Assessing Alternatives to the Proposed Chesterfield Energy Reliability Center (CERC)

Prepared on behalf of Southern Environmental Law Center (SELC)

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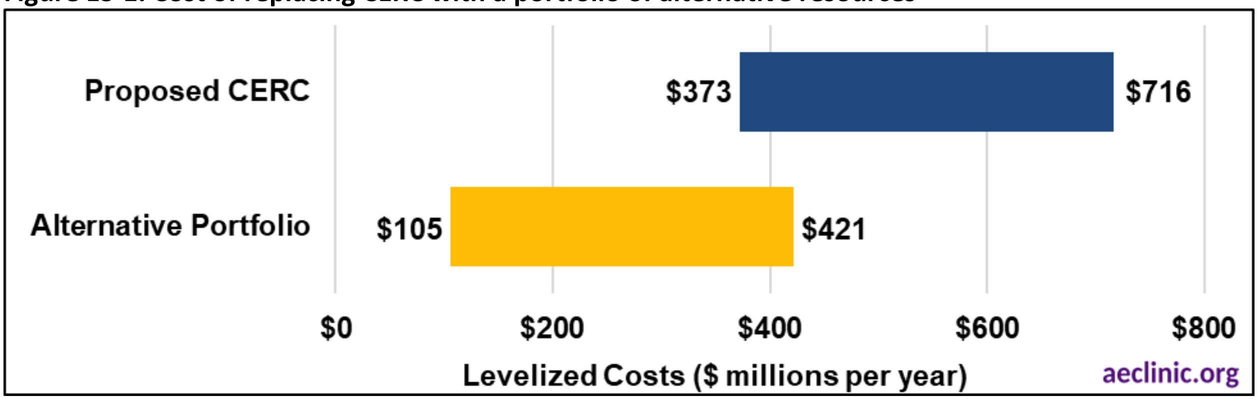
Executive Summary

The Virginia Electric and Power Company, d/b/a Dominion Energy Virginia (Dominion) is proposing a 1,000-megawatt (MW) gas-fired combustion turbine facility in Chesterfield, Virginia: the Chesterfield Energy Reliability Center (CERC). This Applied Economics Clinic (AEC) report—prepared on behalf of the Southern Environmental Law Center (SELC)—presents an alternative resource portfolio of solar, wind and storage that provides the same annual energy and peak capacity as CERC, but at a lower cost (see Figure ES-1).

Figure ES-1. Cost of replacing CERC with a portfolio of alternative resources



Dominion claims that CERC is necessary to serve growing energy and capacity needs and manage extreme weather events. A mix of solar, wind and storage, however, can meet these same needs more cheaply. In its 2023 IRP, Dominion claims that storage resources can only be built later in its planning period and that solar cannot provide sufficient black start capability. Both claims are false or misleading: Dominion argues that storage cannot be built until there are more renewables and that renewables cannot provide black start capability without storage. Taking these two critiques together, the Company finds—erroneously—that neither storage nor renewables can provide the energy services available from CERC. Dominion's critical error is its failure to consider the benefits that are possible when solar and storage are combined: In fact, these resources can provide black start capability. Considered singly, renewables compare poorly to gas on peak capacity and storage provides no generation. Combined together, renewables and storage provide a low-cost, low-risk resource package that can meet growing customer demand and contribute to reducing greenhouse gas emissions from Virginia's electric sector.

Portfolios consisting of solar, wind, and storage resources cost less than CERC to build and operate. AEC examined an alternative portfolio that combines solar, wind and storage that matches CERC's peak capacity and slightly exceeds its annual energy. Notably, the alternative resource portfolio presented in this report includes neither energy efficiency nor demand response, both of which have the potential to lower peak energy demand and reduce customer costs further. Undertaking energy efficiency investments at rates comparable to those required under the Virginia Clean Economy Act would result in energy savings equivalent to the generation expected from CERC.

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I. Introduction

In August 2023, the Virginia Electric and Power Company, d/b/a Dominion Energy Virginia (Dominion), submitted an air permit application for the construction of the Chesterfield Energy Reliability Center (CERC)—a 1,000-megawatt (MW) gas-fired combustion turbine facility—in Chesterfield, Virginia.[1] In its *2023 Integrated Resource Plan* (IRP), Dominion put forward five alternative plans for the acquisition and retirement of generation and storage resources along with the anticipated customer demand and electric load those resources are needed to meet.[2] All five IRP alternatives plan for an increase of at least 970 MW in gas capacity—a similar amount to the proposed 1,000-MW CERC facility. Dominion describes two needs that it hopes to address with CERC: (1) providing a resource mix that can respond to extreme weather events, and (2) providing energy and capacity in response to growing customer load.[3]

This Applied Economics Clinic (AEC) report, prepared on behalf of the Southern Environmental Law Center (SELC), evaluates Dominion's case for the construction of CERC and presents an assessment of an alternative resource portfolio that would provide the same energy and capacity needs. The report begins in Section II with an overview of Dominion's proposed CERC facility as well as the Company's obligations under Virginia's climate legislation. Section III examines: (1) regional customer electric demand forecasts as well as Dominion's modification to those forecasts for use in its own planning documents, and (2) Dominion's arguments for selecting CERC as its preferred resource rather than alternative resources available, including solar, storage, wind, energy efficiency, and demand-side management. Section IV discusses alternatives to gas-fired generation for meeting electric demand while providing reliable electric service in Virginia and presents comparisons of costs, frequency of operation, and ability to operate at time of peak customer demand as assigned in regional markets. Section V presents an alternative resource portfolio of solar, wind, and storage resources capable of providing the same annual energy and peak capacity as CERC. Section VI concludes the report with key takeaways.

II. Dominion's Proposed CERC Facility

Headquartered in Richmond, Virginia, Dominion Energy, Inc. provides electric service to approximately 7 million customers in fifteen states.[4] Dominion Energy, Inc. owns and operates 29,500 MW of electric generating capacity,[5] 20,600 MW of which is located in Virginia.[6] Dominion's subsidiary, Virginia Electric and

[1] Dominion Energy Virginia. August 2023. *Chesterfield Energy Reliability Center Project: Supplemental Revision to Prevention of Significant Deterioration Permit Application.* Available at: https://www.deq.virginia.gov/home/showpublisheddocument/19804/638314272031130000

[2] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. Presented to the Virginia State Corporation Commission and the North Carolina Utilities Commission. Available at: https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/company/2023-va-integrated-resource-plan.pdf

[3] Dominion Energy Virginia. November 2023. *Chesterfield Energy Reliability Center Informational Meeting.* Available at: https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/natural-gas/cerc/cerc-111623-presentation.pdf, p.10

[4] (1) The states include: Colorado, Connecticut, Georgia, Idaho, Illinois, Indiana, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Utah, Virginia, West Virginia, Wyoming. Source: Dominion Energy. N.d. "Company Profile." [Web Archive]. Available at: https://web.archive.org/web/20170703035858/https://www.dominionenergy.com/about-us/company-profile; (2) Dominion Energy. 2024. *Form 10-K*. Available at: https://investors.dominionenergy.com/financials-and-reports/sec-filings/default.aspx, p.11

[5] Dominion Energy. 2024. *Form 10-K*, p.11

[6] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.77

Power Company, submits an IRP to the State Corporation Commission for the Company's Virginia operations. (Throughout this report, AEC refers to Virginia Electric and Power Company as "Dominion" and utilizes Dominion Energy Virginia's 2023 IRP as the basis for analysis.)

Dominion's 2023 IRP does not propose CERC specifically but does present a generic gas-fired combustion turbine plant with a 970 MW nameplate capacity, which closely matches CERC's profile.[7] The proposed CERC facility will be made up of four 250-MW gas-fired combustion turbines—for a total capacity of 1,000 MW[8]—with a planned maximum share of operation (or "capacity factor") of 37 percent.[9] In a November 2023 informational meeting to explain the characteristics and objectives of CERC (called "CERC presentation" throughout this report), Dominion asserted that the proposed plant may operate in the future on gas blended with up to 10 percent hydrogen but did not provide a timeframe.[10] If constructed, Dominion appears to be considering two locations for CERC: (1) a 94-acre site at the James River Industrial Center in Chesterfield, Virginia near the Chesterfield Power Station (see Figure 1 below); and (2) the Chesterfield Power Station site itself.[11]

In its CERC presentation, Dominion described the proposed CERC as an "always-ready" and "dispatchable" "reliability facility" that will operate when needed as a source of "backup generation when other resources are unavailable or insufficient to meet customer needs."[12] (Other resources described by Dominion as "dispatchable" include small modular nuclear reactors and long-duration storage.[13]) When justifying (in its public promotional materials[14]) its claim that a gas-fired source of backup generation is necessary to address reliability concerns Dominion highlights two needs:

1. **Providing a resource mix that can respond to extreme weather events.** Winter Storm Elliot—a highly damaging storm that caused numerous power outages in the Eastern United States in Winter 2022[15]—offers an argument for a need for generation that can operate before sunrise when Winter demand can peak while solar resources are not available until later in the morning.[16]

2. **Providing energy and capacity in response to growing customer load.** This increase in customer demand comes from Dominion's expectation of industry and residential growth, as well as electrification of vehicles and heating—necessitating additional capacity.[17]

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[7] Ibid, Appendix 5P.

