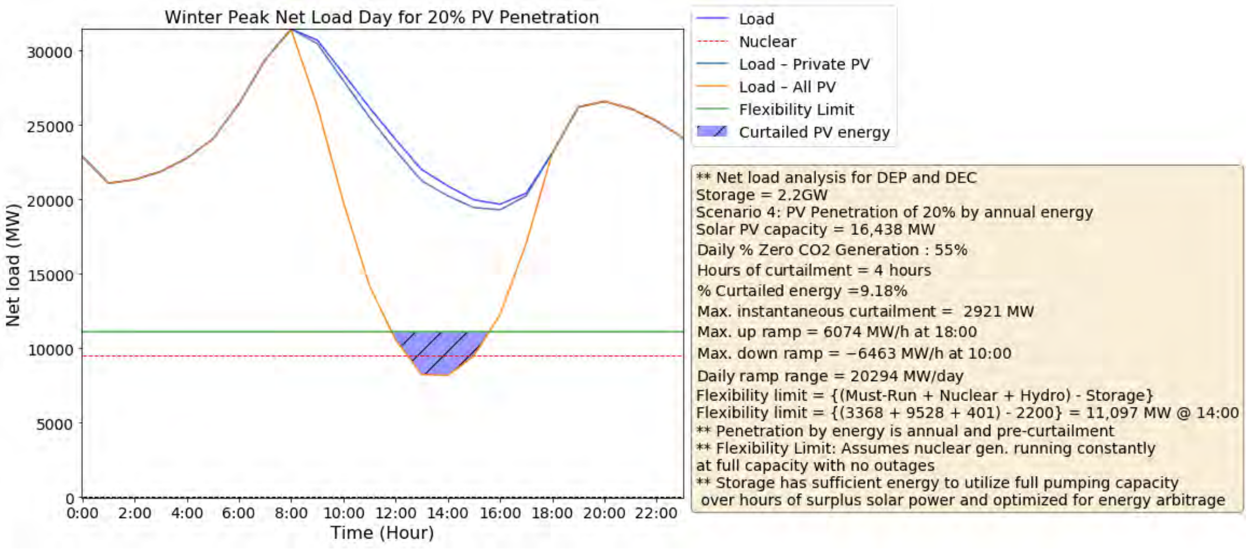

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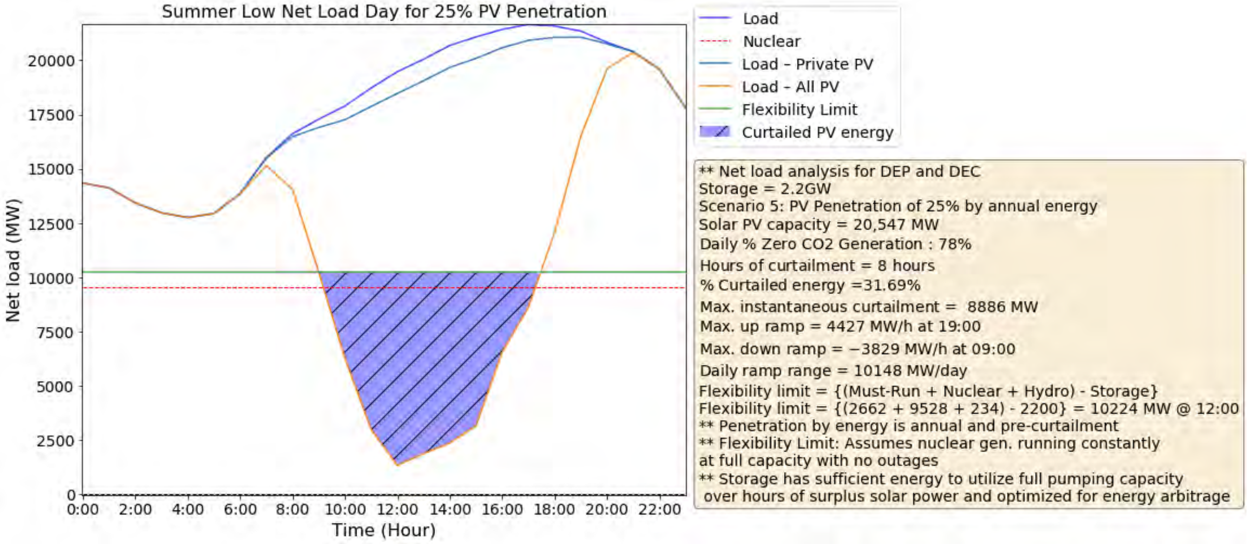
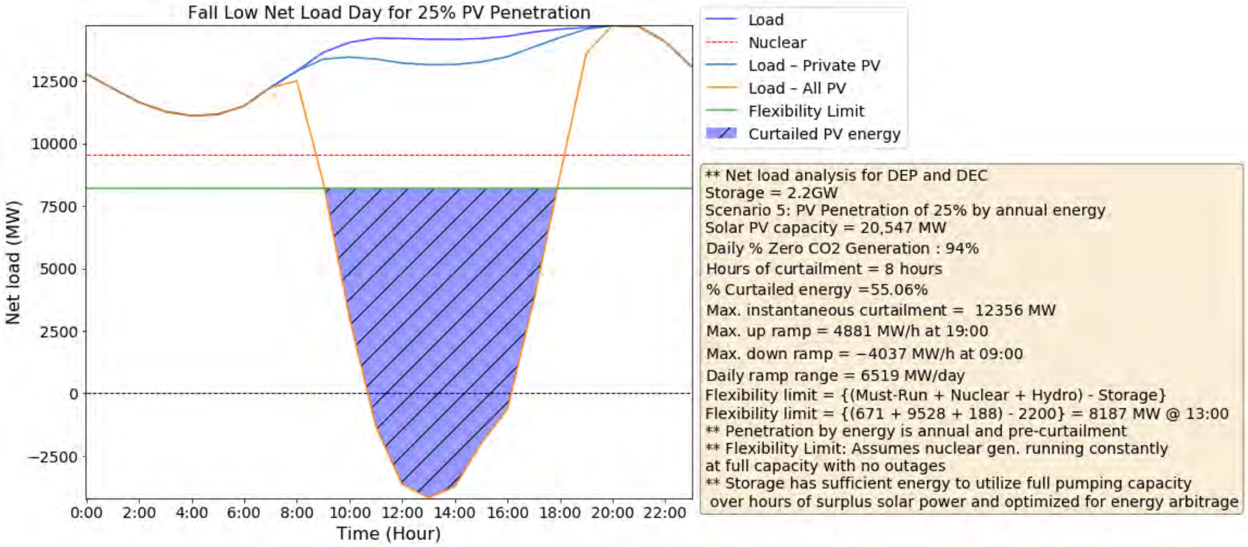
Docket No. E-2, Sub 1276

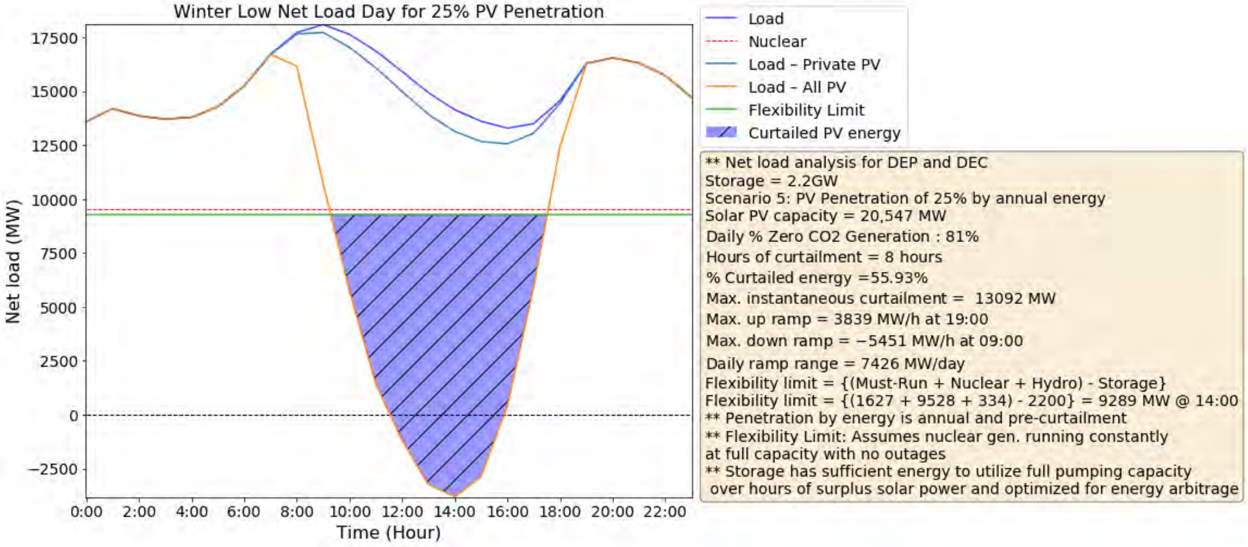
Seasonal Low Net Load Days: 25% PV Penetration



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 78%
Hours of curtailment = 8 hours
% Curtailed energy =31.69%
Max. instantaneous curtailment = 8886 MW
Max. up ramp = 4427 MW/h at 19:00
Max. down ramp = −3829 MW/h at 09:00
Daily ramp range = 10148 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

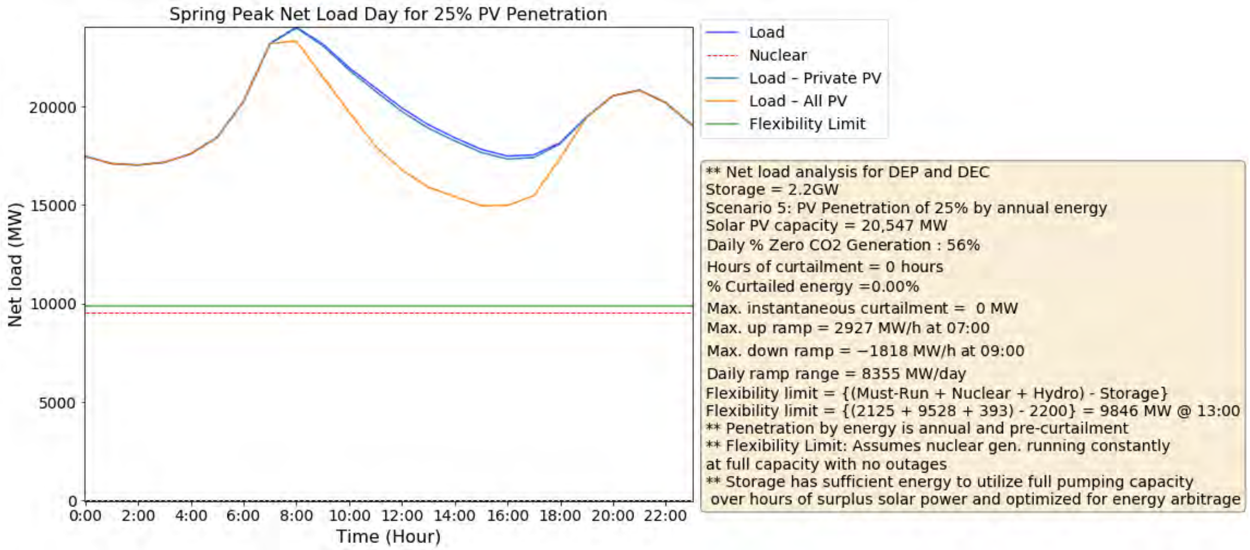


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 94%
Hours of curtailment = 8 hours
% Curtailed energy =55.06%
Max. instantaneous curtailment = 12356 MW
Max. up ramp = 4881 MW/h at 19:00
Max. down ramp = −4037 MW/h at 09:00
Daily ramp range = 6519 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 188) - 2200} = 8187 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

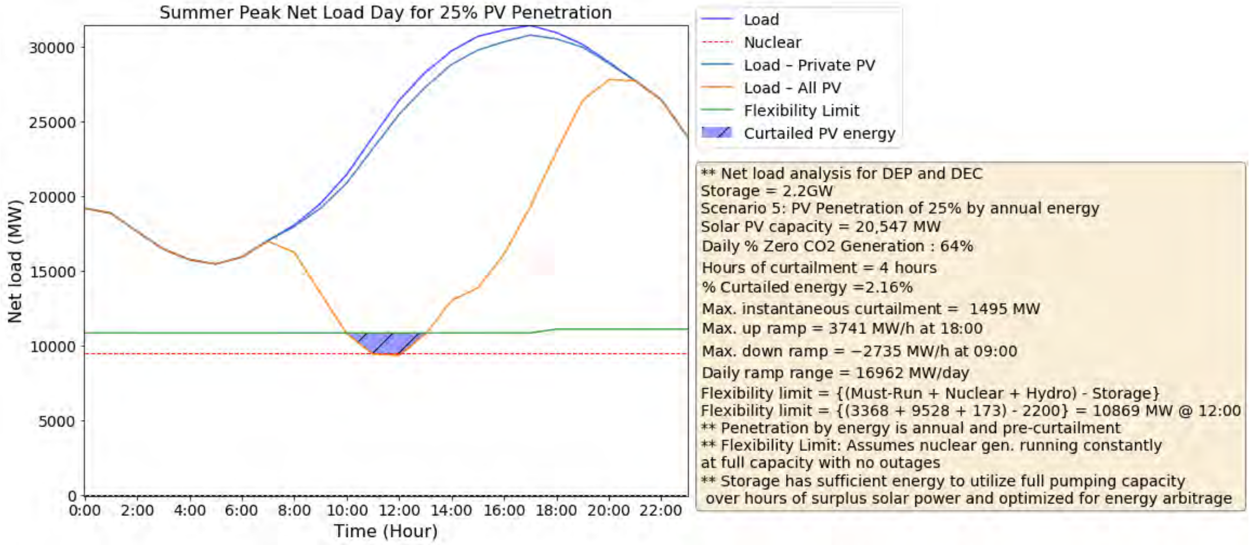


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 81%
Hours of curtailment = 8 hours
% Curtailed energy =55.93%
Max. instantaneous curtailment = 13092 MW
Max. up ramp = 3839 MW/h at 19:00
Max. down ramp = −5451 MW/h at 09:00
Daily ramp range = 7426 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

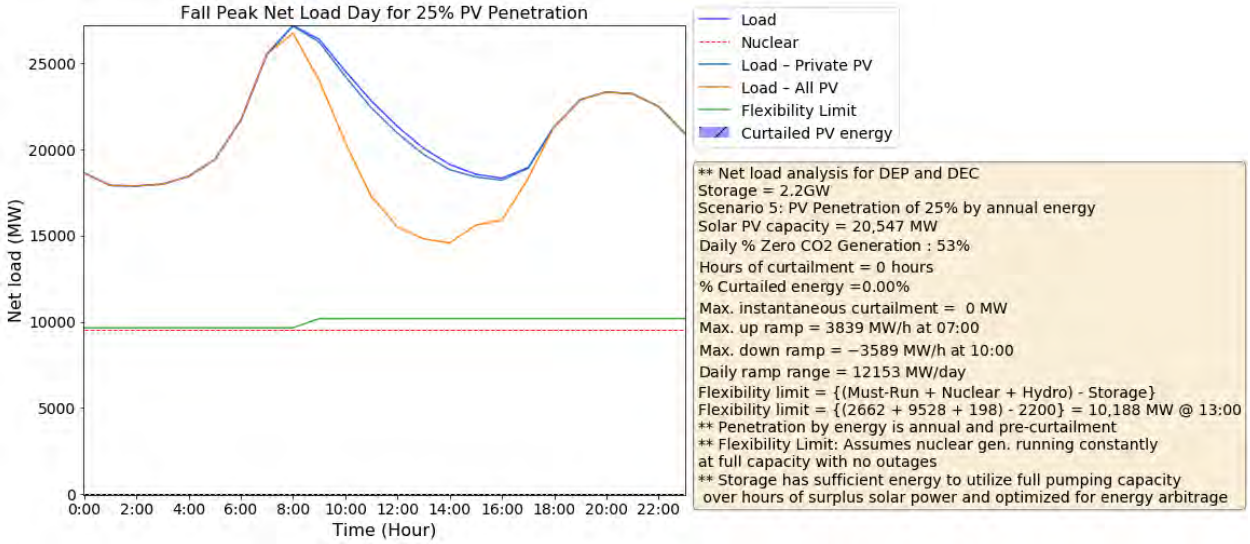
Seasonal Peak Net Load Days: 25% PV Penetration



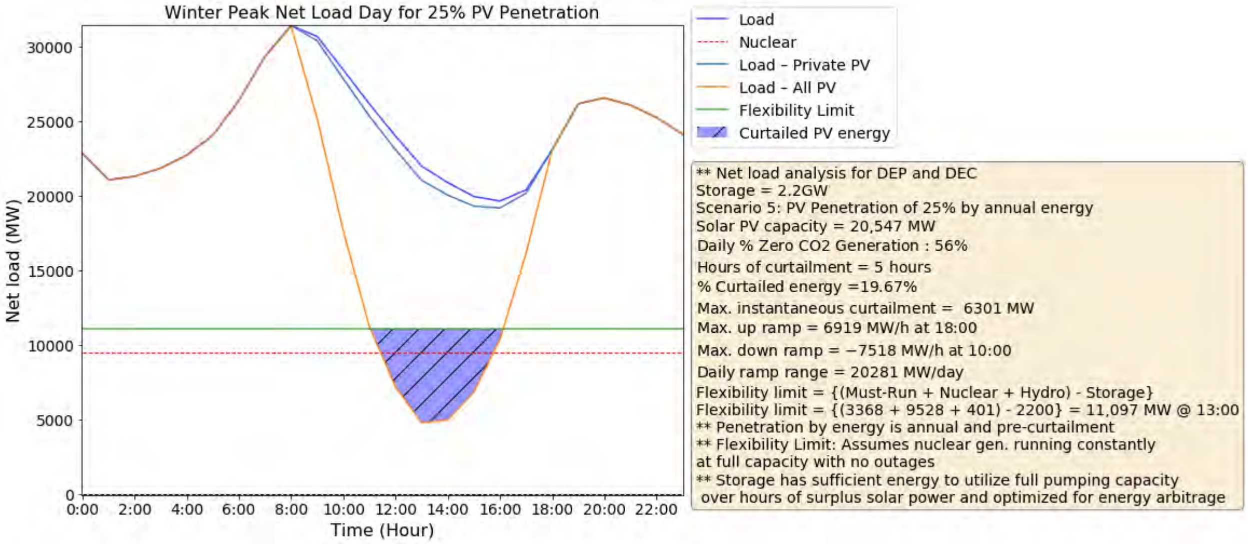
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1818 MW/h at 09:00
Daily ramp range = 8355 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 64%
Hours of curtailment = 4 hours
% Curtailed energy =2.16%
Max. instantaneous curtailment = 1495 MW
Max. up ramp = 3741 MW/h at 18:00
Max. down ramp = −2735 MW/h at 09:00
Daily ramp range = 16962 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

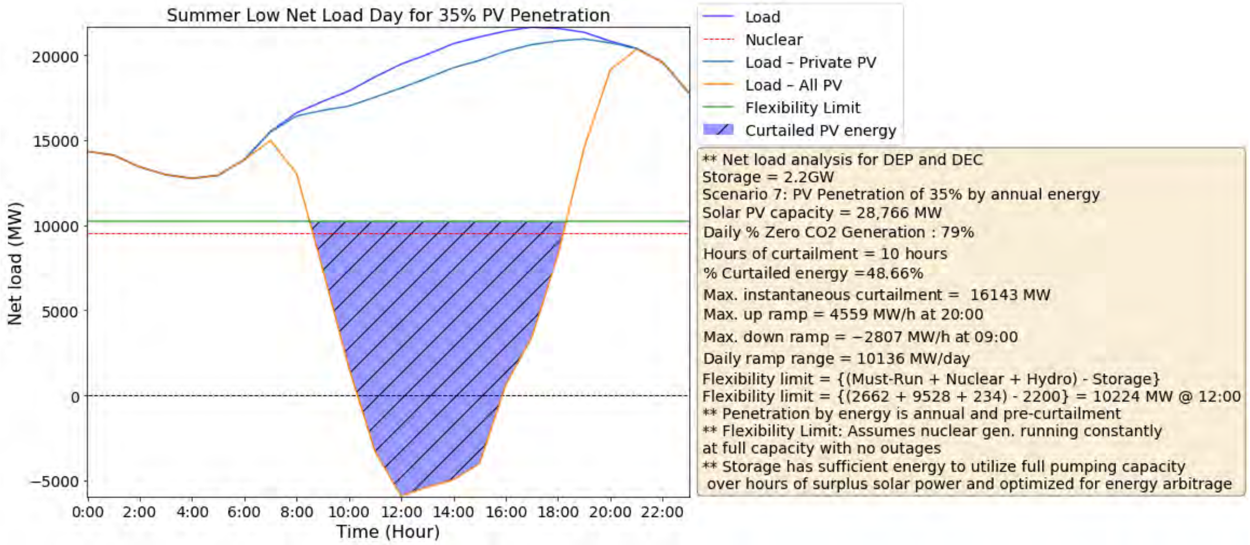


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −3589 MW/h at 10:00
Daily ramp range = 12153 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

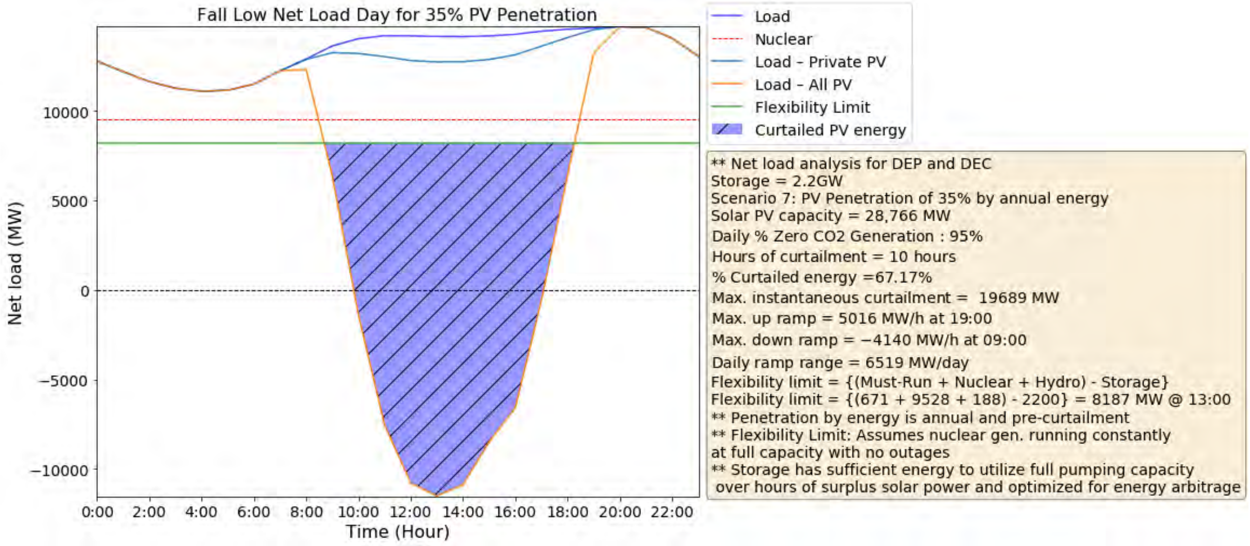


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 5: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 5 hours
% Curtailed energy =19.67%
Max. instantaneous curtailment = 6301 MW
Max. up ramp = 6919 MW/h at 18:00
Max. down ramp = −7518 MW/h at 10:00
Daily ramp range = 20281 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

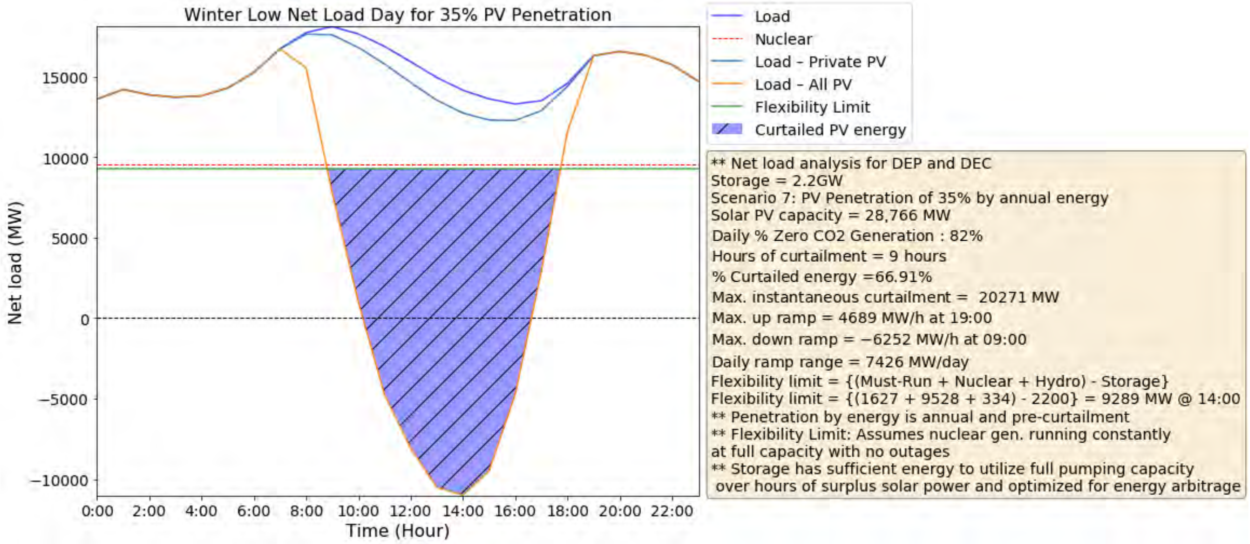
Seasonal Low Net Load Days: 35% PV Penetration



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 79%
Hours of curtailment = 10 hours
% Curtailed energy =48.66%
Max. instantaneous curtailment = 16143 MW
Max. up ramp = 4559 MW/h at 20:00
Max. down ramp = −2807 MW/h at 09:00
Daily ramp range = 10136 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

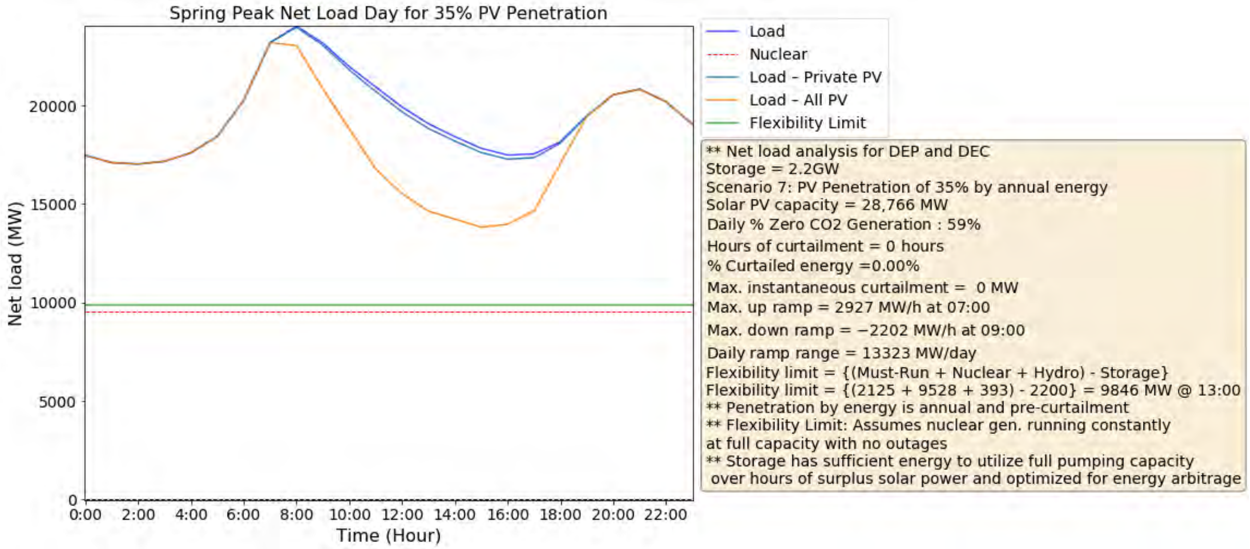


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 95%
Hours of curtailment = 10 hours
% Curtailed energy =67.17%
Max. instantaneous curtailment = 19689 MW
Max. up ramp = 5016 MW/h at 19:00
Max. down ramp = −4140 MW/h at 09:00
Daily ramp range = 6519 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 188) - 2200} = 8187 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

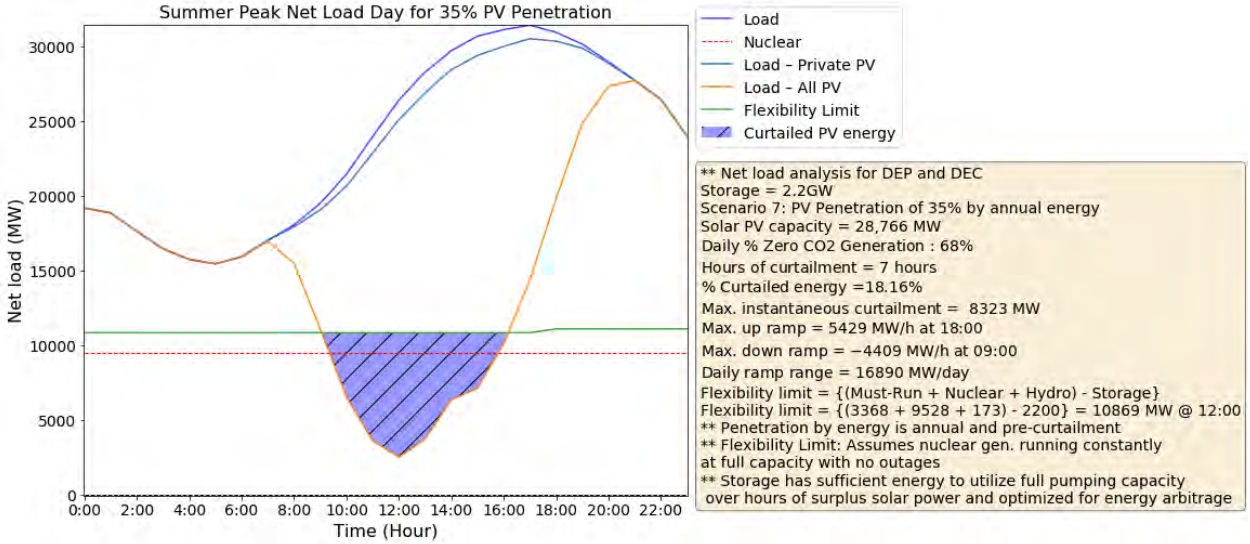


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 82%
Hours of curtailment = 9 hours
% Curtailed energy =66.91%
Max. instantaneous curtailment = 20271 MW
Max. up ramp = 4689 MW/h at 19:00
Max. down ramp = −6252 MW/h at 09:00
Daily ramp range = 7426 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

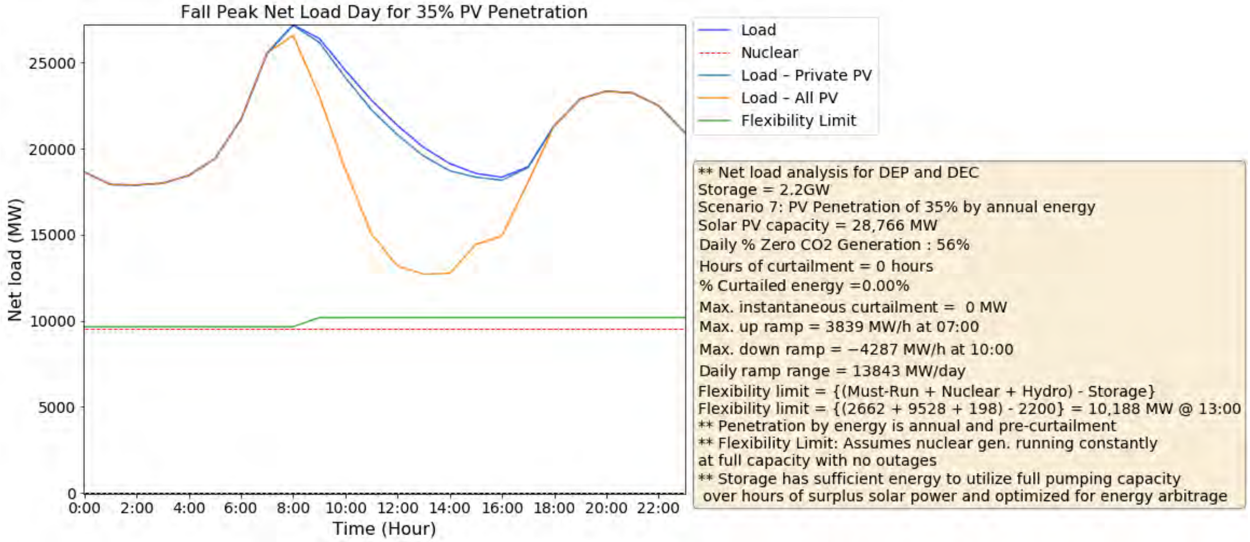
Seasonal Peak Net Load Days: 35% PV Penetration



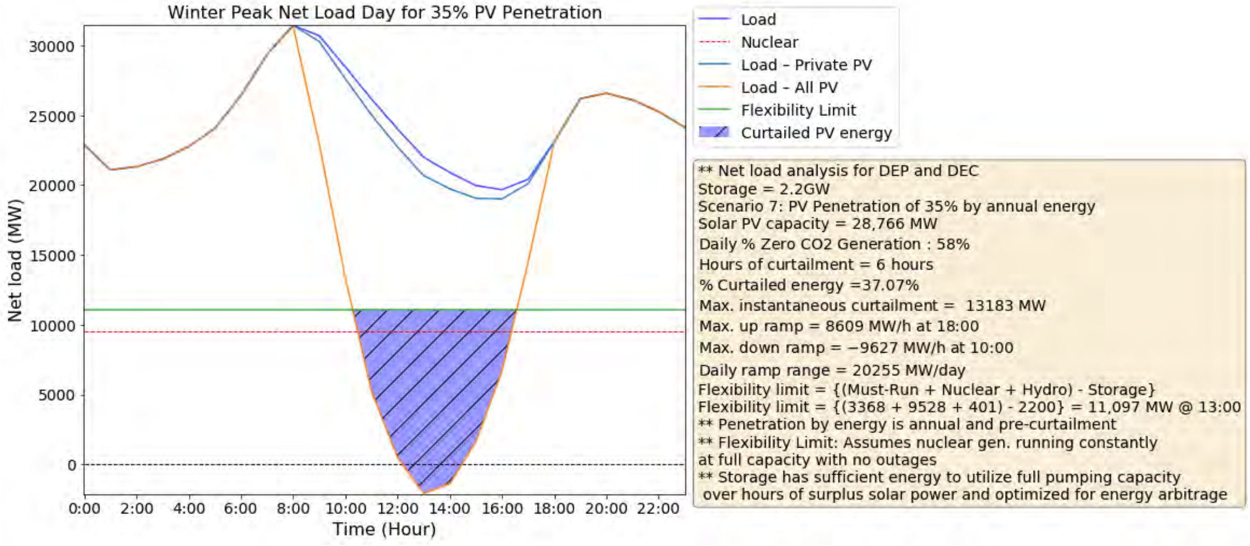
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 59%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −2202 MW/h at 09:00
Daily ramp range = 13323 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 68%
Hours of curtailment = 7 hours
% Curtailed energy =18.16%
Max. instantaneous curtailment = 8323 MW
Max. up ramp = 5429 MW/h at 18:00
Max. down ramp = −4409 MW/h at 09:00
Daily ramp range = 16890 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



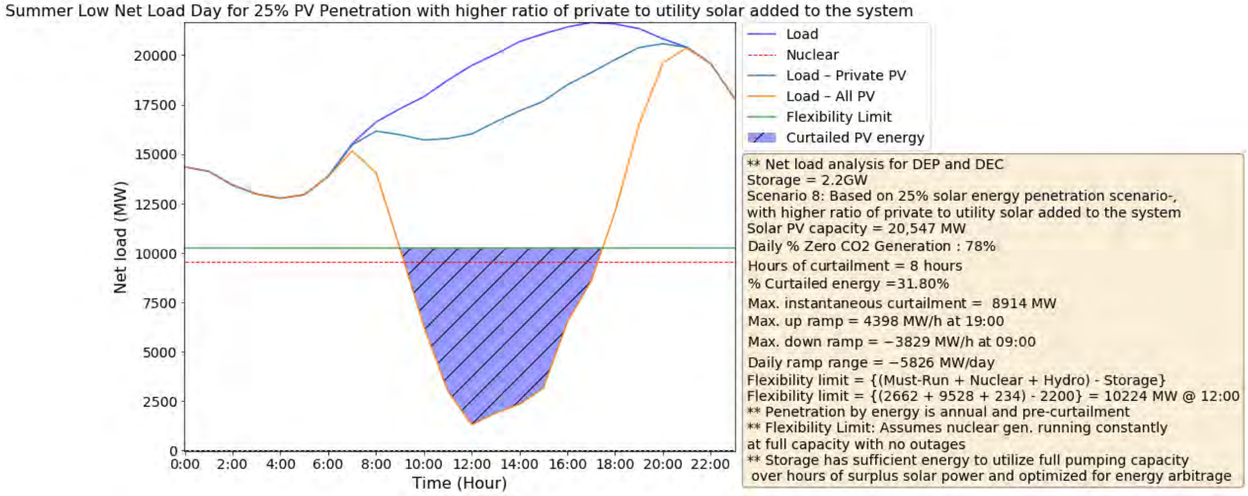
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −4287 MW/h at 10:00
Daily ramp range = 13843 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



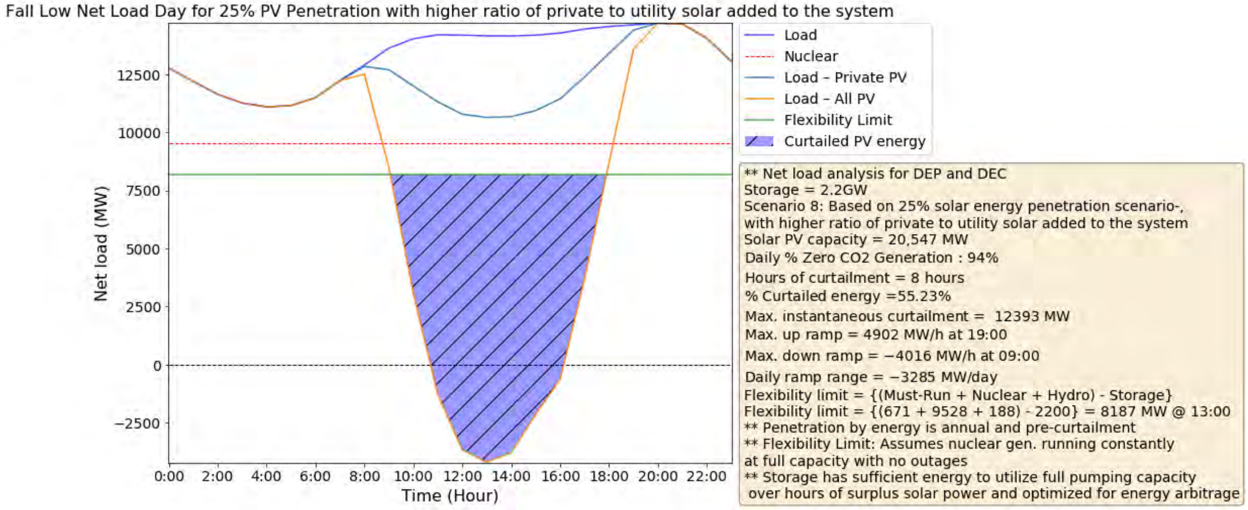
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 7: PV Penetration of 35% by annual energy
Solar PV capacity = 28,766 MW
Daily % Zero CO2 Generation : 58%
Hours of curtailment = 6 hours
% Curtailed energy =37.07%
Max. instantaneous curtailment = 13183 MW
Max. up ramp = 8609 MW/h at 18:00
Max. down ramp = −9627 MW/h at 10:00
Daily ramp range = 20255 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Scenario 8: 25% PV Penetration and Increased Proportion of Distributed Solar

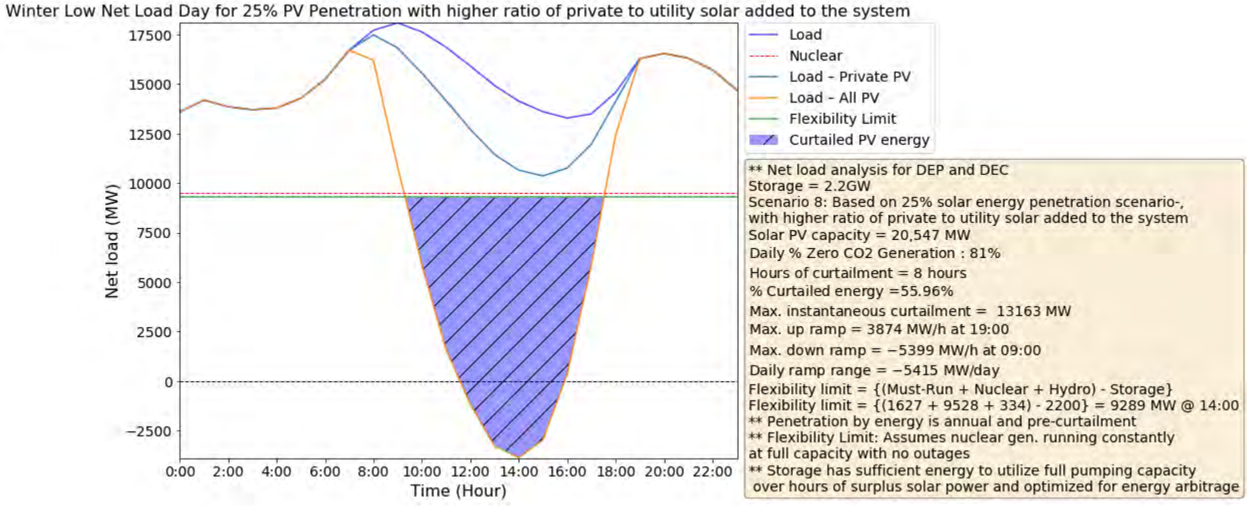
Seasonal Low Net Load Days


Summer Low Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario-,
with higher ratio of private to utility solar added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 78%
Hours of curtailment = 8 hours
% Curtailed energy =31.80%
Max. instantaneous curtailment = 8914 MW
Max. up ramp = 4398 MW/h at 19:00
Max. down ramp = −3829 MW/h at 09:00
Daily ramp range = −5826 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