[8] Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center." Available at: https://www.dominionenergy.com/projects-and-facilities/natural-gas-facilities/chesterfield-energy-reliability-center

[9] Dominion Energy Virginia. November 2023. *Chesterfield Energy Reliability Center Informational Meeting*, p. 4; This proposed capacity factor is calculated by taking the plants' maximum proposed operating hours in a year (3,240 hours) and dividing it by the number of hours in a year.

[10] Ibid, p.4

[11] (1) Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*, p. 77; (2) Dominion Energy. November 2023. *Chesterfield Energy Reliability Center Informational Meeting*, p. 2; 4; (3) Dominion Energy. May 24, 2024. "RE: 500 Coxendale Road, Air Permit." Available at: https://bloximages.newyork1.vip.townnews.com/richmond.com/content/tncms/assets/v3/editorial/f/48/f4809572-34ad-11ef-8263-f3fdbe00414a/667da6de96471.pdf.pdf

[12] (1) Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*, p. 4, 6; (2) Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center."

[13] Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center."

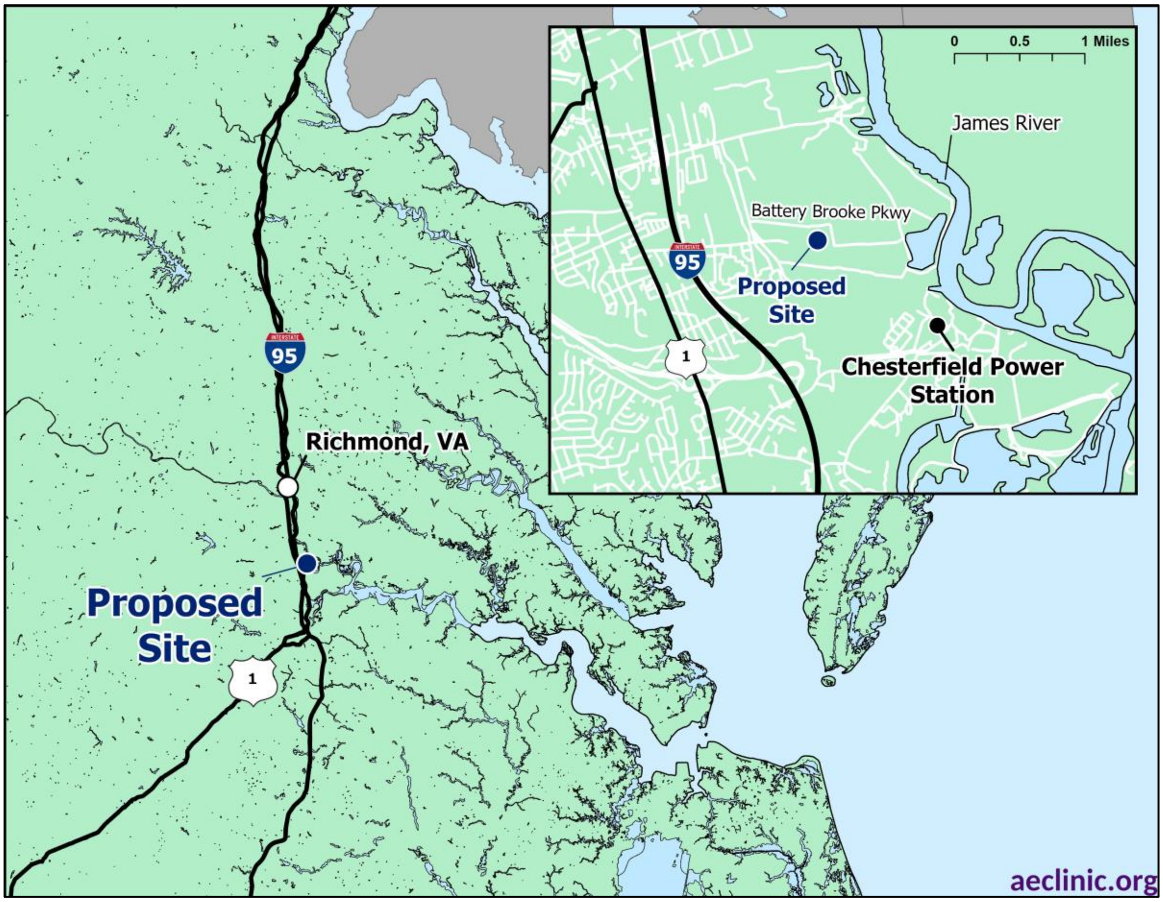
[14] Ibid.

[15] FERC. 2023. "FERC, NERC Release Final Report on Lessons from Winter Storm Elliot." Available at: https://www.ferc.gov/news-events/news/ferc-nerc-release-final-report-lessons-winter-storm-elliott

[16] Dominion Energy Virginia. November 2023. *Chesterfield Energy Reliability Center Informational Meeting*. p.10

[17] Ibid.

Figure 1. Proposed CERC site in Chesterfield, Virginia



Data source: Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center." Available at: *https://www.dominionenergy.com/projects-and-facilities/natural-gas-facilities/chesterfield-energy-reliability-center*.

The policy landscape in Virginia associated with clean energy targets brings about important considerations for Dominion related to the addition of a gas-fired combustion turbine plant such as CERC. (Gas-fired combustion turbines, like CERC, often serve as "peakers", running primarily at times of peak customer demand.[18] Dominion does not call CERC a "peaker"; it instead uses the term "always-ready".[19]) For example, Virginia's 2020 Clean Economy Act (VCEA) requires Dominion to:[20]

1. Comply with Virginia's Renewable Portfolio Standard (RPS) requiring electric distributors to provide an increasing share of energy sales from renewable resources.[21] The required sales of renewable energy will rise from 23 percent of energy sales in 2024 to reach 100 percent of energy sales in 2045.[22]

[18] A typical gas-fired peaker plant operates at a capacity factor between 10 and 15 percent, while the proposed CERC facility is expected to operate at a 37 percent capacity factor. CERC's expected capacity factor is lower than that of non-peaking or "firm" gas-fired plants, which operate above 50 percent capacity factor.

[19] Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center."

[20] Under Virginia law, a Phase II utility is an investor-owned incumbent electric utility that was, as of July 1, 1999, bound by a rate case settlement whose application extended beyond January 1, 2002. Source: Virginia Law. "§ 56-585.1. Generation, distribution, and transmission rates after capped rates terminate or expire." Available at: https://law.lis.virginia.gov/vacode/56-585.1/

[21] General Assembly of Virginia. 2020. *Virginia Clean Economy Act (VCEA).* Available at: https://lis.virginia.gov/cgi-bin/legp604.exe?201+ful+HB1526ER+pdf

[22] Dominion Energy Virginia. N.d. "Renewable Energy Portfolio Standard Program: Mandatory RPS Program established from the VCEA." Available at: https://www.dominionenergy.com/virginia/rates-and-tariffs/rps

2. Implement energy efficiency programs that achieve cumulative energy savings equivalent to 5 percent of 2019 retail electric sales by the end of 2025.[23]

3. Petition to develop 16,100 MW of onshore wind and solar by 2035. These petition requirements are phased, with 3,000 MW required by the end of 2024, an additional 3,000 MW by the end of 2027, 4,000 MW more by the end of 2030, and the last 6,100 MW by the end of 2035.[24]

4. Develop 2,700 MW of energy storage capacity by the end of 2035.[25]

III. Dominion's planning process

To determine which resources it will add and retire, Dominion conducts a biennial planning process, which is described in its 2023 IRP. This report section reviews the 2023 IRP and describes the role of gas in each of Dominion's five alternative resource plans, the importance of load growth in shaping those plans, and Dominion's assessment of renewable and storage resources. Dominion's 2023 IRP summarizes the Company's priorities for resource additions and retirements over the fifteen-year period between 2024 and 2038 using the following steps:[26]

1. **Electric demand forecasts:** Dominion develops long-term annual and peak customer electric requirements forecasts. For this purpose, Dominion modifies forecasts developed by PJM. (PJM is the independent system operator that oversees the wholesale electric grid for thirteen states, including all of Virginia.[27])