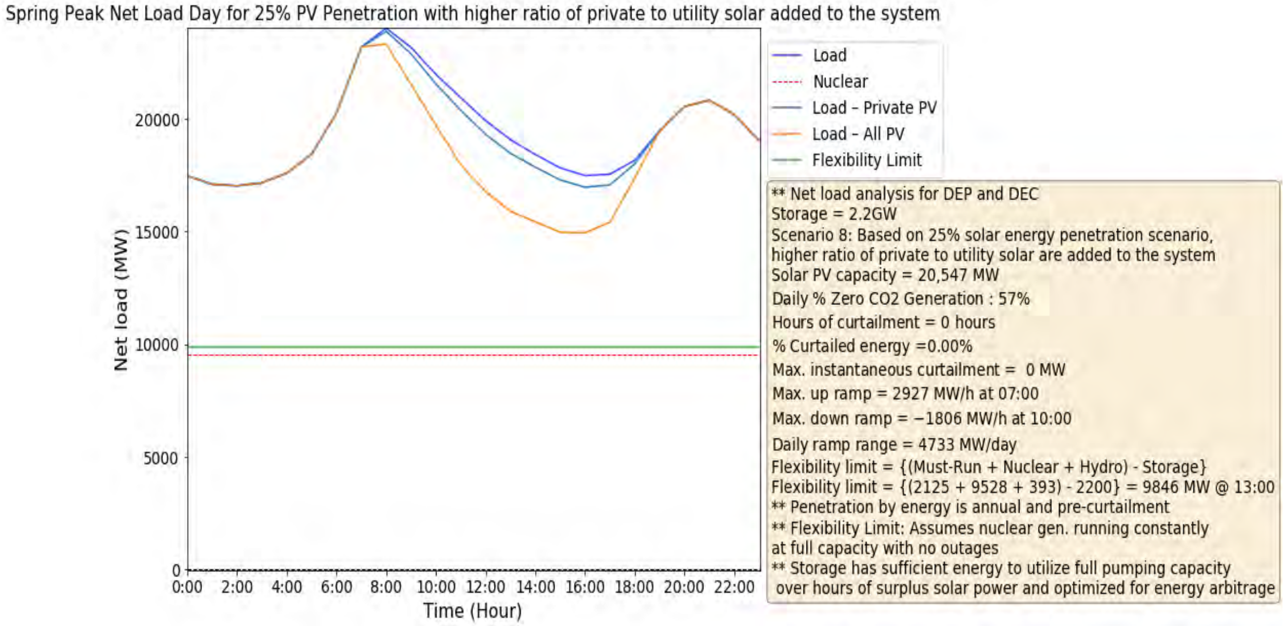

Fall Low Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario-,
with higher ratio of private to utility solar added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 94%
Hours of curtailment = 8 hours
% Curtailed energy =55.23%
Max. instantaneous curtailment = 12393 MW
Max. up ramp = 4902 MW/h at 19:00
Max. down ramp = −4016 MW/h at 09:00
Daily ramp range = −3285 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 188) - 2200} = 8187 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Winter Low Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

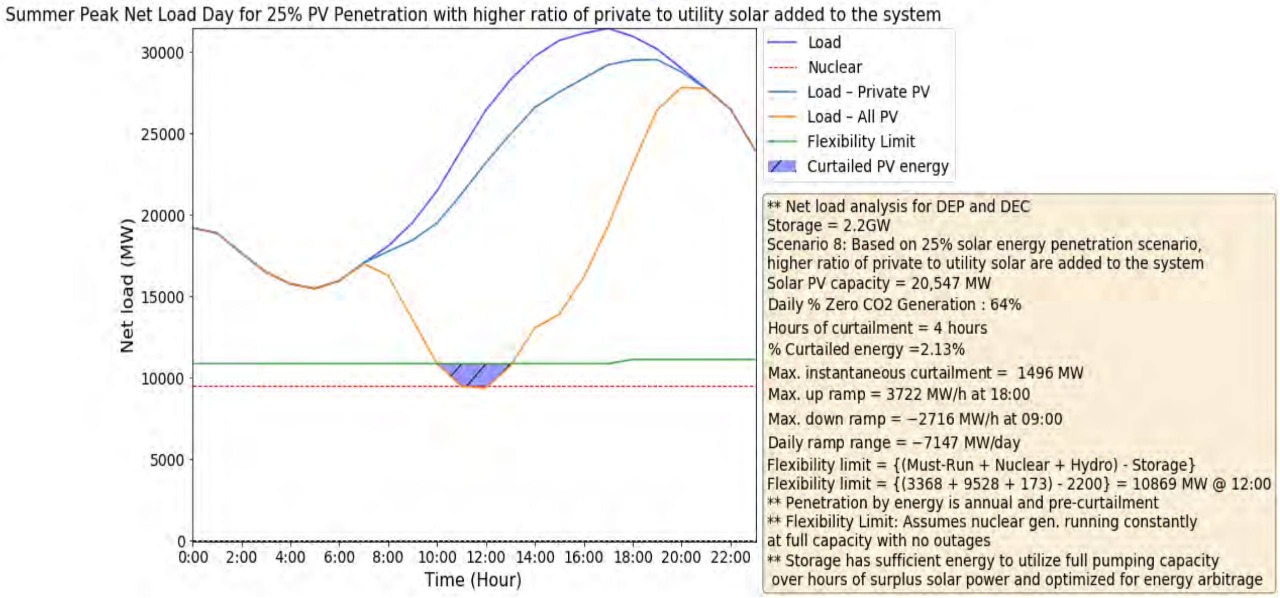
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario-,
with higher ratio of private to utility solar added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 81%
Hours of curtailment = 8 hours
% Curtailed energy =55.96%
Max. instantaneous curtailment = 13163 MW
Max. up ramp = 3874 MW/h at 19:00
Max. down ramp = −5399 MW/h at 09:00
Daily ramp range = −5415 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1627 + 9528 + 334) - 2200} = 9289 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Seasonal Peak Net Load Days



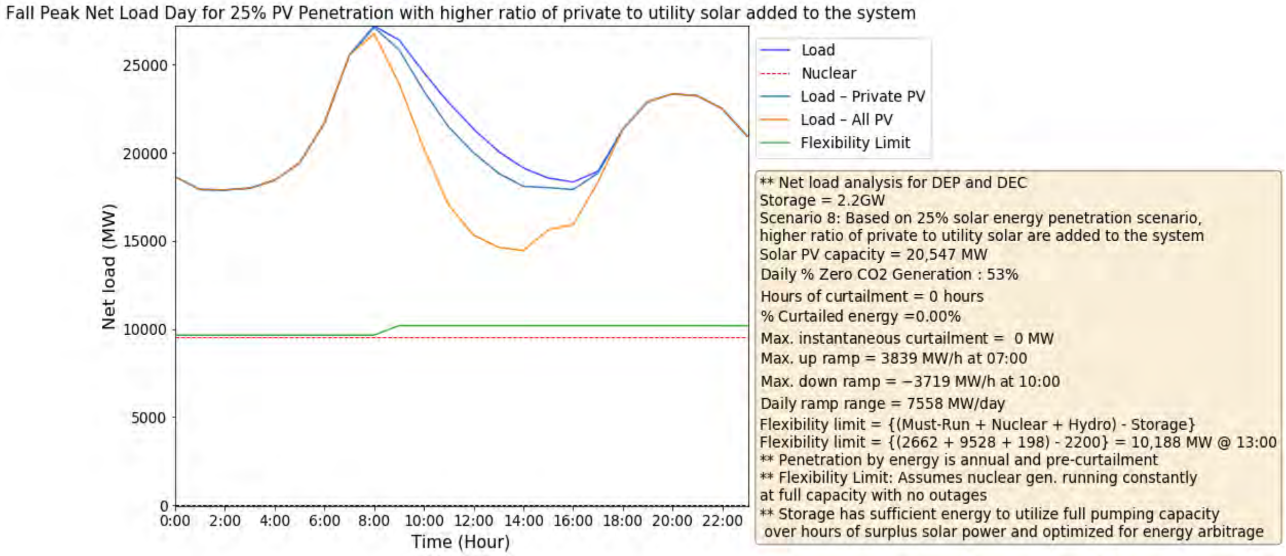
Spring Peak Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario,
higher ratio of private to utility solar are added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 57%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1806 MW/h at 10:00
Daily ramp range = 4733 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



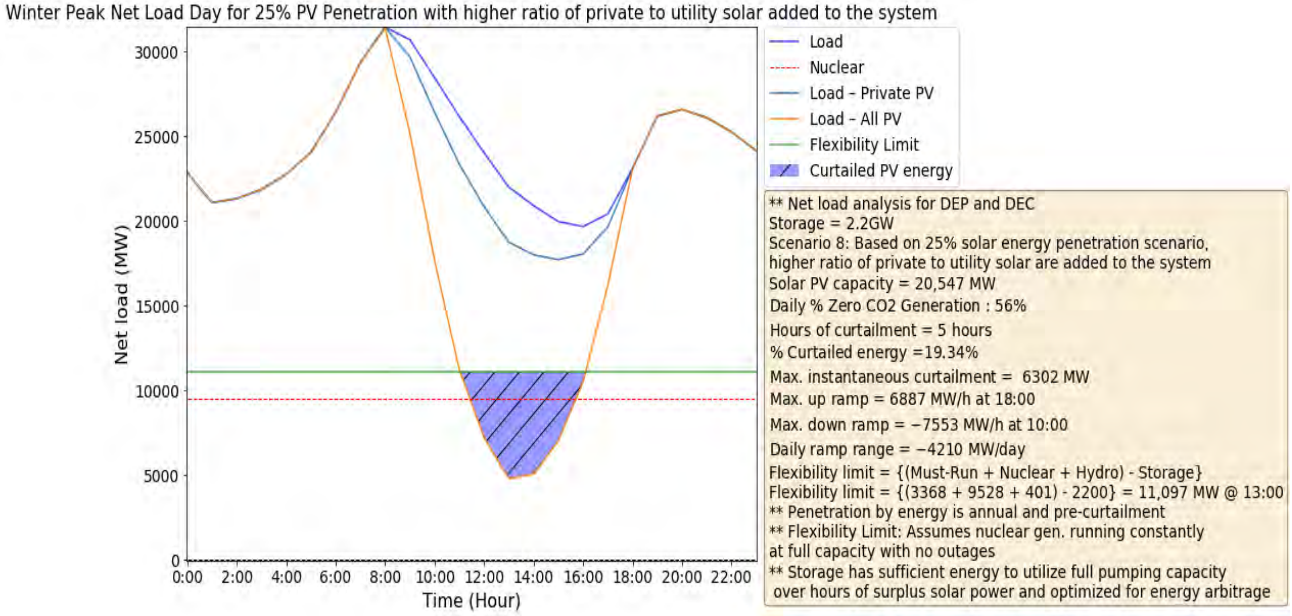
Summer Peak Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario,
higher ratio of private to utility solar are added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 64%
Hours of curtailment = 4 hours
% Curtailed energy =2.13%
Max. instantaneous curtailment = 1496 MW
Max. up ramp = 3722 MW/h at 18:00
Max. down ramp = −2716 MW/h at 09:00
Daily ramp range = −7147 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



Fall Peak Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario,
higher ratio of private to utility solar are added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −3719 MW/h at 10:00
Daily ramp range = 7558 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

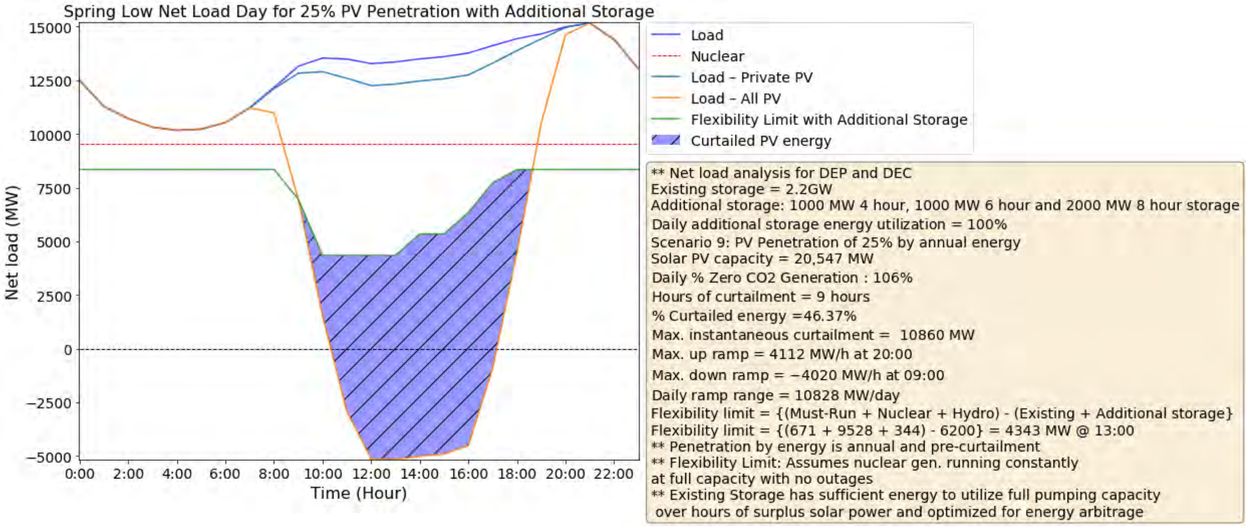


Winter Peak Net Load Day for 25% PV Penetration with higher ratio of private to utility solar added to the system

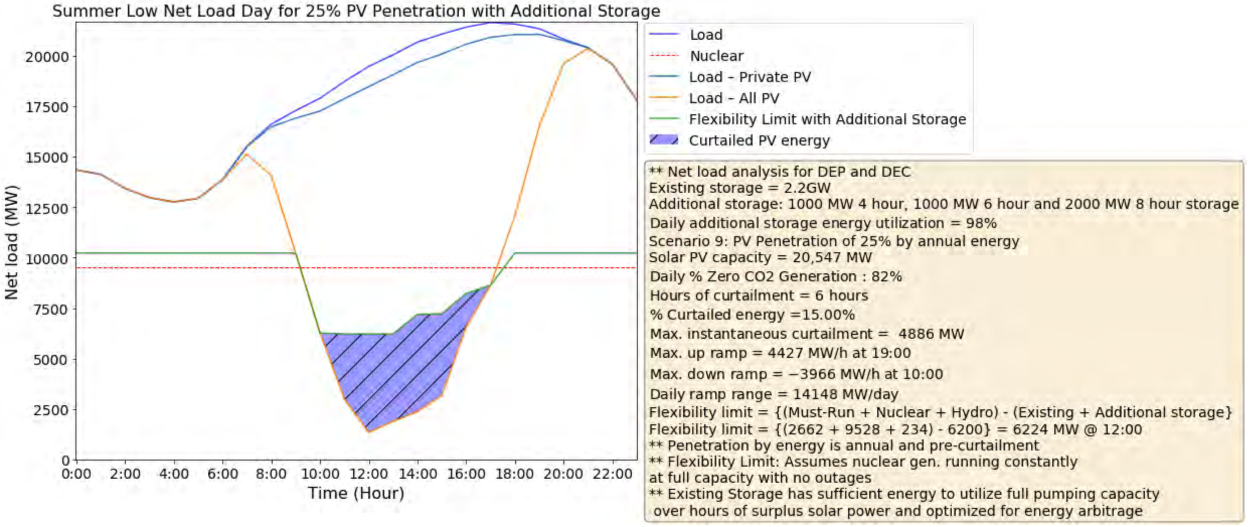
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 8: Based on 25% solar energy penetration scenario,
higher ratio of private to utility solar are added to the system
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 5 hours
% Curtailed energy =19.34%
Max. instantaneous curtailment = 6302 MW
Max. up ramp = 6887 MW/h at 18:00
Max. down ramp = −7553 MW/h at 10:00
Daily ramp range = −4210 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Scenario 9: 25% PV Penetration and Additional Storage

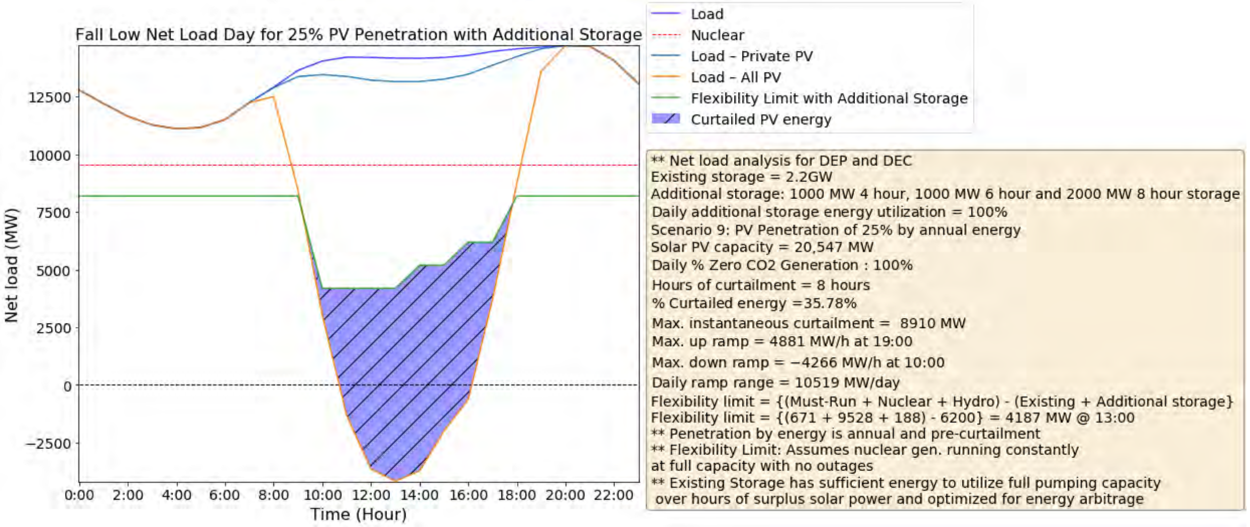
Seasonal Low Net Load Days



** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 100%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 106%
Hours of curtailment = 9 hours
% Curtailed energy =46.37%
Max. instantaneous curtailment = 10860 MW
Max. up ramp = 4112 MW/h at 20:00
Max. down ramp = −4020 MW/h at 09:00
Daily ramp range = 10828 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(671 + 9528 + 344) - 6200} = 4343 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

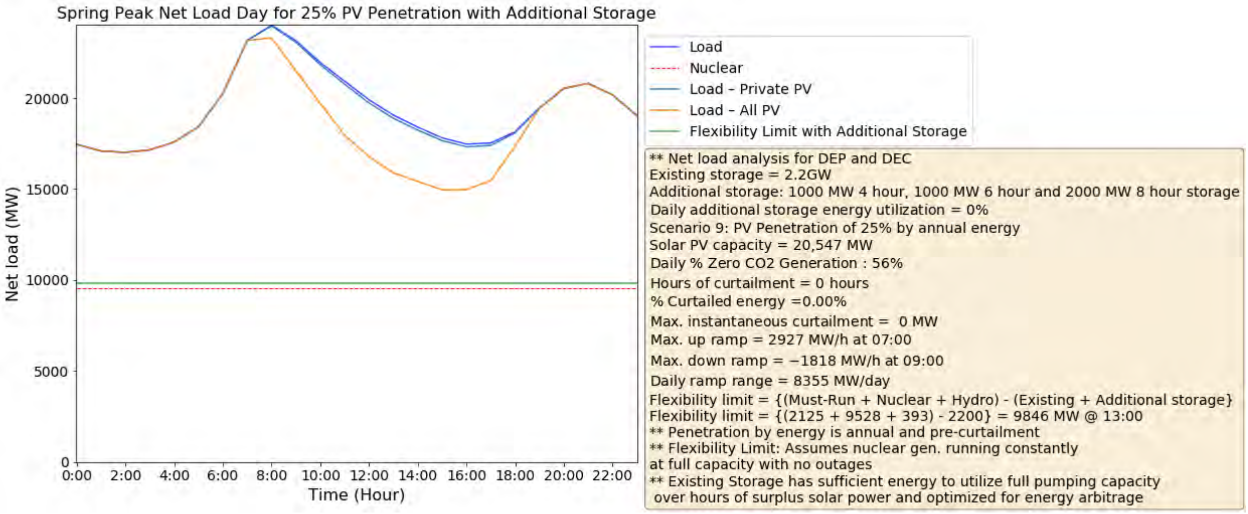


** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 98%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 82%
Hours of curtailment = 6 hours
% Curtailed energy =15.00%
Max. instantaneous curtailment = 4886 MW
Max. up ramp = 4427 MW/h at 19:00
Max. down ramp = −3966 MW/h at 10:00
Daily ramp range = 14148 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(2662 + 9528 + 234) - 6200} = 6224 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

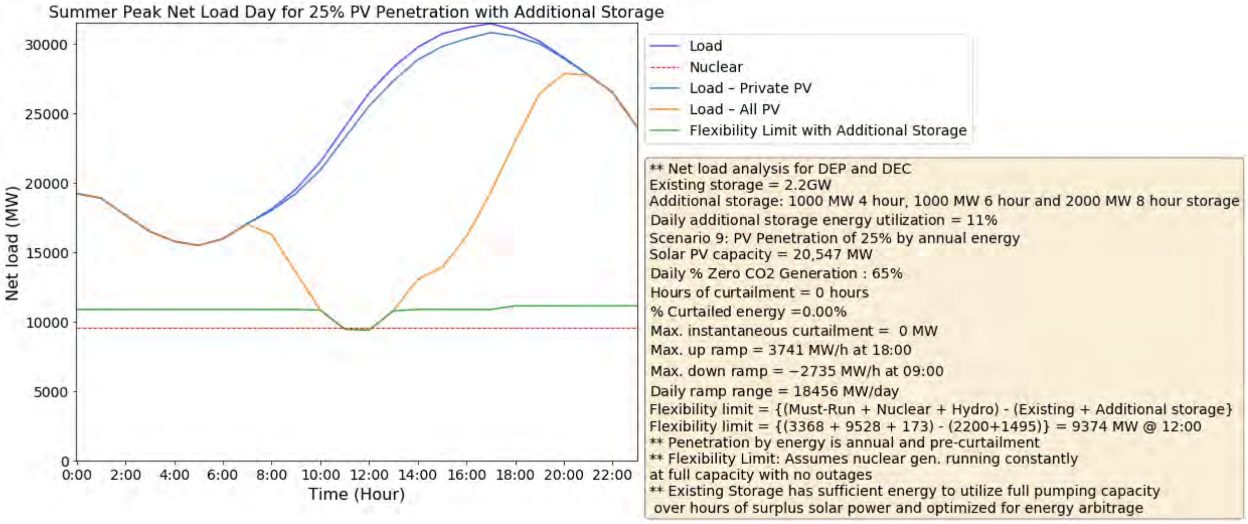


** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 100%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 100%
Hours of curtailment = 8 hours
% Curtailed energy =35.78%
Max. instantaneous curtailment = 8910 MW
Max. up ramp = 4881 MW/h at 19:00
Max. down ramp = −4266 MW/h at 10:00
Daily ramp range = 10519 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(671 + 9528 + 188) - 6200} = 4187 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

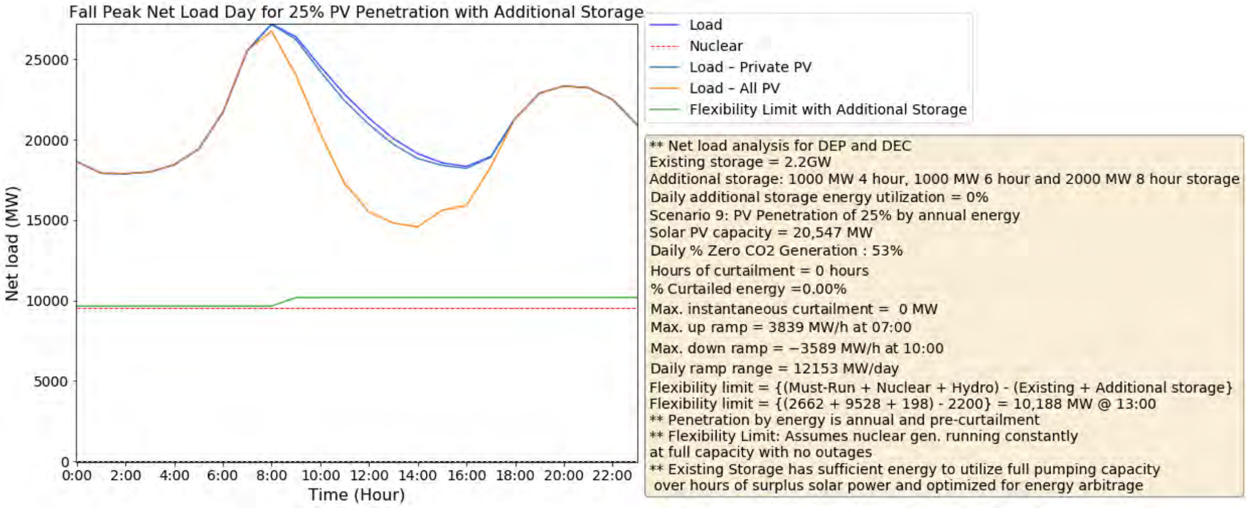
Seasonal Peak Net Load Days



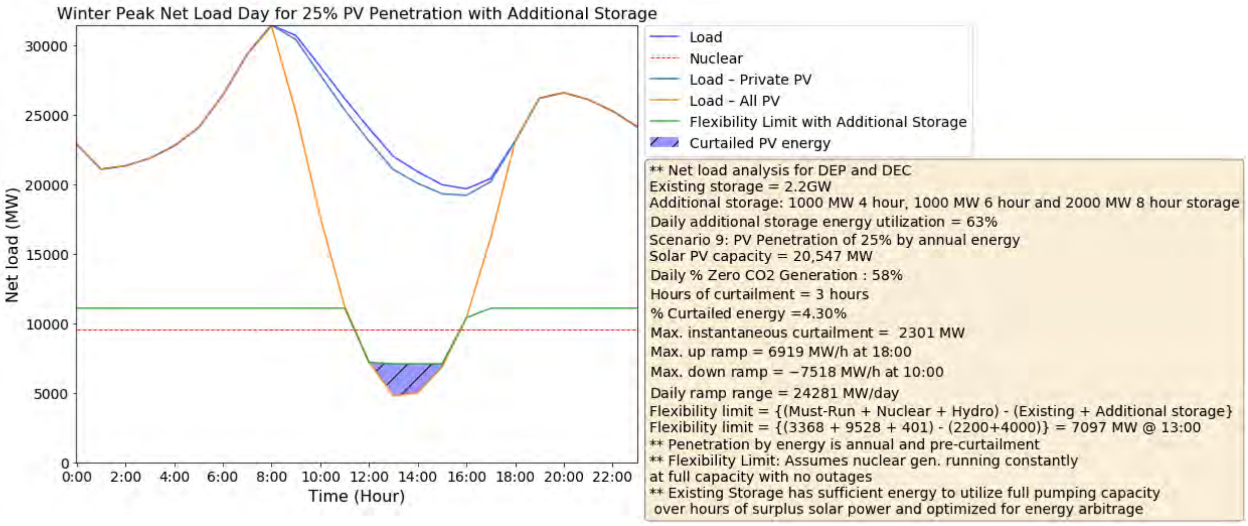
** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 0%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1818 MW/h at 09:00
Daily ramp range = 8355 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(2125 + 9528 + 393) - 2200} = 9846 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 11%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 65%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3741 MW/h at 18:00
Max. down ramp = −2735 MW/h at 09:00
Daily ramp range = 18456 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(3368 + 9528 + 173) - (2200+1495)} = 9374 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



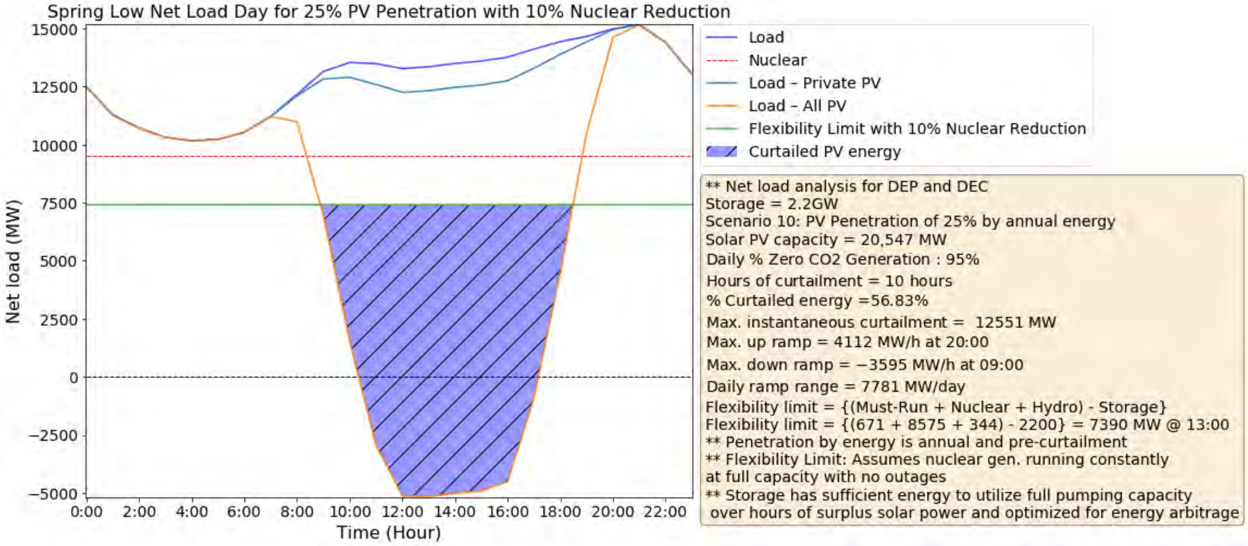
** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 0%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −3589 MW/h at 10:00
Daily ramp range = 12153 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



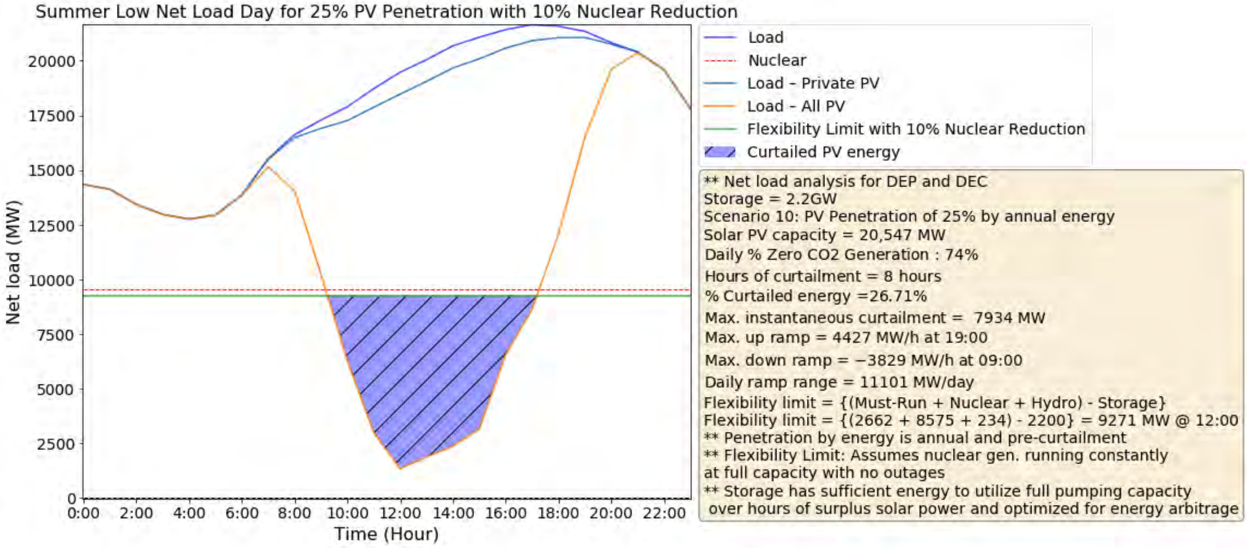
** Net load analysis for DEP and DEC
Existing storage = 2.2GW
Additional storage: 1000 MW 4 hour, 1000 MW 6 hour and 2000 MW 8 hour storage
Daily additional storage energy utilization = 63%
Scenario 9: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 58%
Hours of curtailment = 3 hours
% Curtailed energy =4.30%
Max. instantaneous curtailment = 2301 MW
Max. up ramp = 6919 MW/h at 18:00
Max. down ramp = −7518 MW/h at 10:00
Daily ramp range = 24281 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - (Existing + Additional storage}
Flexibility limit = {(3368 + 9528 + 401) - (2200+4000)} = 7097 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Existing Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Scenario 10: 25% PV Penetration and Generation Retirement

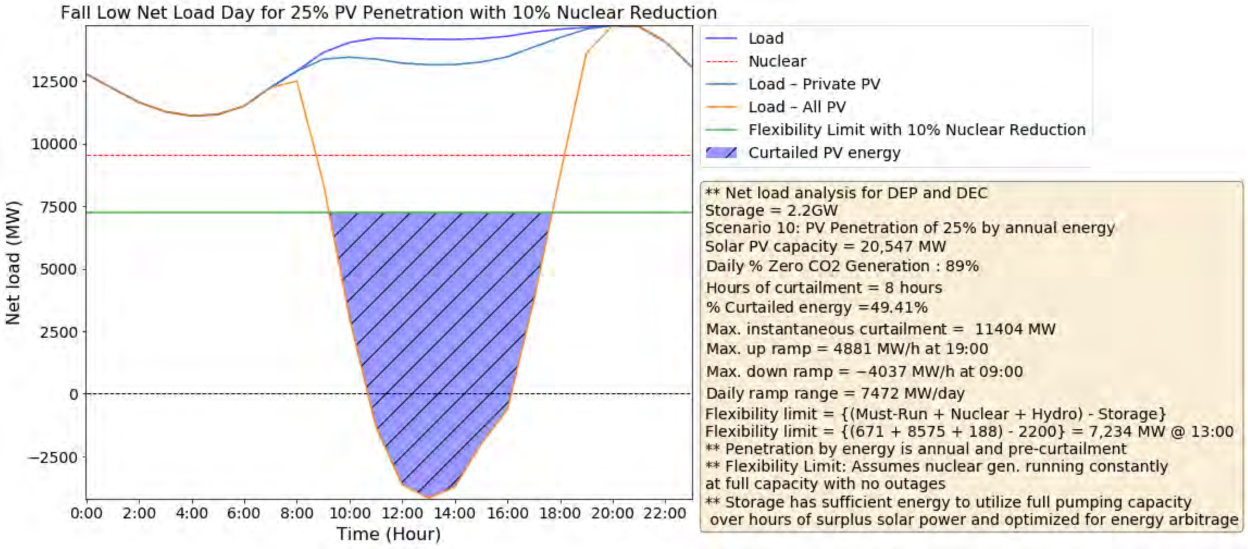
Seasonal Low Net Load Days



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 95%
Hours of curtailment = 10 hours
% Curtailed energy =56.83%
Max. instantaneous curtailment = 12551 MW
Max. up ramp = 4112 MW/h at 20:00
Max. down ramp = −3595 MW/h at 09:00
Daily ramp range = 7781 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 8575 + 344) - 2200} = 7390 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

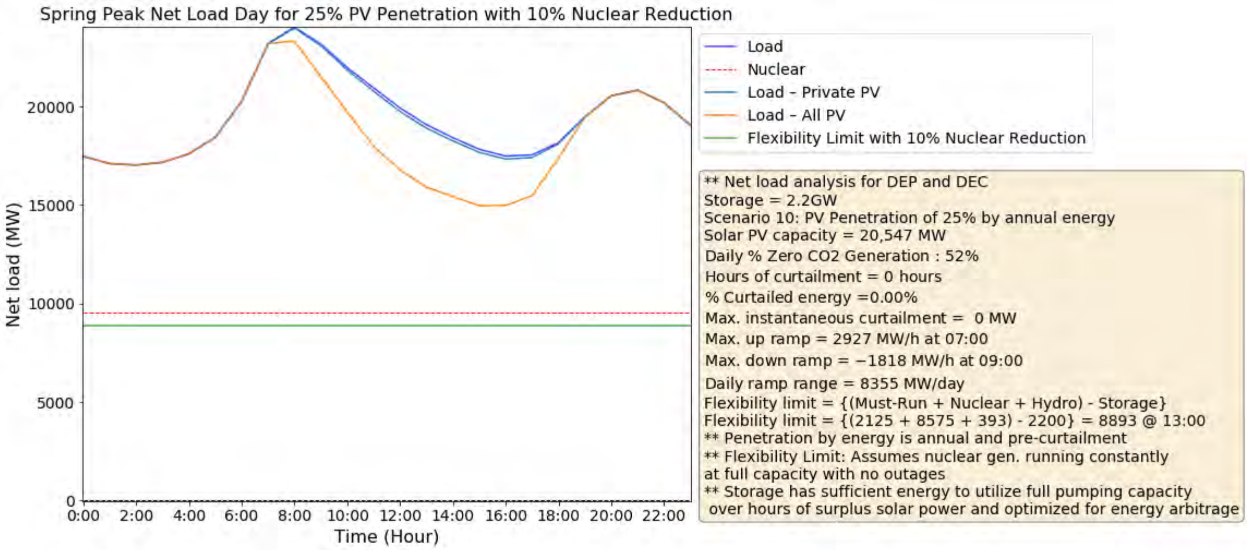


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 74%
Hours of curtailment = 8 hours
% Curtailed energy =26.71%
Max. instantaneous curtailment = 7934 MW
Max. up ramp = 4427 MW/h at 19:00
Max. down ramp = −3829 MW/h at 09:00
Daily ramp range = 11101 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 8575 + 234) - 2200} = 9271 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

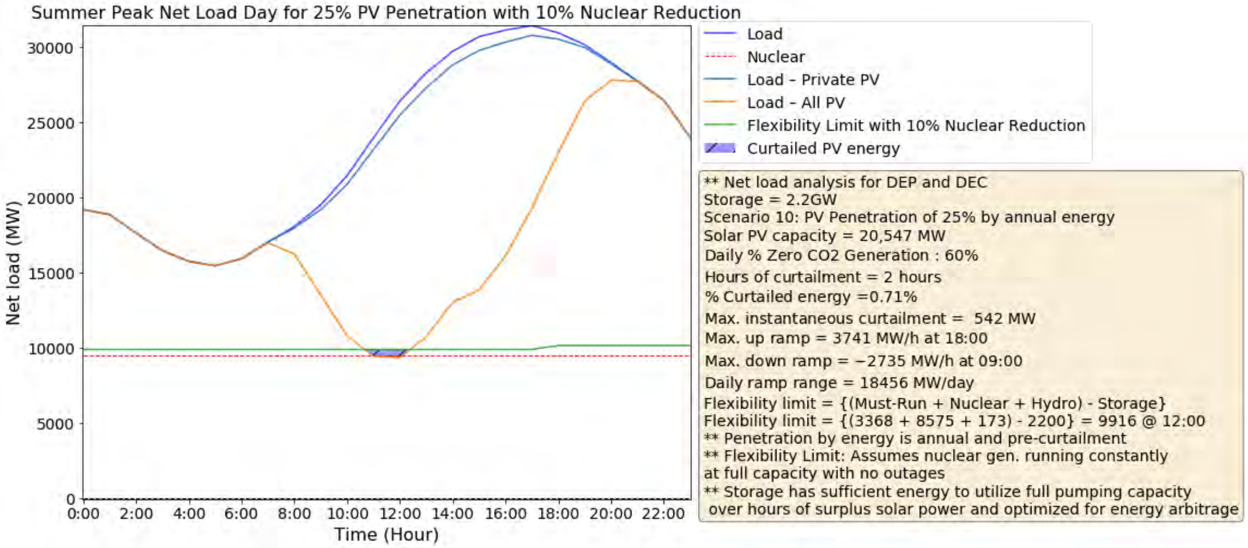


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 89%
Hours of curtailment = 8 hours
% Curtailed energy =49.41%
Max. instantaneous curtailment = 11404 MW
Max. up ramp = 4881 MW/h at 19:00
Max. down ramp = −4037 MW/h at 09:00
Daily ramp range = 7472 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 8575 + 188) - 2200} = 7,234 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

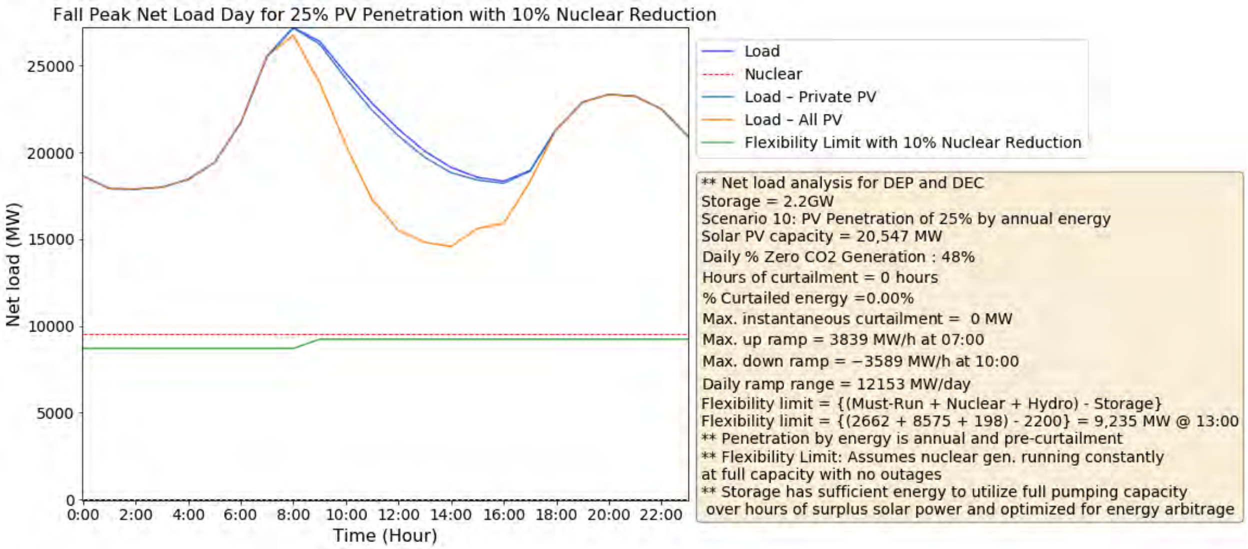
Seasonal Peak Net Load Days



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 52%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2927 MW/h at 07:00
Max. down ramp = −1818 MW/h at 09:00
Daily ramp range = 8355 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 8575 + 393) - 2200} = 8893 @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

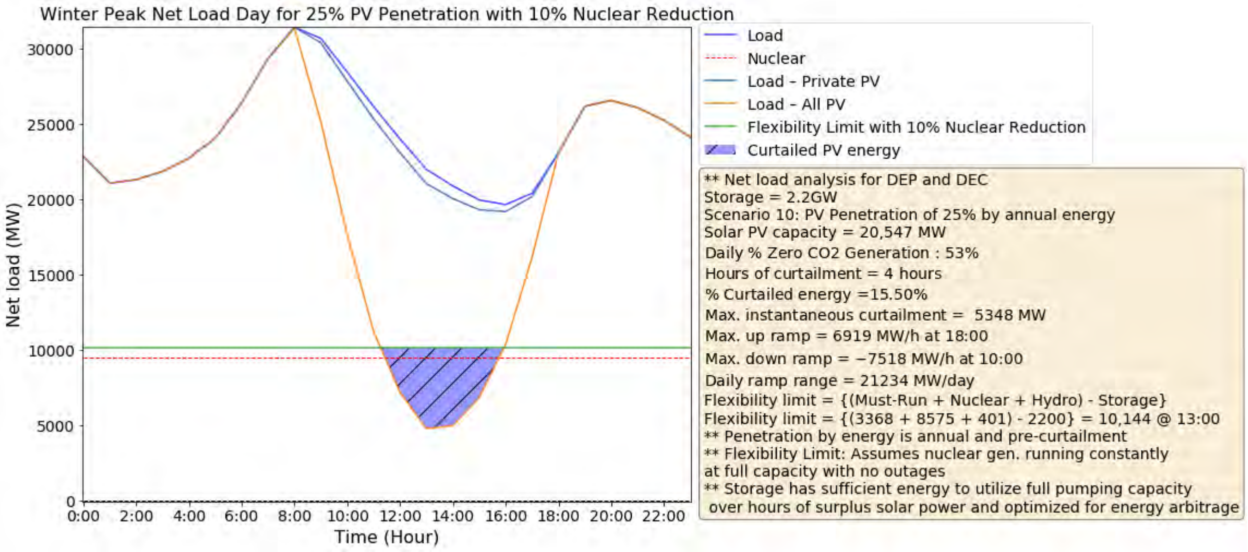


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 60%
Hours of curtailment = 2 hours
% Curtailed energy =0.71%
Max. instantaneous curtailment = 542 MW
Max. up ramp = 3741 MW/h at 18:00
Max. down ramp = −2735 MW/h at 09:00
Daily ramp range = 18456 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 8575 + 173) - 2200} = 9916 @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



Fall Peak Net Load Day for 25% PV Penetration with 10% Nuclear Reduction

** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 48%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 3839 MW/h at 07:00
Max. down ramp = −3589 MW/h at 10:00
Daily ramp range = 12153 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 8575 + 198) - 2200} = 9,235 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