2. **Assessing available resources:** Dominion compares available supply- and demand-side resources to its expected peak load and reserve requirements and assesses the feasibility of additional supply- and demand-side resources. Dominion uses fuel price, emissions cost, maintenance cost, and resource cost input assumptions to assess supply-side resources. Dominion uses cost-benefit screening, an assessment for deciding which demand-side resources to pursue based on a calculation of program cash flow using program costs, the costs of customer incentives, and the costs of evaluation, measurement, and verification.[28] These costs are compared to benefits such as avoided supply-side capacity or avoided energy costs that are netted against program costs.[29]

3. **Developing and modeling alternative plans:** Dominion incorporates demand forecasts from Step 1, resource information from Step 2, regulatory requirements such as those of Virginia's RPS, and expected constraints on capacity purchased from the PJM grid into the energy modeling software PLEXOS[30] to develop a set of alternative resource plans.[31] Dominion also includes forecasted fuel prices, emissions costs, maintenance costs, and resource costs as inputs. Each plan is created to

[23] General Assembly of Virginia. 2020. *Virginia Clean Economy Act (VCEA).*
[24] Ibid.
[25] Ibid.
[26] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.40
[27] PJM. 2023. "Territory Served." Available at: https://www.pjm.com/about-pjm/who-we-are/territory-served
[28] Ibid, p.108
[29] Ibid, p.108
[30] Energy Exemplar. "PLEXOS: The Energy Analytics and Decision Platform for all Systems." Available at: https://www.energyexemplar.com/plexos.
[31] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.40

evaluate how resources perform under different future scenarios that may occur given market or regulatory uncertainties.

4. **Results:** Dominion uses the PLEXOS model to calculate the net present value of system costs of each alternative plan and its mix of resource additions and retirements. System cost outputs include the variable costs of each resource, the costs of capacity purchases from the market, and fixed costs.

Dominion's alternative resource plans

Using this modeling process, Dominion explores a limited set of potential future resource portfolios to meet customer needs. In its 2023 IRP, Dominion evaluates five alternative resource plans (see Table 1 for a summary of the resource mix, costs, and emissions associated with each plan).[32]

Table 1. Dominion's 2023 IRP plans and their capacity additions

		Plan A	Plan B	Plan C	Plan D	Plan E
Total System Costs (NPV, $ billions)		$109.7	$127.7	$127.2	$140.9	$138.0
Approximate CO_2 Emissions from Company in 2048 (Million Metric Tons)		44	36	36	0	0
15 Year	Solar (MW)	10,800	10,875	10,800	10,875	11,094
	Wind (MW)	3,040	3,040	3,040	3,040	3,040
	Storage (MW)	1,050	2,370	2,220	2,370	2,910
	Nuclear (MW)	-	804	804	1,608	1,072
	Gas-Fired (MW)	5,905	2,910	2,910	970	970
	Retirements (MW)	-	-	-	-	-
	Capacity Purchases (MW)	27,100	21,900	28,200	25,100	29,100
Total Capacity (MW)		**47,895**	**41,899**	**47,974**	**43,963**	**48,186**
25 Year	Solar (MW)	19,800	19,875	19,800	23,955	24,294
	Wind (MW)	3,220	3,220	3,220	3,220	3,220
	Storage (MW)	3,960	5,190	5,220	9,780	10,350
	Nuclear (MW)	-	1,608	1,608	4,824	4,288
	Gas-Fired (MW)	9,300	2,910	2,910	970	970
	Retirements (MW)	-	-	-	11,399	11,399
	Capacity Purchases (MW)	41,500	64,400	70,800	97,500	100,900
Total Capacity (MW)		**77,780**	**97,203**	**103,558**	**151,648**	**155,421**

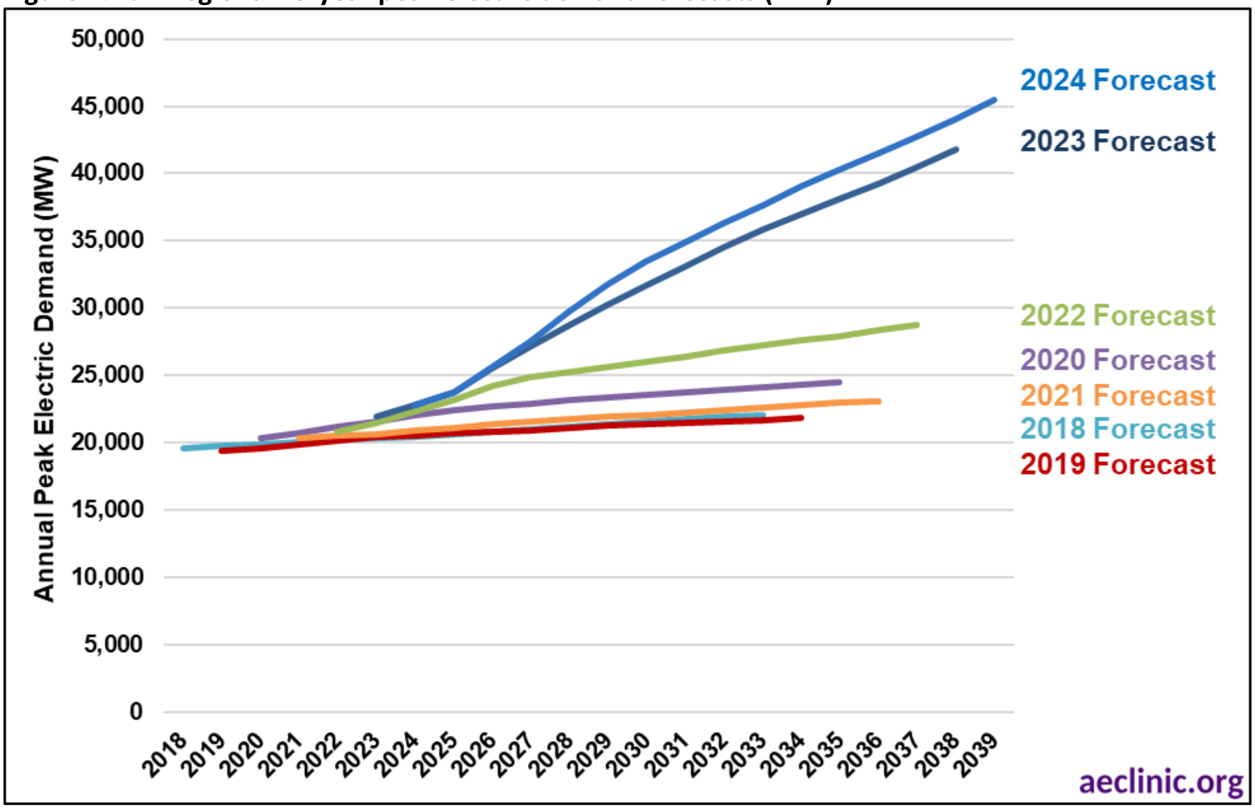
Data source: Dominion Energy Virginia. May 1, 2023. Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan. Executive Summary Table: 2023 Plan Results, p.4.

[32] Ibid, pp.1-2

Customer demand forecasts used by PJM and Dominion

PJM's expectations for peak electric demand have dramatically increased over the past few years (see Figure 2, which shows peak demand for the entire PJM region). Dominion's 2023 IRP, which utilizes the 2023 forecast from PJM, flagged the dramatic increase in projected peak electric demand between PJM's 2022 and 2023 forecasts.[33] PJM's 2024 forecast continues to expect this very high trajectory, predicting peak electric load for 2035 to be 44 percent higher than the forecast issued in 2022—an increase of 12,356 MW.[34]

Figure 2. PJM regional 15-year peak electric demand forecasts (MW)



Data source: PJM. 2018-2024. "Load Forecast." Available at: https://www.pjm.com/library/reports-notices