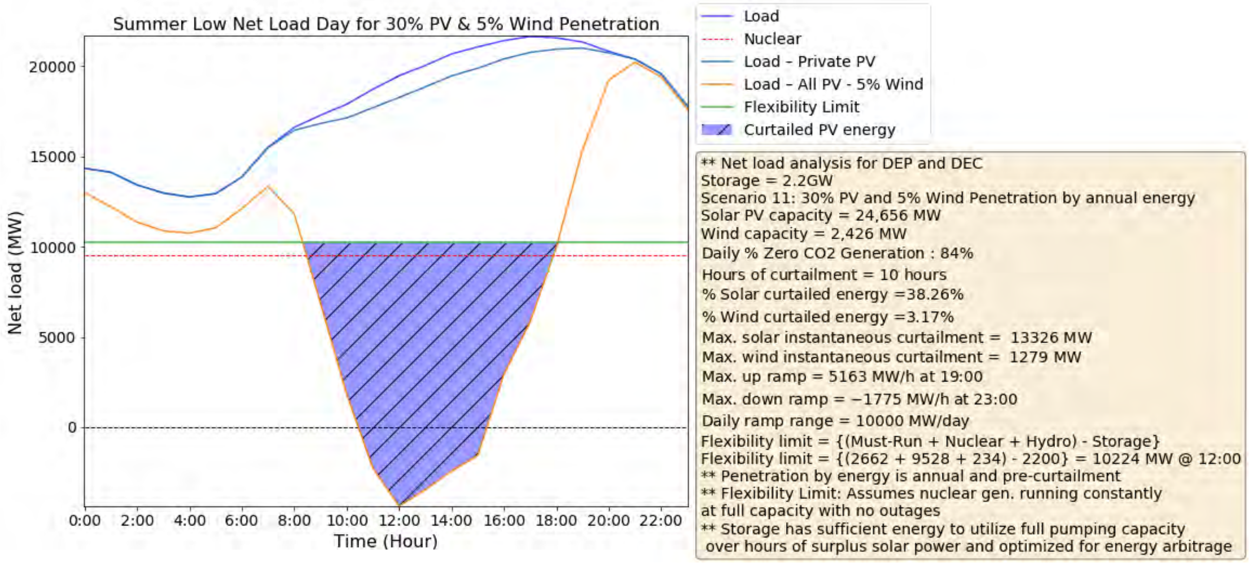


Winter Peak Net Load Day for 25% PV Penetration with 10% Nuclear Reduction

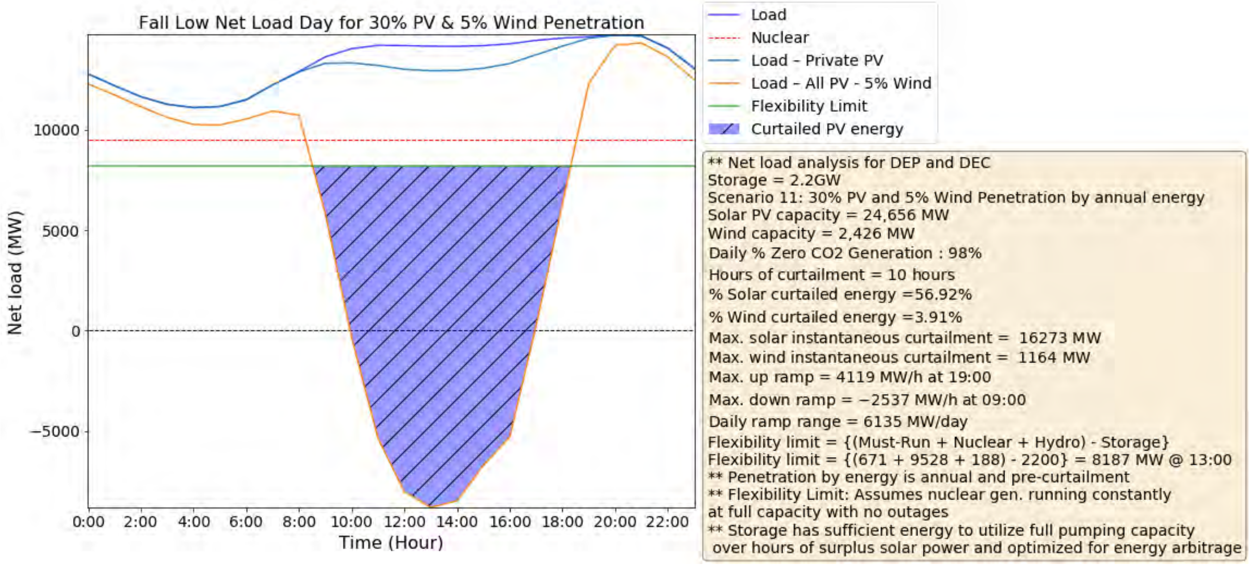
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 10: PV Penetration of 25% by annual energy
Solar PV capacity = 20,547 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 4 hours
% Curtailed energy =15.50%
Max. instantaneous curtailment = 5348 MW
Max. up ramp = 6919 MW/h at 18:00
Max. down ramp = −7518 MW/h at 10:00
Daily ramp range = 21234 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 8575 + 401) - 2200} = 10,144 @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Scenario 11: 30% PV and 5% Wind Penetration

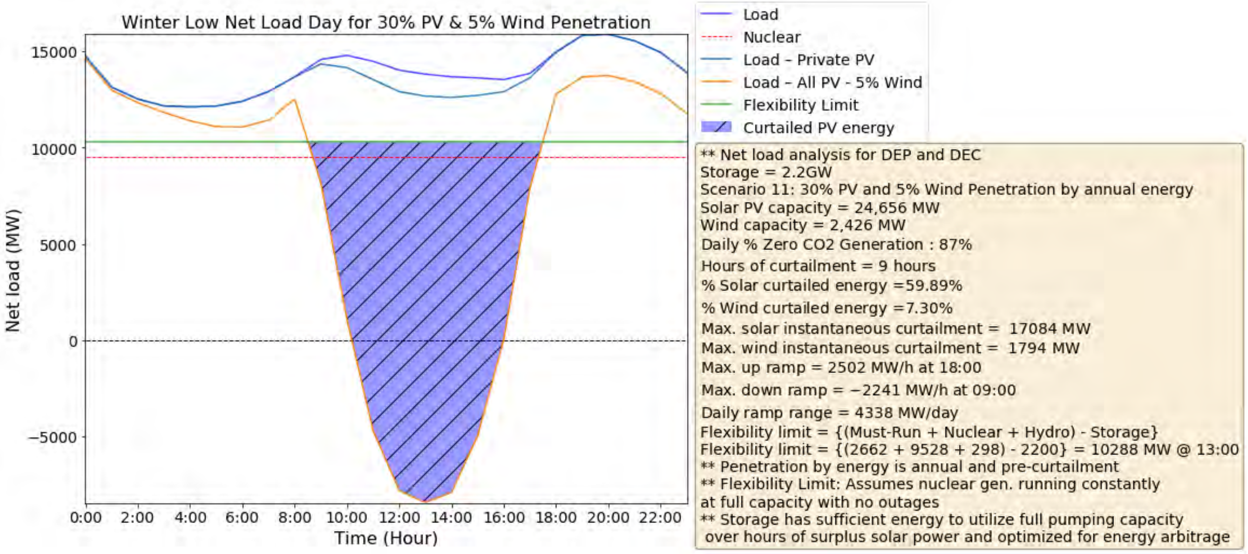
Seasonal Low Net Load Days



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 84%
Hours of curtailment = 10 hours
% Solar curtailed energy =38.26%
% Wind curtailed energy =3.17%
Max. solar instantaneous curtailment = 13326 MW
Max. wind instantaneous curtailment = 1279 MW
Max. up ramp = 5163 MW/h at 19:00
Max. down ramp = −1775 MW/h at 23:00
Daily ramp range = 10000 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 234) - 2200} = 10224 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

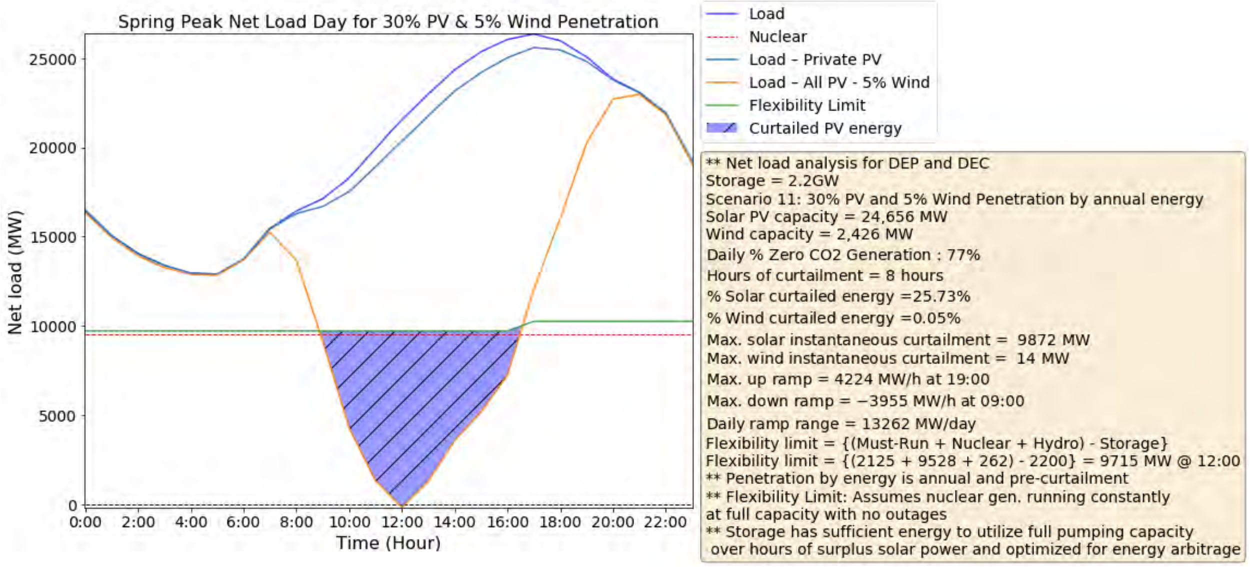


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 98%
Hours of curtailment = 10 hours
% Solar curtailed energy =56.92%
% Wind curtailed energy =3.91%
Max. solar instantaneous curtailment = 16273 MW
Max. wind instantaneous curtailment = 1164 MW
Max. up ramp = 4119 MW/h at 19:00
Max. down ramp = −2537 MW/h at 09:00
Daily ramp range = 6135 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(671 + 9528 + 188) - 2200} = 8187 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

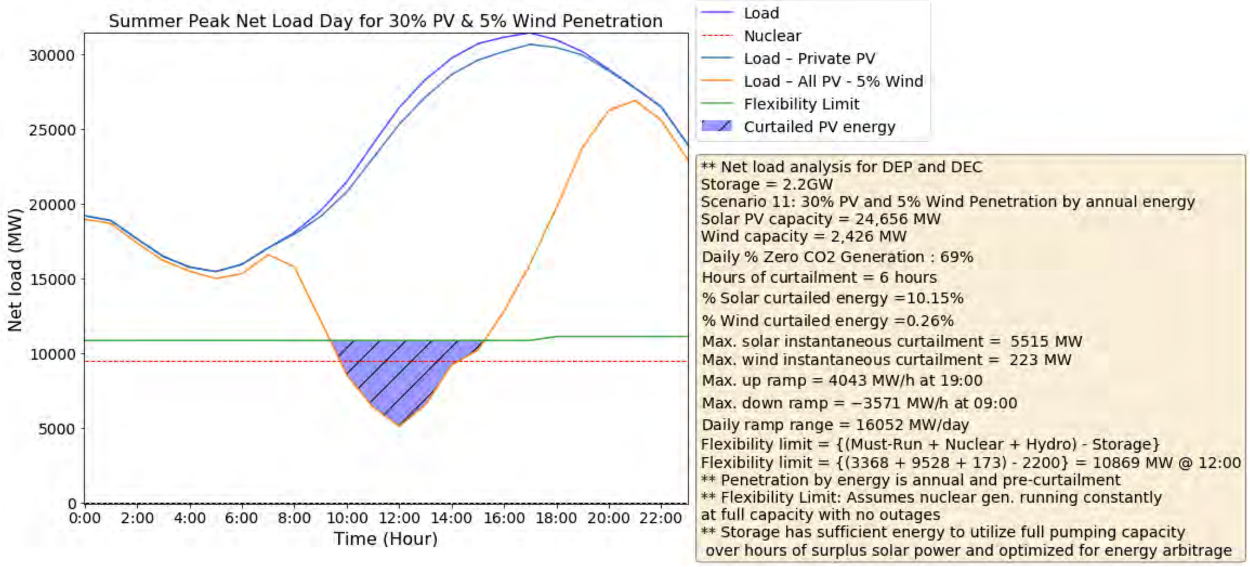


** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 87%
Hours of curtailment = 9 hours
% Solar curtailed energy =59.89%
% Wind curtailed energy =7.30%
Max. solar instantaneous curtailment = 17084 MW
Max. wind instantaneous curtailment = 1794 MW
Max. up ramp = 2502 MW/h at 18:00
Max. down ramp = −2241 MW/h at 09:00
Daily ramp range = 4338 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 298) - 2200} = 10288 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

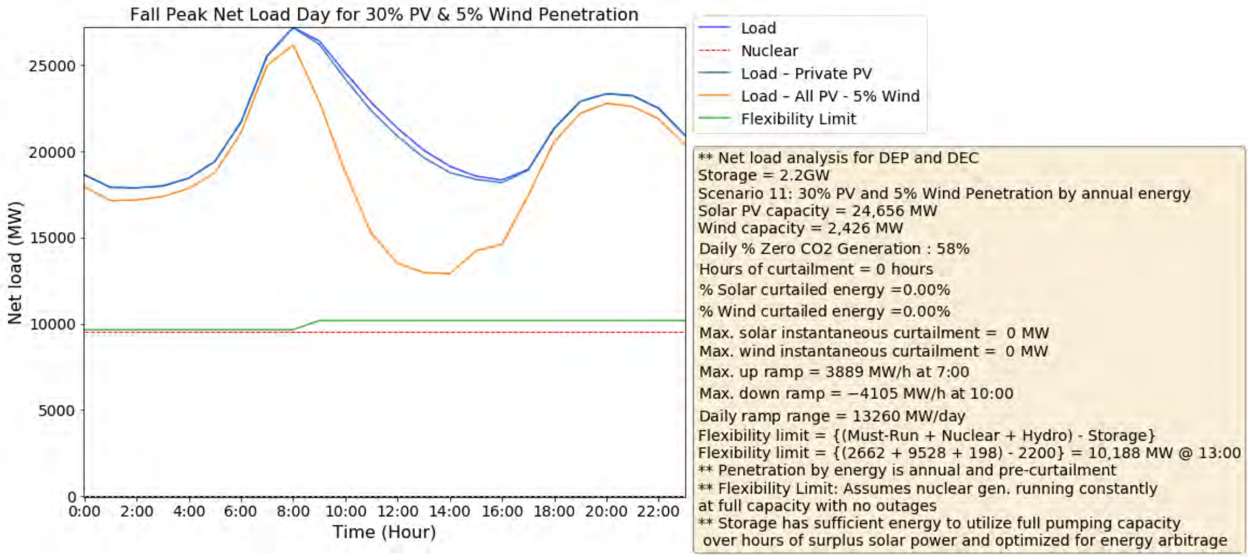
Seasonal Peak Net Load Days



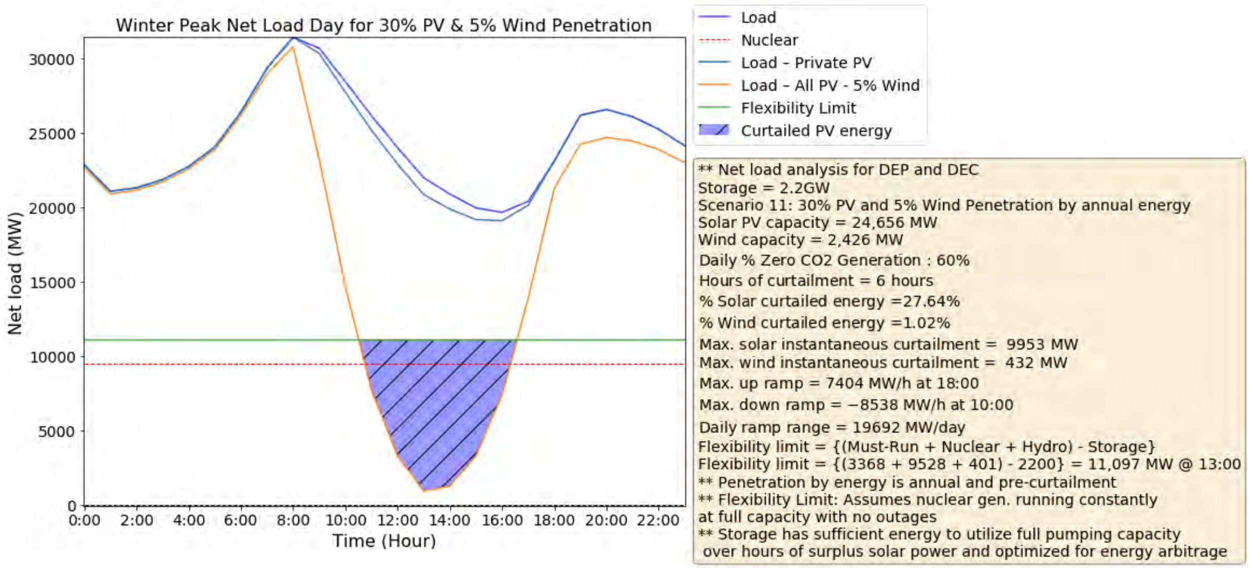
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 77%
Hours of curtailment = 8 hours
% Solar curtailed energy =25.73%
% Wind curtailed energy =0.05%
Max. solar instantaneous curtailment = 9872 MW
Max. wind instantaneous curtailment = 14 MW
Max. up ramp = 4224 MW/h at 19:00
Max. down ramp = −3955 MW/h at 09:00
Daily ramp range = 13262 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2125 + 9528 + 262) - 2200} = 9715 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 69%
Hours of curtailment = 6 hours
% Solar curtailed energy =10.15%
% Wind curtailed energy =0.26%
Max. solar instantaneous curtailment = 5515 MW
Max. wind instantaneous curtailment = 223 MW
Max. up ramp = 4043 MW/h at 19:00
Max. down ramp = −3571 MW/h at 09:00
Daily ramp range = 16052 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 173) - 2200} = 10869 MW @ 12:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



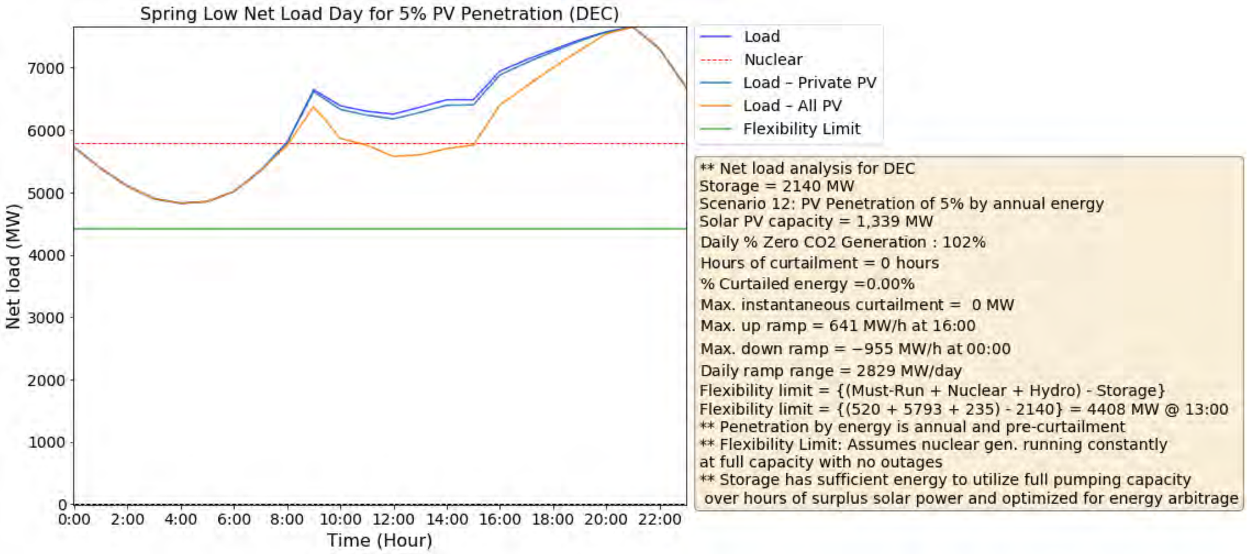
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 58%
Hours of curtailment = 0 hours
% Solar curtailed energy =0.00%
% Wind curtailed energy =0.00%
Max. solar instantaneous curtailment = 0 MW
Max. wind instantaneous curtailment = 0 MW
Max. up ramp = 3889 MW/h at 7:00
Max. down ramp = −4105 MW/h at 10:00
Daily ramp range = 13260 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2662 + 9528 + 198) - 2200} = 10,188 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



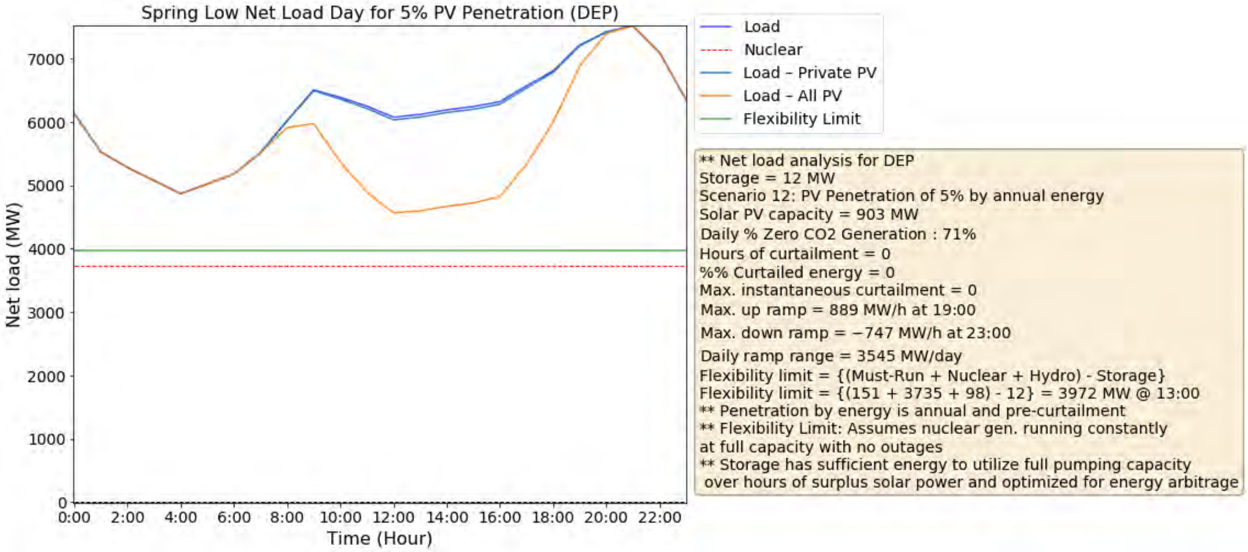
** Net load analysis for DEP and DEC
Storage = 2.2GW
Scenario 11: 30% PV and 5% Wind Penetration by annual energy
Solar PV capacity = 24,656 MW
Wind capacity = 2,426 MW
Daily % Zero CO2 Generation : 60%
Hours of curtailment = 6 hours
% Solar curtailed energy =27.64%
% Wind curtailed energy =1.02%
Max. solar instantaneous curtailment = 9953 MW
Max. wind instantaneous curtailment = 432 MW
Max. up ramp = 7404 MW/h at 18:00
Max. down ramp = −8538 MW/h at 10:00
Daily ramp range = 19692 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(3368 + 9528 + 401) - 2200} = 11,097 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Scenario 12: DEC and DEP Modeled as Separate Balancing Authorities with 5%, 10%, and 15% PV Penetration

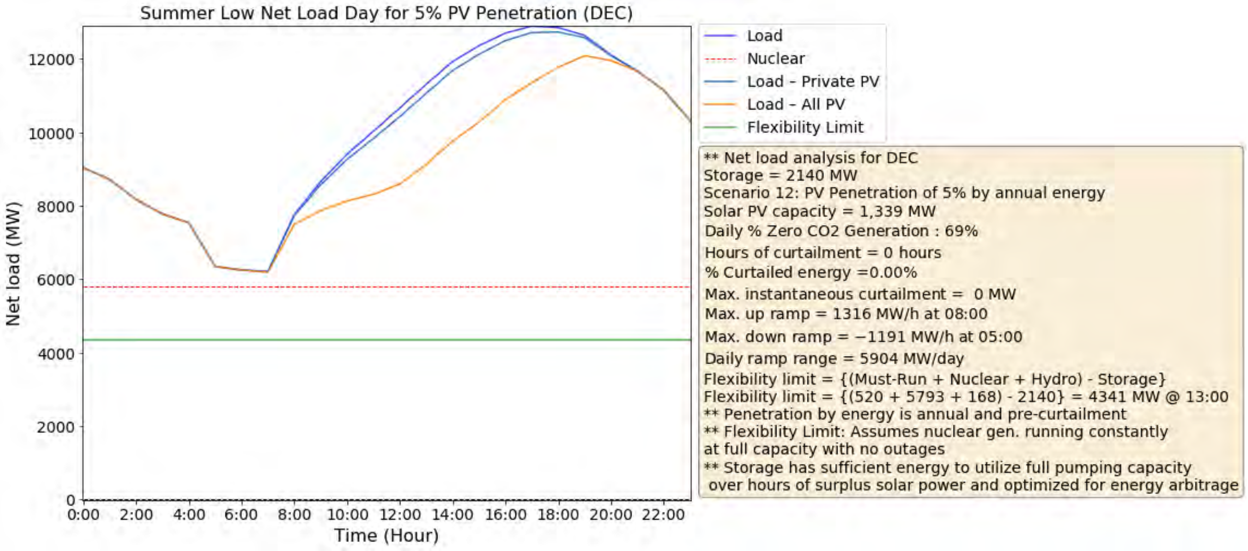
Seasonal Low Net Load Days: 5% PV Penetration



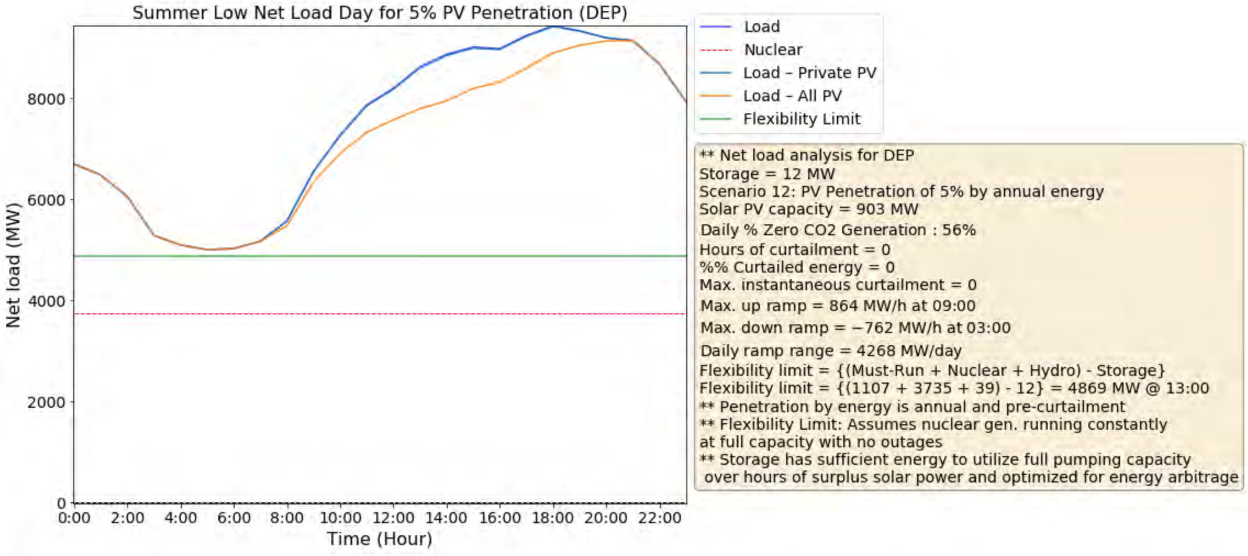
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 102%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 641 MW/h at 16:00
Max. down ramp = −955 MW/h at 00:00
Daily ramp range = 2829 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 235) - 2140} = 4408 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



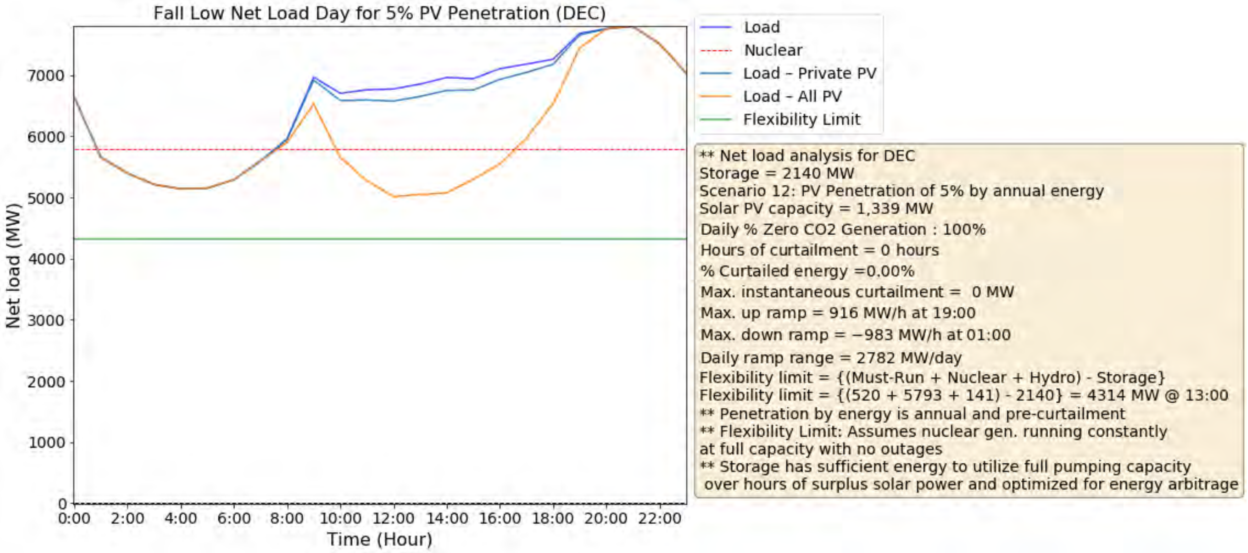
** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 71%
Hours of curtailment = 0
%% Curtailed energy = 0
Max. instantaneous curtailment = 0
Max. up ramp = 889 MW/h at 19:00
Max. down ramp = −747 MW/h at 23:00
Daily ramp range = 3545 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 98) - 12} = 3972 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 69%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1316 MW/h at 08:00
Max. down ramp = −1191 MW/h at 05:00
Daily ramp range = 5904 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 168) - 2140} = 4341 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

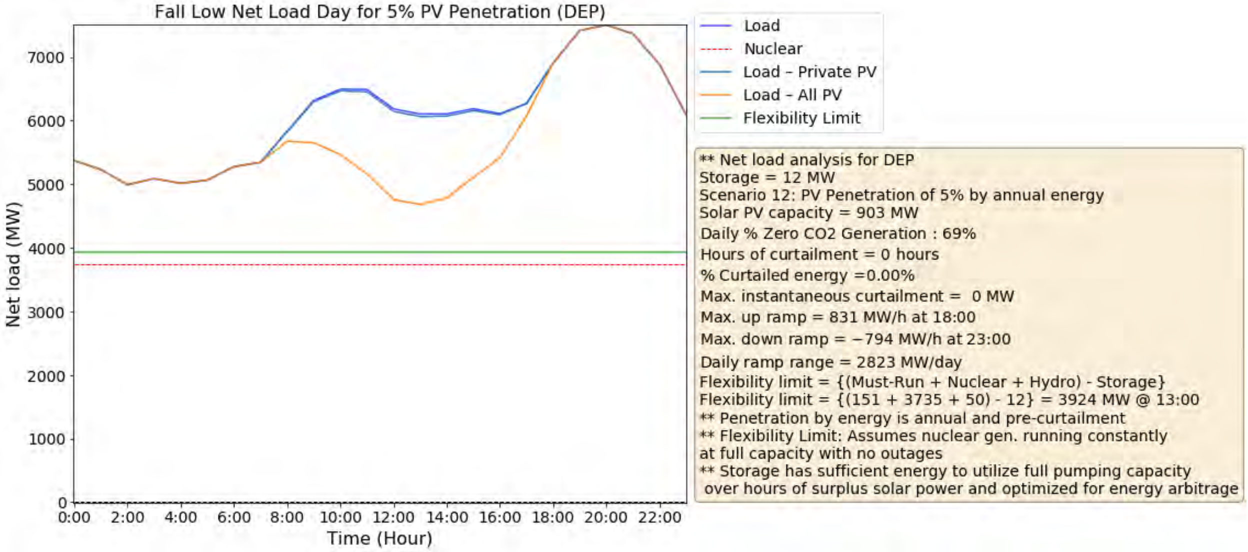


** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0
%% Curtailed energy = 0
Max. instantaneous curtailment = 0
Max. up ramp = 864 MW/h at 09:00
Max. down ramp = −762 MW/h at 03:00
Daily ramp range = 4268 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 39) - 12} = 4869 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



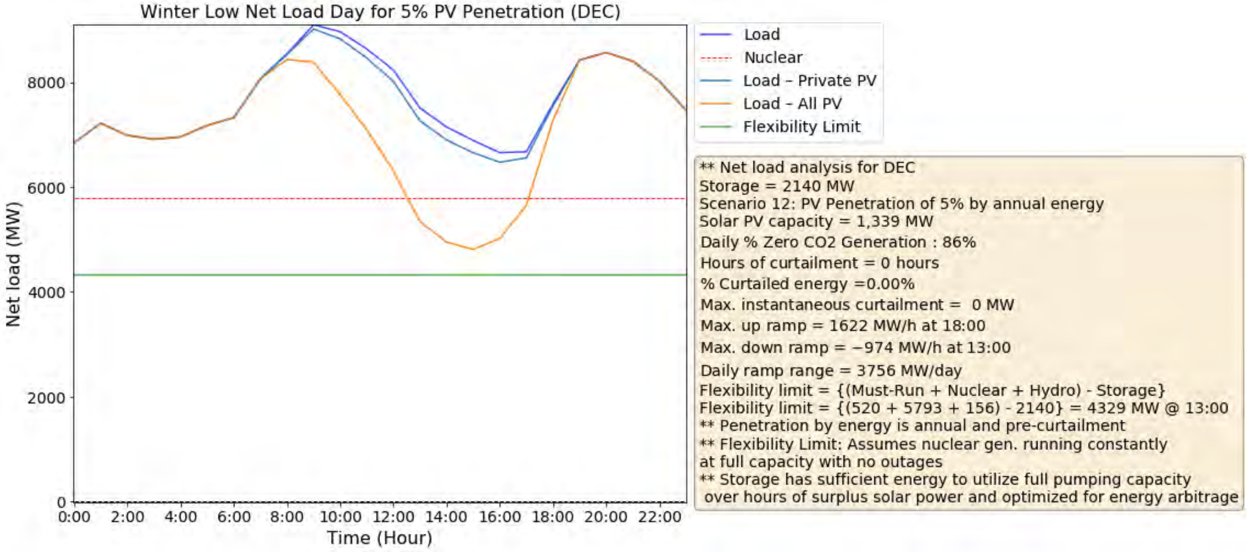
Fall Low Net Load Day for 5% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 100%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 916 MW/h at 19:00
Max. down ramp = −983 MW/h at 01:00
Daily ramp range = 2782 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 141) - 2140} = 4314 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



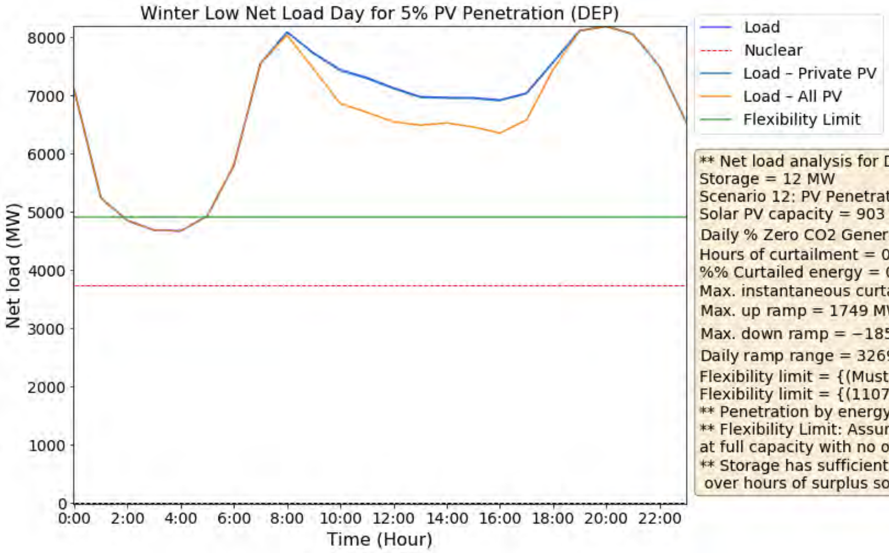
Fall Low Net Load Day for 5% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 69%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 831 MW/h at 18:00
Max. down ramp = −794 MW/h at 23:00
Daily ramp range = 2823 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 50) - 12} = 3924 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



Winter Low Net Load Day for 5% PV Penetration (DEC)

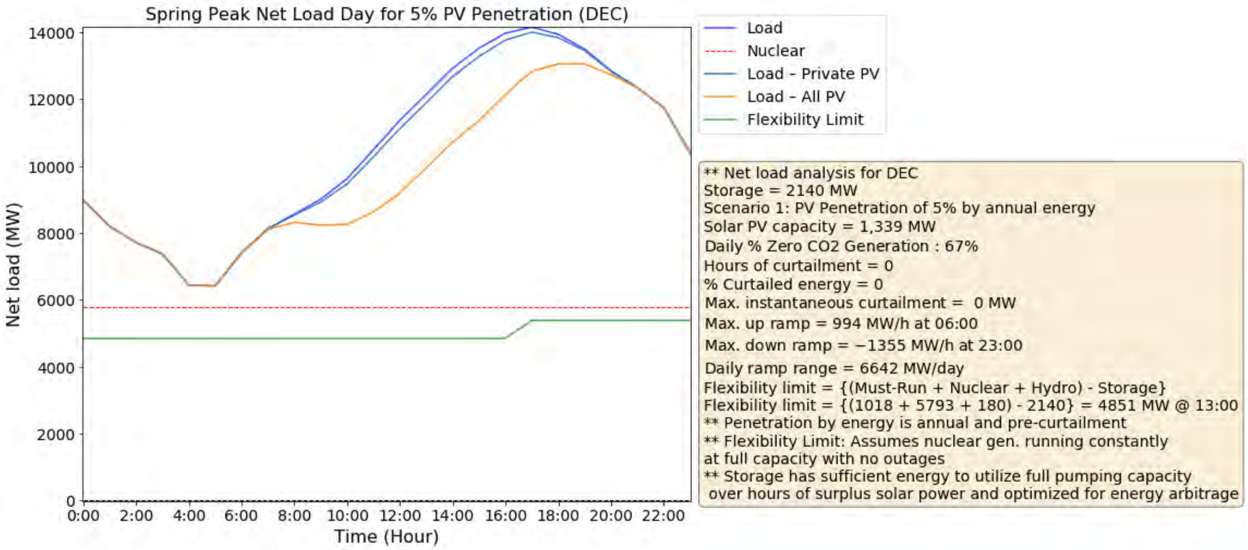
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 86%
Hours of curtailment = 0 hours
% Curtailed energy =0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1622 MW/h at 18:00
Max. down ramp = −974 MW/h at 13:00
Daily ramp range = 3756 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 156) - 2140} = 4329 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



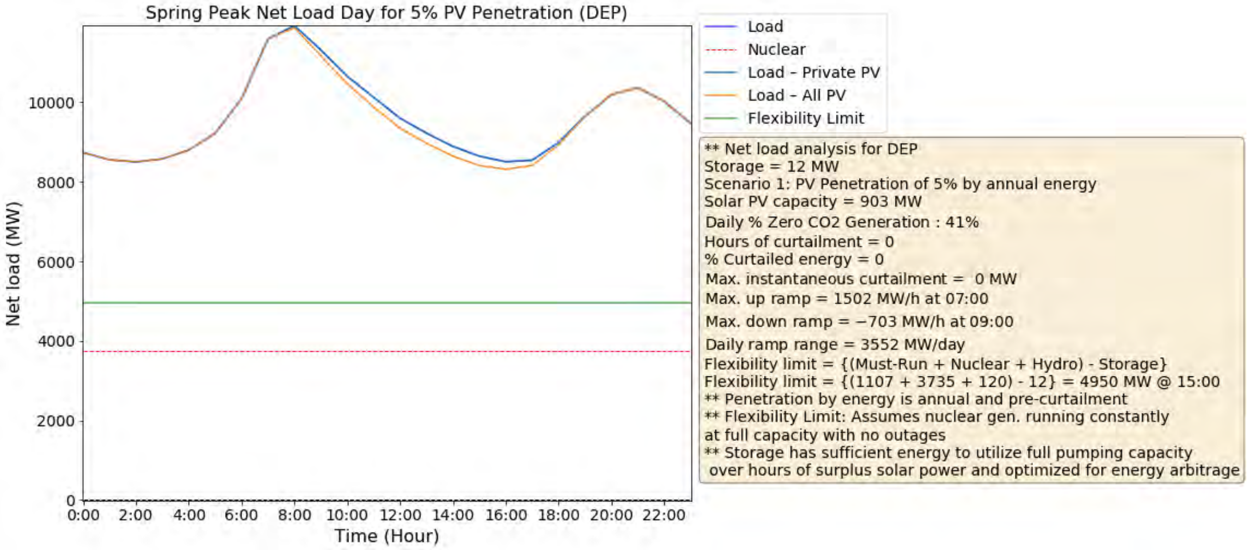
Winter Low Net Load Day for 5% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 60%
Hours of curtailment = 0
%% Curtailed energy = 0
Max. instantaneous curtailment = 0
Max. up ramp = 1749 MW/h at 07:00
Max. down ramp = −1857 MW/h at 01:00
Daily ramp range = 3269 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 92) - 12} = 4922 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

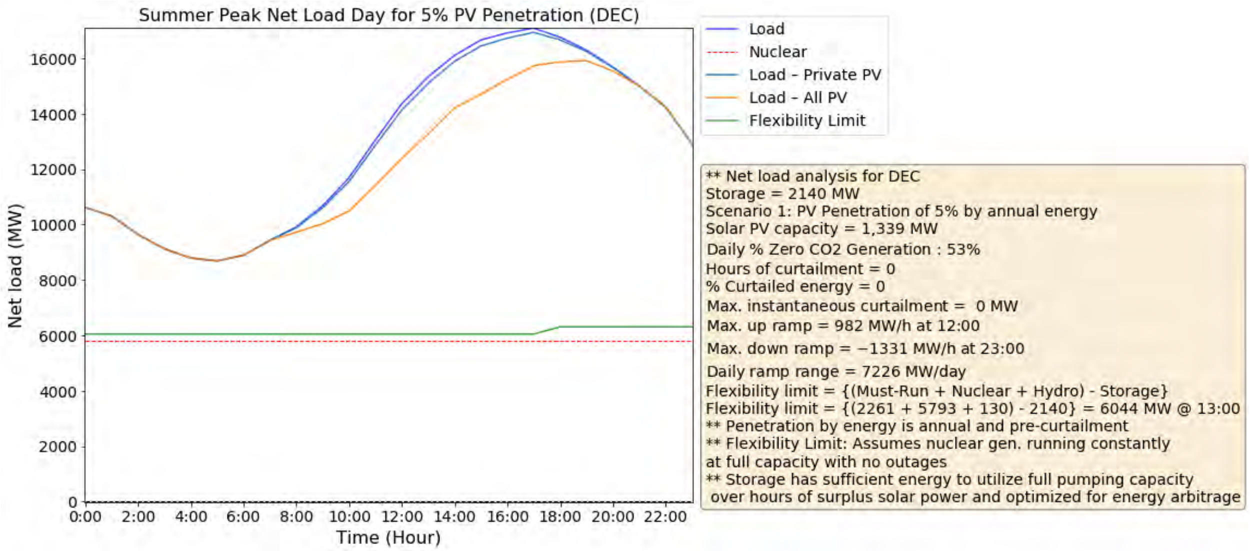
Seasonal Peak Net Load Days: 5% PV Penetration



** Net load analysis for DEC
Storage = 2140 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 67%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 994 MW/h at 06:00
Max. down ramp = −1355 MW/h at 23:00
Daily ramp range = 6642 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1018 + 5793 + 180) - 2140} = 4851 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

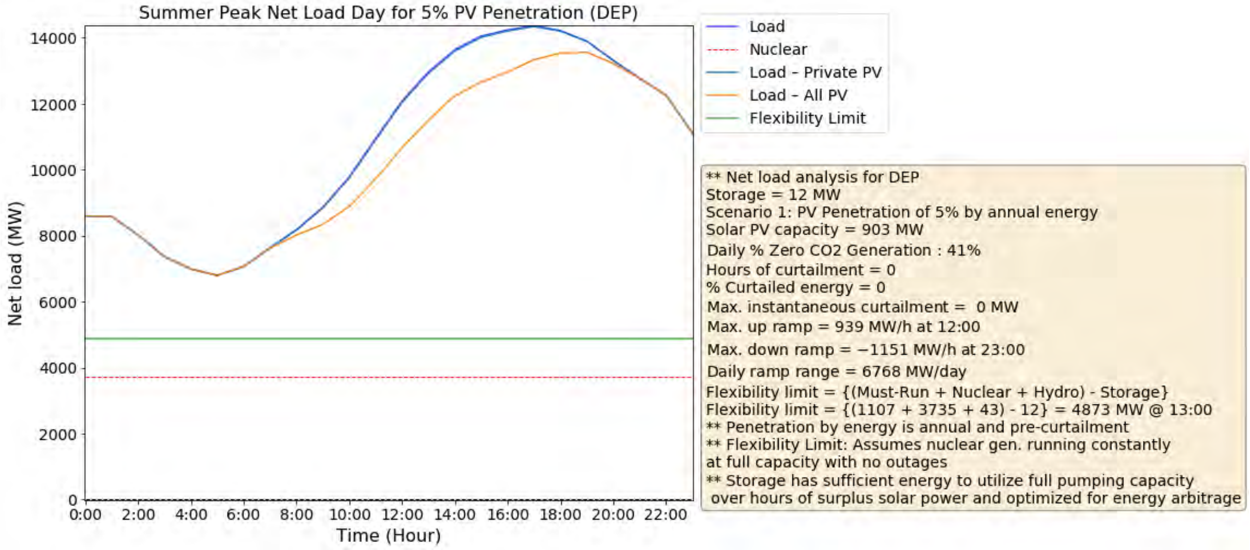


** Net load analysis for DEP
Storage = 12 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 41%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1502 MW/h at 07:00
Max. down ramp = −703 MW/h at 09:00
Daily ramp range = 3552 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 120) - 12} = 4950 MW @ 15:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



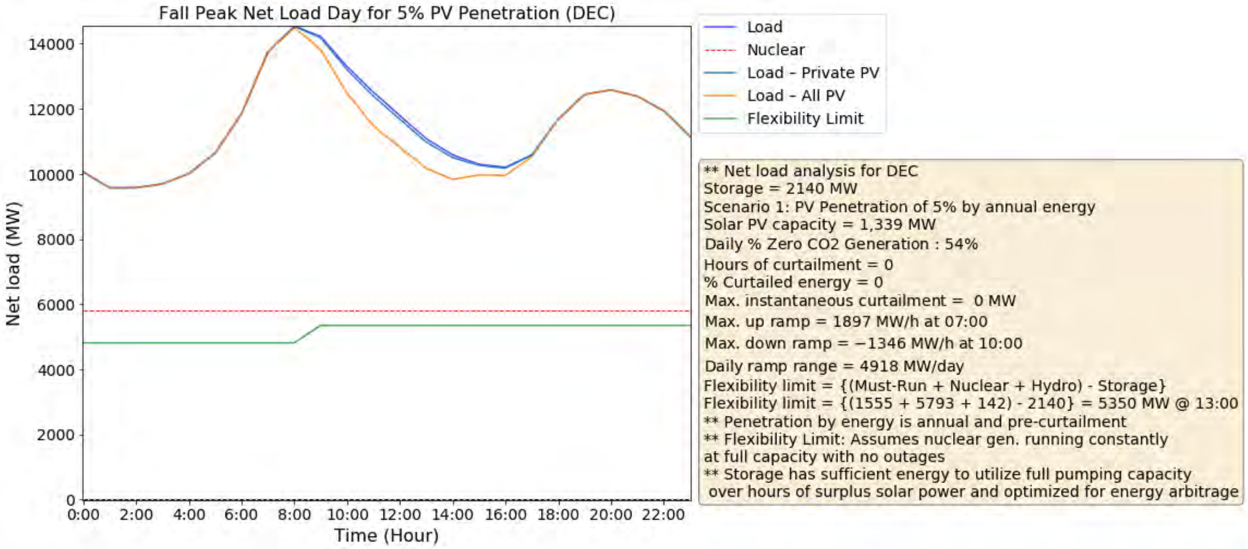
Summer Peak Net Load Day for 5% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 53%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 982 MW/h at 12:00
Max. down ramp = −1331 MW/h at 23:00
Daily ramp range = 7226 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 130) - 2140} = 6044 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

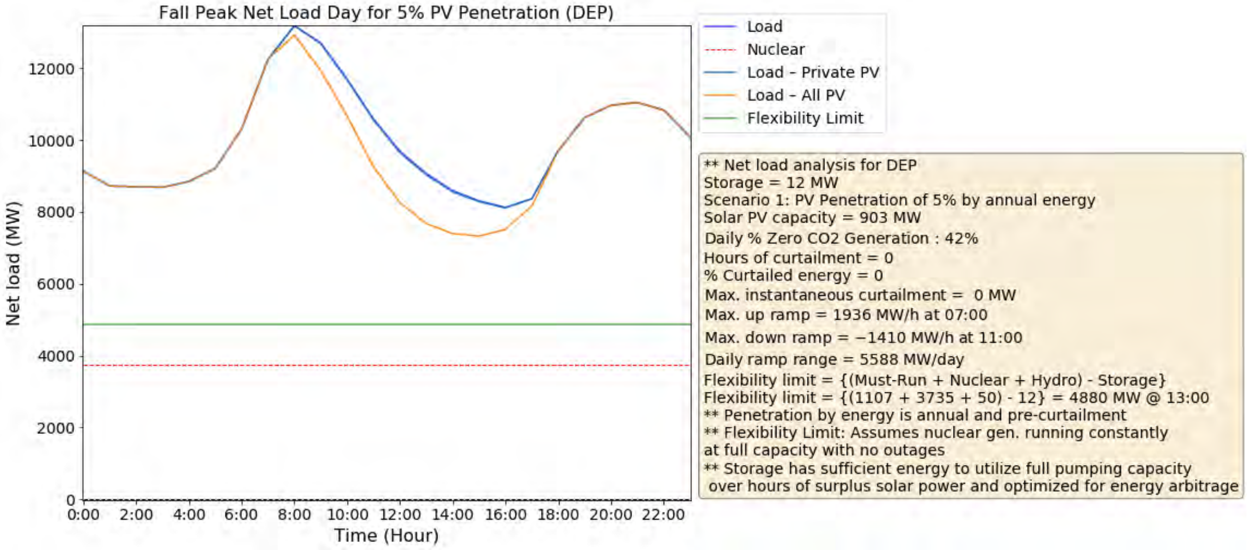


Summer Peak Net Load Day for 5% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 41%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 939 MW/h at 12:00
Max. down ramp = −1151 MW/h at 23:00
Daily ramp range = 6768 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 43) - 12} = 4873 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEC
Storage = 2140 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 54%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1897 MW/h at 07:00
Max. down ramp = −1346 MW/h at 10:00
Daily ramp range = 4918 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1555 + 5793 + 142) - 2140} = 5350 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP
Storage = 12 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 42%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1936 MW/h at 07:00
Max. down ramp = −1410 MW/h at 11:00
Daily ramp range = 5588 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 50) - 12} = 4880 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

Jennings Exhibit No. 16
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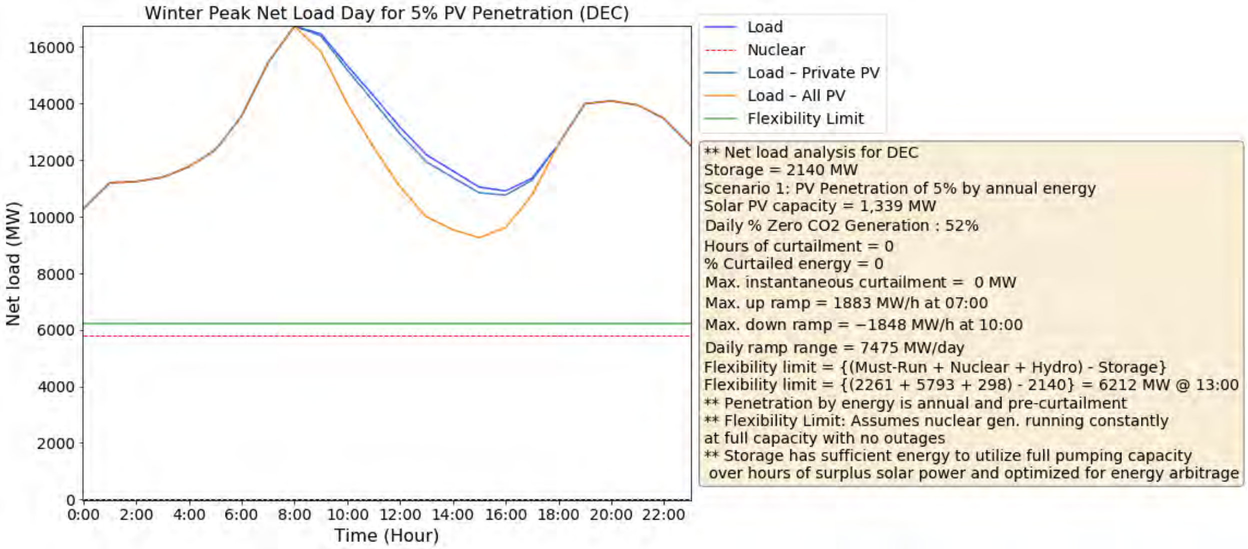
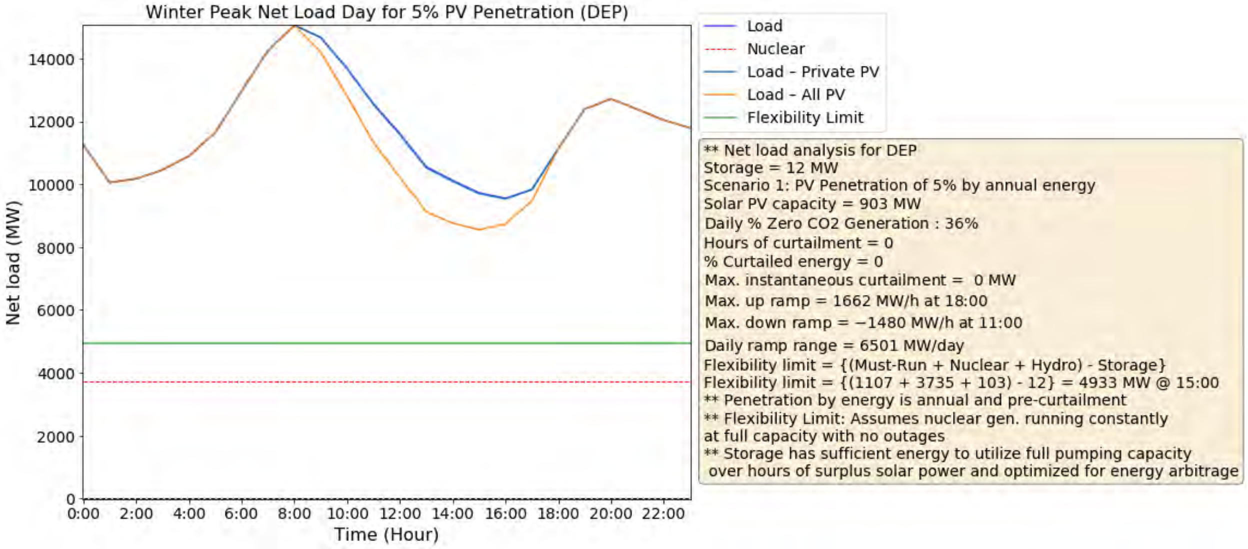
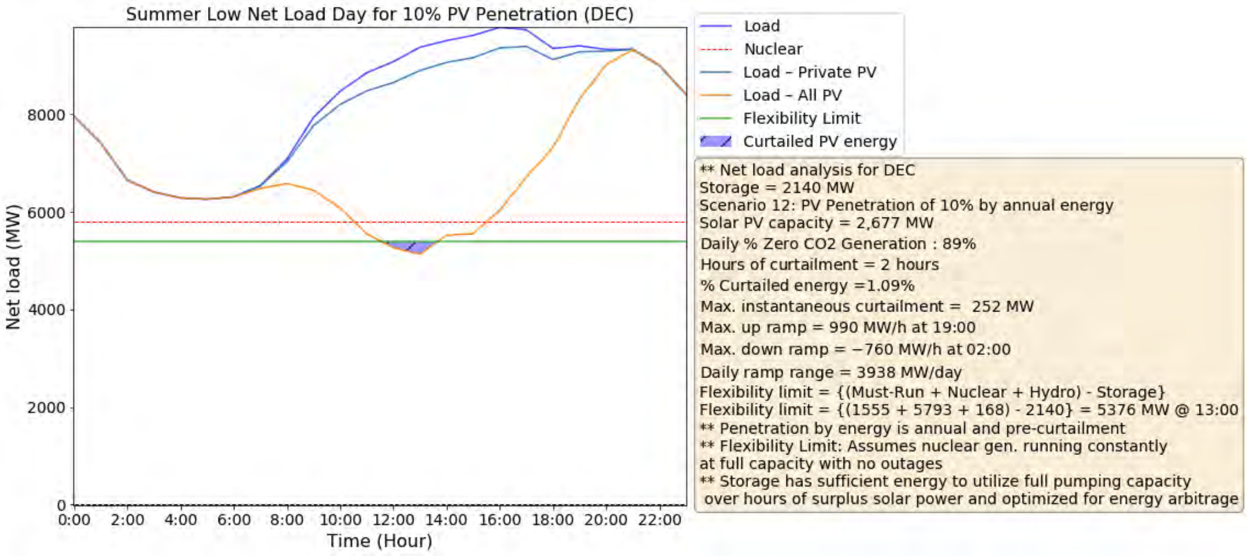


** Net load analysis for DEC
Storage = 2140 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 1,339 MW
Daily % Zero CO2 Generation : 52%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1883 MW/h at 07:00
Max. down ramp = −1848 MW/h at 10:00
Daily ramp range = 7475 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 298) - 2140} = 6212 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

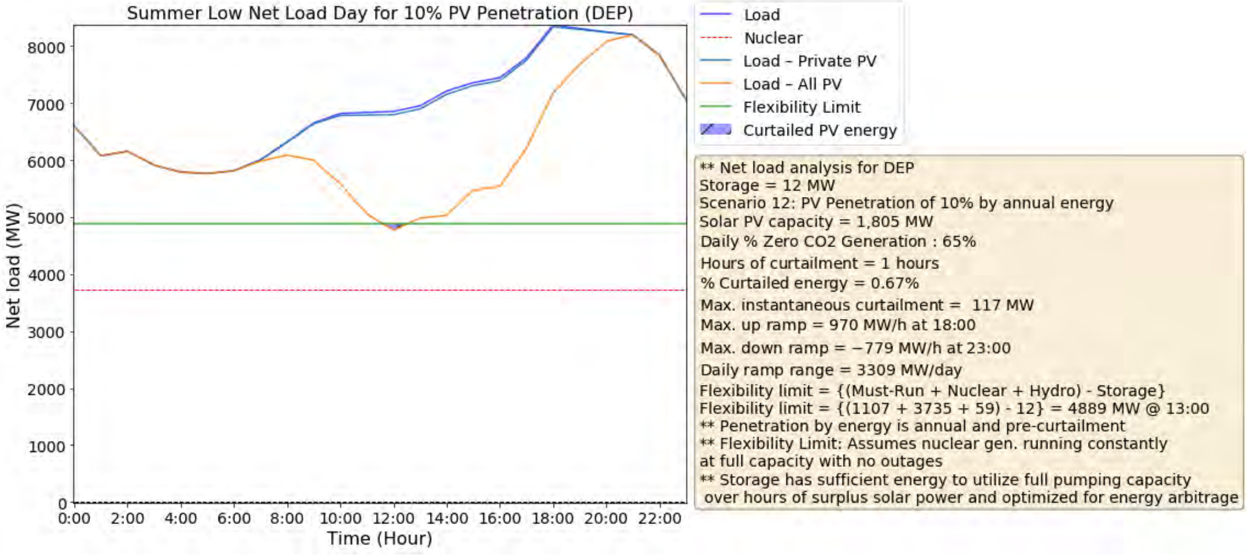


** Net load analysis for DEP
Storage = 12 MW
Scenario 1: PV Penetration of 5% by annual energy
Solar PV capacity = 903 MW
Daily % Zero CO2 Generation : 36%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1662 MW/h at 18:00
Max. down ramp = −1480 MW/h at 11:00
Daily ramp range = 6501 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 103) - 12} = 4933 MW @ 15:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

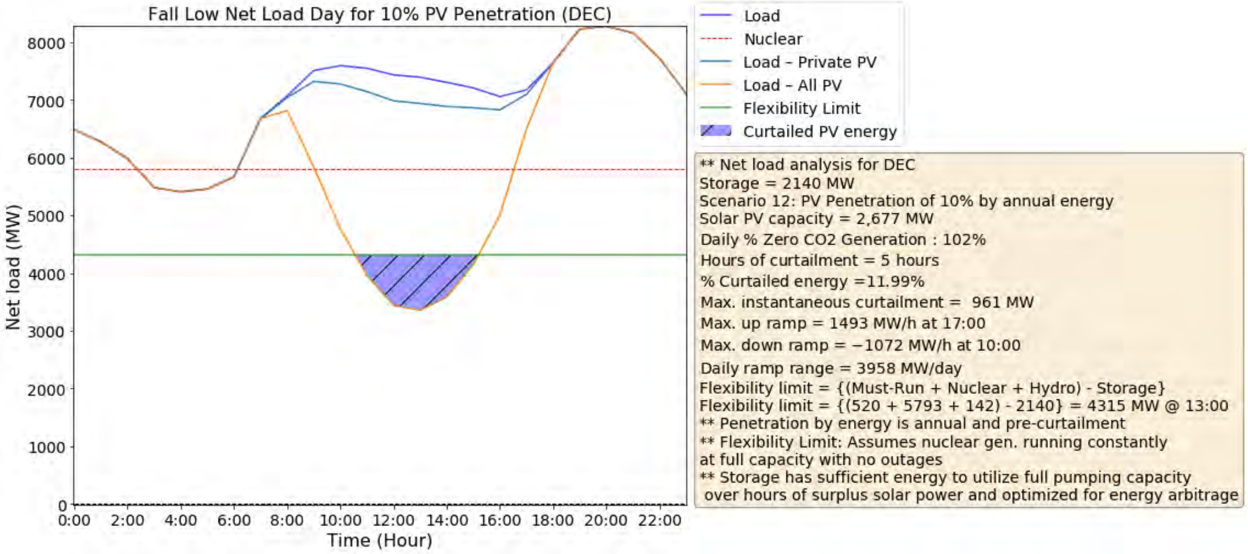
Seasonal Low Net Load Days: 10% PV Penetration



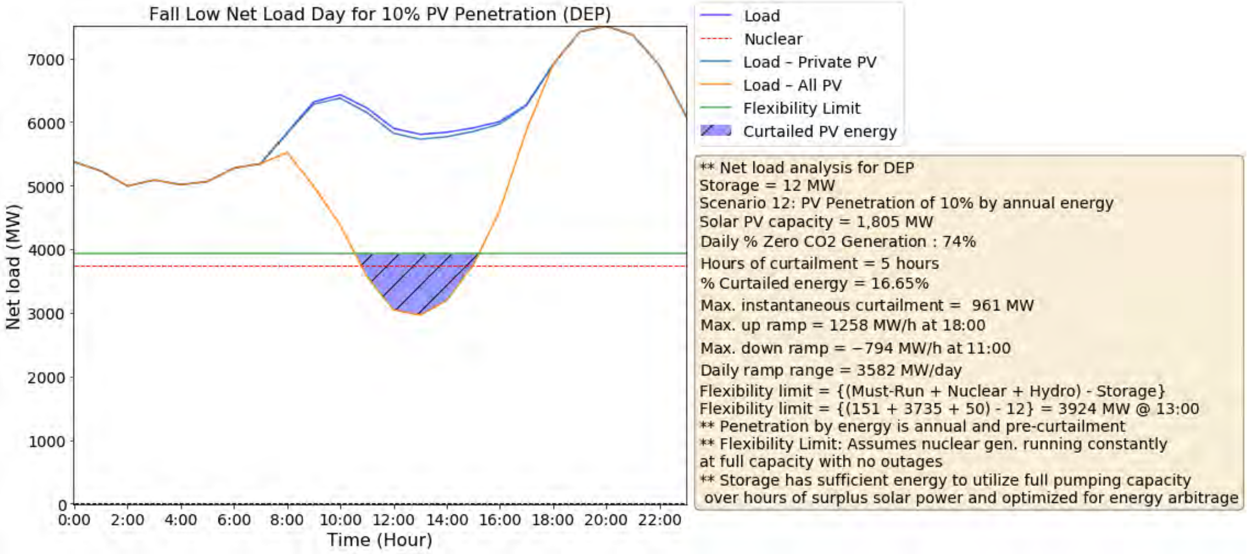
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 89%
Hours of curtailment = 2 hours
% Curtailed energy =1.09%
Max. instantaneous curtailment = 252 MW
Max. up ramp = 990 MW/h at 19:00
Max. down ramp = −760 MW/h at 02:00
Daily ramp range = 3938 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1555 + 5793 + 168) - 2140} = 5376 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



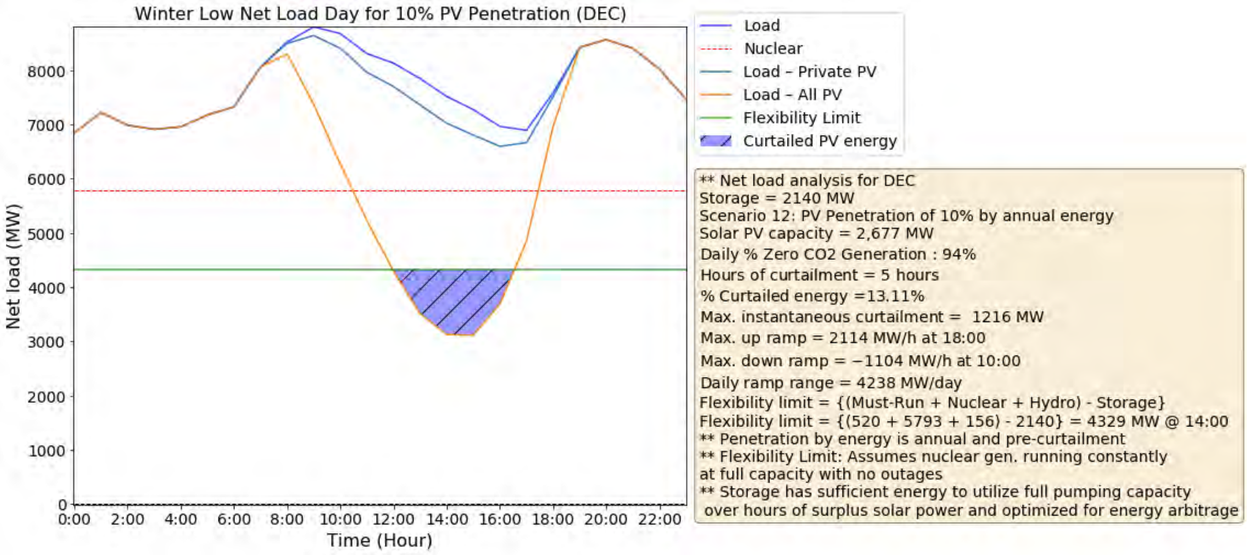
** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 65%
Hours of curtailment = 1 hours
% Curtailed energy = 0.67%
Max. instantaneous curtailment = 117 MW
Max. up ramp = 970 MW/h at 18:00
Max. down ramp = −779 MW/h at 23:00
Daily ramp range = 3309 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 59) - 12} = 4889 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Fall Low Net Load Day for 10% PV Penetration (DEC)

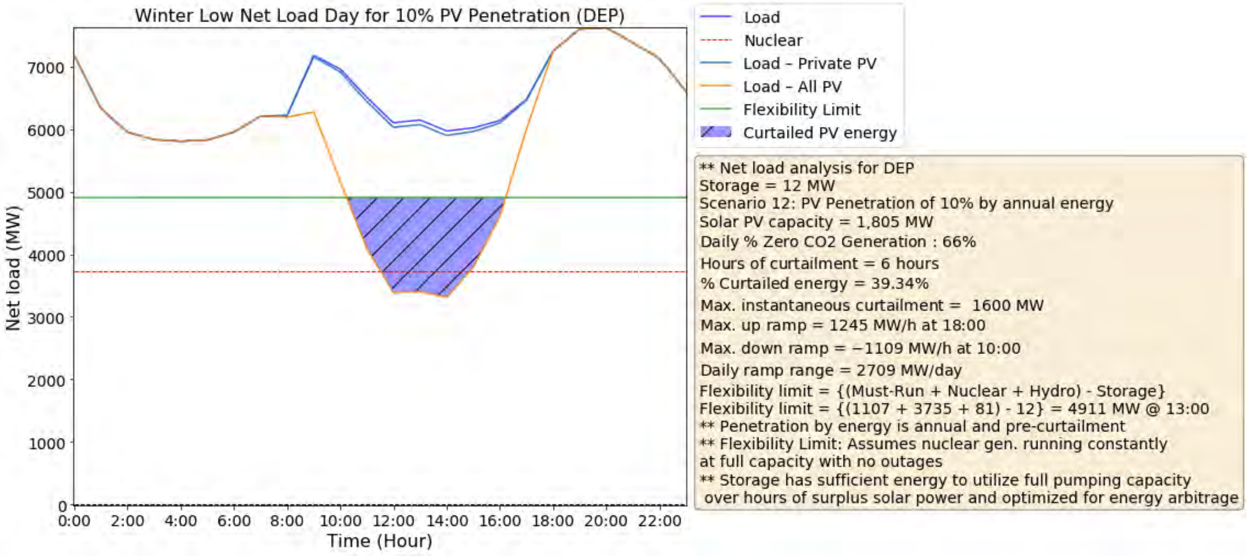
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 102%
Hours of curtailment = 5 hours
% Curtailed energy =11.99%
Max. instantaneous curtailment = 961 MW
Max. up ramp = 1493 MW/h at 17:00
Max. down ramp = −1072 MW/h at 10:00
Daily ramp range = 3958 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 142) - 2140} = 4315 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Fall Low Net Load Day for 10% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 74%
Hours of curtailment = 5 hours
% Curtailed energy = 16.65%
Max. instantaneous curtailment = 961 MW
Max. up ramp = 1258 MW/h at 18:00
Max. down ramp = −794 MW/h at 11:00
Daily ramp range = 3582 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 50) - 12} = 3924 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

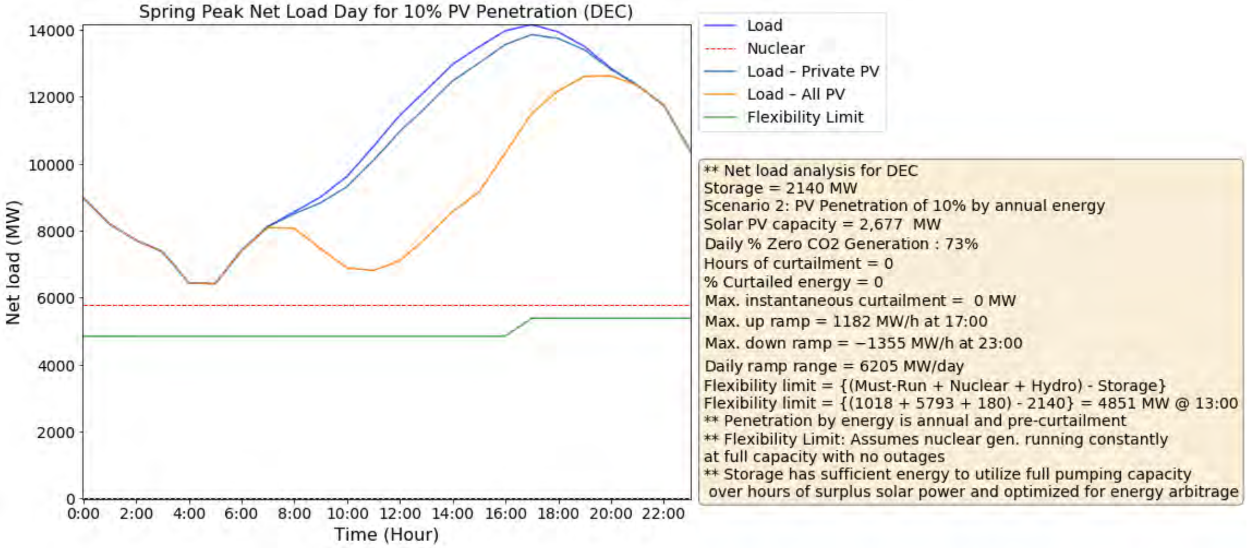

Winter Low Net Load Day for 10% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 94%
Hours of curtailment = 5 hours
% Curtailed energy =13.11%
Max. instantaneous curtailment = 1216 MW
Max. up ramp = 2114 MW/h at 18:00
Max. down ramp = −1104 MW/h at 10:00
Daily ramp range = 4238 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 156) - 2140} = 4329 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

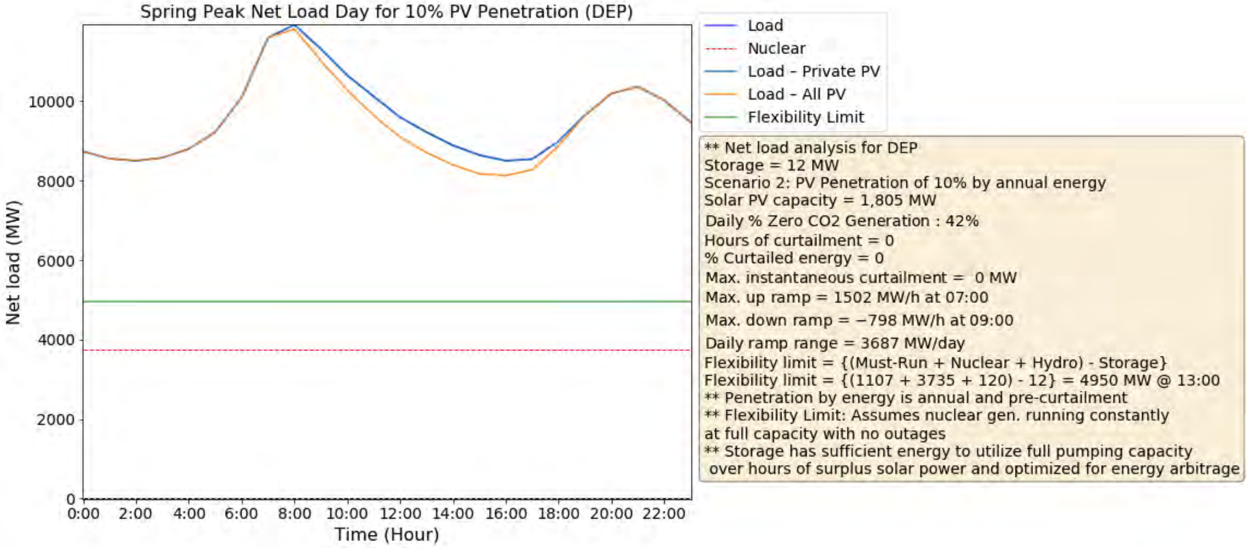


** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 66%
Hours of curtailment = 6 hours
% Curtailed energy = 39.34%
Max. instantaneous curtailment = 1600 MW
Max. up ramp = 1245 MW/h at 18:00
Max. down ramp = −1109 MW/h at 10:00
Daily ramp range = 2709 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 81) - 12} = 4911 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity over hours of surplus solar power and optimized for energy arbitrage

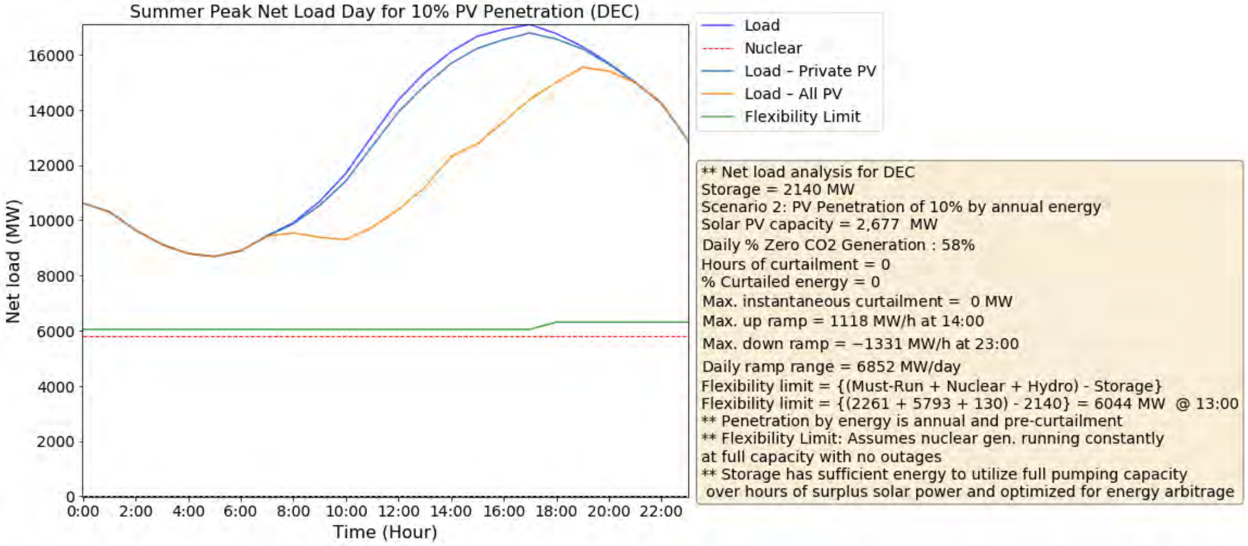
Seasonal Peak Net Load Days: 10% PV Penetration



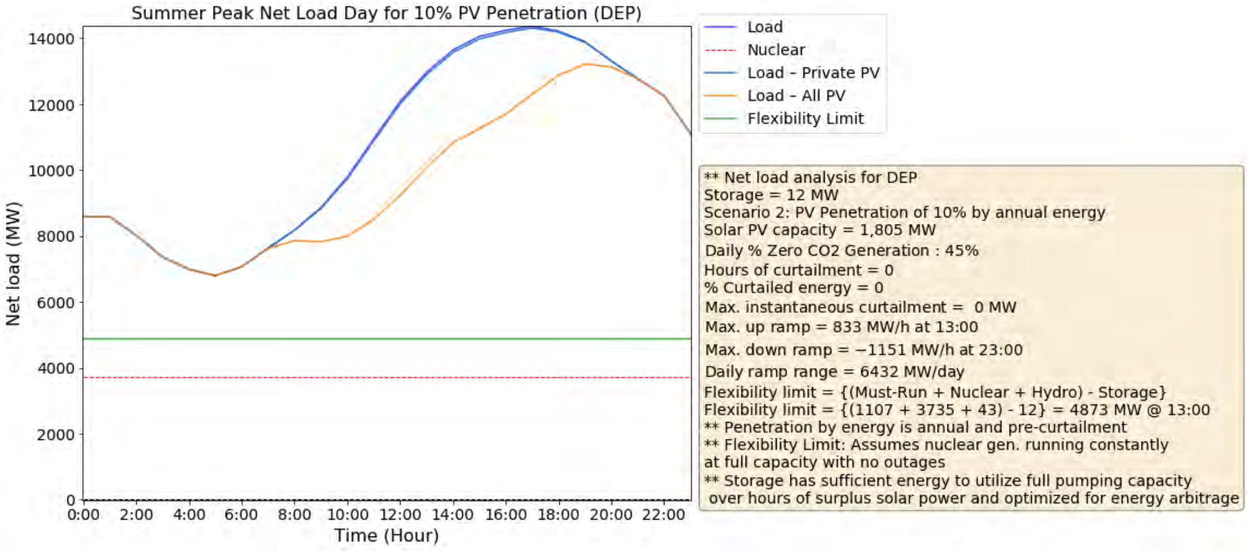
** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 73%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1182 MW/h at 17:00
Max. down ramp = −1355 MW/h at 23:00
Daily ramp range = 6205 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1018 + 5793 + 180) - 2140} = 4851 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 42%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1502 MW/h at 07:00
Max. down ramp = −798 MW/h at 09:00
Daily ramp range = 3687 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 120) - 12} = 4950 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

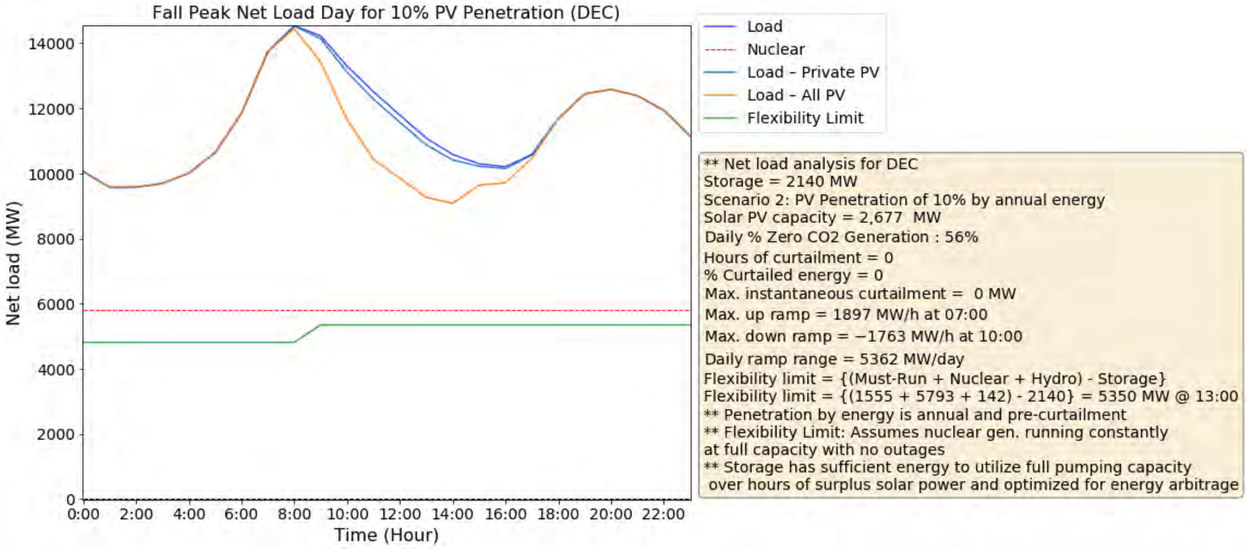


** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 58%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1118 MW/h at 14:00
Max. down ramp = −1331 MW/h at 23:00
Daily ramp range = 6852 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 130) - 2140} = 6044 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



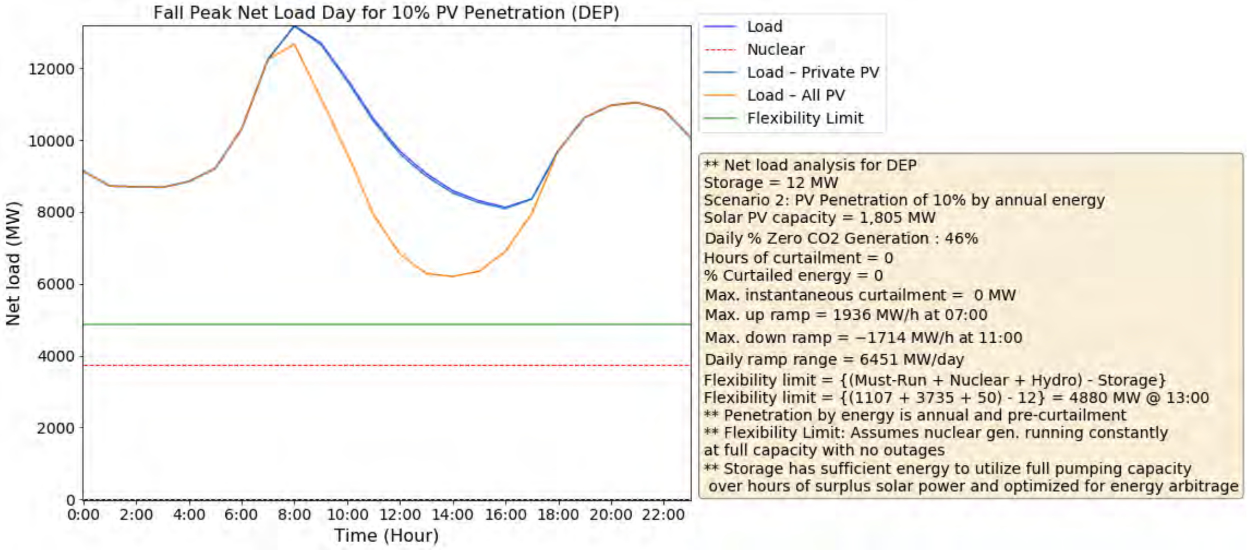
Summer Peak Net Load Day for 10% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 45%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 833 MW/h at 13:00
Max. down ramp = −1151 MW/h at 23:00
Daily ramp range = 6432 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 43) - 12} = 4873 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