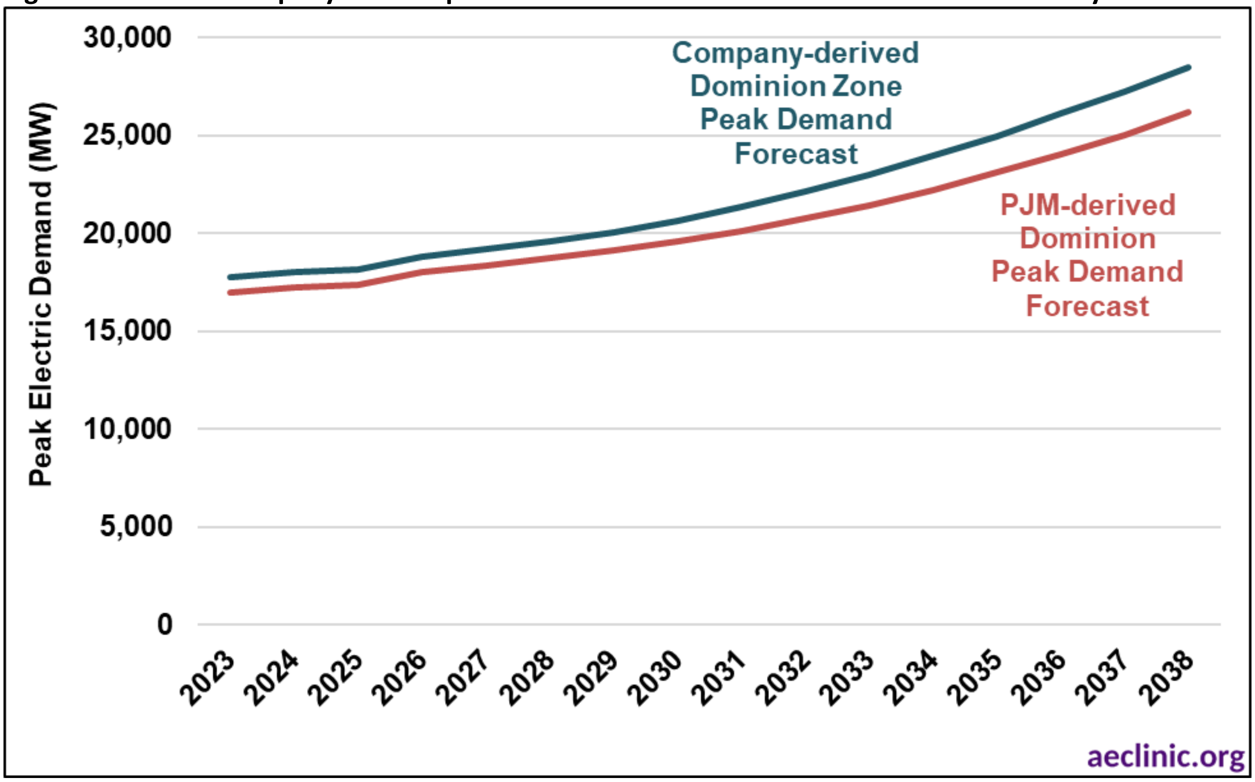
Dominion presents two peak demand forecasts in its 2023 IRP: (1) a 2023 "PJM-derived forecast" in which summer peak demand and energy use grow an average 2.9 percent and 4.2 percent per year respectively between 2023 and 2038;[35] and (2) a "Company-derived" forecast showing summer peak and annual energy use growing annually by 3.2 percent and 4.2 percent respectively between 2023 and 2038 (see Figure 3).[36]

Dominion's "PJM-derived forecast" is calculated from annual *PJM Load Forecast* reports by (1) adjusting PJM's data for its "Dominion Energy Zone" to better reflect Dominion's actual service area; and (2) adjusting the forecast downward for retail choice customers (i.e., customers who purchase energy from third-party retail electric suppliers) and energy efficiency savings.[37] For example, Dominion adjusts its load forecasts to account

[33] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.6
[34] AEC calculations utilizing PJM "Load Forecast" workbooks.
[35] Ibid, p.43
[36] Ibid, p.50
[37] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*, p.42; 54.

for VCEA energy efficiency targets energy savings (5 percent of 2019 sales by the end of 2025).[38] (Note that Dominion does not include any additional energy efficiency savings targets after 2025 in their 2023 IRP.[39] However, as required by the Virginia Code, Dominion will be subject to an as yet unspecified energy efficiency target or incremental savings goal for successive periods following 2025.[40]) Dominion's "Company-derived forecast" is an internally developed forecast (not based on PJM forecasts), which the Company utilizes for sensitivity analysis on its Plan B.[41]

Figure 3. PJM and company-derived peak electric demand forecasts for Dominion territory



Data source: (1) Dominion Energy Virginia. May 1, 2023. Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan, p. 46; (2) PJM. 2024. "Load Forecast" [Workbook]. Available at: *https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report-data.ashx*

Both PJM and Dominion note that data centers are key drivers of peak demand growth in PJM's forecast for the "Dominion Zone", which encompasses much of Eastern and Northern Virginia as well as a portion of Northeastern North Carolina.[42] In the Dominion service territory, where 75 data centers have been connected since 2019, the data center industry has seen an average annual growth of 0.5 GW of capacity for the last three years.[43] A February 2023 report by PJM, entitled *Energy Transition in PJM: Resource Retirements, Replacements, and Risks,* also highlights four trends presenting potential risks to reliability:[44]

[38] Ibid, p.50
[39] Ibid, p.50
[40] Virginia Law LIS. 2023. "§ 56-596.2:2. (Expires January 1, 2031) Energy efficiency savings targets for certain customers. (2023 updated section)." Available at: https://law.lis.virginia.gov/vacodeupdates/title56/section56-596.2:2/
[41] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. pp.44-45
[42] (1) Ibid, p. 6; (2) PJM. 2024. *PJM Load Forecast Report: January 2024.* p.1
[43] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.55
[44] PJM. 2023. *Energy Transition in PJM: Resource Retirements, Replacements, and Risks.* Available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx. p.1

- A rapid growth in electric demand;
- The retirement of thermal generators (such as coal- and gas-fired power plants);
- Power plant retirements outpacing the construction of new generation resources; and
- An interconnection queue that consists primarily of intermittent and limited-duration resources (solar, wind, and storage), slowing the growth of capacity needed for reliability.

The reliability concerns noted in PJM's 2023 report together with the increase in PJM's peak electric demand projections are used in Dominion's 2023 IRP to justify its claim that new gas-fired resources like the proposed CERC facility are necessary for reliable and dispatchable generation because of what Dominion asserts are limitations to storage and solar penetration on its grid—a claim that this report calls into question. Section V below presents an alternative resource portfolio that utilizes renewables and energy storage to provide peak electric capacity.

Dominion's assessments of gas, solar, and storage resources

When assessing alternative resources and developing its IRP, Dominion considered various types of generating resources including gas-fired combustion turbines and combined-cycle units, combined heat and power, waste-heat to power, small modular nuclear reactors, 4-hour batteries, other energy storage options,[45] fuel cells, pumped storage, solar (distributed and utility-scale), and wind (onshore and offshore).[46] Dominion also considered the potential for energy efficiency and demand-side management measures such as a Residential Peak Time Rebate Program, a Residential Home Retrofit Bundle Program, and a Residential EV Telematics Program, among others.[47]

Gas-fired power plants: Dominion's 2023 IRP asserts that gas-fired combustion turbines (the same type of resource as the proposed CERC) can provide firm energy during periods of high demand.[48] ("Firm energy" is available on demand for any length of time.[49]) Both Dominion's IRP and its CERC presentation identify the need to ramp up power early in the morning during severe storms (citing Winter Storm Elliot) as well as the reliability concerns driven by higher electricity demand forecasts.[50] Dominion's IRP claims that its future combustion turbines will be able to run on both gas and No. 2 ultra-low sulfur fuel oil,[51] have an onsite backup fuel supply, and be capable of running on gas blended with hydrogen in the future—all justifications it later incorporates into its arguments for the proposed CERC facility.[52] Finally, Dominion's high-level assessment found "system reliability concerns" for Plans D and E. (Plan D is the only plan that sees significant retirement of gas resources and meets VCEA's renewable and storage development requirements; Plan E does not meet

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[45] Dominion states that the term "energy storage" refers to "a diverse set of technologies that can store energy at one time and make it available at another time. The technologies range in size, cost, performance characteristics, and application." Source: Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.93
[46] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.92
[47] Ibid, p.101
[48] Ibid, p.90
[49] Long, JCS, et al. N.d. *California needs clean firm power, and so does the rest of the world.* Available at: https://www.edf.org/sites/default/files/documents/SB100%20clean%20firm%20power%20report%20plus%20SI.pdf, p.1
[50] (1) Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.90; (2) Dominion Energy Virginia. November 2023. *Chesterfield Energy Reliability Center Informational Meeting*.
[51] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.91
[52] Dominion Energy Virginia. November 2023. *Chesterfield Energy Reliability Center Informational Meeting*. pp.4; 6

VCEA's renewable and storage development targets.[53]) The Company does not report reliability concerns for plans retaining gas resources (i.e., Plans A, B, and C).[54]

Solar and storage: Dominion's 2023 IRP emphasizes what it characterizes as challenges with solar deployment.[55] In particular, Dominion notes that solar generation cannot provide sufficient "black start" capabilities—the ability to restart power from a blackout—without sufficient energy storage.[56] Dominion's IRP also argues that solar resources are projected to see declining effective load carrying capacity (ELCC)—its measure of the additional load that a resource can provide without affecting grid reliability—over time[57] due to a shift in the timing of peak periods of demand.[58] Finally, Dominion presented its concerns with solar generation's intermittency, and the differences in operating profile from data centers' needs. The 2023 IRP did not rule out further solar and storage in the future, but Dominion expressed concerns regarding these resources feasibility at scale.