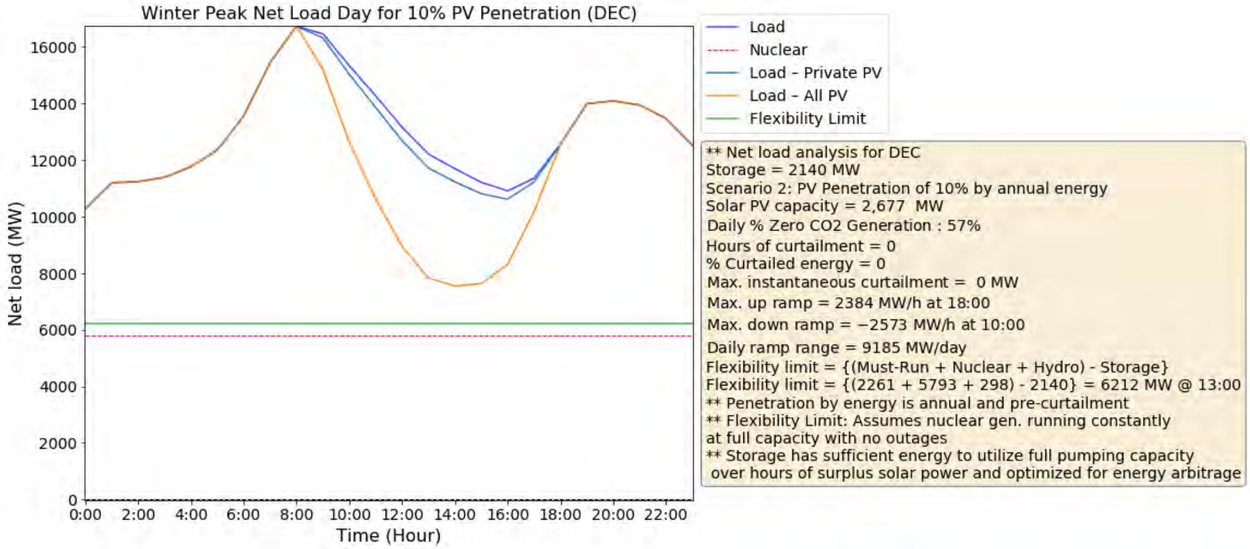
Fall Peak Net Load Day for 10% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 56%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1897 MW/h at 07:00
Max. down ramp = −1763 MW/h at 10:00
Daily ramp range = 5362 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1555 + 5793 + 142) - 2140} = 5350 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

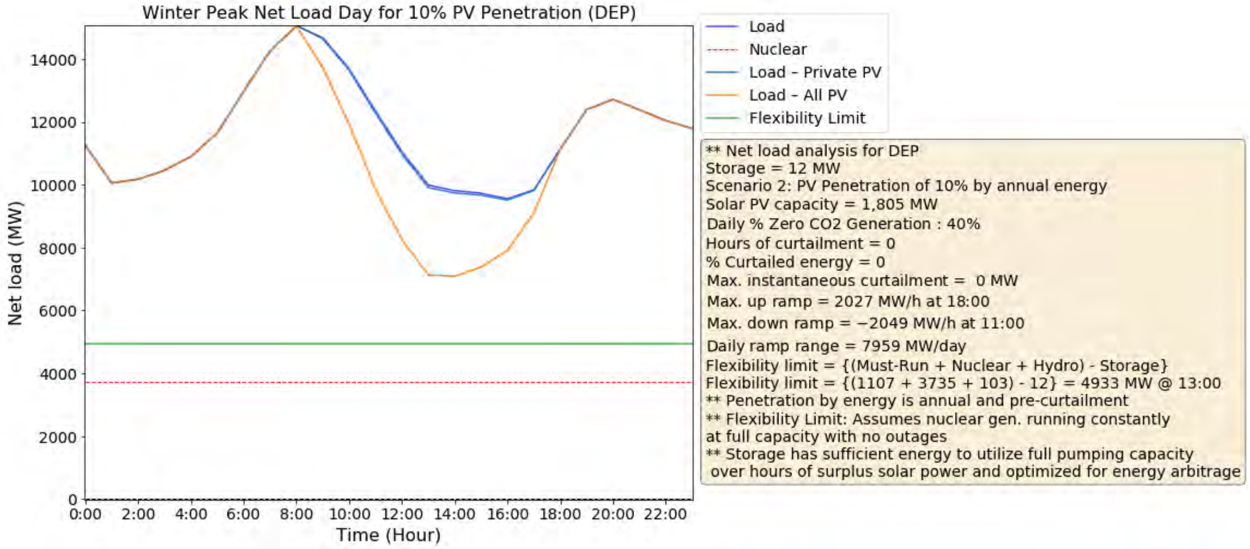


Fall Peak Net Load Day for 10% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 46%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1936 MW/h at 07:00
Max. down ramp = −1714 MW/h at 11:00
Daily ramp range = 6451 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 50) - 12} = 4880 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

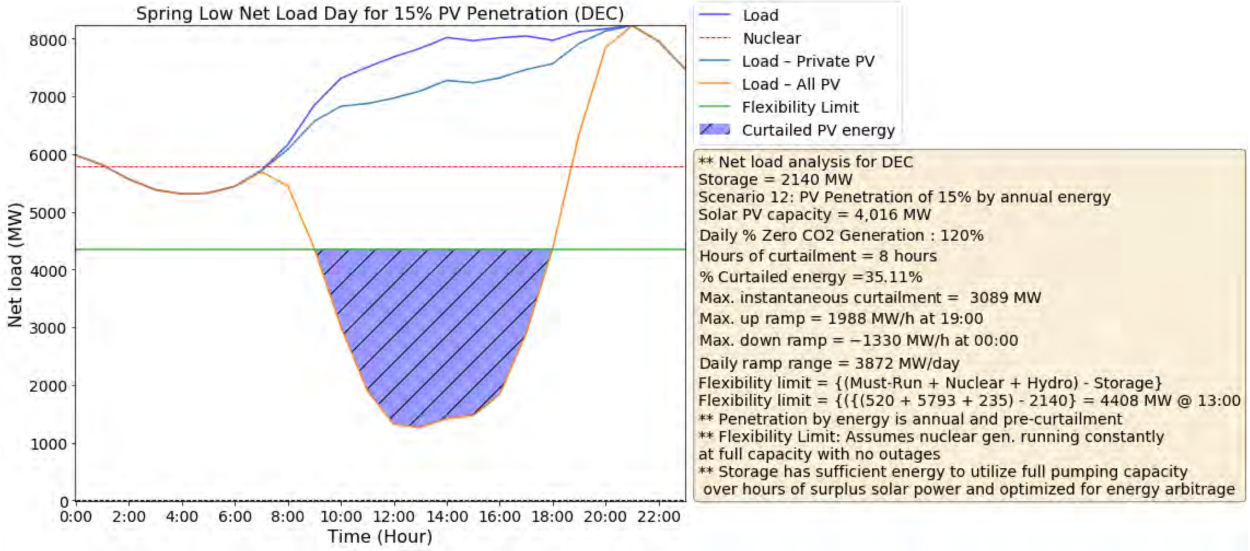


** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 2,677 MW
Daily % Zero CO2 Generation : 57%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2384 MW/h at 18:00
Max. down ramp = −2573 MW/h at 10:00
Daily ramp range = 9185 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 298) - 2140} = 6212 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

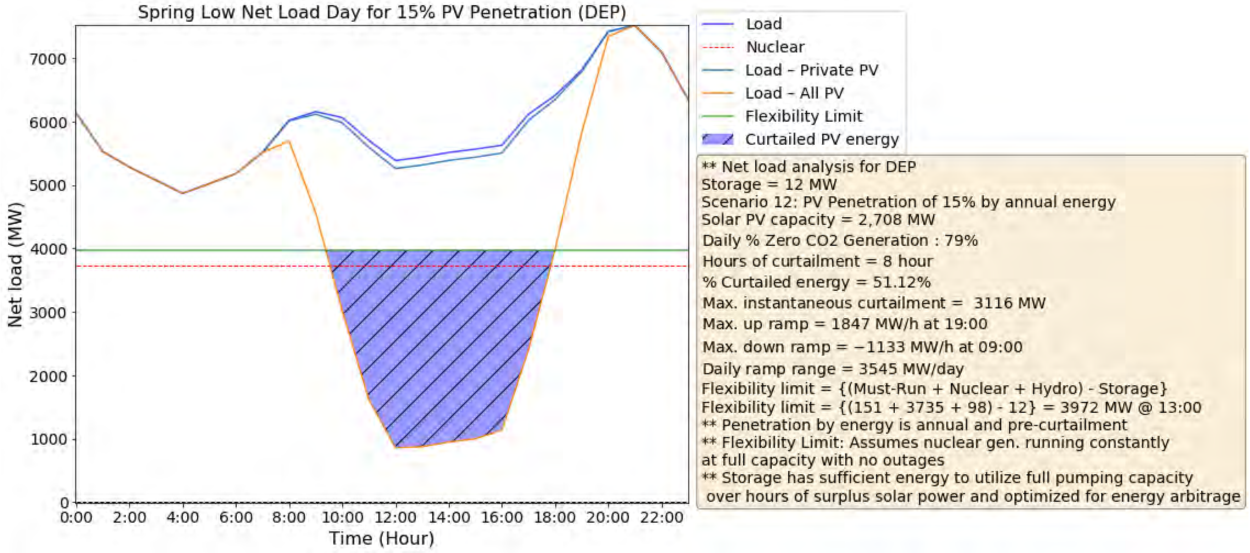


** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 10% by annual energy
Solar PV capacity = 1,805 MW
Daily % Zero CO2 Generation : 40%
Hours of curtailment = 0
% Curtailed energy = 0
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2027 MW/h at 18:00
Max. down ramp = −2049 MW/h at 11:00
Daily ramp range = 7959 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 103) - 12} = 4933 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

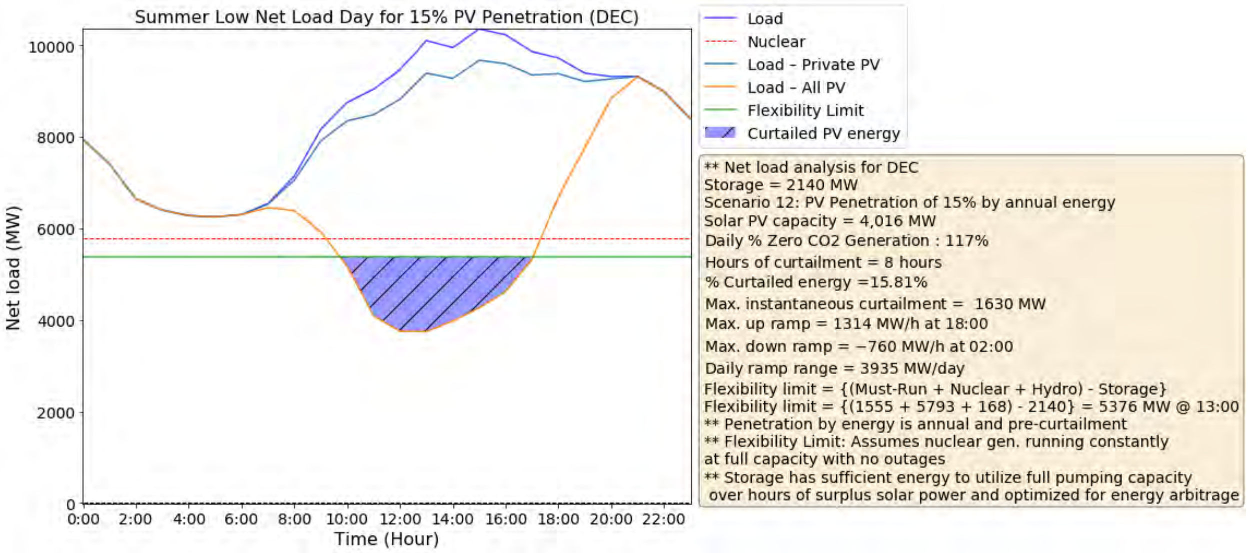
Seasonal Low Net Load Days: 15% PV Penetration



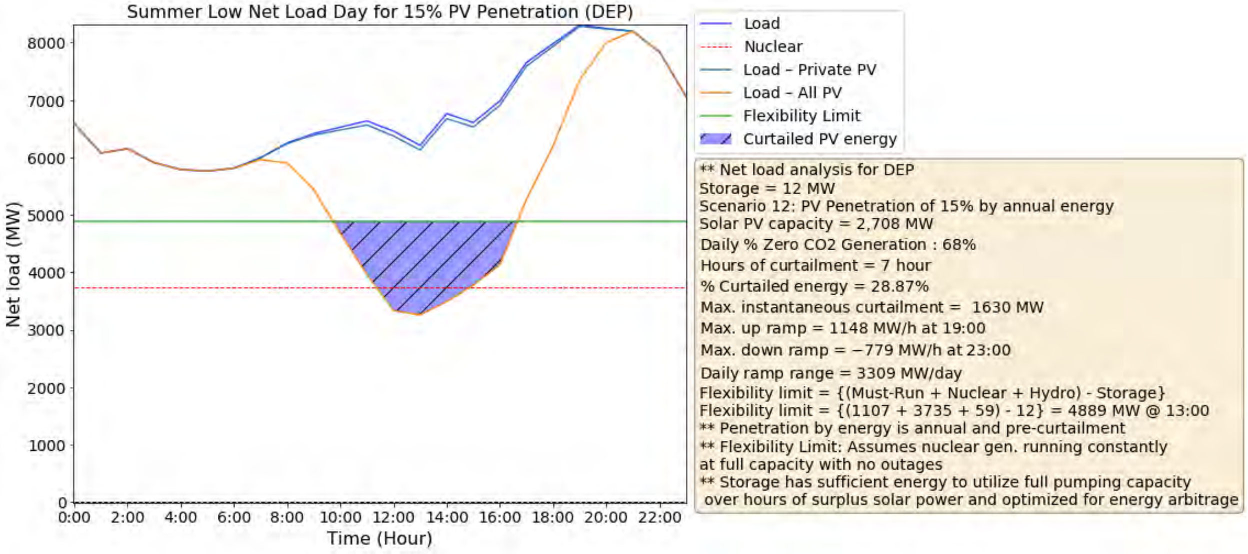
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 120%
Hours of curtailment = 8 hours
% Curtailed energy =35.11%
Max. instantaneous curtailment = 3089 MW
Max. up ramp = 1988 MW/h at 19:00
Max. down ramp = −1330 MW/h at 00:00
Daily ramp range = 3872 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {({(520 + 5793 + 235) - 2140} = 4408 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



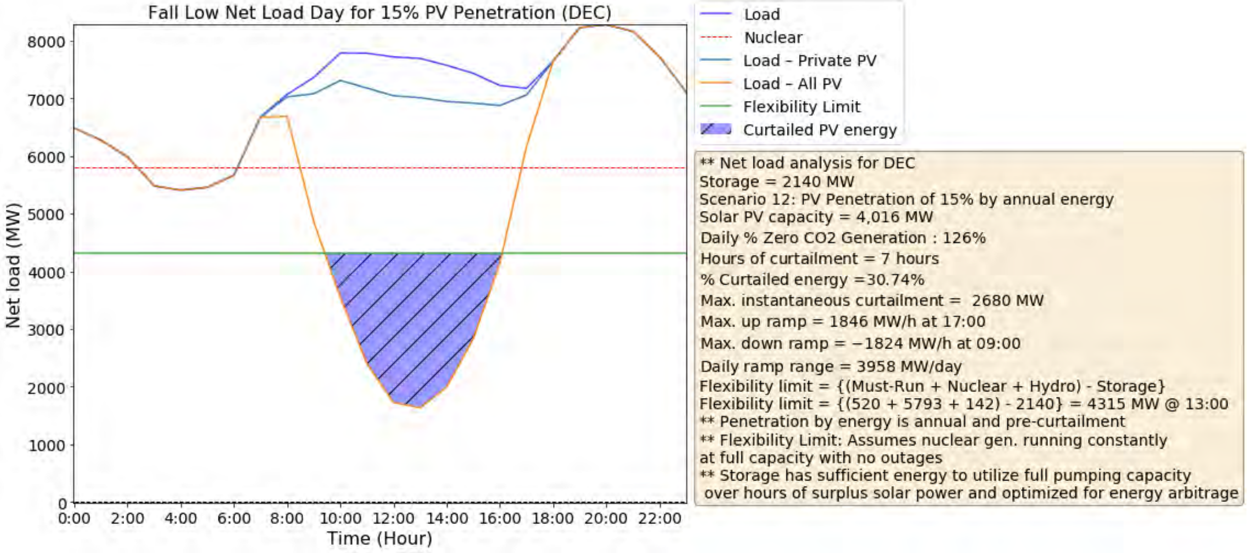
** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 79%
Hours of curtailment = 8 hour
% Curtailed energy = 51.12%
Max. instantaneous curtailment = 3116 MW
Max. up ramp = 1847 MW/h at 19:00
Max. down ramp = −1133 MW/h at 09:00
Daily ramp range = 3545 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 98) - 12} = 3972 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



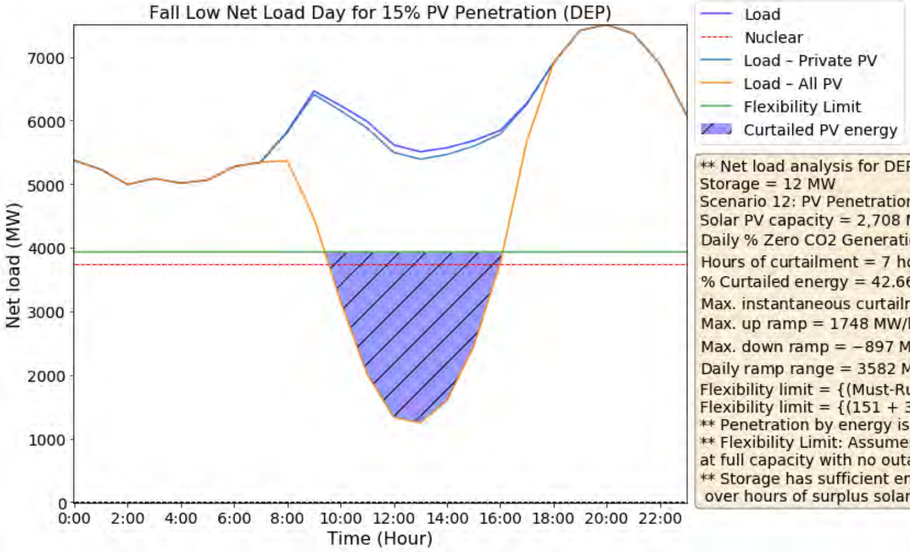
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 117%
Hours of curtailment = 8 hours
% Curtailed energy =15.81%
Max. instantaneous curtailment = 1630 MW
Max. up ramp = 1314 MW/h at 18:00
Max. down ramp = −760 MW/h at 02:00
Daily ramp range = 3935 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1555 + 5793 + 168) - 2140} = 5376 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



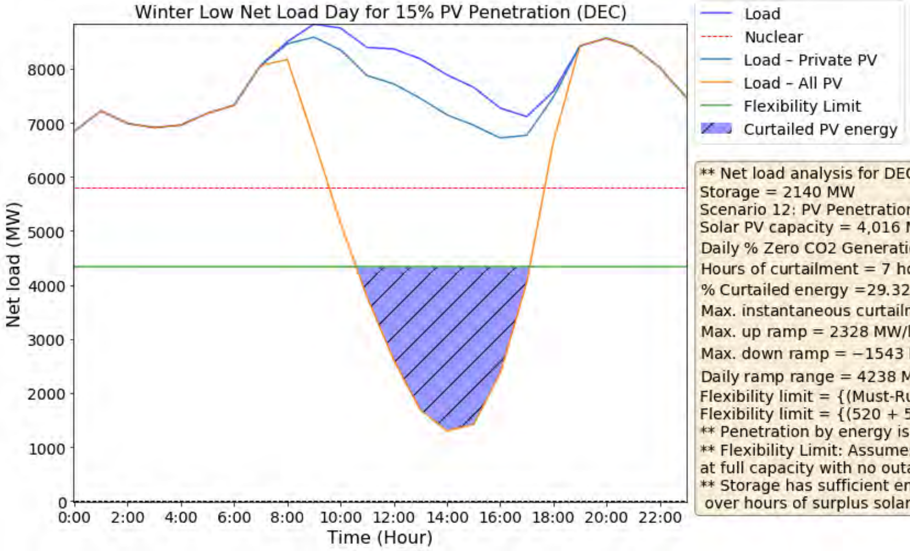
** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 68%
Hours of curtailment = 7 hour
% Curtailed energy = 28.87%
Max. instantaneous curtailment = 1630 MW
Max. up ramp = 1148 MW/h at 19:00
Max. down ramp = −779 MW/h at 23:00
Daily ramp range = 3309 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 59) - 12} = 4889 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



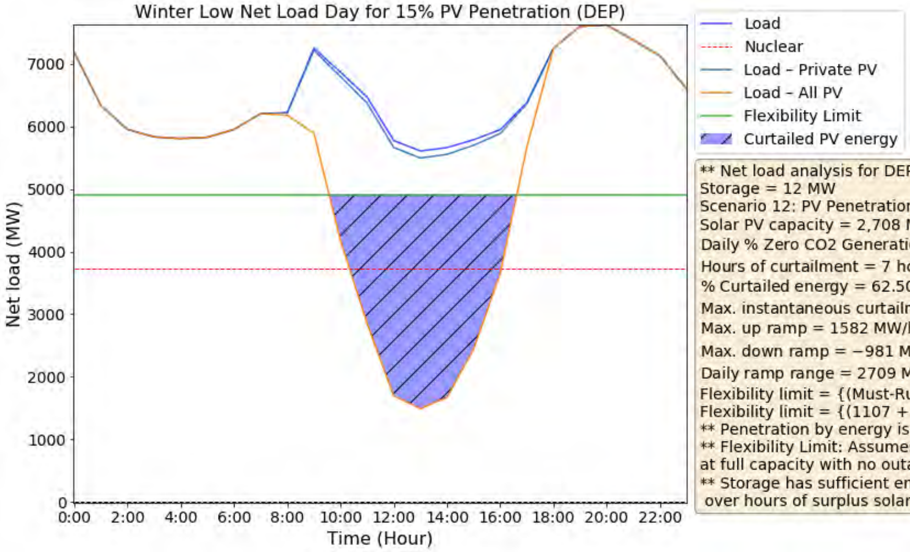
** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 126%
Hours of curtailment = 7 hours
% Curtailed energy =30.74%
Max. instantaneous curtailment = 2680 MW
Max. up ramp = 1846 MW/h at 17:00
Max. down ramp = −1824 MW/h at 09:00
Daily ramp range = 3958 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 142) - 2140} = 4315 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 76%
Hours of curtailment = 7 hour
% Curtailed energy = 42.66%
Max. instantaneous curtailment = 2680 MW
Max. up ramp = 1748 MW/h at 17:00
Max. down ramp = −897 MW/h at 09:00
Daily ramp range = 3582 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(151 + 3735 + 50) - 12} = 3924 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

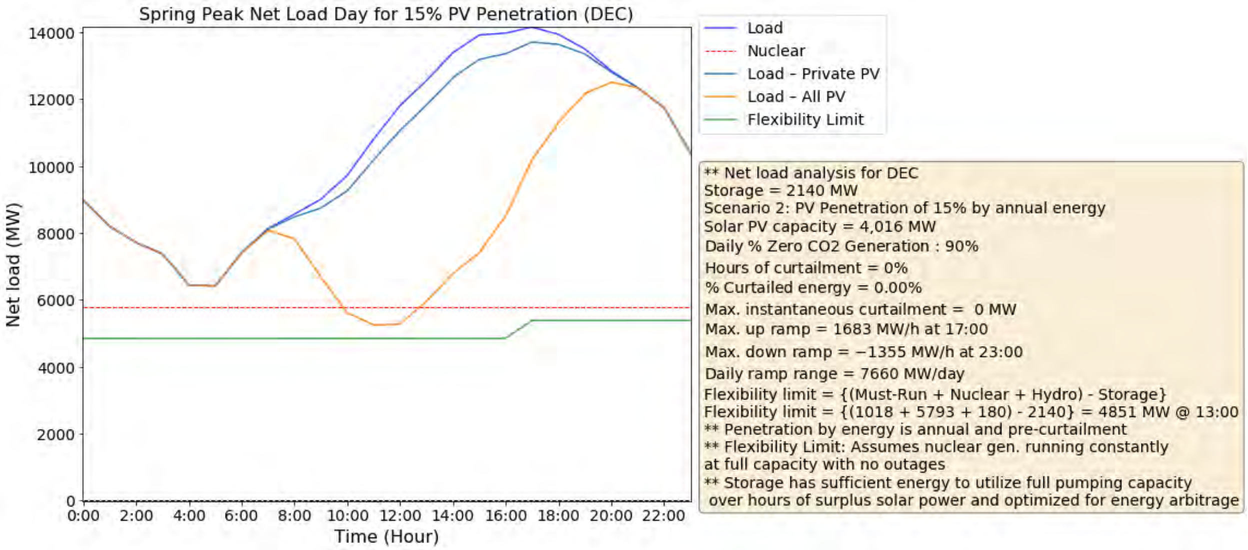


** Net load analysis for DEC
Storage = 2140 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 104%
Hours of curtailment = 7 hours
% Curtailed energy =29.32%
Max. instantaneous curtailment = 3027 MW
Max. up ramp = 2328 MW/h at 18:00
Max. down ramp = −1543 MW/h at 10:00
Daily ramp range = 4238 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(520 + 5793 + 156) - 2140} = 4329 MW @ 14:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

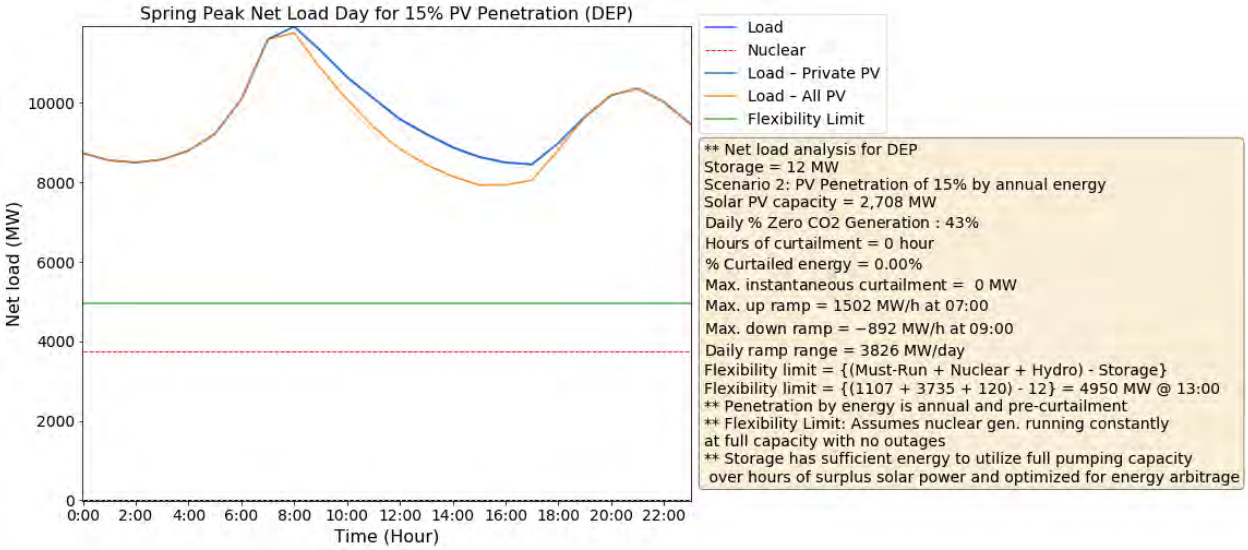


** Net load analysis for DEP
Storage = 12 MW
Scenario 12: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 66%
Hours of curtailment = 7 hour
% Curtailed energy = 62.50%
Max. instantaneous curtailment = 3418 MW
Max. up ramp = 1582 MW/h at 18:00
Max. down ramp = −981 MW/h at 10:00
Daily ramp range = 2709 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 81) - 12} = 4911 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

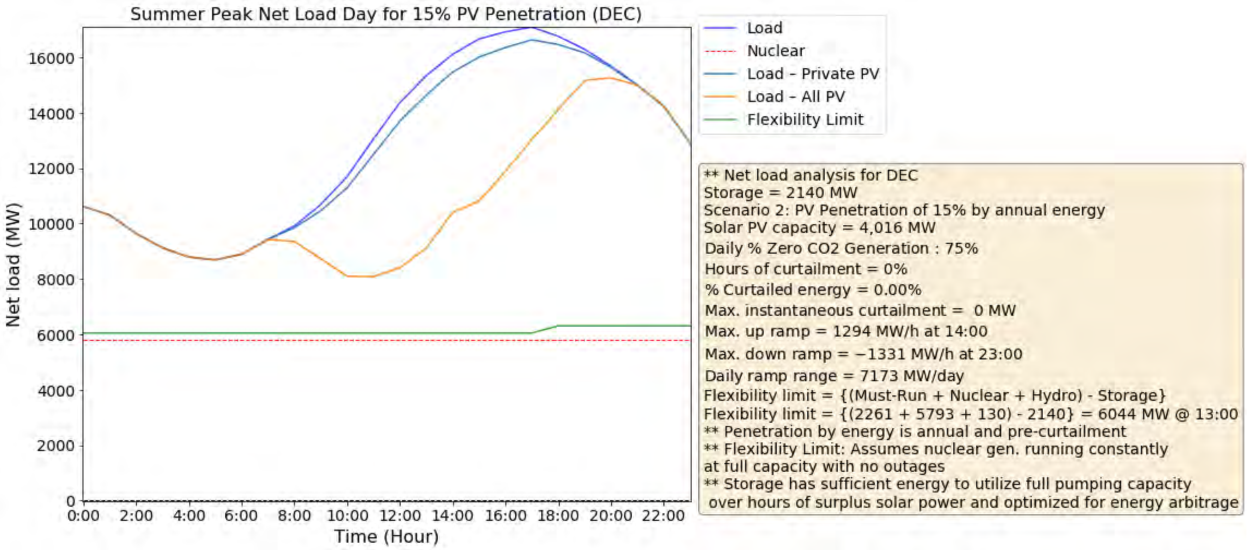
Seasonal Peak Net Load Days: 15% PV Penetration



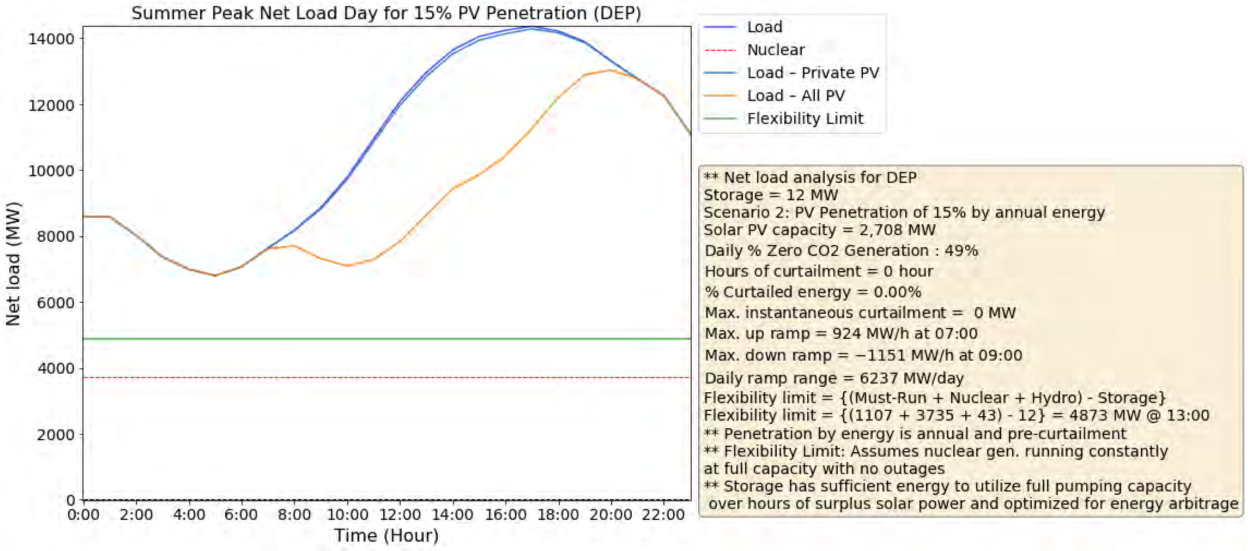
** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 90%
Hours of curtailment = 0%
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1683 MW/h at 17:00
Max. down ramp = −1355 MW/h at 23:00
Daily ramp range = 7660 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1018 + 5793 + 180) - 2140} = 4851 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 43%
Hours of curtailment = 0 hour
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1502 MW/h at 07:00
Max. down ramp = −892 MW/h at 09:00
Daily ramp range = 3826 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 120) - 12} = 4950 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

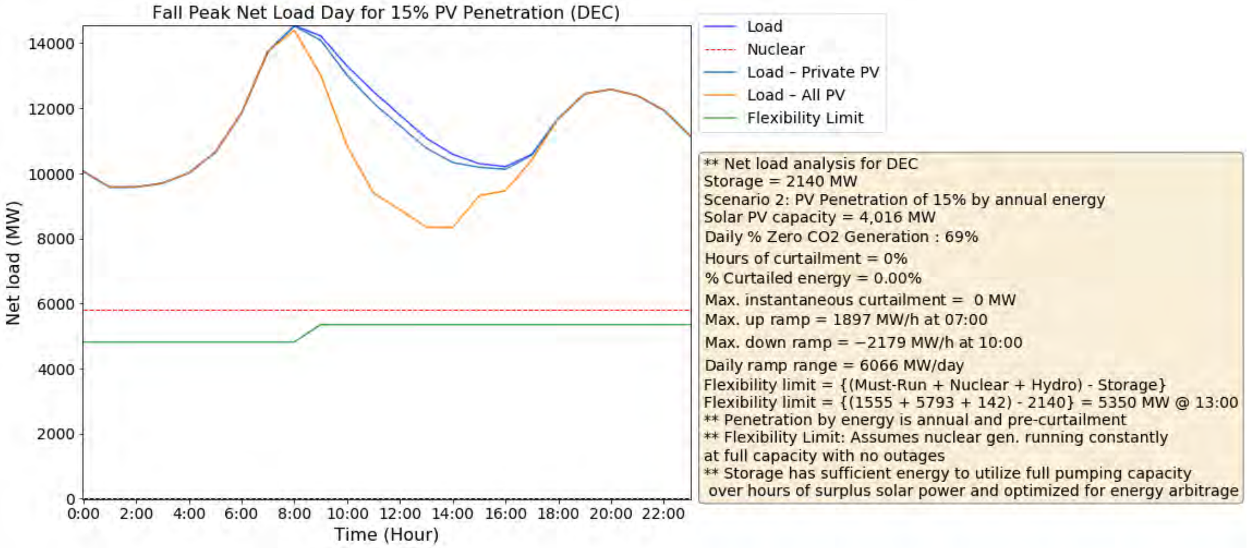


** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 75%
Hours of curtailment = 0%
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1294 MW/h at 14:00
Max. down ramp = −1331 MW/h at 23:00
Daily ramp range = 7173 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 130) - 2140} = 6044 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



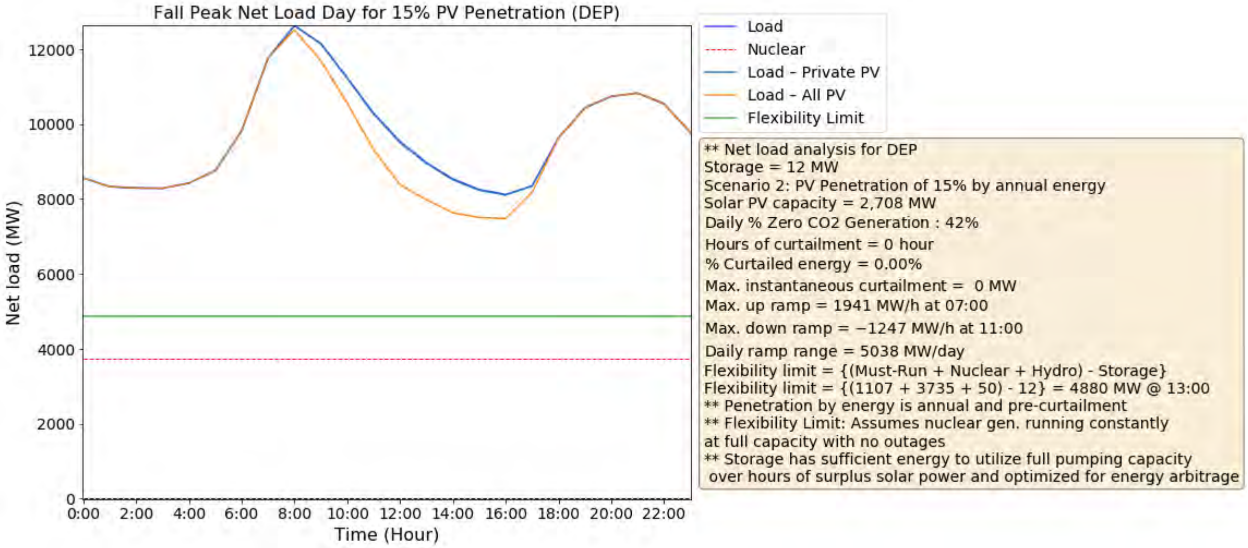
Summer Peak Net Load Day for 15% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 49%
Hours of curtailment = 0 hour
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 924 MW/h at 07:00
Max. down ramp = −1151 MW/h at 09:00
Daily ramp range = 6237 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 43) - 12} = 4873 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage



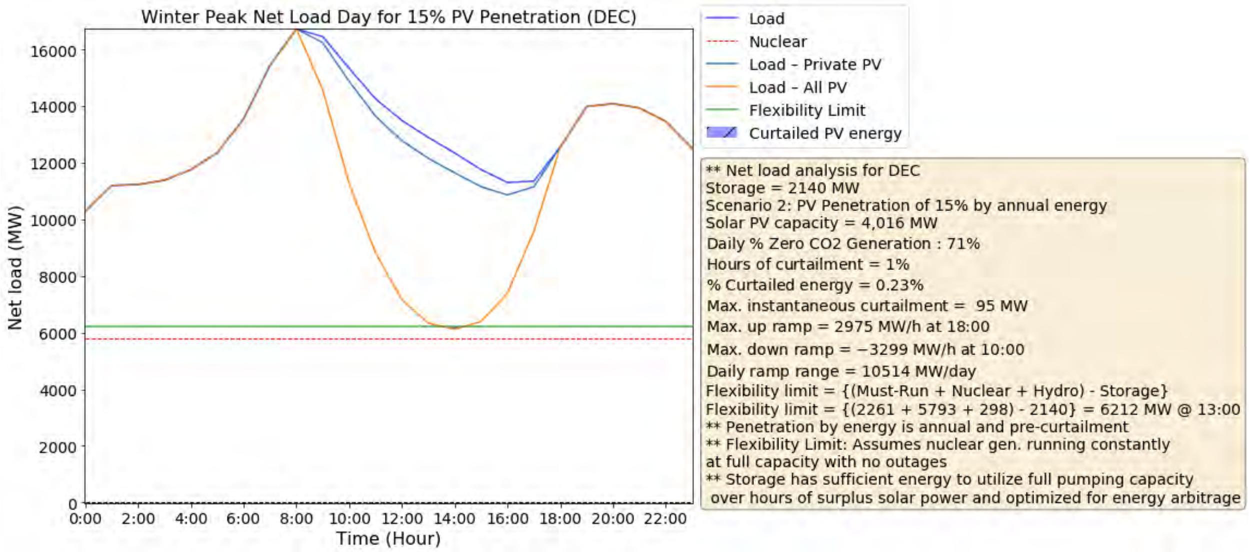
Fall Peak Net Load Day for 15% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 69%
Hours of curtailment = 0%
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1897 MW/h at 07:00
Max. down ramp = −2179 MW/h at 10:00
Daily ramp range = 6066 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1555 + 5793 + 142) - 2140} = 5350 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

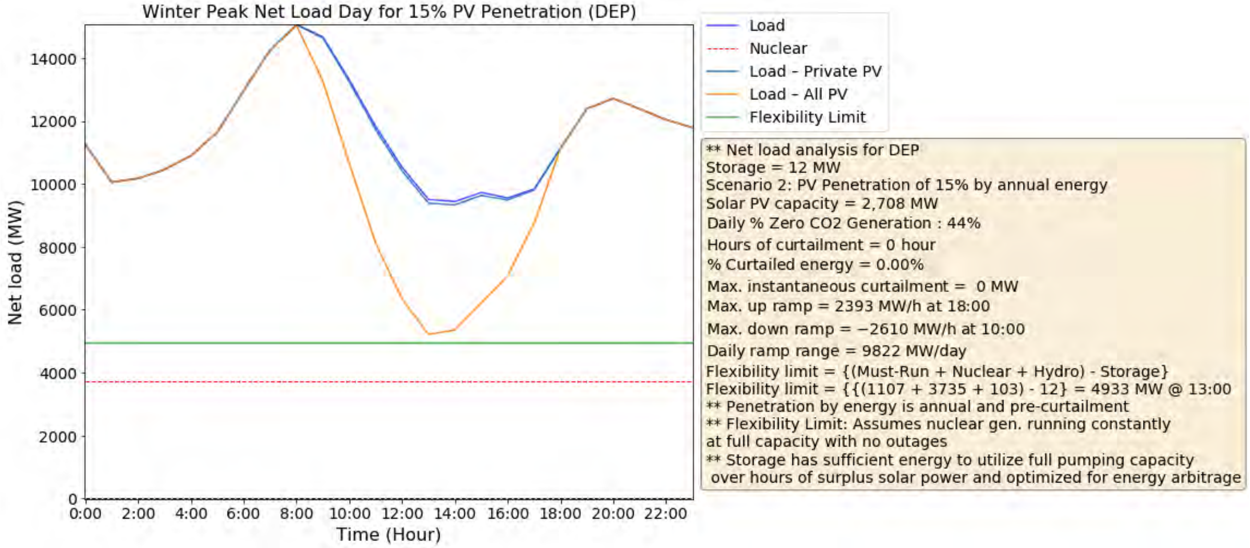


Fall Peak Net Load Day for 15% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 42%
Hours of curtailment = 0 hour
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 1941 MW/h at 07:00
Max. down ramp = −1247 MW/h at 11:00
Daily ramp range = 5038 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(1107 + 3735 + 50) - 12} = 4880 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Winter Peak Net Load Day for 15% PV Penetration (DEC)

** Net load analysis for DEC
Storage = 2140 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 4,016 MW
Daily % Zero CO2 Generation : 71%
Hours of curtailment = 1%
% Curtailed energy = 0.23%
Max. instantaneous curtailment = 95 MW
Max. up ramp = 2975 MW/h at 18:00
Max. down ramp = −3299 MW/h at 10:00
Daily ramp range = 10514 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {(2261 + 5793 + 298) - 2140} = 6212 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage


Winter Peak Net Load Day for 15% PV Penetration (DEP)

** Net load analysis for DEP
Storage = 12 MW
Scenario 2: PV Penetration of 15% by annual energy
Solar PV capacity = 2,708 MW
Daily % Zero CO2 Generation : 44%
Hours of curtailment = 0 hour
% Curtailed energy = 0.00%
Max. instantaneous curtailment = 0 MW
Max. up ramp = 2393 MW/h at 18:00
Max. down ramp = −2610 MW/h at 10:00
Daily ramp range = 9822 MW/day
Flexibility limit = {(Must-Run + Nuclear + Hydro) - Storage}
Flexibility limit = {{(1107 + 3735 + 103) - 12} = 4933 MW @ 13:00
** Penetration by energy is annual and pre-curtailment
** Flexibility Limit: Assumes nuclear gen. running constantly
at full capacity with no outages
** Storage has sufficient energy to utilize full pumping capacity
over hours of surplus solar power and optimized for energy arbitrage

A.5 Geospatial Analysis

Several maps were produced for the purpose of visualizing available solar and wind resource in North & South Carolina, and show the *typical* exclusions applied in our technical potential analysis. The technical potential shows a broad overview of technically developable resources. This type of analysis does not take into account economic or market factors.

The technical potential analysis uses time-series data to calculate potential system generation across multiple years or weather data. This type of analysis can be useful for narrowing down places for further exploration for development.

Capacity Factors

Capacity factors were produced for photovoltaic (PV) and wind generating systems using the System Advisor Model (SAM) (Freeman et al., 2018). Input resource time-series data for calculating capacity factors include the National Solar Radiation Database (NSRDB) (Sengupta et al., 2018) for PV systems, and the Wind Integration National Dataset (WIND) Toolkit (Draxl, Clifton, Hodge, & McCaa, 2015) for wind systems. The capacity factors produced reflect the multi-year mean capacity factors across all available resource years. For the NSRDB, this encompasses the years 1998-2017 inclusive, for the WIND Toolkit, this covers years 2007-2013 inclusive.