All storage in the 2023 IRP is assumed to be 4-hour lithium-ion batteries, and resource additions are limited to 300 MW per year in all plans with Plans D and E allowing up to 900 MW of additions per year after 2038.[59] For Plans B and D, Dominion caused its model to select 2,700 MW of energy storage by 2035 per the requirements of the VCEA.[60] The IRP's Plans B and D also timed the development of storage resources towards the end of the planning period rather than at the beginning so that, according to Dominion, increasing renewable penetration can render battery storage more valuable and additional technology options become commercially viable.[61] Dominion justified building storage later in its planning period by arguing, without evidence, that storage built later would coincide with rising renewable penetration.[62] In reality, Dominion's choice to prioritize building storage resources later in its IRP planning period actually limits the effectiveness of renewables that are deployed on the grid earlier in the planning period. The notion that renewables like solar and wind are ineffective underlies Dominion's argument for retaining or expanding gas resources and is a problem of the Company's own making that could be addressed through appropriately assessing available resources as described in Section IV.

IV. Alternatives to Dominion's Proposed CERC Facility

Dominion's proposed CERC facility is anticipated to become operational in 2028.[63] Given that the expected economic lifetime of a gas-fired combustion turbine is 50 years, the CERC plant, were it not for VCEA restrictions, would likely operate through the end of 2078.[64] The VCEA, however, requires utilities, with very

[53] Ibid, p.32
[54] Ibid, pp.31-32
[55] Ibid, pp.97-98
[56] Ibid, p.98
[57] At higher levels of solar penetration, the assigned effective load carrying capacity of solar would decline because the likely "peak" events would have shifted to times at which solar is not operating. Pairing solar with additional storage mitigates this problem.
[58] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.60; 97
[59] Ibid, p.73
[60] Ibid.
[61] Ibid.
[62] Ibid.
[63] Dominion Energy Virginia. N.d. "Chesterfield Energy Reliability Center." Available at: https://www.dominionenergy.com/projects-and-facilities/natural-gas-facilities/chesterfield-energy-reliability-center
[64] Gagnon, P., Pham, A., & Cole, W. 2023. "2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook. Prepared on behalf of National Renewable Energy Laboratory." Available at: https://www.nrel.gov/docs/fy24osti/87724.pdf, p.41

limited exceptions, to retire all carbon-emitting electric generating units that are located in Virginia by December 31, 2045.[65] This will require retiring fossil resources on Dominion's system and replacing them with resource portfolios that do not emit carbon.

AEC's assessment of alternatives to the proposed CERC facility is based on four metrics: cost, emissions, technical potential, and flexibility. Alternative resources assessed include utility-scale solar, distributed solar, onshore and offshore wind, battery storage (short- and long-duration), energy efficiency, and demand response. Also addressed is the potential for interconnection delays to affect the deployment of renewable and storage resources. While individual comparisons may be useful in describing various resources, this is not the best way to compare resources to CERC. Combining resources like renewables and storage into resource portfolios (as evaluated in Section V below) creates synergies that allow for a more comprehensive assessment of what resources are able to replace CERC's energy and peak capacity.

Gas-fired peaking resources

The proposed CERC is composed of four simple-cycle gas combustion turbines (called "gas-fired combustion turbines" or simply "combustion turbines" throughout this report) with a combined capacity of 1,000 MW. (As of 2022, gas-fired combustion turbines represented 26 percent of U.S. gas generating capacity and had an average capacity factor of 13 percent. In contrast, 58 percent of U.S. gas capacity was composed of combined-cycle generators with a capacity factor of 56 percent.[66]) Combustion turbines are designed to "ramp" up and down rapidly (that is, be turned off and on suddenly) when called upon during periods of high demand.[67] These types of gas-fired power plants are notoriously less energy efficient than typical power plants when it comes to converting fuel into usable electricity.[68] Combustion turbines pollute more than typical power plants; pollution controls are not able to effectively capture all pollutants—such as the methane, carbon dioxide, and particulate matter that are emitted in higher concentrations from burning gas when they are ramping up.[69]

In addition, low-income communities and people of color have been disproportionately impacted by the placement of polluting facilities including gas-fired combustion turbines in close proximity to homes, schools and other community facilities.[70] Because of this bias in power plant siting, these communities are made increasingly vulnerable to the social and health impacts of long-term exposure to pollution.[71] Adverse health outcomes brought on by exposure to air pollution from combustion turbines can include respiratory diseases, pulmonary diseases, and premature mortality.[72]

Gas is also the costliest of the resources examined in this paper, costing between \$115 and \$221 per MWh to build and operate.[73] (Here and elsewhere in this report operating costs are what is called "levelized costs" and

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[65] General Assembly of Virginia. 2020. *Virginia Clean Economy Act (VCEA).*
[66] U.S. Energy Information Administration. February 22, 2024. "Use of natural gas-fired generation differs in the United States by technology and region." Available at: https://www.eia.gov/todayinenergy/detail.php?id=61444
[67] Clean Energy Group & Strategen. July 2022. *The Peaker Problem: An Overview of Peaker Power Plant Facts and Impacts in Boston, Philadelphia, and Detroit.* Available at: https://www.cleanegroup.org/wp-content/uploads/The-Peaker-Problem.pdf
[68] Ibid.
[69] Ibid.
[70] (1) Ibid; (2) U.S. Environmental Protection Agency. "Power Plants and Neighboring Communities." Available at: https://www.epa.gov/power-sector/power-plants-and-neighboring-communities.
[71] Ibid.
[72] Ibid.
[73] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf, p.2

include operational expenses, fuel costs, and capital costs—the costs of building the power plant spread out across the number of years it will operate.) While the cost to build gas-fired combustion turbines—$700 to $1,150 per kW—is cost competitive to other resources (see Table 2), the total operating costs of gas-fired combustion turbines render them more expensive than renewable and storage resources.[74] PJM assigns gas-fired combustion turbines a higher effective load carrying capability (ELCC, this measure is one version of what is often called a "capacity credit") of 62 percent.[75] In comparison, PJM assigns utility-scale solar plus storage an ELCC of 70 percent.[76] In assigning these ELCC values, PJM is assuming that gas-fired combustion turbines can, on average, be counted on to answer fewer peak load events than utility-scale solar plus storage. Considered singly, both solar generation and battery storage resources have lower ELCCs than gas resources. When combined, solar and battery can together provide better reliability than gas-fired combustion turbines.

Table 2. Resource alternatives to the proposed CERC facility

Resources	Levelized Costs ($/MWh)	Capital Cost ($/kW)	Capacity Factors	ELCC
Gas-fired combustion turbine	$115 - $221	$700 - $1,150	10 - 15%	62%
Distributed solar	$32 - $229	$1,200 - $4,150	15 - 25%	9%
Utility-scale solar	$0 - $77	$700 - $1,400	15 - 30%	14%
Utility-scale solar + storage	$31 - $88	$1,075 - $1,600	20 - 27%	70%
Onshore wind	$0 - $66	$1,025 - $1,700	30 - 55%	35%
Onshore wind + storage	$12 - $103	$1,375 - $2,250	30 - 45%	N/A
Offshore wind	$56 - $114	$3,000 - $5,000	45 - 55%	60%
Energy efficiency	$17 - $72	N/A	N/A	76%

Note: Lazard considers the investment tax credit, production tax credit, and a domestic content adder, among other provisions in the IRA when accounting for sensitivity to U.S. federal tax subsidies. *All dollar values are presented in 2023 dollars converted (when necessary) using the CPI-U. Source:* U.S. Bureau of Labor Statistics. Consumer Price Index for January 2024. Available at: https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202401.pdf, pp.2-3
Data sources: (1) Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." Available at: https://www.lazard.com/media/2ozoovyg/lazards-lcoeplus-april-2023.pdf*, pp. 3, 8, 37-39; (2) PJM. March 2024. ELCC Class Ratings for the 2025/2026 Base Residual Auction. Available at:* https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx; *(3) Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. Available at:* https://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf*, p.17*

[74] Ibid, p.11
[75] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.* Available at: https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx
[76] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.8

Alternative generation resources

Grid reliability can also be provided by carbon-free electric generating resources including distributed and utility-scale solar, onshore and offshore wind, and energy efficiency. This section presents an assessment of several alternative generation resources based on cost and capability to provide reliable service (see Table 2 above):

- **Levelized costs:** total operating costs including annualized cost of building the facility
- **Capital cost:** cost of building the facility
- **Capacity factor:** how much of the year it runs
- **ELCC:** assigned likelihood of its running at the moment of peak customer demand ("capacity credit").