The system configurations used in this analysis are described below:

PV

Array Type	1-Axis Tracking
Azimuth	180 Degrees (South)
Tilt	0 Degrees
Module Type	Standard
Inverter Efficiency	96%
DC/AC Ratio	1.3
Losses	14.07%

Wind

	Land-Based	Offshore
Hub Height	80m	100m
Wind Shear Coefficient	0.143	0.143
Rotor Diameter	92m / 108m / 117m	155m
Wind Turbulence Coefficient	0.10	0.10
Losses	15%	15%
Availability	98%	98%

Rotor diameter and power curves for land-based turbines depends on multi-year mean wind speed using the logic below:

- ws* <= 5.5 m/s: 117m Rotor Diameter
- 5.5 m/s < ws <= 10 m/s: 108m Rotor Diameter
- ws > 10 m/s: 92m Rotor Diameter

*ws = wind speed (m/s)

Exclusions

In order to determine locations for further investigation of new PV or wind development, assumptions are made based on land categories and use-type to exclude locations from consideration. The exclusions used in this analysis may be adjusted and new data used in the future to account for more locally-sourced data or other assumptions that aren’t considered at this time.

PV

The land exclusions used for PV include the following:

Slope > 5%
Urban Areas
Water and Wetlands
Parks and Landmarks
National Parks and Other Environmentally or Culturally Sensitive Areas

Wind

The land exclusions used for wind analysis include the following:

Slope > 20%
Urban Areas
Water and Wetlands
Forests
National Parks and Other Environmentally or Culturally Sensitive Areas

Maps

The results of the Technical Potential analysis are visualized in maps and web application layers. The descriptions of the maps can be found below. Due to their large size, they have been sent to Duke in a separate file.

1. Duke GHI-01.jpg: Multi-year mean Global Horizontal Irradiance (GHI) from the NSRDB.
2. Duke GHI with Exclusions-01.jpg: Multi-year mean GHI from the NSRDB with excluded areas removed using the PV exclusion logic listed above.
3. Duke PV CF-01.jpg: Multi-year mean capacity factors using the PV system configurations listed above.
4. Duke PV with Exclusions-01.jpg: Multi-year mean capacity factors using the PV system configurations listed above and excluded areas removed using the PV exclusion logic listed above.
5. Duke Wind Speed 80-01.jpg: Multi-year mean wind speed from the WIND Toolkit.
6. Duke Wind Speed 80 with Exclusions-01.jpg: Multi-year mean wind speed from the WIND Toolkit with excluded areas removed using the wind exclusion logic listed above.
7. Duke Wind CF-01.jpg: Multi-year mean capacity factors using the wind system configurations listed above.
8. Duke Wind CF with Exclusions-01.jpg: Multi-year mean capacity factors using the wind system configurations listed above with excluded areas removed using the wind exclusion logic listed above.

Duke Energy Carbon-Free Resource Integration Study

Capacity Expansion Findings and Production Cost Modeling Plan

Brian Sergi, Bri-Mathias Hodge, Daniel Steinberg, Gregory Brinkman, Scott Haase, Michael Emmanuel, and Omar Jose Guerra Fernandez

November 10, 2020

NREL/PR-5D00-78386

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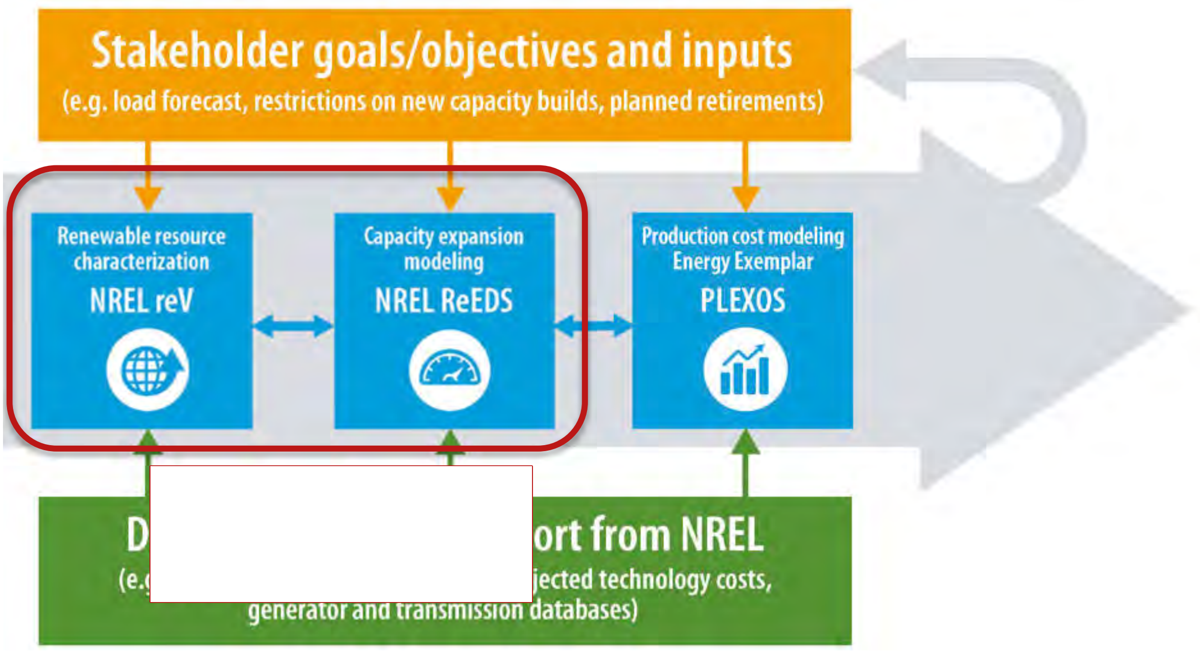
Duke low-carbon integration study (Phase II)

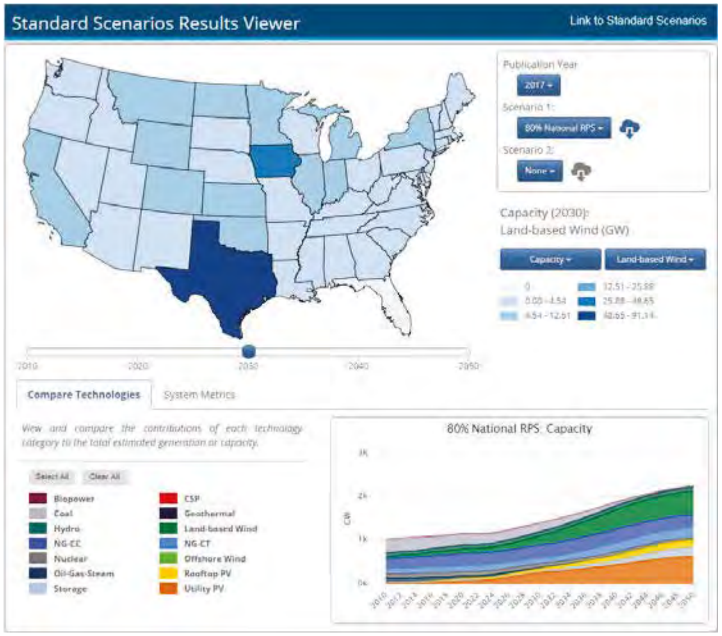


- Three-part study
  1. Characterize available resource capacity (reV)
  2. Explore buildout scenarios to meet policy objectives (ReEDS)
  3. Test operational performance of system buildouts (PLEXOS)
- Slides today will present results from the reV and ReEDS analysis
  - **The projected system buildouts from ReEDS are subject to change based on the findings in the production cost modeling**

Use of ReEDS for the Duke project

ReEDS is NREL's flagship capacity expansion tool. Details of the model were presented to Duke stakeholders on May 5

- **Main assumptions**
  - NREL ATB 2020 capital cost assumptions / AEO 2020 fuel projections
  - Surrounding state policies implemented (e.g. VA Clean Economy Act)
- **Key modifications of ReEDS for this project**
  - Adoption of an 18th timeslice representing the winter morning peak (top 20 hours)
  - Coal retirement dates based on book like from Duke's last depreciation study (model can retire coal and other existing fossil earlier than their retirement dates)
  - Assumption cost adder to natural gas combined cycle plants built in the Carolinas (proxy for the cost of firm pipeline capacity)
  - Modified exclusion areas for onshore wind supply curves



Standard Scenarios Results Viewer

Publication Year: 2017

Scenario 1: 80% National RPS

Scenario 2: None

Capacity (2030): Land-based Wind (GW)

View and compare the contributions of each technology category to the total estimated generation or capacity.

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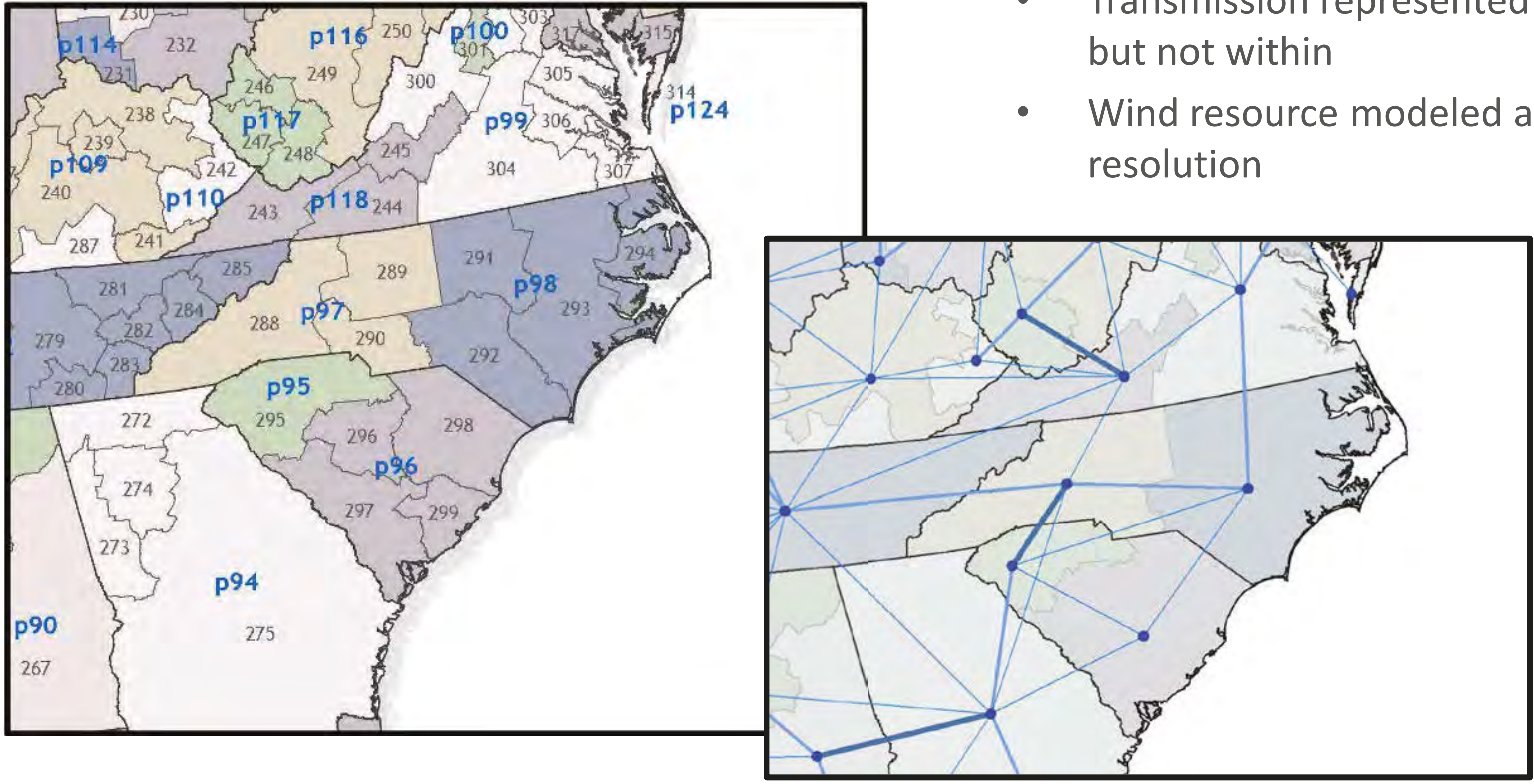
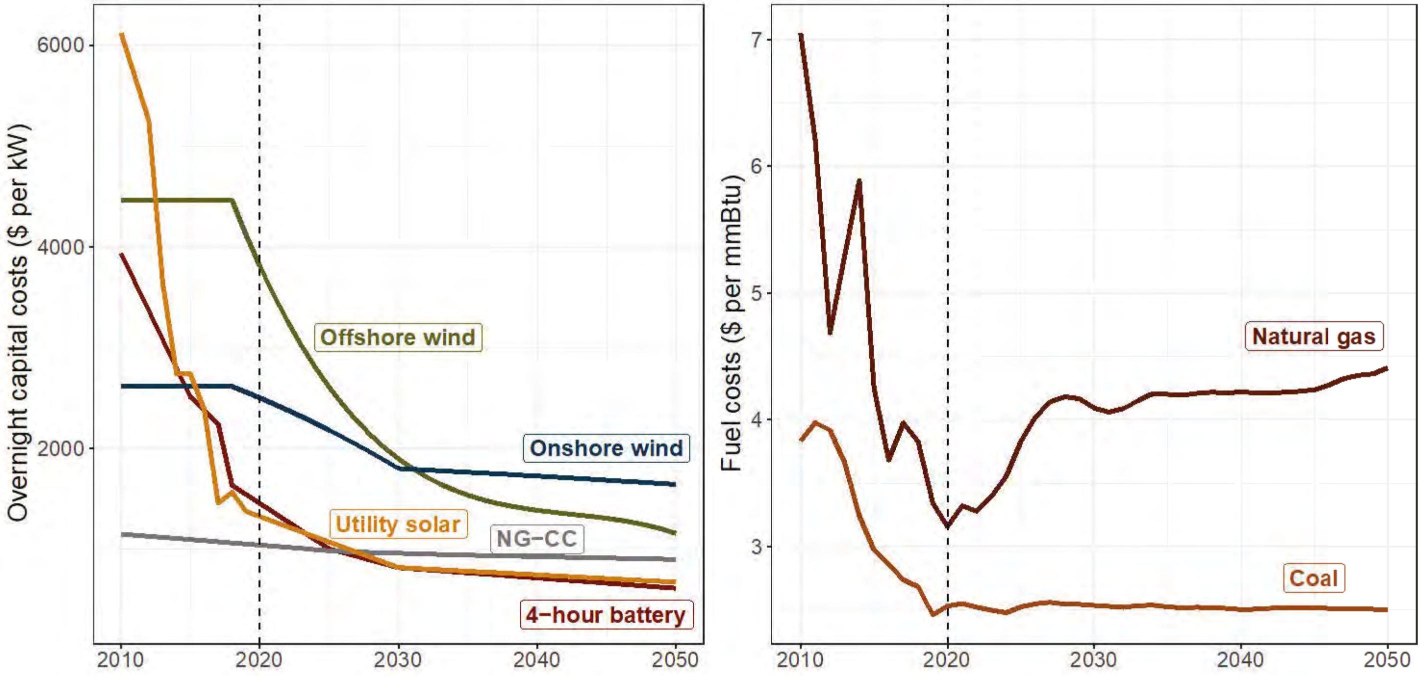
ReEDS approach to modeling the Carolinas



- Carolinas modeled as four balancing areas (BAs) where load and planning constraints must be met
- Transmission represented between BAs, but not within
- Wind resource modeled at finer spatial resolution

Technology cost assumptions



- Model assumes falling capital costs for solar, wind, and battery storage
- Coal prices stable, natural gas costs increase slightly over time
- Natural gas adder applied to any new NG-CC facilities built after 2020

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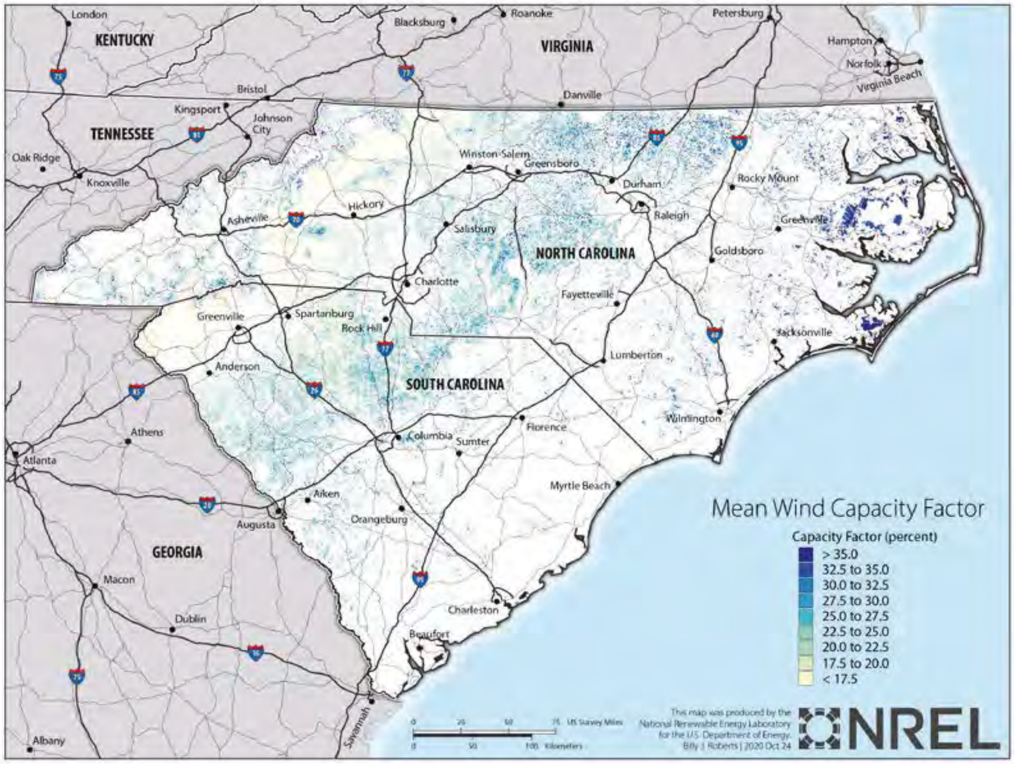
Onshore wind exclusions



Basic exclusions include:

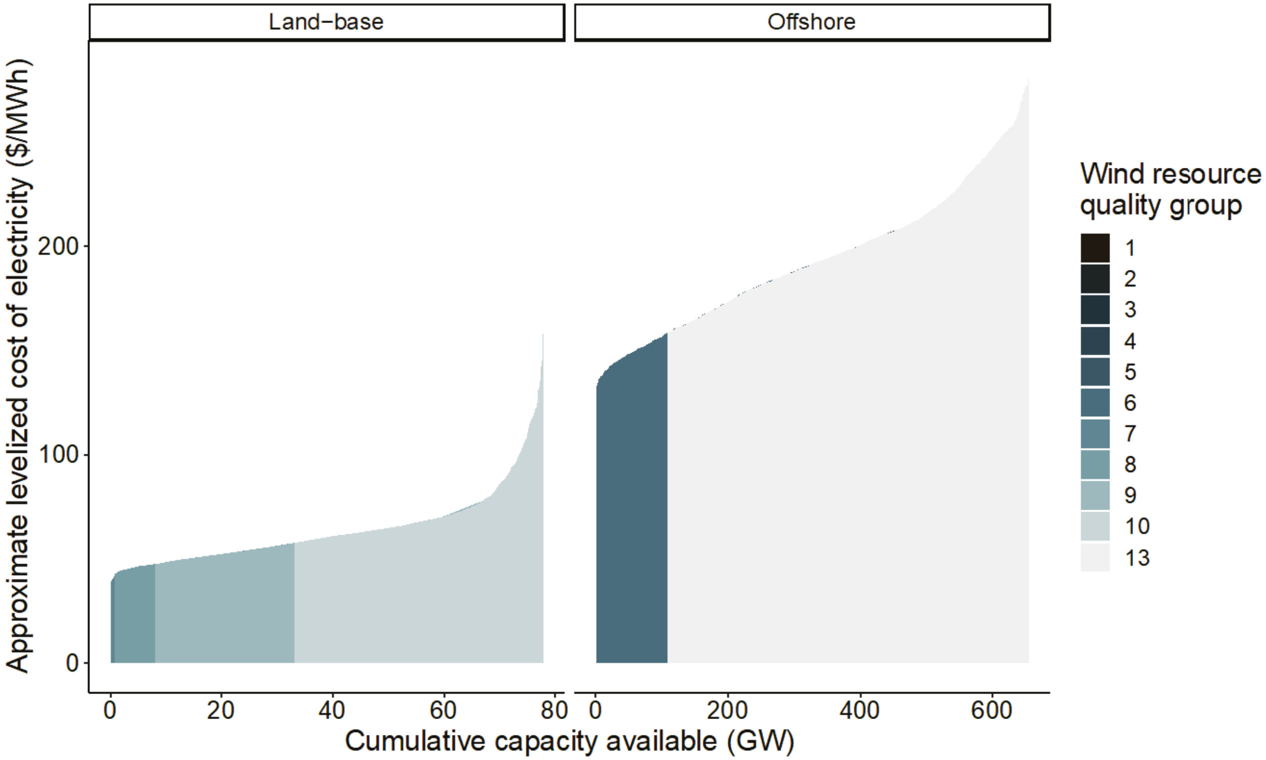
- Urban areas
- Bodies of water
- Protected lands
- Sloped lands
- Distance from structures

Exclusions added for this project:

- Ridgetop lands
- Military base and radar line-of-sight

Wind supply curves for the Carolinas

- Total available onshore capacity reduced from ~250 GW in previous estimates to ~80 GW

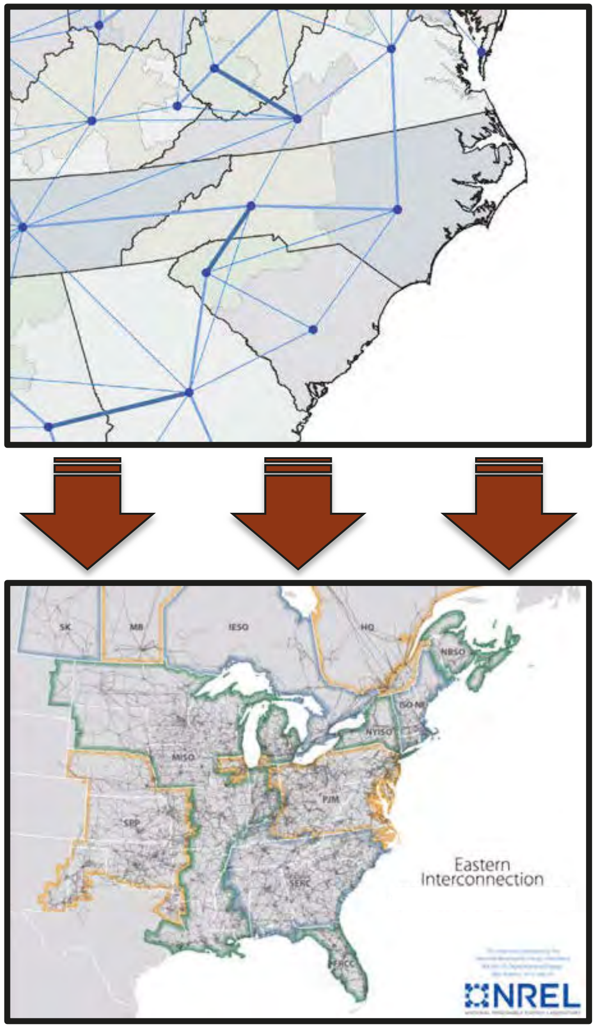


Scenario overview

	Base (no emissions constraints)	**Policy** (70% CO_2 reduction in NC by 2030 + net-zero electricity in NC by 2050)
Main case	Standard modeling assumptions	
Cost sensitivities	Low cost wind	
	High cost solar/storage	
	High cost solar/storage + low cost natural gas	
Other sensitivities	Eastern Interconnect has similar CO_2 targets (70% in 2030, net-zero in 2050)	
	Duke able to secure firm capacity outside of the Carolinas	
	All fossil fuel must retire as part of net-zero 2050 target	

Putting the ReEDS results in context

- The portfolios built by ReEDS still need to be tested in PLEXOS for operational robustness
- Although we can gain insights from the ReEDS results, more work is needed to be done to ensure these system buildouts are feasible
- The production cost modeling may refine the conclusions from the ReEDS work
- Discussion on the plans for the production cost modeling phase later in the presentation



Capacity expansion in ReEDS

Production Cost Modeling in PLEXOS

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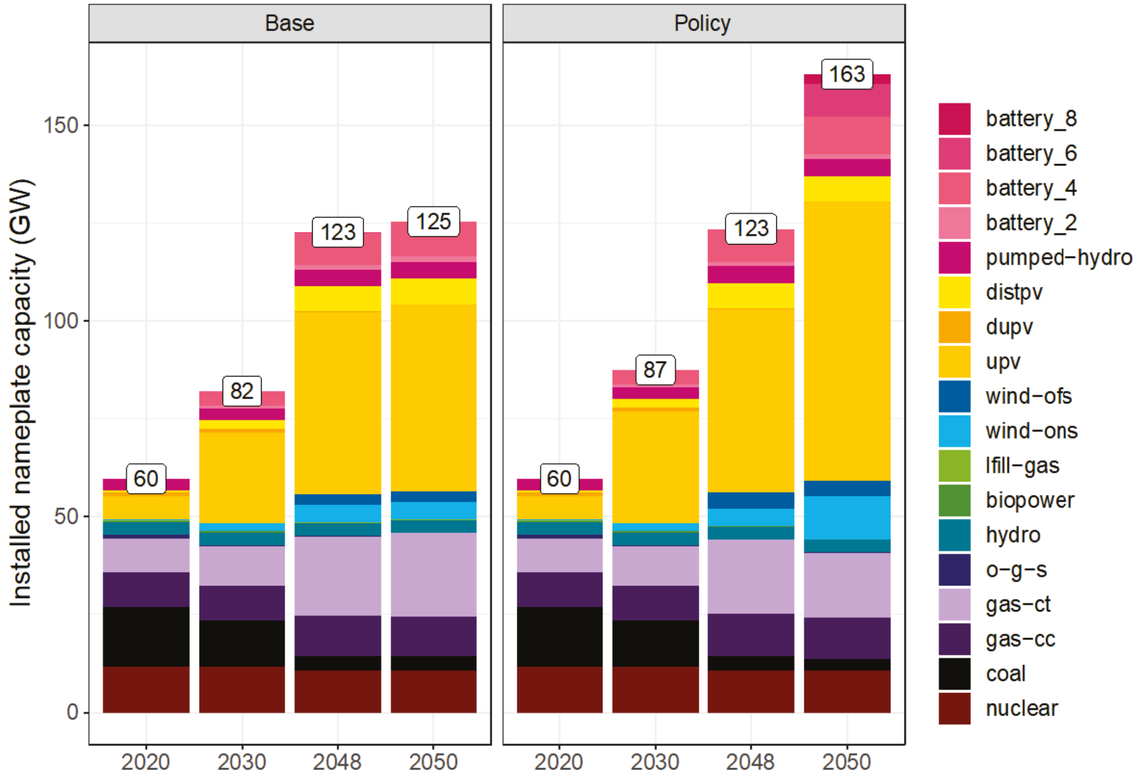
Capacity and generation results

Installed capacity

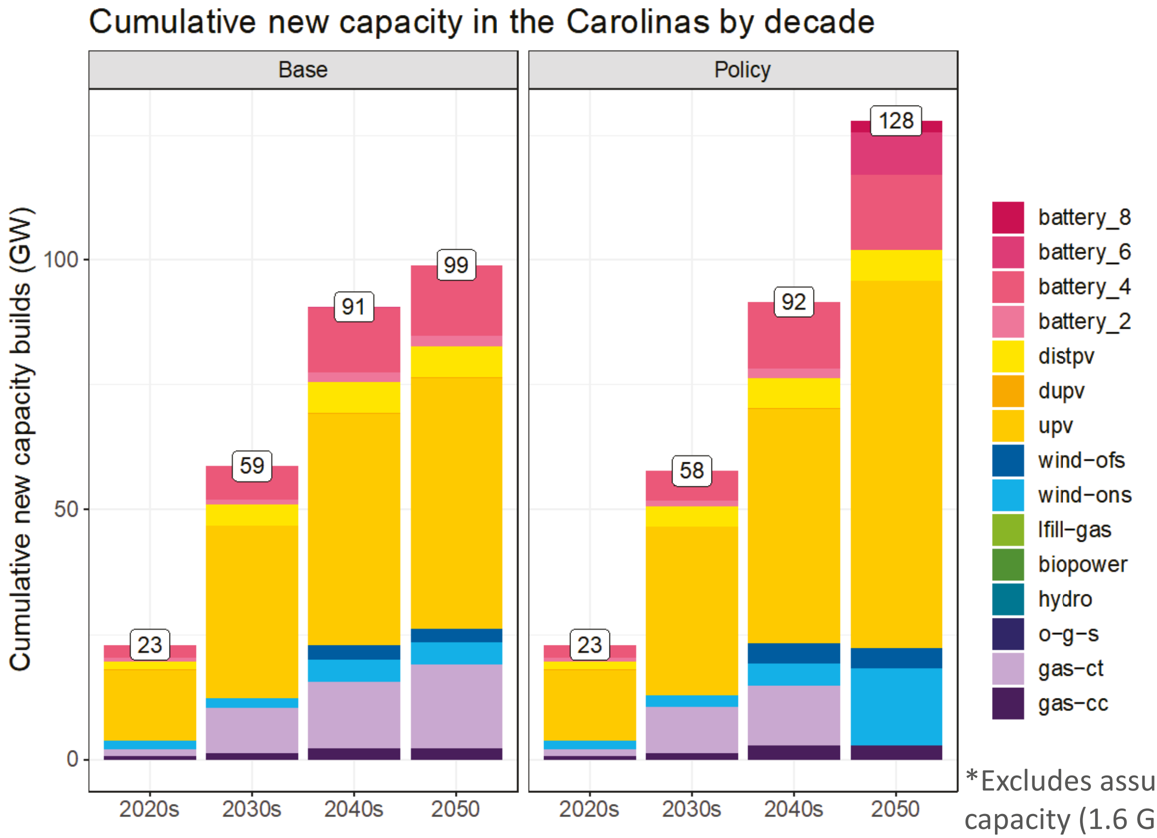


Installed capacity in the Carolinas

	Base				Policy			
	2020	*2030*	*2048*	*2050*	*2020*	*2030*	*2048*	*2050*
Battery storage	0.03	4.5	9.5	10.3	0.03	4.5	9.5	21.5
Solar	7.6	26.5	53.1	54.3	7.6	31.9	53.5	77.8
Wind onshore)	0.2	1.9	4.4	4.4	0.2	1.9	4.5	11.0
Wind offshore)	-	-	2.8	2.8	-	-	4.0	4.0
atural gas	17.5	18.8	30.6	31.5	17.5	18.8	29.7	27.2

- Both scenarios rely on a mix of solar, gas, and nuclear through 2030
- Capacity mix in 2050 is similar across scenarios, with additional storage, solar, and wind in the net-zero 2050 case
- Note that the model allows fossil capacity to meet capacity planning requirements / reserves in the 2050 net-zero scenario
- First year of offshore wind build:
  - Base: 2042
  - Policy: 2040

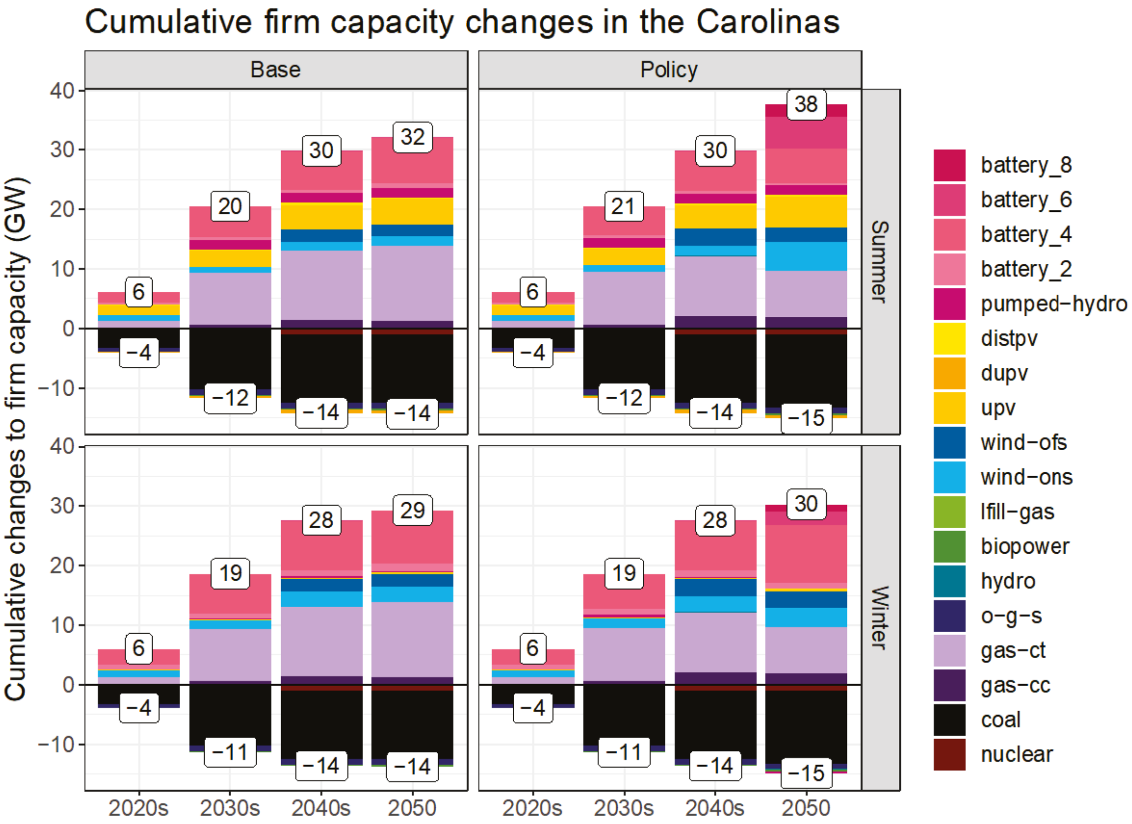
New nameplate capacity builds*



- Solar and storage are the primary builds through 2030 across both scenarios
  - 2030 target moves up some new capacity investments
- Achieving net-zero in 2050 acquires substantial additional capacity buildout
  - Model delays building this capacity to take advantage of declining costs
  - New gas capacity in the policy case reflects the model seeking dispatchable resources
    - Primarily used to meet reserve margins (Gas CTs have capacity factor < 1%)
    - Suggests the need for cheap, firm, zero-emissions technology
  - Reflects the operational challenge of getting to net-zero

*Excludes assumed expansion of pumped hydro storage capacity (1.6 GW in 2035) that occurs in both cases

Changes to firm capacity



- Firm capacity credits determined by full 8760-hour analysis of net load
- Retiring firm capacity—primarily coal—is replaced by natural gas, solar, wind, and increasingly battery storage
  - Little solar available to meet winter peak; requires wind and battery storage
- As more firm capacity is retired, the amount of new capacity needed to replace it increases
  - Increasing need for the ability to shift energy across time using storage

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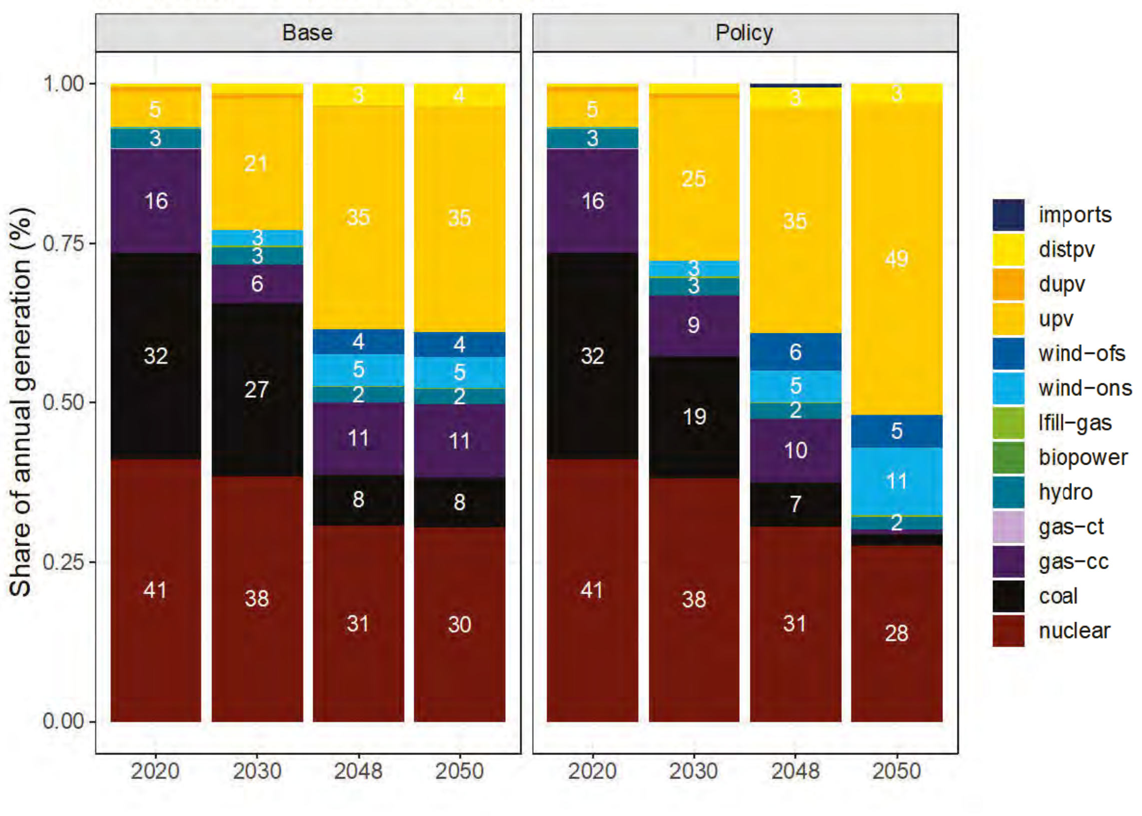
Generation mix*

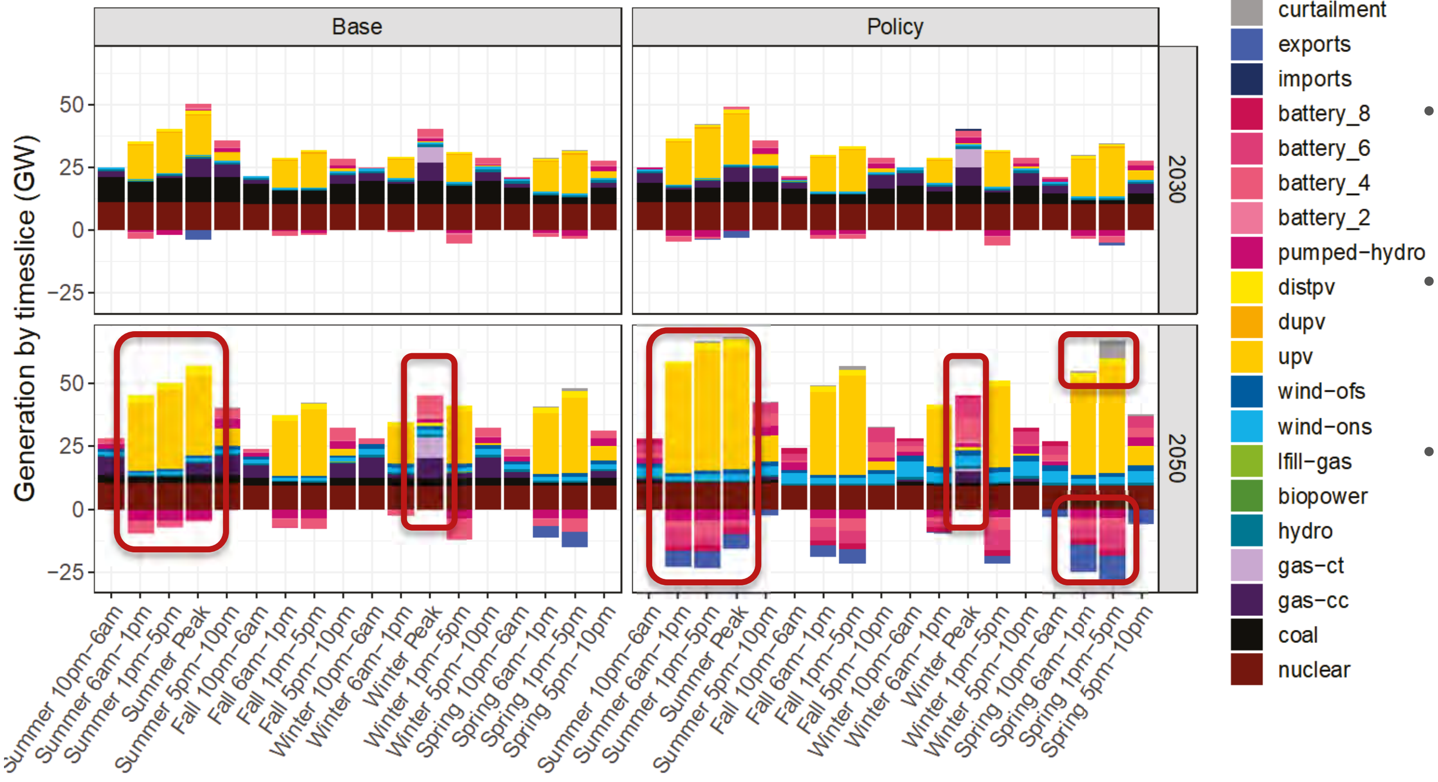


Generation mix in the Carolinas

- Existing nuclear supplies 28-30% of generation in 2050
  - – assumed all licenses extended through 2050
- Very high penetrations of solar in the emissions constrained scenario
- Net-zero target relies on contributions from both onshore and offshore wind
- Note that remaining coal operates in SC outside of Duke’s territory

Generation by ReEDS timeslice

Timeslices are representative dispatch periods used in ReEDS, representing each combination season and time of day (along with peaks)



Carolinas Generation by ReEDS timeslice

- Nuclear generates consistently across timeslices in all cases
- Solar provides most of the mix in summer afternoon also fall and spring
- Large amount of storage dispatched to meet winter morning peak; wind also used
- Extensive storage charging and exports to handle solar overgeneration
  - Despite this, there is still solar curtailment

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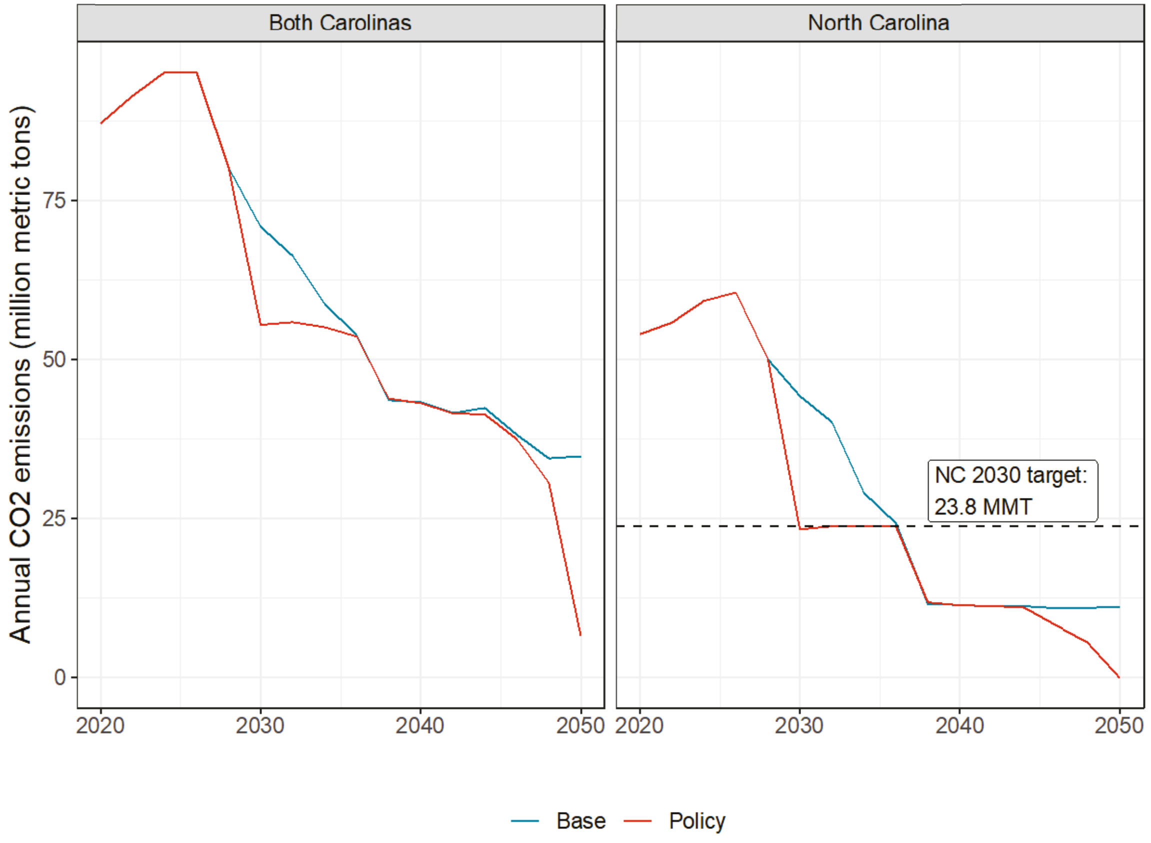
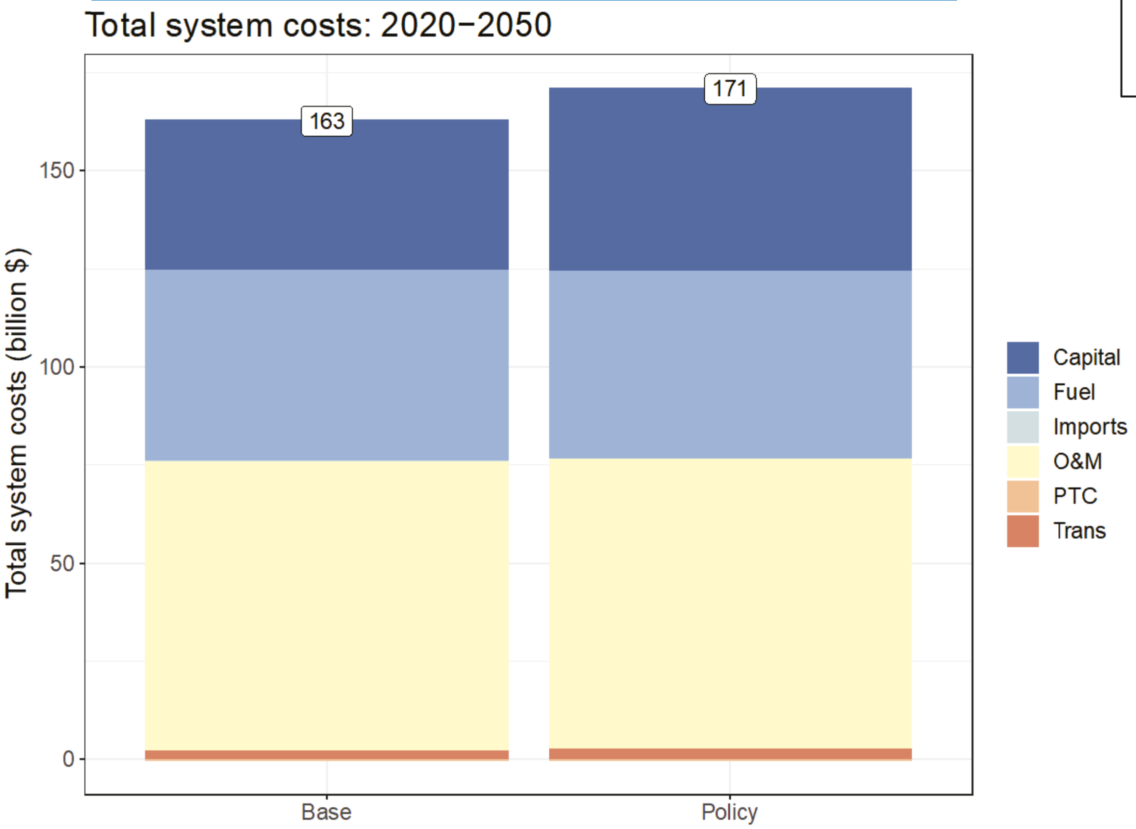
Emissions and system costs

CO_2 emissions



- Emissions decline without policy intervention, but 2030 NC target accelerates decline and reduces cumulative emissions
- Assuming base case emissions stabilize at 2050 levels, the policy yields **avoided annual emissions** 6.5 MMT in NC / 23 MMT in the Carolinas starting in 2050
- Some cumulative emissions reductions in NC from the 2030 target may be partially offset by dispatch changes in SC without any SC emissions policy

Total system costs



Cost assumptions

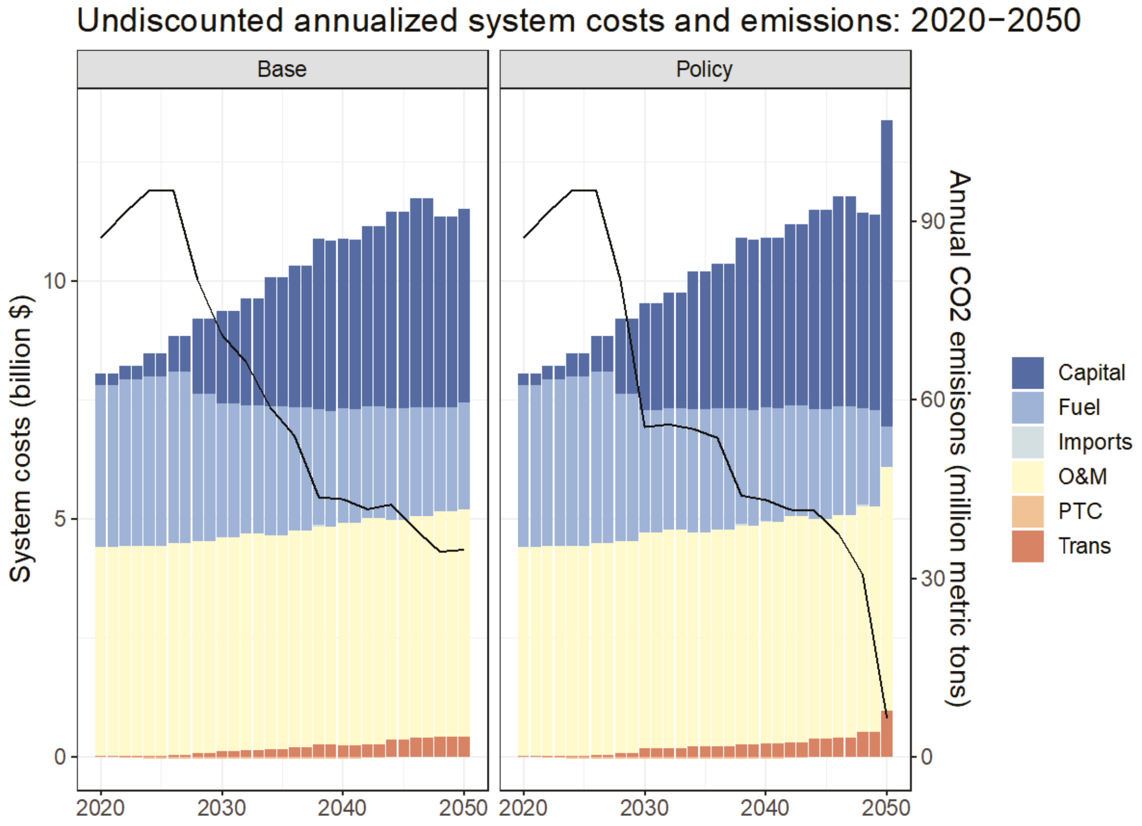
- Results in $2018
- Capital costs annualized over a 20-year period using a capital recovery factor that varies from 6.5-7%
  - Total costs includes full payments for any capital built through 2050
- Discounting using a 5% discount rate

- Policy scenario associated with ~$8 billion above Base for the Carolinas
  - Without discounting, this difference is $52 billion
- Approximately 5% of total system costs over the time period
- Policy cost comes primarily from capital costs, along with increased transmission and O&M

Annualized system costs

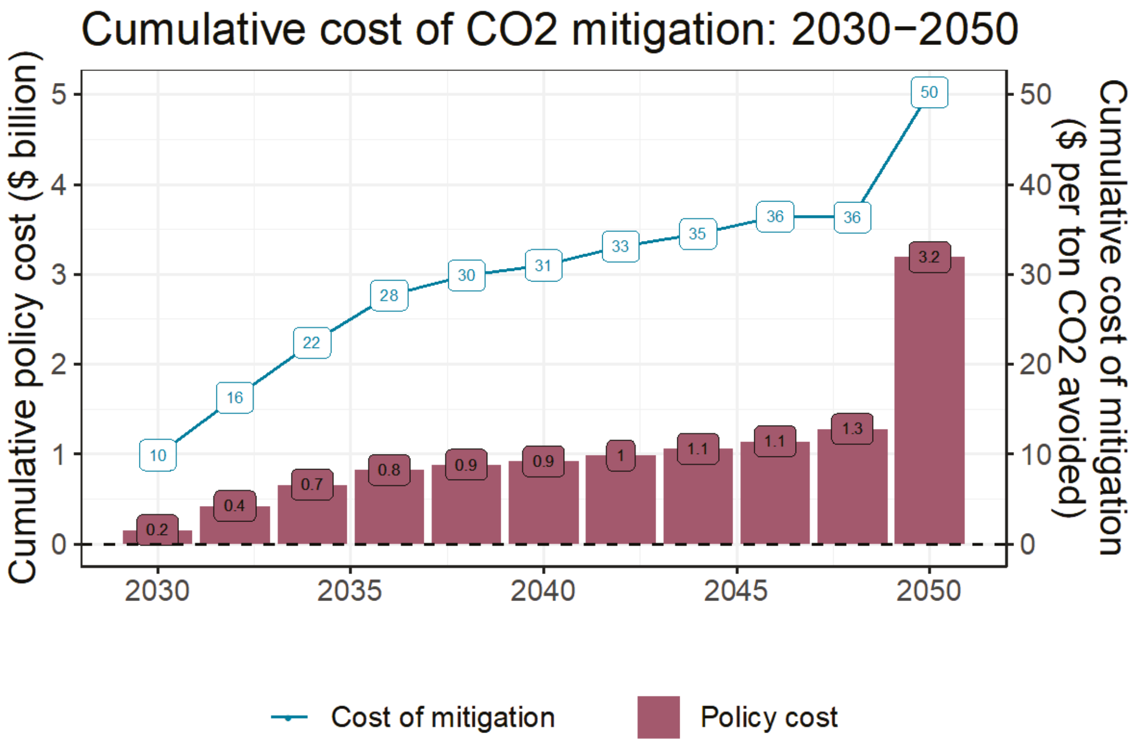
Cost assumptions

- Results in nominal dollars
- Capital costs annualized over a 20-year period using a capital recovery factor that varies from 6.5-7%



- Costs increasing over time for both scenarios
- Policy case incurs relatively large cost increases in 2050
  - Net-zero scenario requires more installed capacity and is harder than initial CO_2 reductions
  - Spike in costs reflects the increasing cost for eliminating the last bit of CO_2 in NC

Cost of mitigation for both Carolinas


Cumulative cost of CO2 mitigation: 2030−2050

- Cost of mitigation calculation:
  - $COM^T = \frac{\sum_{t0}^{T}\left[Costs_t^{policy} - Costs_t^{base}\right]}{\sum_{t0}^{T}\left[Emit_t^{base} - Emit_t^{policy}\right]}$
  - Calculated using undiscounted annualized values
  - Starting year (t0) of 2030 (base and policy cases similar between 2020 and 2030)
- Cost of mitigation increases sharply as toward meeting 2050 net-zero target (increasing marginal cost of reductions)

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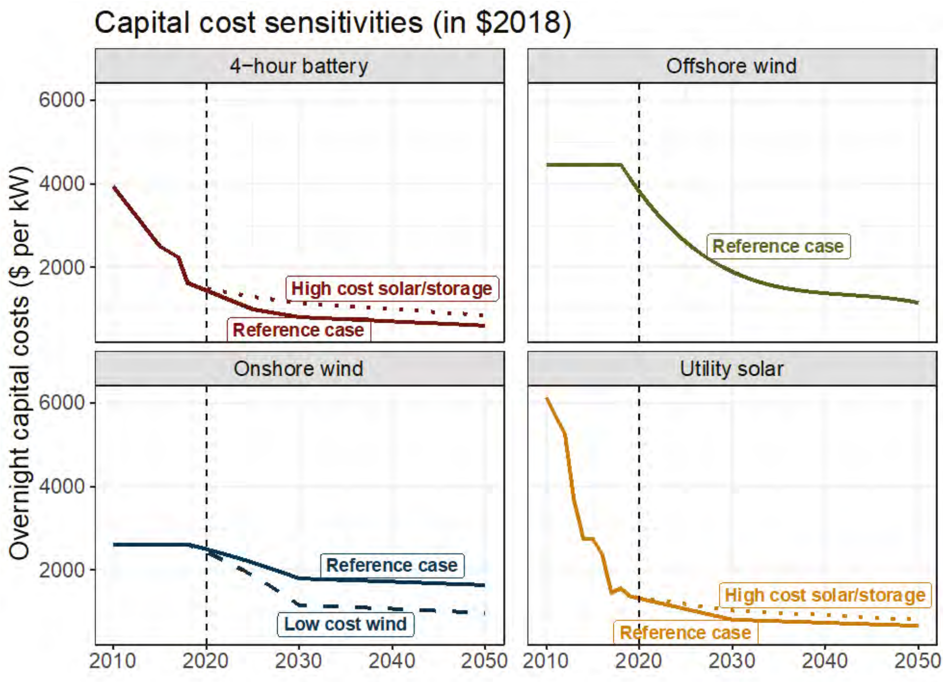
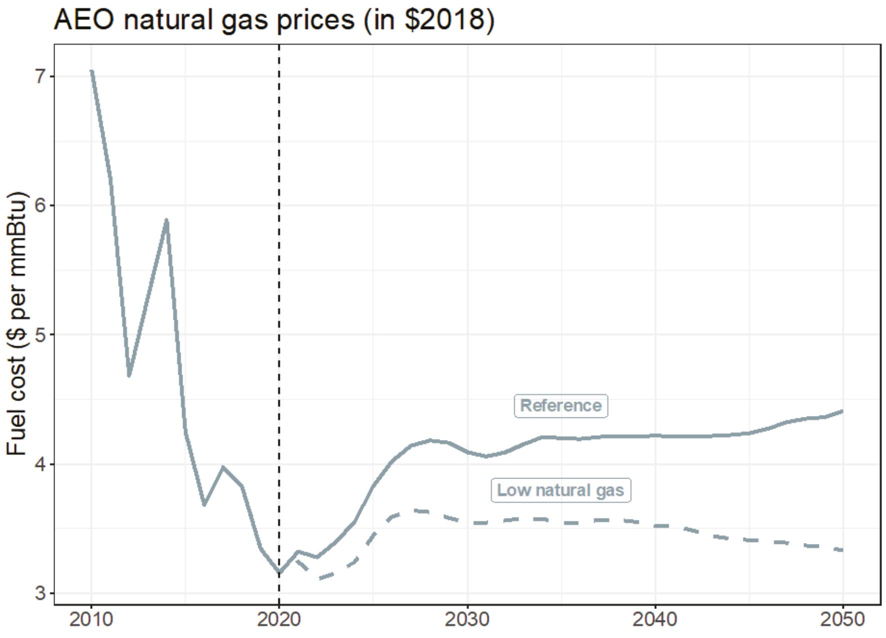
Sensitivity analyses

Cost sensitivities





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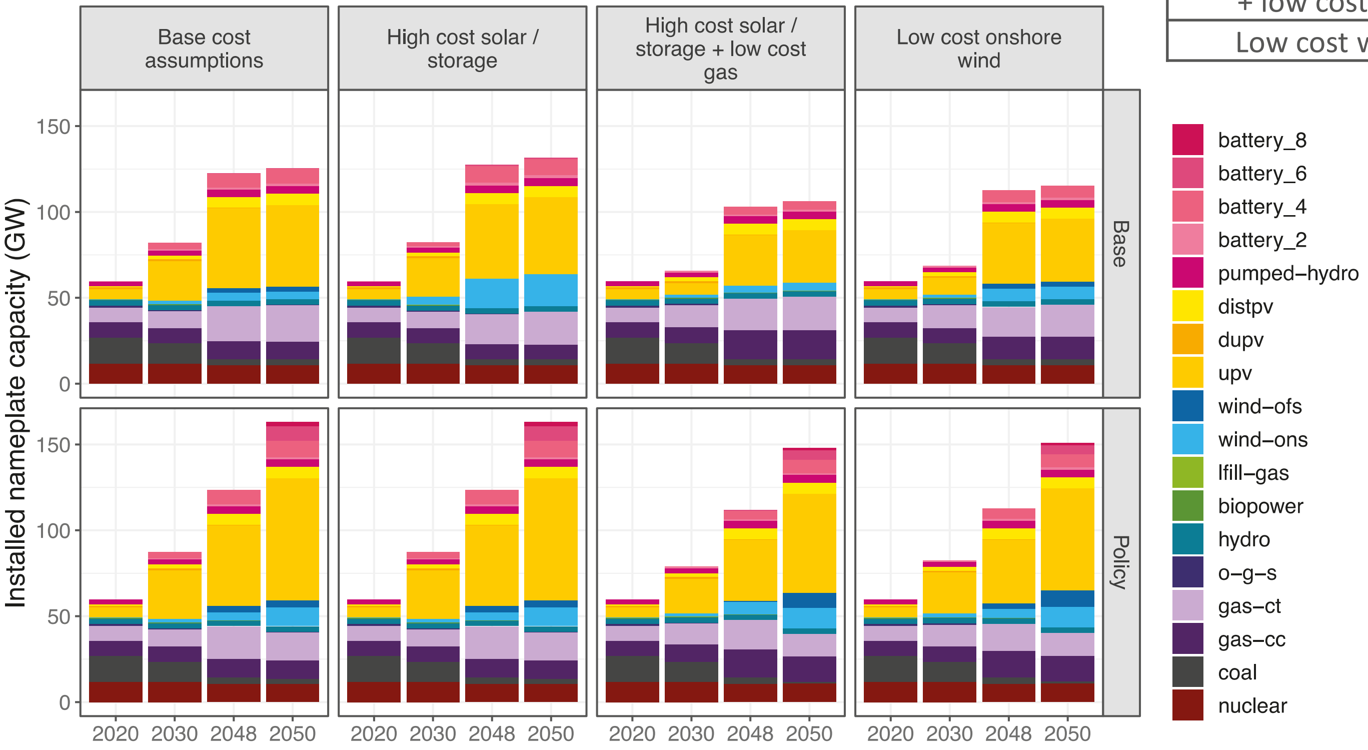
Cost sensitivities

Installed capacity in the Carolinas



Cost difference relative to base cost assumptions ($ billion)

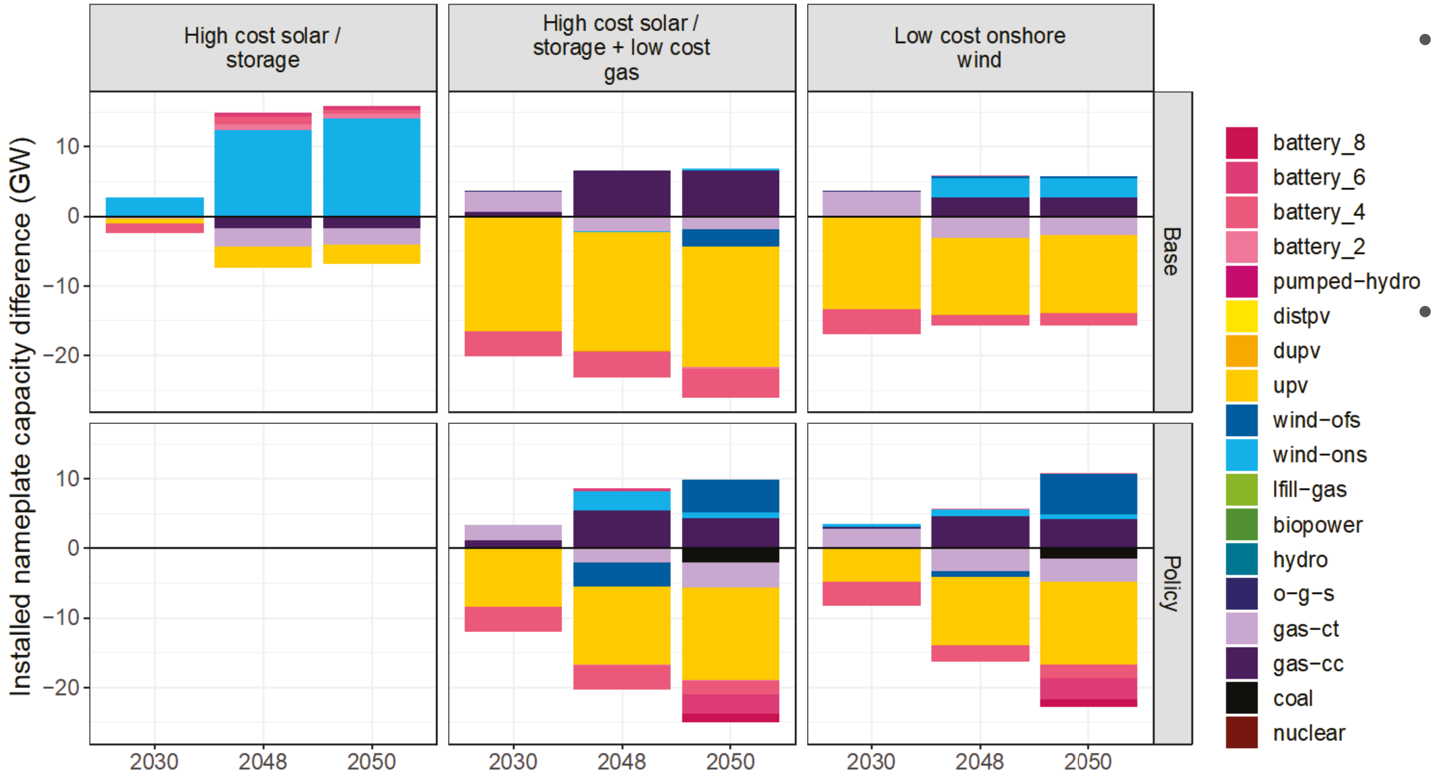
	Base	Policy
High cost solar/storage	$ 2.11	$ 4.05
High cost solar/storage + low cost gas	$ (2.60)	$ 1.35
Low cost wind	$ (1.76)	$

-

- Sensitivities to cost of onshore **shift investments slightly, but do not radically change** the technology mix
- First offshore wind builds:
  - Base cost assumptions, Base: 2042
  - Base cost assumptions, Policy: 2040
  - High cost solar / storage, Base: 2038
  - High cost solar / storage, Policy: 2034

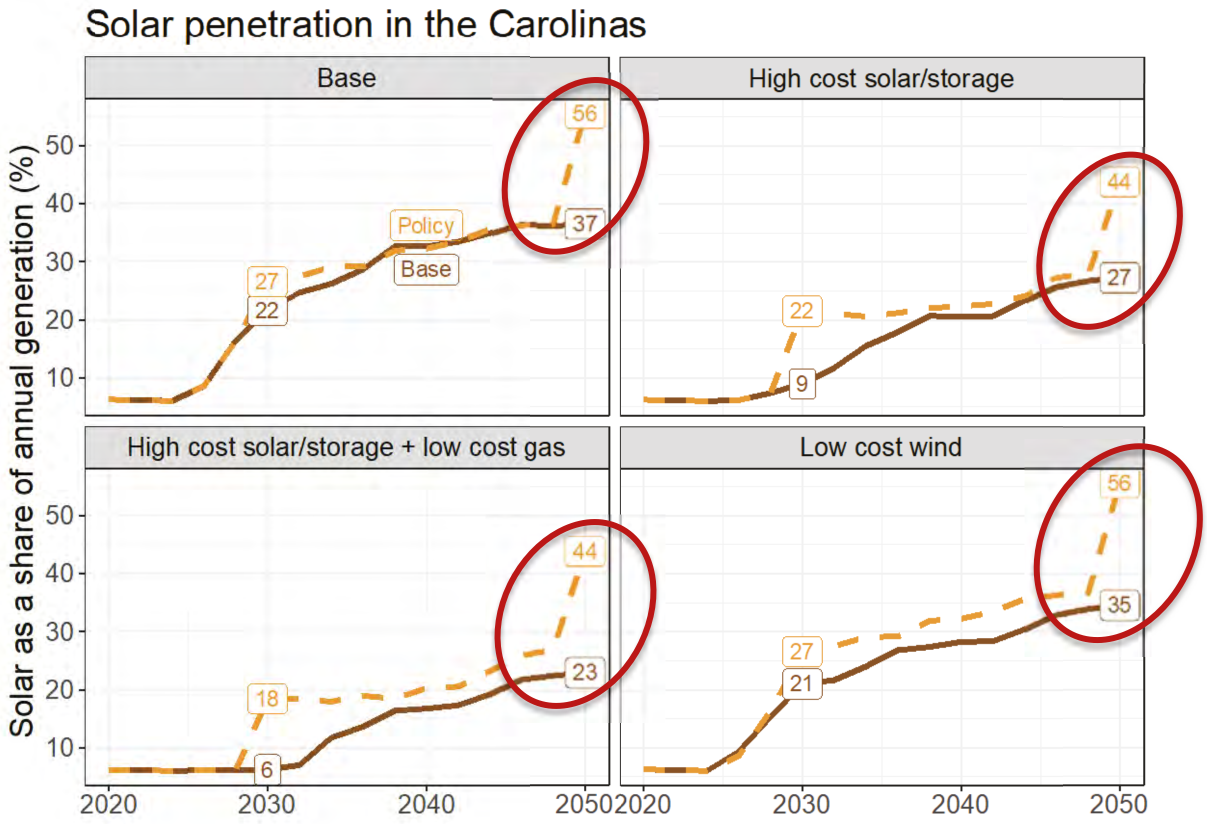
Capacity differences

Difference in installed capacity in the Carolinas (relative to base cost assumptions)



- **High solar/storage**: more wind in the base, no difference in the policy case
- **High solar/storage with low gas prices**: less solar/storage, more gas, later offshore wind builds in the policy case
- **Low onshore wind:** less solar/storage, more onshore wind in the base, more onshore/offshore wind in the policy case

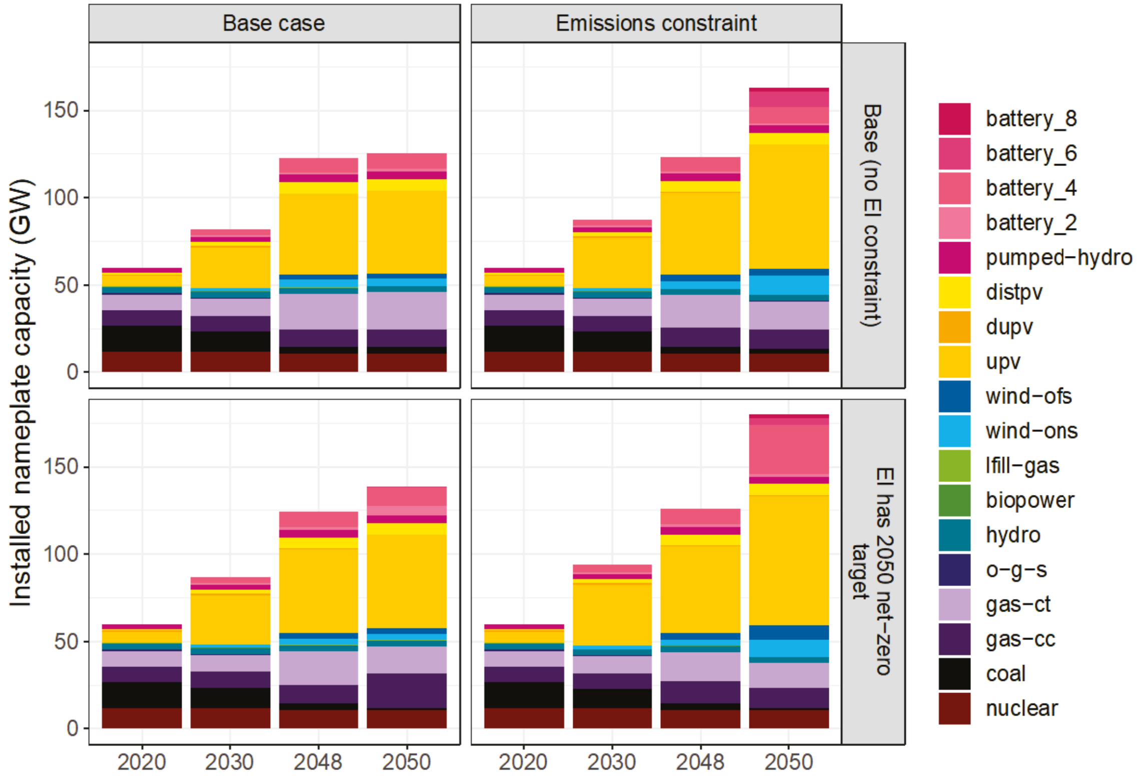
Solar penetration



- Under baseline cost assumption, policy accelerates solar adoption but base case "catches up" quickly
- Other cost assumptions yield lower solar adoption and more divergence between base and policy
- Large increase to meet 2050 net-zero target under all cost assumptions

What happens to the rest of the Eastern Interconnect?

Installed capacity in the Carolinas

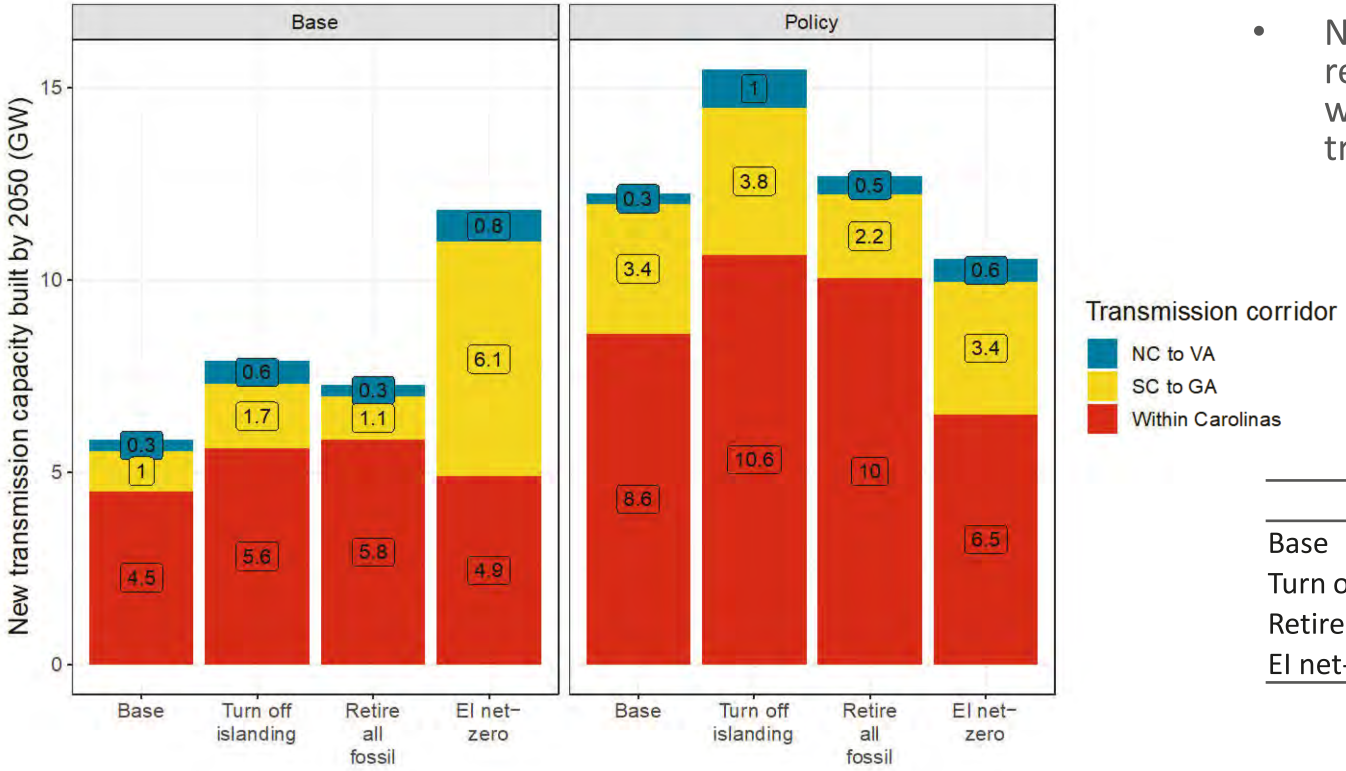


Cost difference relative to base cost assumptions ($ billion)

	Base	Policy
Constrained Eastern Interconnect	$ 4.94	$ 4.45

- An Eastern Interconnect (EI) wide net-zero target leads to more installed capacity in the Carolinas
  - Approximately 17 more GW capacity (10% increase)
  - Increase primarily in battery capacity
- EI constraint reduces the ability of the system to export excess solar generation when needed
  - Addressed with more storage, shift to more offshore wind

Interface transmission expansion



- Additional inter-BA transmission investments in all scenarios
- Policy cases rely on more transmission assets, both within Carolina balancing areas and with neighbors
- Note that these results do not reflect all the friction associating with building or using transmission
  - Production Cost Modeling will better simulate transmission system operations

Total capital expenditures on new transmission through 2050 ($ billion)

	Base	Policy
Base	2.27	2.71
Turn off islanding	2.70	3.15
Retire all fossil	2.34	2.82
EI net-zero	3.01	3.37

Summary of insights from the ReEDS modeling

- 2030 targets can be achieved primarily with a buildout of solar and storage
  - Wind can also provide a valuable contribution, particularly if there are constraints on the ability to deploy new solar and storage
  - Resource mix is robust across sensitivities to costs of wind, solar, storage
  - Baseline also reduces emissions relative to 2020, but 2030 target results in faster decrease and more cumulative emissions avoided

- 2050 net-zero target more challenging to meet with existing technologies
  - Decreasing value of solar at high penetrations, increasing value of diversity (wind, additional storage) to achieve net-zero
  - Large capacity buildout required to eliminate last 5 million tons of CO2 in NC
  - Different resources needed to meet summer and winter peaks

- Sensitivities
  - Cost sensitivities tend shift from solar to other technologies, but generally the technology buildouts are similar, and none of the sensitivities impede getting to net-zero in 2050.
  - Increased value of storage, wind, and transmission if the entire Eastern Interconnect pursues a 2050 net-zero target

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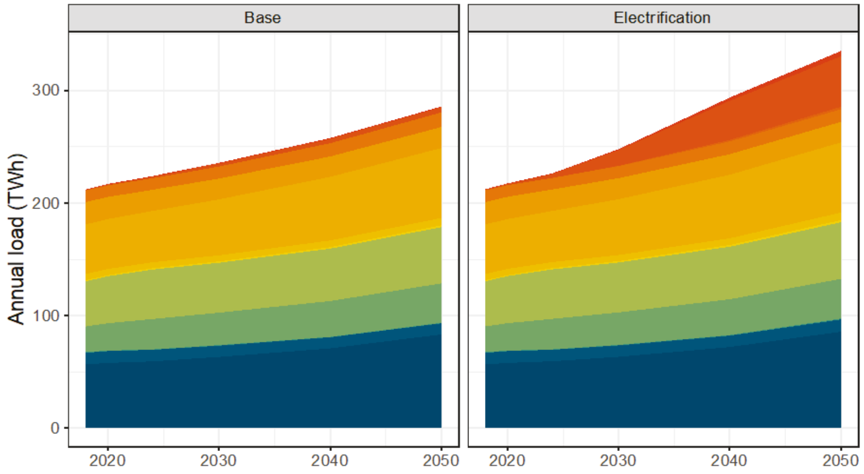
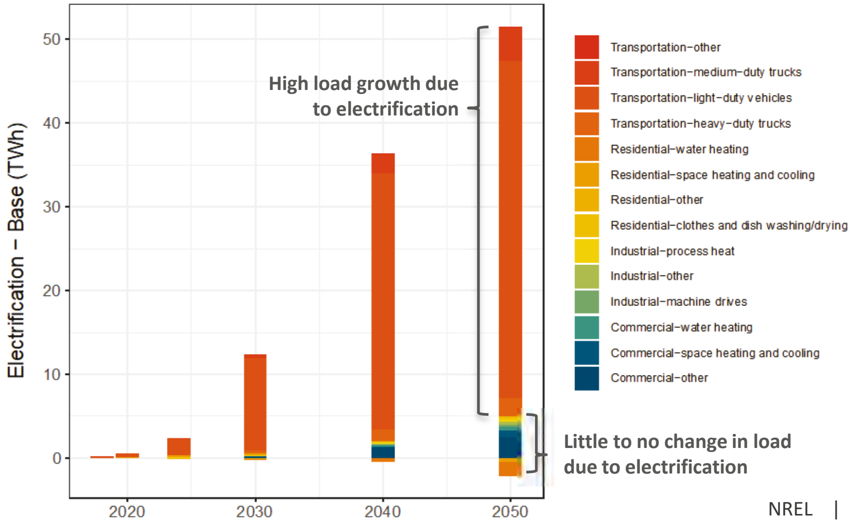
Additional analysis in ReEDS

- Will test sensitivity of ReEDS buildout to scenario with higher electrification
  - 1.5% annual load growth
  - 12.5% EV growth
  - Additional load flexibility, some efficiency gains from electrification
- Electrification scenario based on data from NREL's Electrification Futures Study and corroborated by Duke





High load growth due to electrification

Little to no change in load due to electrification

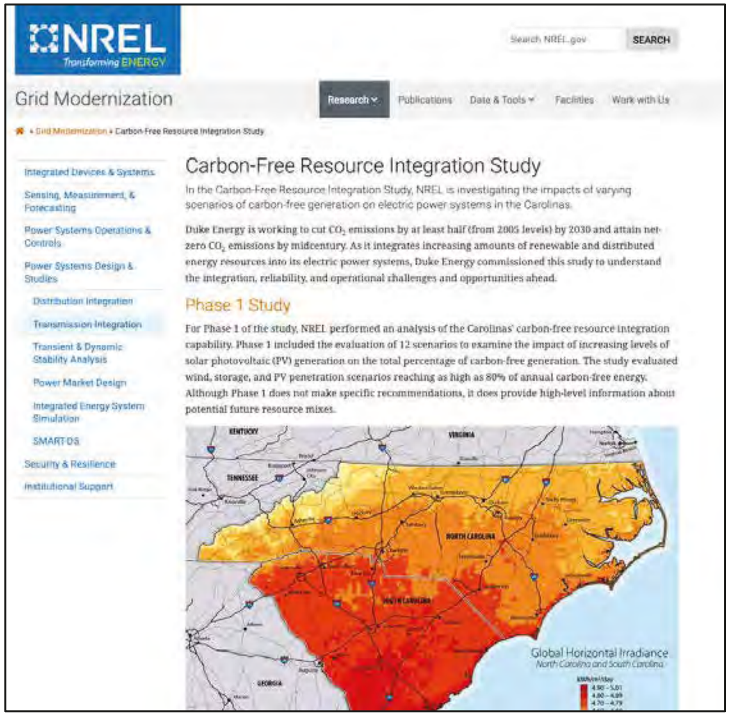
Caveats and challenges to consider

- ReEDS is not a full planning study – does not represent all the costs and challenges associated with siting new generation and transmission capacity
- Large amounts of new capacity required to achieve policy targets, particularly of solar and storage
  - Further work should investigate potential constraints on the ability to connect large amounts of new capacity
  - Larger and earlier investments in wind (on land or offshore) can provide additional benefits in terms of buildout diversification
- The capacity buildouts presented have not yet been tested for reliability in an operational model
  - **Production cost modeling in the next step will help determine the robustness of the portfolios built by ReEDS**
  - High-level findings presented here may change based on that analysis

Questions about the capacity expansion results?

For more information, see the NREL Carbon-Free Resource Integration Study website: https://www.nrel.gov/grid/carbon-free-integration-study.html

In the coming weeks, NREL will be posting details related to the capacity expansion results, including a “Frequently Asked Questions” document



Carbon-Free Resource Integration Study

In the Carbon-Free Resource Integration Study, NREL is investigating the impacts of varying scenarios of carbon-free generation on electric power systems in the Carolinas.

Duke Energy is working to cut CO_2 emissions by at least half (from 2005 levels) by 2030 and attain net-zero CO_2 emissions by midcentury. As it integrates increasing amounts of renewable and distributed energy resources into its electric power systems, Duke Energy commissioned this study to understand the integration, reliability, and operational challenges and opportunities ahead.

Phase 1 Study

For Phase 1 of the study, NREL performed an analysis of the Carolinas' carbon-free resource integration capability. Phase 1 included the evaluation of 12 scenarios to examine the impact of increasing levels of solar photovoltaic (PV) generation on the total percentage of carbon-free generation. The study evaluated wind, storage, and PV penetration scenarios reaching as high as 80% of annual carbon-free energy. Although Phase 1 does not make specific recommendations, it does provide high-level information about potential future resource mixes.