Distributed solar

Distributed solar generates electricity for use at or near the site of consumption and is intermittent in nature— solar photovoltaic (PV) panels are dependent on exposure to the sun for electric generation, which limits the period of the day during which electricity can be generated.[77] Solar PV panels can be used in front of the meter (FTM), behind the meter (BTM), or for community solar depending on where the energy is consumed:[78]

- **FTM** energy is exported to the grid and is typically located on large plots of land or commercial rooftops.
- **BTM** energy is consumed on-site and is typically installed on rooftops at residential and commercial spaces, and
- **Community solar** can serve the load of nearby sites, often through a user-subscription system, and export excess energy to the grid. Community solar PV panels are typically located on large plots of land or rooftops.[79] Subscribers to the system receive an on-bill credit each month proportional to the amount of electricity generated from their share in the system.[80]

Lazard reports levelized costs of $32 to $229 per MWh for distributed solar.[81] PJM assigns distributed solar a 9 percent ELCC.[82] According to the National Renewable Energy Laboratory (NREL), technical potential (an upper bound estimate of how much generation can be produced in a particular region[83]) for distributed solar in Virginia totals 42,863 MW and 71.1 terawatt-hours (TWh).[84]

[77] U.S. Department of Energy (DOE). N.d. "Community Solar Basics." Available at: https://www.energy.gov/eere/solar/community-solar-basics.
[78] (1) U.S. Environmental Protection Agency (EPA). N.d. "Distributed Generation of Electricity and its Environmental Impacts." Available at: https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts; (2) Catalyze. May 9, 2023. "What is the Difference Between FTM, BTM & Community Solar?" Available at: https://catalyze.com/2023/05/09/what-is-the-difference-between-ftm-btm-community-solar/.
[79] Ibid.
[80] U.S. DOE. N.d. "Community Solar Basics."
[81] Lazard considers the investment tax credit, production tax credit, and a domestic content adder, among other provisions in the IRA when accounting for sensitivity to U.S. federal tax subsidies. The unsubsidized range is $49 to $282 per MWh. Source: Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.3
[82] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*
[83] NREL. "Renewable Energy Technical Potential." Available at: https://www.nrel.gov/gis/re-potential.html
[84] NREL. February 2024. "Technical Potential and Meaningful Benefits of Community Solar in the United States." Available at: https://www.nrel.gov/docs/fy24osti/87524.pdf, Table 2.

Utility-scale solar and utility-scale solar with storage

Utility-scale solar is typically a large-scale[85] solar "farm."[86] PJM assigns utility-scale solar without storage a relatively low ELCC of 14 percent compared to 62 percent for gas-fired combustion turbines.[87] In layperson's terms, this means a solar system with a capacity of 100 MW would be viewed by PJM as providing 14 MW of peak capacity, while a comparably sized gas-fired combustion turbine would be expected to provide 62 MW.

When paired with battery storage, however, utility-scale solar generation can be stored and deployed as needed at times of peak electric demand. PJM assigns the combination of utility-scale solar and storage a higher ELCC than gas-fired combustion turbines—70 percent.[88]

According to NREL, Virginia's utility-scale solar generation's technical potential is 27.5 TWh in urban settings and 1,882.5 TWh in rural settings.[89] For context, utility-scale solar generation in Virginia in 2022 amounted to just 5.7 TWh, less than 1 percent of the total potential.[90]

Lazard found in 2023 that the levelized cost of utility scale solar ranges from $0 to $77 per MWh,[91] compared to $115 to $221 per MWh for gas-fired combustion turbines like the proposed CERC.[92]

Onshore wind and onshore wind with storage

Wind generation does not produce greenhouse gas emissions and is intermittent, depending on the presence of wind. When paired with battery storage, surplus wind power can be stored for later use.[93] The levelized cost of onshore wind ranges from $0 to $66 per MWh,[94] compared to $12 to $103 per MWh[95] for onshore wind paired with storage and $115 to $221 per MWh for gas-fired peaking resources like the proposed CERC facility.[96] PJM's assigns onshore wind an ELCC of 35 percent, higher than either utility-scale or distributed solar, but still lower than that of gas-fired combustion turbines.[97] Onshore wind's capacity factors range between 30 to 55 percent, a range higher than that of either utility-scale or distributed solar.

According to U.S. Energy Information Administration (EIA) data through the end of 2022, Virginia had no

[85] There is no strict cutoff for projects to be classified as utility-scale. NREL focuses on data-collection for projects with a capacity of greater than 5 MW (AC). Meanwhile, the EIA refers to "small-scale solar" (also called distributed solar or rooftop solar) as systems of 1 MW of capacity or less. Source: (1) NREL. "Utility-Scale PV" Annual Technology Baseline. Available at: https://atb.nrel.gov/electricity/2023/utility-scale_pv; (2) EIA. 2023. "Record U.S. small-scale solar capacity was added in 2022." Available at: https://www.eia.gov/todayinenergy/detail.php?id=60341

[86] Solar Energy Industries Association (SEIA). N.d. "Utility-Scale Solar." Available at: https://www.seia.org/initiatives/utility-scale-solar-power.

[87] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*

[88] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.8

[89] Lopez, A. et al. 2012. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis." [Workbook]. Prepared on behalf of National Renewable Energy Laboratory. Available at: https://www.nrel.gov/gis/assets/docs/us-re-technical-potential.xlsx

[90] U.S. EIA. 2022. EIA Form 860 [Workbook]. Available at: https://www.eia.gov/electricity/data/eia860/

[91] This range reflects the sensitivity of utility-scale solar to the production tax credit. The unsubsidized range is $24 to $96 per MWh. Source: Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.3

[92] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.2; (2) In 2023, NREL provided a levelized cost of energy for utility scale solar of $42.41 per megawatt-hour (MWh). Source: NREL. July 2023. "Annual Technology Baseline [Version 8.0]. Available at: https://atb.nrel.gov/electricity/2023/utility-scale_pv

[93] Reilly, J., et al. 2022. Hybrid Distributed Wind and Battery Energy Storage Systems. Prepared on behalf of NREL. Available at: https://www.nrel.gov/docs/fy22osti/77662.pdf, p.1

[94] This range reflects the sensitivity of onshore wind to the production tax credit. The unsubsidized range is $24 to $75 per MWh. Source: Lazard. April 2023"Levelized Cost of Energy+ (LCOE+)." p.3

[95] This range reflects the sensitivity of onshore wind with storage to both the investment tax credit and the production tax credit. The unsubsidized range is $42 to $114 per MWh. Source: Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.3

[96] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.2

[97] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*

onshore wind capacity installed. NREL finds that Virginia's onshore wind potential totals 4.6 TWh.[98]

Offshore wind

NREL estimates Virginia's offshore wind generation's technical potential to total 361.1 TWh.[99] As of 2022, Virginia had 0.012 GW of installed offshore wind capacity.[100] On October 31, 2023, the Bureau of Ocean Energy Management approved Dominion's 2.6 GW Coastal Virginia Offshore Project, which would be the largest commercial offshore wind venture in the United States.[101] Project construction began in 2024 with the project expected to come online in 2026.[102]

The levelized cost of offshore wind ranges from \$56 to \$114 per MWh,[103] compared to \$115 to \$221 per MWh for gas-fired peaking resources like Dominion's proposed CERC.[104] Offshore wind achieves capacity factors of 45 to 55 percent. PJM's assigns offshore wind an ELCC of 60 percent, which is just below that of gas-fired combustion turbines.[105]

Energy efficiency

Energy efficiency measures reduce overall energy use, avoid the use of electric generators, and can avoid the need for investment in new generating and transmission resources. Examples of energy efficiency measures include weatherization upgrades to homes and businesses, insulation, LED lights, and programs incentivizing changes in the timing of energy consumption of home appliances. In 2021, Dominion's Demand-Side Management Long-Term Plan, prepared by Cadmus, provided a "framework for its customer-facing demand-side management programs and a path to transition its existing operating environment to achieve its goals."[106] The plan presented "a portfolio of seven comprehensive [energy efficiency] programs that together are estimated to achieve Dominion Energy's VCEA savings targets by the end of 2025."[107] The Cadmus' study found that—if Dominion meets its VCEA savings target using the measures presented therein—the Company would reduce average annual coincident peak demand by 85 to 87 MW between 2022 and 2025.[108]

According to a 2014 review from American Council for an Energy-Efficient Economy, energy efficiency measures cost between \$17 to \$72 per MWh,[109] compared to the range of levelized costs of gas-fired peaking

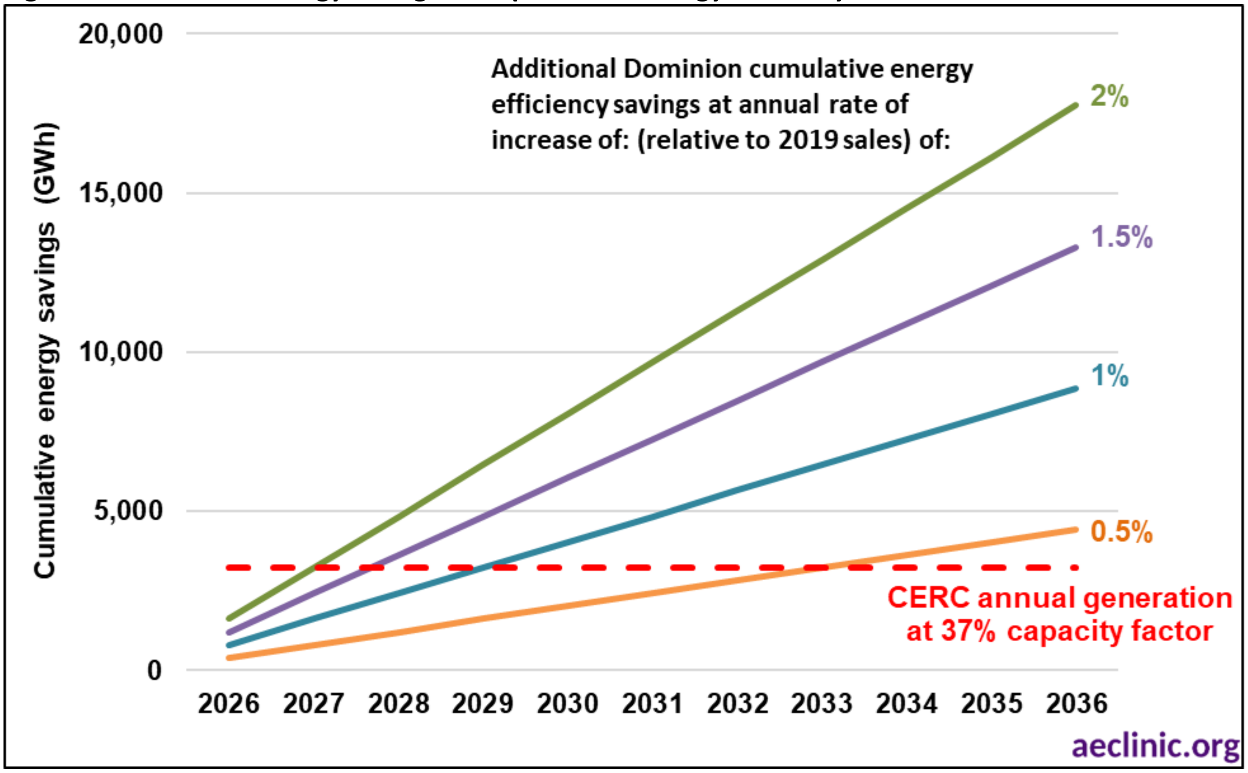
[98] Lopez, A. et al. 2012. "U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis." [Workbook]. Prepared on behalf of National Renewable Energy Laboratory. Available at: https://www.nrel.gov/gis/assets/docs/us-re-technical-potential.xlsx
[99] Ibid.
[100] U.S. EIA. 2022. EIA Form 860 [Workbook]. Available at: https://www.eia.gov/electricity/data/eia860/
[101] U.S. Department of the Interior. 2023. "Biden-Harris Administration Approves Largest Offshore Wind Project in the Nation." Available at: https://www.doi.gov/pressreleases/biden-harris-administration-approves-largest-offshore-wind-project-nation.
[102] (1) Dominion Energy. "Coastal Virginia Offshore Wind: Project Timeline." Available at: https://coastalvawind.com/about-offshore-wind/timeline.aspx; (2) Dominion Energy. n.d. "Dominion Energy Achieves Another Major Milestone for Coastal Virginia Offshore Wind with Installation of the First Monopile Foundation." Available at: https://news.dominionenergy.com/2024-05-22-Dominion-Energy-Achieves-Another-Major-Milestone-for-Coastal-Virginia-Offshore-Wind-with-Installation-of-the-First-Monopile-Foundation
[103] This range reflects the sensitivity of offshore wind to the production tax credit. The unsubsidized range is \$72 to \$140 per MWh. Source: Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.3
[104] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.2
[105] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*
[106] Ellsworth, A. et al. 2021. *Demand-Side Management Long-Term Plan.* Cadmus. Available at: https://www.dominionenergy.com/-/media/pdfs/virginia/save-energy/long-term-plan.pdf, p.8
[107] Ibid, p.15
[108] Ibid, pp.15-16
[109] (1) Energy savings range adjusted for inflation from 2014 dollars (\$13 to \$56) to 2023 dollars using the Historical Consumer Price Index for All Urban Consumers. Source: U.S. Bureau of Labor Statistics. *Consumer Price Index for January 2024.* Available at: https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202401.pdf, pp.2-3; (2) Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. Available at: https://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf, p.17

resources like the proposed CERC facility ($115 to $221 per MWh).[110] According to the National Conference of State Legislatures, over 30 other states have mandatory energy efficiency resource standards, with Virginia's 2020 law being the most recent.[111] Cumulative energy savings targets and annual incremental savings targets vary across states, but incremental targets are usually in the range of 1 to 3 percent of annual sales.[112]

The 2020 VCEA requires Dominion to implement energy efficiency programs that achieve cumulative energy savings equivalent to five percent of 2019 retail electric sales by the end of 2025.[113] Virginia's State Corporation Commission, however, has not yet set energy efficiency targets for the period after 2025. If Dominion were to continue to make annual investments in energy efficiency to achieve incremental energy savings at rates equivalent to 0.5, 1, 1.5, or 2 percent of Dominion's 2019 generation in Virginia per year,[114] it could entirely replace the generation promised by CERC with reduced energy consumption between 2027 and 2033 (see Figure 4). The proposed CERC, if built, would be operational in 2028.[115]

[110] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.2
[111] National Conference of State Legislatures. September 15, 2021. "Energy Efficiency Resource Standards." Available at: https://www.ncsl.org/energy/energy-efficiency-resource-standards-eers
[112] (1) National Conference of State Legislatures. September 15, 2021. "Energy Efficiency Resource Standards." Available at: https://www.ncsl.org/energy/energy-efficiency-resource-standards-eers; (2) Arizona Corporation Commission. February 7, 2022. Docket No. E-00000V-19-0034. Revised Amendment No. 2. Available at: https://docket.images.azcc.gov/E000017819.pdf?i=1644282783233; (3) Arizona Corporation Commission. February 7, 2022. Docket No. E-00000V-19-0034. Revised Amendment No. 1. Available at: https://docket.images.azcc.gov/E000017818.pdf?i=1644282783233; (4) Illinois General Assembly. No date. Chapter 5 Section 8-103B Available at: https://www.ilga.gov/legislation/ilcs/documents/022000050K8-103B.htm
[113] General Assembly of Virginia. 2020. *Virginia Clean Economy Act (VCEA).*
[114] As the State Corporation Commission has not yet established a post-2025 energy efficiency target, these percentages represent hypothetical annual incremental energy efficiency savings (as a percentage of total 2019 retail sales). The actual target could well be different once the Commission decides it and might not be denoted in the same units.
[115] Dominion Energy. "Chesterfield Energy Reliability Center." Available at: https://www.dominionenergy.com/projects-and-facilities/natural-gas-facilities/chesterfield-energy-reliability-center

Figure 4. Cumulative energy savings from post-2025 energy efficiency investments



Note: AEC calculated cumulative energy efficiency savings per year by multiplying four assumed fixed rates times Dominion's 2019 annual generation in Virginia.
Data source: U.S. EIA. 2023. "Form EIA-861 [Sales and Revenue]." Available at: https://www.eia.gov/electricity/data/eia861m/

Alternative capacity resources

Capacity resources like battery storage and demand response can also contribute to grid reliability (see Table 3). Storage resources can provide dispatchable power by charging and discharging battery storage systems to reduce energy demand directly or alter the timing of demand. Because capacity resources vary in their operating profiles, the costs provided in Table 3 use different units and are not directly comparable to those in Table 2 above.