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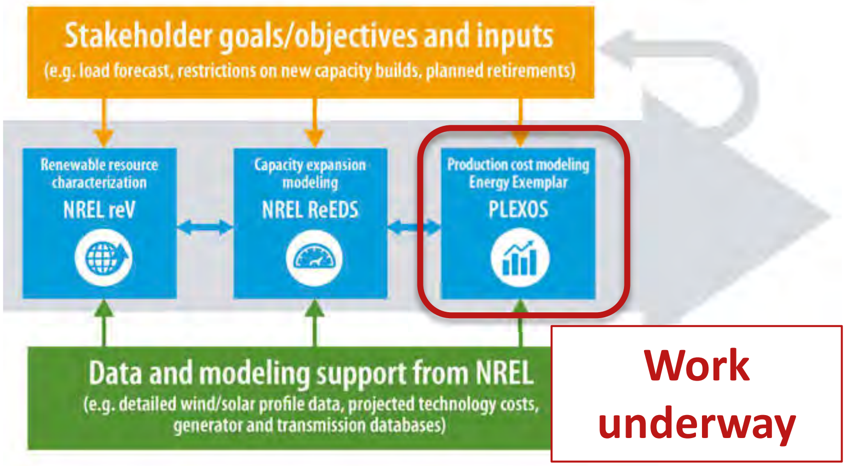
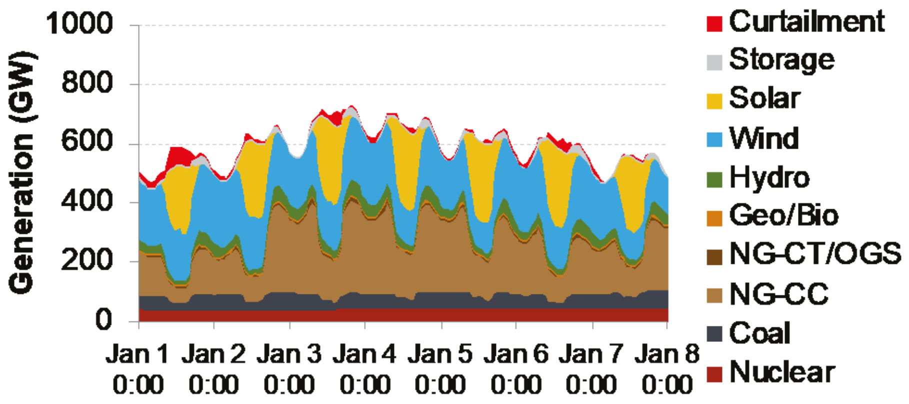
Plans for production cost modeling

Goals of the production cost modeling

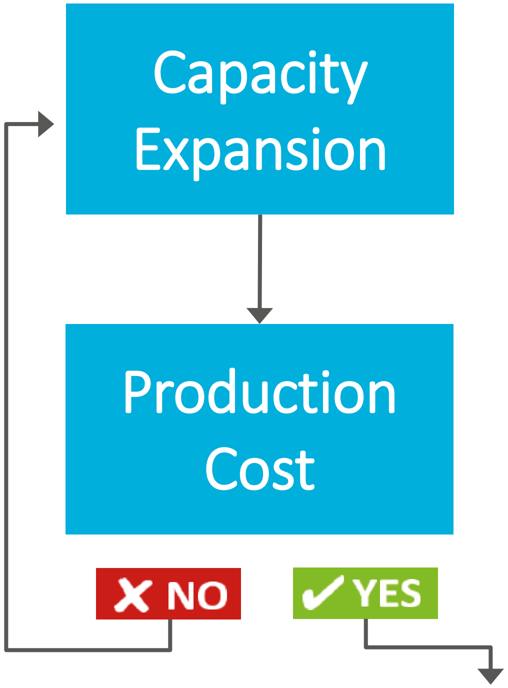
- Test system built by ReEDS with production cost modeling using PLEXOS
  - Is the system able to serve load in all hours of the year?
  - Production cost model includes more detailed representation of key parameters (e.g. transmission network topology, generator characteristics, wind/solar availability)
- Evaluate system with more detailed representation of the Eastern Interconnection
- Production cost modeling may inform additional ReEDS modeling



Work underway



From capacity expansion to production cost modeling



Capacity Expansion

Production Cost

✗ NO

✓ YES

BUILD

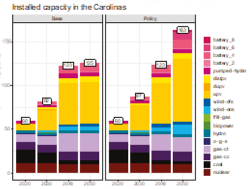
What do we build?
Where and when?

WORK?

Does it work?
(hourly operation)

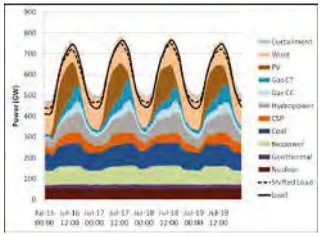
ReEDS

National policy, market technology analysis



PLEXOS

Security-constrained unit commitment & economic dispatch



Differences between ReEDS and PLEXOS

	 **ReEDS** National policy, market, technology analysis	**PLEXOS** Security-constrained unit commitment & economic dispatch
Model scope / purpose	Find *least cost* technology mix to meet power system requirements over decades	*Simulate* detailed operations of the power system using unit commitment and economic dispatch
Spatial resolution	4 balancing areas in the Carolinas	Nodal or zonal representation
Temporal resolution	18 representative time slices	Chronological hourly dispatch
Transmission	Between balancing areas	Full transmission system
Generator parameters	Average parameters assumed by generator type and vintage	Full heat rates, operational constraints (e.g. min gen levels, ramp rates) by plant
Dispatch	Dispatch according to time slices	Hourly unit commitment + economic dispatch

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Capacity Model Scenario Zonal Translation

- Scenario translation (ReEDS to PLEXOS)
  - Planning to translate three cases:
    - *2024 Business-as-Usual case (nodal benchmark)*
    - *2030 70% emissions reduction*
    - *2050 Zero emissions target*
- PLEXOS will be used to validate hourly operational feasibility of buildouts from ReEDS for the three translated scenarios

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Zonal Runs for Translated Cases

- **Objectives of zonal modeling**
  - Test translation workflow and used to understand how ReEDS intends power to flow across regions
  - Allows iteration with ReEDS as PCM encounters issues in results
- **PLEXOS zonal representation**: The transmission network is modeled to the zonal level with all resources within a zone connected to a single notional node
  - Only links between zones are modeled
  - Inter-zonal constraints are enforced
  - Zones are generally connected with adjacent zones for transferring electric energy

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Eastern Interconnection (EI) 2024 Nodal Model

*Note: the following slides show a **preliminary characterization** of the EI model and do not represent final PLEXOS findings

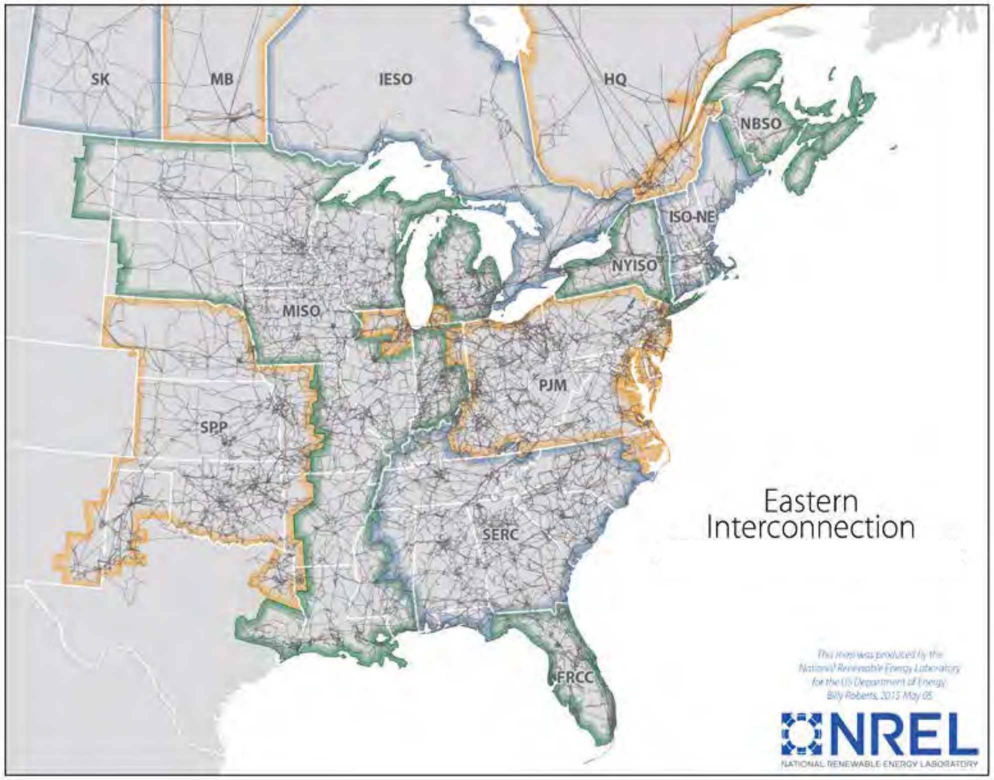
Eastern Interconnection Model Runs with PLEXOS

- **Eastern Interconnection (EI) 2024 Model**
  - 2024 nodal model with high resolution of the transmission network
    - Considers all transmission constraints such as thermal and interface limits
  - Computes optimal power flow – ensures generation dispatch and resulting DC power flow are at minimum cost and feasible with respect to transmission constraints
  - Model updated with current Duke's winter and summer capacities
    - Additional input planned from Duke on key parameters and constraints
  - For benchmarking and to represent Duke's existing power system

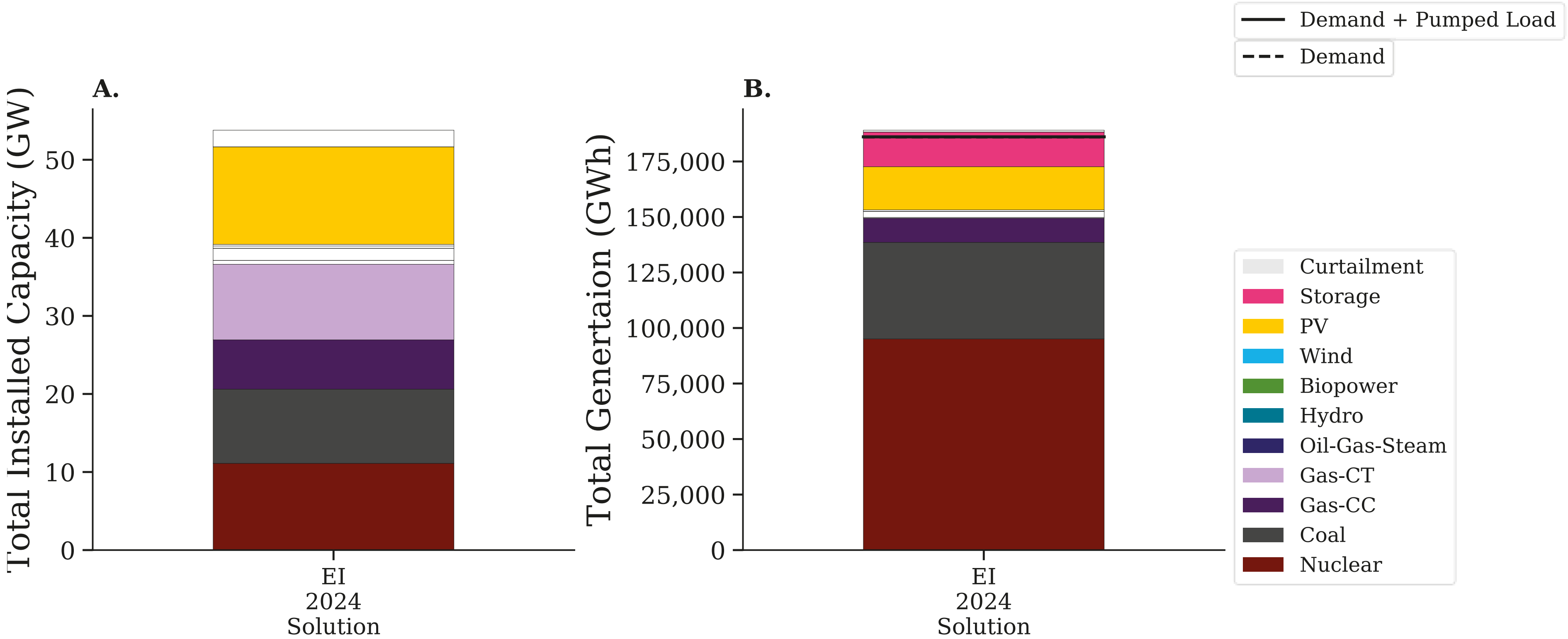
EI 2024 Base Transmission

Base system data

	EI	Duke
Buses	78,463	2,944
Lines	71,328	3,176
Transformers	27,901	890



Duke’s Total Installed Capacity and Generation



** Current model generates more with coal and less with gas than 2019 results

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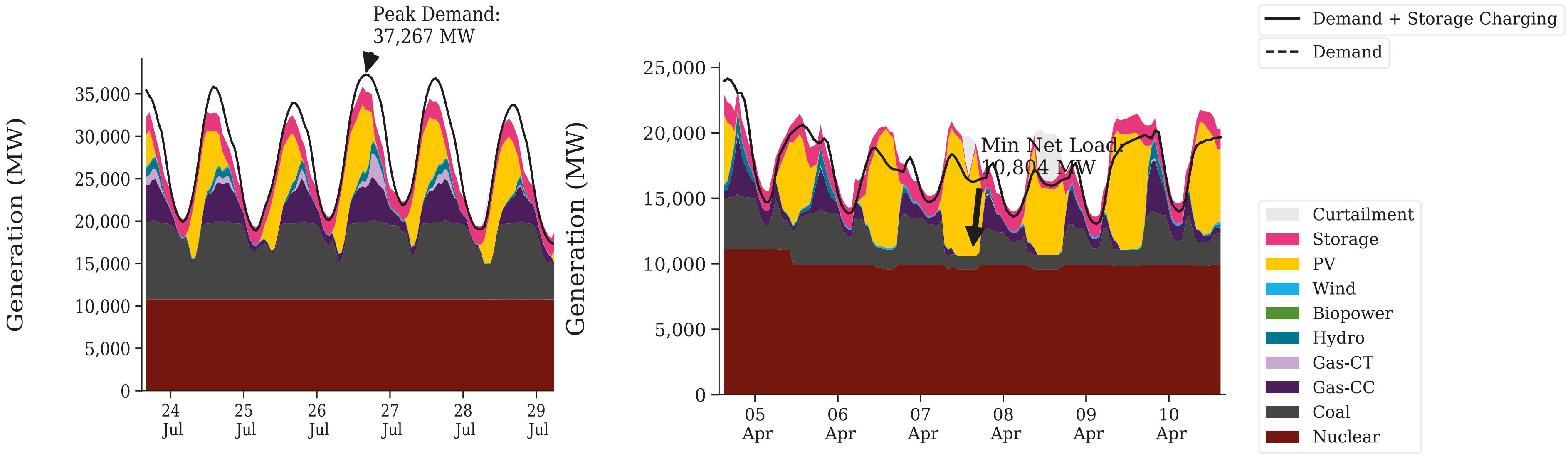
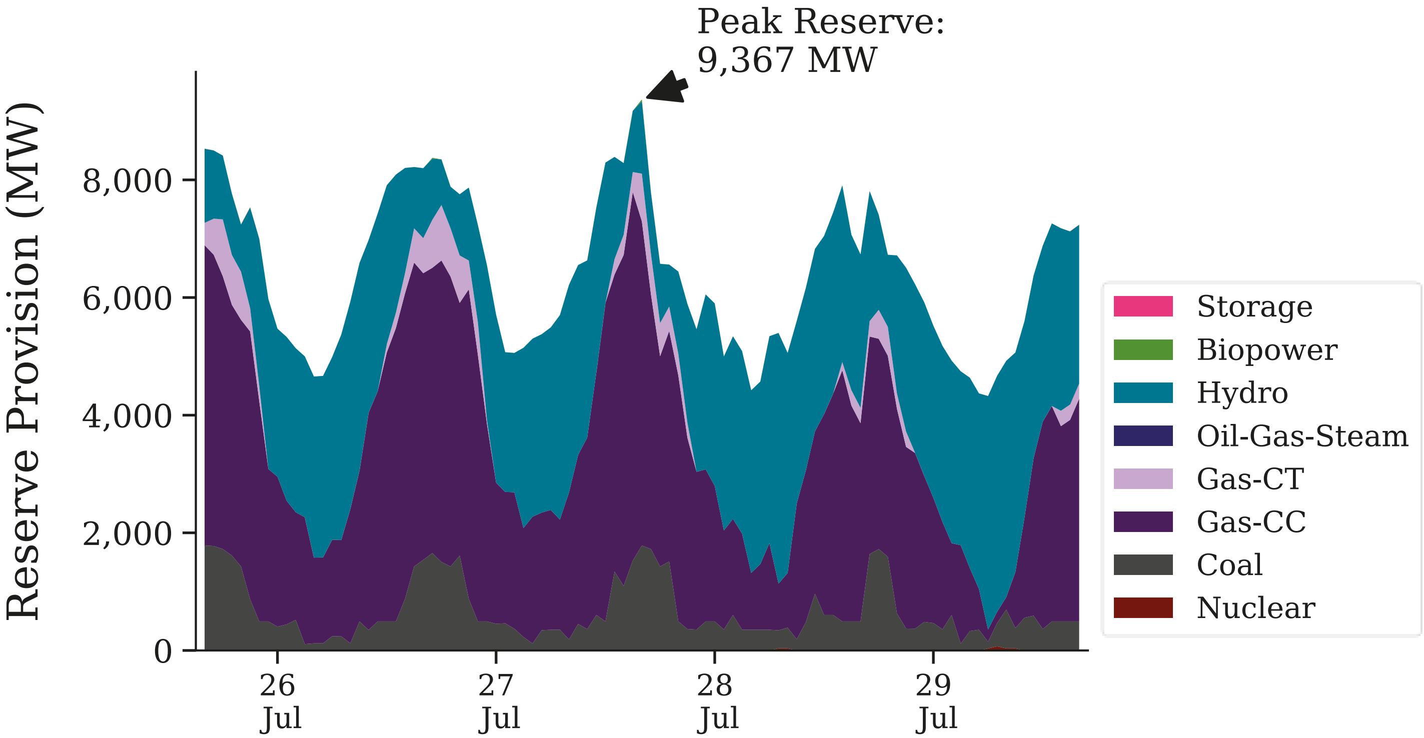
Duke's Dispatch during peak demand and Min Net Load



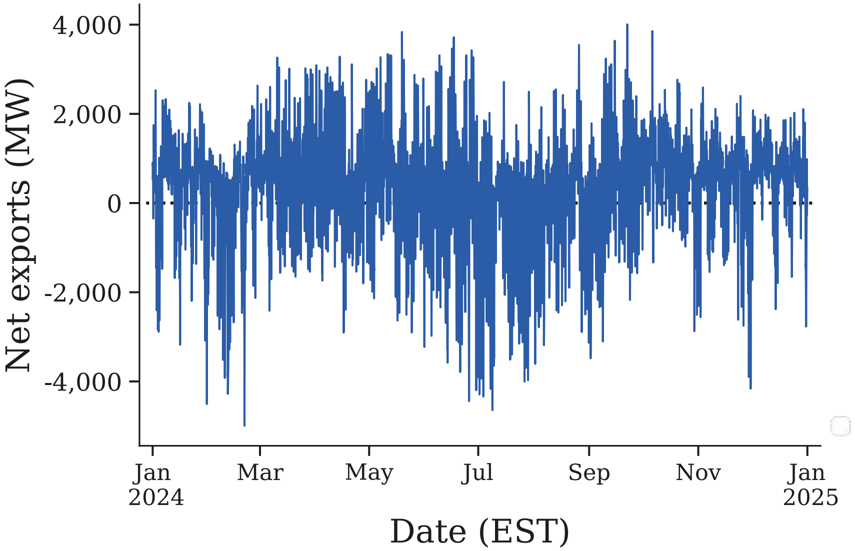
**Current model allows limited nuclear ramping; future runs to assume nuclear operates at 100% full capacity

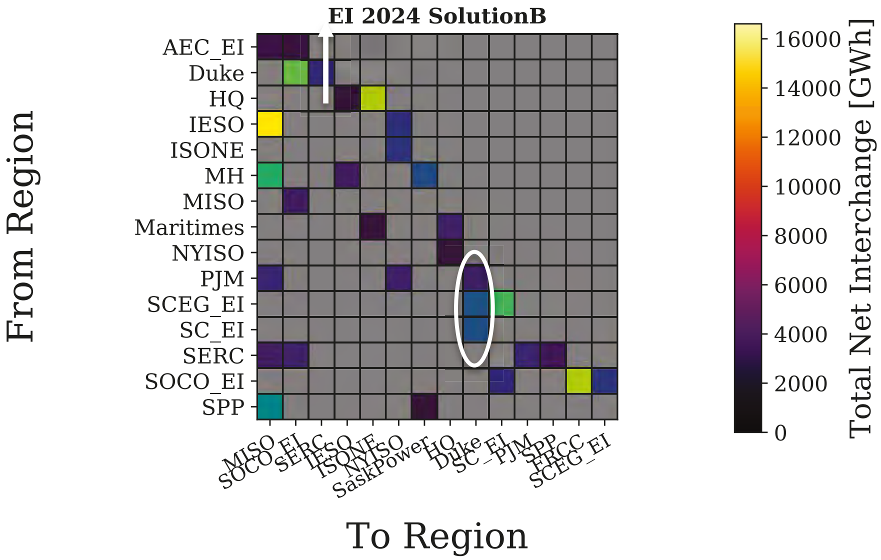
Reserve Provision



**Reserve provision for the entire SERC region

Duke’s Net Export (Export – Import)





SERC includes Duke, Southern Company (SOCO), South Carolina Electric & Gas Company (SCEG), Santee Cooper (SC), Aiken Electric Cooperative (AEC)

ReEDS-PLEXOS Comparison

- Production cost modeling more equipped to capture key operational issues:
  - large curtailment
  - dispatching of quick start units and ramping
  - periods of capacity shortages
- Comparison with of ReEDS and PLEXOS results can illustrate areas for refinement of planning results

ReEDS-PLEXOS Comparison Metrics

- Total generation by technology
- Are there hours of unserved load in the PLEXOS runs?
- VG Curtailment
- Transmission Utilization

ReEDS-PLEXOS Comparison Cases

- ReEDS BAU 2024 case vs. EI 2024 Nodal model (benchmarking)
- ReEDS 2030 70% emissions reduction
- ReEDS 2050 net zero

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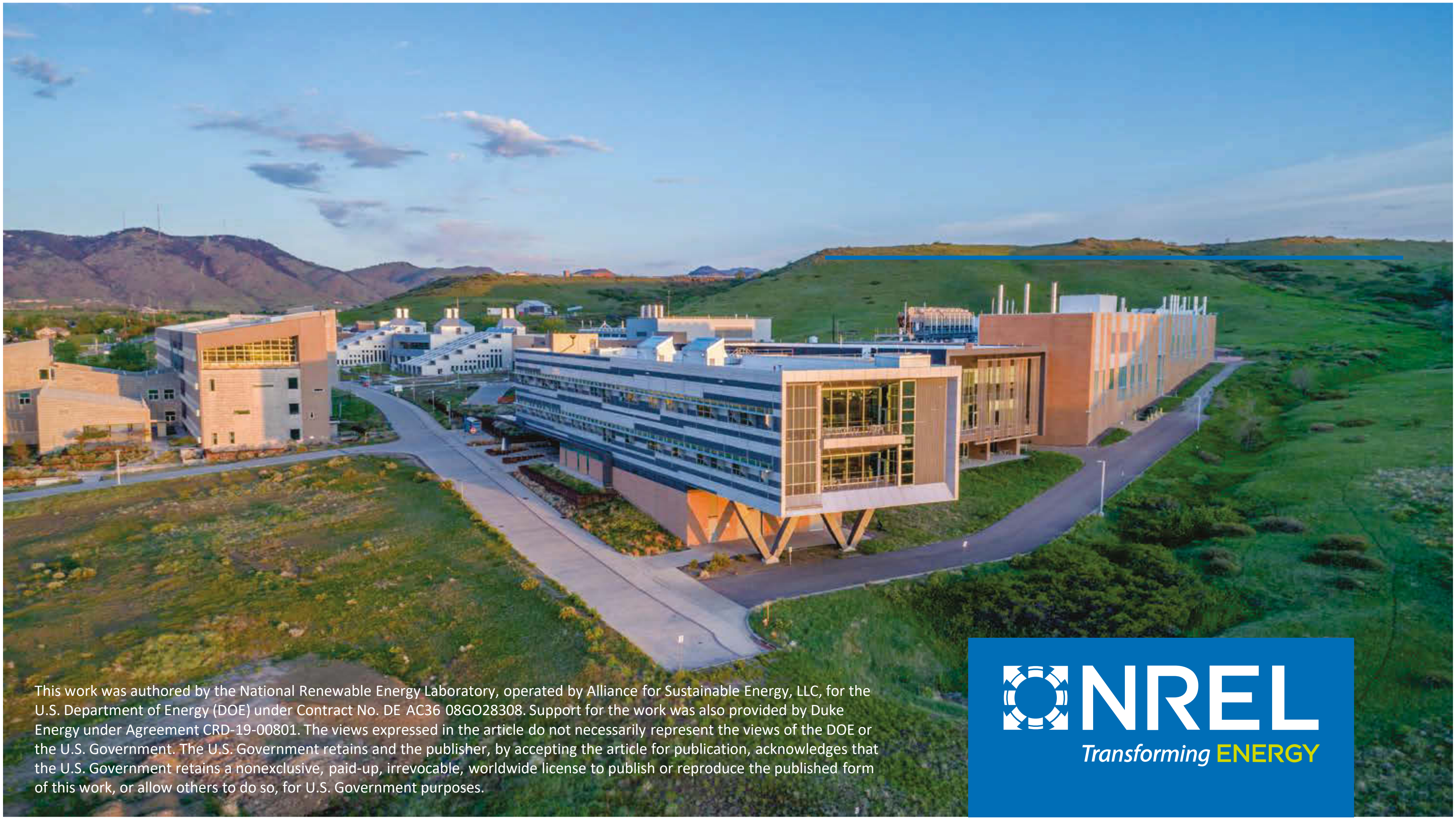
Summary and next steps

- Production cost modeling will provide detailed insight into operation of ReEDS buildouts with finer resolution than a capacity expansion model alone
- Next steps:
  - Refine the EI 2024 model
  - Translate ReEDS runs into zonal cases for running in PLEXOS



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NREL

Transforming ENERGY

NREL Phase 2 Capacity Expansion Results

Frequently Asked Questions

Modeling and Key Assumptions Questions:

1. What is a capacity expansion model? How does it differ from a production cost model and why are both being used for this study?

Capacity expansion models simulate mid- to long-term evolution of the power system and are frequently used as a component of long-term power system planning efforts. Capacity expansion models are important tools to help identify and evaluate long-term power system transformation. They synthesize the many different constraints and drivers of change and investment in the power sector, including prices of technologies and fuels, policies and regulations, technology performance and constraints, fuel supply constraints, and changes in load shape and total demand, to identify investment pathways and future systems that meet the policy and/or planning criteria.

Typically, capacity expansion models are formulated as “least-cost” optimizations—they identify generation and transmission investment and operational pathways that meet all power system and environmental/policy constraints at lowest cost. These constraints require that sufficient generation and transmission capacity exists to meet load (plus an additional margin for resource adequacy) at all times and in all regions, that sufficient resources exist to meet ancillary service needs, and that all policy and environmental requirements are met. The models typically use, as inputs, projections of future electricity demand, fuel prices, technology cost and performance, and policy and regulation.

Given that these models simulate both the investment in and operation of a power system over years to decades, they necessarily use simplified representations of grid parameters and power system operations—such as aggregated transmission representations, representative load shapes, and model or aggregate generating units—to ensure that they can be computationally solved in a reasonable amount of time. Furthermore, because such models typically seek a system-wide least-cost optimization, they implicitly assume perfect market conditions. As a result, they do not capture the effects of market failures (or imperfections)—e.g., asymmetric information, market power—nor do they typically capture risk, or non-economic/social drivers of investment. In this study, we use NREL’s Regional Energy Deployment System (ReEDS) model[1] for the capacity expansion modeling.

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[1] See https://www.nrel.gov/analysis/reeds/about-reeds.html for ReEDS model documentation.

By comparison, production cost models utilize higher resolution data on transmission, load, and other parameters to simulate how a power system buildout would operate. Such models explore routine power system operations, covering each hour of the year using detailed load, transmission and generation fleet data, and determine the commitment and operation schedule that minimizes production costs.[2]

Although capacity expansion models are often used by utilities in their planning processes, given that they make necessary simplifications and do not capture all power system factors or factors that can impact investment decisions, they are used as a component or core input to developing resource plans. Utility integrated resource plans (IRPs) involve further analysis of investment options, operational (production cost) modeling of future systems, and stakeholder engagement among other aspects that ultimately inform the plans.

In this study, the future systems identified through the ReEDS analysis will be further evaluated with more detailed production cost modeling (using the PLEXOS model) in the next step of Phase 2. It is important to note that investment pathways identified in the ReEDS analysis and are subject to change based on the findings of the production cost modeling analysis.

2. What are some of the key assumptions of the capacity expansion model?

Assumptions for this study were reviewed and agreed upon by Duke Energy. Cost assumptions were based on the NREL Annual Technology Baseline (ATB) moderate generation and storage cost and performance projections and Annual Energy Outlook (AEO) 2020 reference fuel cost projections for the South Atlantic region. This ATB case assumes falling capital costs for solar, wind, and battery storage over the period modeled. The AEO projects relatively stable coal and uranium prices, and natural gas prices that increase over this decade but remain relatively steady between 2030 and 2050, slowly climbing from $4.10 per MMBtu (2030) to $4.40 per MMBtu (2050). The ReEDS model includes a representation of all current federal and state-level emissions regulations, tax incentives, and portfolio standards relevant to the power sector. This includes a representation of the Virginia Clean Economy Act. Coal retirement dates are based on the current book life of the asset—which is consistent with Duke Energy's 2018 and 2019 IRPs—but with the option to retire the coal units earlier. New natural gas combined-cycle plants built in the Carolinas are assumed to incur a cost of $1.50 per MMBtu of natural gas fuel as a proxy for the cost of additional firm pipeline capacity. Existing nuclear plants are assumed to receive approval for relicensing. Additional details on the assumptions and input data used in the ReEDS model

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[2] See https://www.osti.gov/biblio/1233204 for additional discussion on the distinction between capacity expansion and production cost models.

can be found in the ReEDS documentation. This study also includes an analysis of a number of sensitivities to the cost assumptions and other key parameters.

3. **Why is NREL modeling the entire Carolinas for capacity expansion and not just the Duke Energy balancing areas (BAs) as was done in Phase 1?**

   The ReEDS capacity expansion model simulates the power sector evolution of the entire Eastern Interconnection in order to more accurately capture interactions between the Duke Energy system and its neighbors. For this portion of Phase 2, NREL is focusing the analysis on the Carolinas, which are spatially resolved within ReEDS into four balancing areas. The underlying boundaries of the ReEDS balancing areas do not perfectly align with the Duke Energy service territory; thus, results for only Duke Energy's assets are not feasible to produce and we report results for North Carolina and South Carolina (see question 7 for a map of the balancing areas).

4. **How did NREL determine scenario design and assumptions for the base case and the policy case? How were the emissions targets selected and designed?**

   The scenario design and assumptions were determined collectively by NREL and Duke Energy subject matter experts. Design and assumptions for the base case were chosen to reflect as best as possible existing and near- to mid-term future conditions. The policy case includes all the same assumptions but layers on the emissions targets—this allows for the exploration of the impact of those targets on investment pathways and the technology mix. The base case generally represents the current state with respect to the lack of any policy or required carbon limits. The policy cases assumed mass-based carbon dioxide emissions limits to represent the North Carolina Clean Energy Plan (CEP) target of 70% reduction carbon dioxide emissions by 2030 relative to 2005 levels and net-zero carbon by 2050. Because the CEP does not include interim target pathways, the modeled scenario did not include such a trajectory. Such targets (assuming a linear ramp between 2030 and 2050) would generally be expected to spread out more of the investment across time, but would be unlikely to substantially affect the portfolio of technologies built.

5. **Why does the study assume that Duke Energy's coal plants run through their book life?**

   The analysis assumes that Duke Energy's coal plants must retire by the end of their book life. This retirement date serves as an upper bound for each coal unit; the model also includes logic that allows a coal plant to be retired prior to the end of its book life if the plant's net-value is unfavorable. However, in the scenarios explored, no early retirements are observed. The core scenarios assume that fossil units are allowed to provide operating reserves and in the resulting simulations of the scenarios coal units remain online to help meet reserve requirements. However, it should be noted that even in the base case the utilization of these plants is reduced substantially over time, and the policy case eliminates coal use for energy provision in North Carolina in 2050.

6. **In the simulations, are any of the other regions assumed to have net zero targets?**

The base case assumption includes the Virginia Clean Economy Act (VCEA), as well as the existing renewable portfolio standards, clean energy standards, and carbon emissions policies (e.g., Regional Greenhouse Gas Initiative, or RGGI) for other states passed as of June 2020. In addition, we examine a sensitivity that explores the potential impacts of an Eastern Interconnection-wide net-zero target in 2050.

7. **Are the Carolinas modeled as one transmission area (i.e., no transmission limits between Duke Energy Progress (DEP), Duke Energy Carolinas (DEC), and Dominion South Carolina)?**

Within ReEDS, the Carolinas are represented as four balancing areas, two each in North and South Carolina. These balancing areas have broadly similar boundaries to the DEP/DEC footprint, but because those utility territories span across states they are not analogous. ReEDS captures the aggregate transmission limits between each of the four geographic balancing areas, but it does not capture the transmission within each modeled balancing area. The figure below highlights the balancing area and transmission representation of the Carolinas in ReEDS.

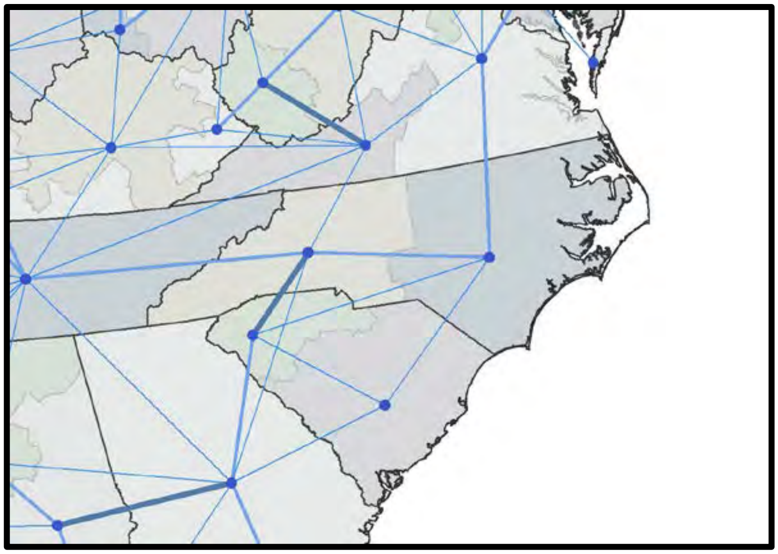

Figure 1: ReEDS representation of the Carolinas.

8. **What are the assumptions around energy exports and imports?**

Overall, the ability to exchange energy between regions is governed by the transmission limits, specifically the assumed thermal rating of the aggregate transmission capacity between regions. Power flow in ReEDS is represented as simple pipe-flow between regions. However, in addition to these physical limits, this analysis assumes a hurdle rate of approximately $10/MWh for energy imported by the Carolinas from its neighbors or exported from the Carolinas to its neighbors. This assumed hurdle rate is intended to capture existing challenges in inter-regional coordination and the associated costs to secure transmission for imports and exports. As a result, imports to or exports from the Carolinas will only occur if the difference in the price across regions exceeds this assumed hurdle rate. Lastly, we assume that the Carolinas must attain all firm capacity resources needed to meet its planning reserve from within the geographic boundary of the Carolinas. Although the optimization considers costs in all regions, the costs reported for the Carolinas exclude the costs of capacity builds outside the Carolinas, but do include the costs (or revenues) associated with any imports (or exports).

9. Does this study evaluate reliability or resilience?

The capacity expansion model used in this study, ReEDS, includes resource adequacy constraints to ensure that sufficient capacity is available to meet load at all times. These constraints are used as a proxy for formal reliability analysis, which involves computationally intensive AC power flow simulations that are not feasible to include within a long-term investment model or even within a production cost model. Instead, within ReEDS a resource adequacy proxy is used. The model dynamically calculates and assigns the capacity credit (the portion of a given plant’s nominal capacity that can be relied on during times of system stress, such as high load or low renewable resource quality hours) of both variable generation assets (wind and PV) and non-variable generation assets (e.g., natural gas combined cycle, nuclear) and ensures that during the hours of highest system stress, sufficient capacity (plus a margin for reserves) is available.

Furthermore, NREL will use production cost modeling to evaluate the robustness of the system and identify if the ReEDS buildout can serve load in all hours of a representative year. This type of analysis still differs from formal steady-state and transient reliability analysis. However, it is worth noting that to the extent that the historical representative weather year used for the production cost modeling captures severe weather (e.g., loss of solar output during hurricane), NREL’s modeling can assess the ability of the system to operate during extreme events. The modeling will not include a full evaluation of system resilience to major disasters, transmission line outages, or other hazards. Such analysis would require more detailed modeling and can be conducted, but it is beyond the scope of the current study.

10. What are the assumptions on energy efficiency and demand response?

The AEO 2020 reference load projections account for consumer and utility adoption of energy efficiency measures over the next few decades. After including these estimates, these projections estimate an approximate 0.9% continuous annual load growth rate in the Carolinas from 2020 to 2050. After consulting with Duke Energy, NREL revised the projection to represent additional energy efficiency adoption by reducing annual load growth rates to 0.6%. Demand response resources are not considered in the analysis.

Case results questions

11. What are the key takeaways from this part of Phase 2?

Overall, the results reinforce the value of diversity in renewable resources as well as flexible dispatchable resources, particularly over the longer planning horizon. The emissions targets are shown to be achieved through rapid deployment of new PV, storage, and wind resources. In the near- to mid-term, PV and storage account for the majority of the new builds with onshore wind playing a smaller role. However, over the longer term, as the capacity value of solar decreases with higher levels of deployment, the economics for wind become more favorable leading to further deployment of both onshore- and offshore-wind resources beginning in the 2030s and growing through the 2040s.

These results are driven in part by the assumed declining costs and increasing performance of solar and storage technologies, along with a gas price forecast substantially above observable market gas prices over this period. However, explored sensitivities to the assumptions about future solar, storage, and wind costs as well as natural gas prices show that although alternative future technology or fuel costs can impact the level of deployment of different technologies (e.g. reduced PV deployment under the High Cost Solar/Low Cost Gas sensitivity), the major trends observed are consistent: solar and storage play a larger role in the near term with wind assets being deployed at increasing rates later in the analysis period. This does not rule out that other sensitivities could result in substantial changes to the resource mix.

Under the net-zero 2050 policy case for North Carolina, a rapid buildout of solar, storage, and wind in the final years leading to 2050 is observed to meet winter and summer peaks and eliminate the last 5 million metric tons of CO_2. We note that this study did not evaluate the feasibility of the implied rate of siting and interconnection of the resources identified in the ReEDS analysis. Limitations on the rate of siting and/or interconnection could require spreading resource deployment across more time.

12. What is the significance of the base case?

The base case is meant to be a source of comparison for evaluating the technology buildout, emissions trajectory, and system costs relative to the policy case. The base case is not intended to be a forecast of future evolution, but rather a reference projection that adopts reasonable assumptions for future variables over the long term (such as capital and fuel costs) with which to compare the policy case.

13. Does the large amount of solar indicate no role for wind?

While the analysis identifies the high value of solar and storage resources, both onshore and offshore wind are deployed jointly to meet the net-zero target and future energy demand. Substantially greater deployment of wind is observed in sensitivities exploring alternative future capital costs and technology performance, and broader Eastern Interconnection-wide decarbonization. This indicates that under certain conditions, wind will play an even greater role in the Carolinas. In addition, supply chain or logistical constraints on solar and/or storage deployment or siting could lead to a near-term need for further wind deployment. The importance of wind in these instances illustrates the benefits of having a diverse mix of resources for achieving deep decarbonization.

14. Why do the results show a large jump in installed capacity in 2050 in the policy case?

The large jump in resources occurs, in part, due to the myopic nature of the model used—it is a sequential model that optimizes for existing conditions, including policy constraints. Therefore, the optimization does not consider future changes in the stringency of the target that could result in alternative resource mixes. The policy case includes a net-zero CO_2 emissions target for 2050 for North Carolina. This constraint becomes active in 2050 without interim targets beyond the 70% CO_2 reduction (relative to 2005 levels) required in 2030; accordingly, the least-cost solution from the myopic model is to wait until the constraint is binding to build sufficient capacity to meet this target. As noted above, the ReEDS model does not include constraints on the rate of buildout of new capacity; potential limiting factors such as supply chain, permitting, or interconnection/grid upgrades may require that the buildout needed to achieve the 2050 target be spread out over more time, which could impact both the total costs and timing of those costs.

15. Why do emissions in the policy case flatline from 2030 to 2035?

The mass-based CO_2 emissions limits for the policy case were set at discrete points, 2030 and 2050, with no additional interim targets. Therefore, there is no incentive represented within model to achieve additional reductions on a linear emissions trajectory between the targets. In practice, emissions policies often create flexibility in timing of investments and associated emissions reductions with mechanisms such as banking and borrowing of allowances. Such policy mechanisms, allow for a smoother trajectory of investment and associated emissions reductions, although outcomes are not predetermined and banking and borrowing can result in reductions/investment being concentrated more in the nearer-term or long-term.

16. Is the study evaluating a specific carbon policy tied to the CEP goals?

For the purposes of modeling, a policy must be assumed in the model, and we assume a mass-based CO_2 emissions limit, without the option to trade allowances, bank and borrow allowances, or use alternative compliance methods (e.g., offsets). However, our intent is not to evaluate the merits of alternative policies that might drive deployment toward this goal. Rather, the intent of the NREL study is to explore potential technology pathways to achieving a decarbonized Duke Energy power system in the Carolinas, and to estimate the associated cost of such pathways.

Technology-based questions:

17. Is the capacity credit (or the share of nominal capacity that contributes to net-peak demand reduction) of battery resources constant, or does it drop as you add more?

ReEDS includes a detailed module for endogenously calculating the capacity credit of storage and variable renewable energy technologies. This module uses detailed hourly load, wind, and solar data for a full-year (8,760 hours) to calculate the capacity credit for new wind, solar, and storage technologies. As more storage resources are added to the system, the net load peaks become wider and flat (due to the shifting of load from peak to trough), which decreases the capacity contribution of a storage technology with a specific duration of storage (e.g., 4-hr),), all else equal. However, the declining capacity credit can be mitigated by increasing the duration of new storage technologies built, e.g., from 2-hr to 4-hr, or 4-hr to 6-hr. Furthermore, increasing penetrations of solar PV assets can shift the peak to the evening (from afternoon) and also narrow the peak's duration; this effect is synergistic with storage as it allows shorter-duration storage to maintain its capacity credit. These effects are all captured endogenously within the ReEDS model—they are dynamic with the system composition and load.

18. What are the assumptions around pumped hydro storage?

In addition to the pumped hydro storage resources that already exist in the region, all cases assume that 1,600 MW of 12-hour pumped hydro storage capacity is added 2035. This could be thought of interchangeably with an equivalent amount of 12-hour battery energy storage.

19. Can excess solar generation move between the four BAs?

Yes, within the four Carolina BAs represented, energy generated from any technology can pass between regions, but the amount is limited by the available transmission capacity between these modeled BAs and informed by the assumed hurdle rate.

20. What's the assumption for coal unit retirements in the rest of the Eastern Interconnection?

For existing plants in the Eastern Interconnection, the ReEDS model uses a combination of information on announced plant retirements and technology-specific lifetimes to determine retirements. This retirement date represents that latest existing coal units could operate; the model can also retire plants whose costs exceed the value they provide to the system before its announced retirement date.

Comparisons to other recent long-term planning studies of the region

21. How does the model used for this study and the associated modeling results compare to the models used and results for other recent studies of the region, e.g., the Duke Energy IRPs, or ongoing Nicholas Institute study being conducted for the State?

In comparing various modeling analyses, key aspects to consider are: 1) the assumptions and input data; and, 2) the model structure and underlying methods. Assumptions and input data, such as future technology costs and performance assumptions, projected fuel prices, load, resource supply (e.g., wind or solar resource availability), and other baseline policy or market conditions can be compared, evaluated, and, with some effort, even harmonized across studies if desired. However, model structures (spatial and temporal resolution, spatial and temporal extent), and methods, including the optimization approach and the methods used to capture complex power system processes and often non-linear phenomena (e.g., generator dispatch, resource adequacy and capacity credit of variable resources and storage, and transmission/power flow) often differ substantially, and these structural and methodological differences can lead to differences in results.

Given this, it is challenging without a deeper analysis to identify the full set of drivers that can lead to different results of two seemingly analogous scenarios simulated by different models.

The ReEDS model is designed to analyze scenarios that achieve high penetrations of variable renewable energy and storage technologies. To that end the model includes very high spatial and temporal resolution of wind and solar resources to characterize to the best degree possible resource availability and quality. The model also employs hourly chronological algorithms (re-evaluated between solve years) to dynamically assign capacity credit to variable resource and storage assets, and minimum curtailment rates to variable resources. These features allow for a robust treatment of both the values of variable renewable and storage assets as well as the challenges operating systems with high penetrations of such technologies.

For further information on ReEDS, see https://www.nrel.gov/docs/fy20osti/74111.pdf.

For further discussion on the representation of wind and solar technologies within long-term capacity expansion models (including ReEDS, IPM, NEMS, and REGEN), see https://www.nrel.gov/docs/fy18osti/70528.pdf.

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