Table 3. Capacity resource alternatives to the proposed CERC facility

Resources	Levelized Costs ($/kW-year)	PJM Capacity Credit
4-hour storage	$194 - $258	59%
Demand response	$35	76%

Note: All dollar values are presented in 2023 dollars converted (when necessary) using the CPI-U. Source: U.S. Bureau of Labor Statistics. Consumer Price Index for January 2024. Available at: https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202401.pdf, pp.2-3.
Source: (1) PJM. March 2024. ELCC Class Ratings for the 2025/2026 Base Residual Auction. Available at: https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx; (2) Molina, M. 2014. The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. Available at: https://www.aceee.org/sites/default/files/publications/researchreports/u1402.pdf, p.17; (3) Lazard. April 2023. "Levelized Cost of

Energy+ (LCOE+)." Available at: https://www.lazard.com/media/2ozoovyq/lazards-lcoeplus-april-2023.pdf, pp.18; 35

Battery storage

Battery storage can be called on to release energy to mitigate both peak demand and high electric costs for customers.[116] Batteries have the potential to reduce emissions by being charged with renewable resources, thereby offsetting emissions from emitting plants that would otherwise be run at times of peak demand. But battery storage resources neither produce nor sequester greenhouse gas emissions on their own. (The generation that is used to charge them can be emitting or non-emitting.) The levelized cost of storage of 4-hour batteries ranges from $194 to $258 per kW-year according to Lazard.[117]

While not widely available commercially as of yet, longer-duration storage—batteries with 8 or more hours of duration—provides greater flexibility to match intermittent generation and demand, enables higher penetrations of renewables, and enhances the ability of storage to provide energy at peak.[118] PJM assigns 4- and 8-hour battery storage resources ELCCs of 59 and 67 percent, respectively;[119] gas-fired combustion turbines receive as ELCC of 62 percent.[120]

Demand response

Demand response measures reduce or shift energy use away from periods of peak electric demand,[121] reducing the need for "peaking" resources like the proposed CERC facility. Examples of demand response measures include commercial and industrial incentive programs, time-of-use rates, smart thermostats and other building energy management controls, or smart electric vehicle chargers. In general, customers receive incentives in exchange for allowing their electric distribution company to reduce the energy used and/or draw on the energy stored in customer-sited resources at times of peak electric demand. PJM's assigns demand resources an ELCC of 76 percent, the highest of any resources examined in this report:[122] Demand resources have the largest share of their full potential capacity available at peak. A 2014 estimate by NREL yields a savings value of $34.64 per kW-year of avoided cost for demand response.[123]

Impacts of the grid interconnection process

To utilize alternative generation or capacity, Dominion will have to ensure that these resources can plug into the PJM grid. Grid interconnection is the process by which generation and storage projects connect to transmission and distribution lines and it includes network or hosting capacity upgrades to allow those lines to handle the new power flow from generation or capacity resources. As part of this process, projects are placed in a "queue" (or an order in which their upgrade needs are assessed) before the project is given permission to interconnect and begin operation. Projects' interconnection, however, can experience significant delays and cost increases due to the requirement that interconnecting projects shoulder any

116 National Grid. N.d. "What is battery storage?" Available at: https://www.nationalgrid.com/stories/energy-explained/what-is-battery-storage
117 Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.18
118 Denholm, P., et al. 2019. "The potential for battery energy storage to provide peaking capacity in the United States." U.S. DOE Office of Scientific and Technical Information. Available at: https://www.osti.gov/servlets/purl/1580099
119 PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*
120 Ibid.
121 U.S. DOE. "Demand Response." Available at: https://www.energy.gov/oe/demand-response
122 PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*
123 (1) Savings value adjusted for inflation from 2014 dollars ($26.91) to 2023 dollars using the Historical Consumer Price Index for All Urban Consumers. Source: U.S. Bureau of Labor Statistics. *Consumer Price Index for January 2024.* Available at: https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202401.pdf, pp.2-3; (2) Hummon, M. 2014. *Value of Demand Response: Quantities from Production Cost Modeling.* NREL. Available at: https://www.nrel.gov/docs/fy14osti/61815.pdf, p.2

related costs of upgrading the grid and the lack of anticipatory planning for new capacity in advance of interconnecting requests.[124] Interconnection queues have grown and backlogs disproportionately consist of renewable and storage resources in most ISOs and RTOs across the country.[125] A 2023 brief published by the Lawrence Berkely National Laboratory (LBNL) assessed PJM's interconnection processes and queues finding that:[126]

- PJM's average interconnection costs for completed projects in 2019 to 2022 ($82 per kW) were twice as high as the average costs for completed projects in 2010 to 2019 ($42 per kW). Projects that are still moving through the queue or those that withdraw from the queue face even higher costs. Increases in costs are due primarily to required changes to the electrical grid that go beyond the specific interconnection substation for the project.[127]

- At the end of 2021, the PJM queue contained more than double the projects than it did at the end of 2019.

- Interconnection costs charged to solar, storage, onshore wind, and offshore wind resources far exceed those of gas. Respectively, interconnection costs for non-gas resources from 2019 to 2022 were $335, $253, $136, and $385 per kilowatt (kW)—compared to $24 per kW for gas-fired resources.

Additional data published by LBNL shows that PJM's total interconnection queue at the end of 2023 was 286.7 gigawatts (GW).[128] Of this, only 7 GW represented gas-fired resources; the rest was utility-scale solar (113.7 GW), battery storage projects (86.9 GW), utility-scale solar plus storage (35.8 GW), and offshore wind (30.3 GW).[129]

To address the backlog associated with interconnection queues, PJM is currently pursing comprehensive reforms to its interconnection process.[130] These reforms will increase efficiency in handling new service requests by moving away from a "first-come, first-served" approach to a "first-ready, first-served" approach.[131] The transition to the reformed interconnection process began in July 2023, and, according to *PJM Inside Lines*, aims to "streamline generation interconnection requests, improve project cost certainty, and significantly improve the process by which new and upgraded generation resources are introduced onto the electrical grid."[132] While as of June 2023 the average wait for an interconnection in PJM was 40 months, PJM's new interconnection process is expected to clear all projects in its queue in December 2023 by mid-2025 (18

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[124] Lala, C., J. Burt, and S. Peddada. May 2023. *The Interconnection Bottleneck: Why Most Energy Storage Projects Never Get Built.* Applied Economics Clinic. Prepared on behalf of Clean Energy Group. Available at: https://www.cleanegroup.org/wp-content/uploads/Interconnection-Bottleneck.pdf, p.3
[125] Rand, J. et al. 2024. "Queued Up: 2024 Edition Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023." LBNL. Available at: https://emp.lbl.gov/queues.
[126] Seel, J. et al. 2023. *Interconnection Cost Analysis in the PJM Territory.* LBNL. Available at: https://live-etabiblio.pantheonsite.io/sites/default/files/berkeley_lab_2023.1.12-_pjm_interconnection_costs.pdf, p.1
[127] Ibid, p.1
[128] LBNL. "Generation, Storage, and Hybrid Capacity in Interconnection Queues." Available at: https://emp.lbl.gov/generation-storage-and-hybrid-capacity
[129] Ibid.
[130] PJM. "Interconnection Process Reform." Available at: https://www.pjm.com/planning/service-requests/interconnection-process-reform
[131] Ibid.
[132] PJM. July 6, 2023. "Transition to New Interconnection Process Begins July 10." PJM Inside Lines. Available at: https://insidelines.pjm.com/transition-to-new-interconnection-process-begins-july-10/

months) and "Fast Lane" projects by the end of 2024 (12 months).[133]

To provide capacity on Dominion's system in place of CERC, resources such as solar, wind and energy storage will undergo PJM's interconnection process. To the extent PJM's queue continues to grow and the interconnection of alternative generation and storage resources decelerates, Dominion's ability to meet its obligations under the VCEA will be impacted with slower additions of new resources. These challenges, however, do not obviate the need for Dominion to demonstrate why investment in CERC is preferable to solar, wind, and storage resources working together. Instead, these challenges point to key policy work necessary at the state and federal levels, in conjunction PJM, Dominion, and local and community stakeholders.

V. Resource Portfolios to Provide Peak Capacity

CERC cannot be economically replaced in its entirety with just one resource. Renewables and other alternative resources are most successful in meeting system needs when combined in portfolios, packaging together generating and capacity resources. Wind and solar will have to operate together to provide a comparable level of generation. Storage will be crucial to providing peak capacity in conjunction with renewable generation. By operating together, these resource portfolios not only supply more peak load—as illustrated by the higher ELCC assigned by PJM for utility-scale solar plus storage resources—but also provide benefits that individual renewable resources could not achieve on their own, such as rapid response to sudden energy needs in storms or from sharp spikes in demand at various times of the day.

CERC's size (measured in "nameplate capacity") is 1,000 MW; that is the maximum amount of energy CERC is expected to produce at a given moment. The relevant measure of size for electric planning purposes is "peak capacity," which is nameplate capacity multiplied by the ELCC assigned to resource type by PJM (i.e., how much energy a resource is expected to provide at a moment of peak customer demand). For a gas-fired combustion turbine like CERC, PJM assigns an ELCC of 62 percent. Therefore, CERC's peak capacity is 1,000 MW times 62 percent, or 620 MW. For most other resource types when considered singly, PJM assigns a lower ELCC reflecting the expectation that renewables and storage cannot reliably provide 100 percent of their capacity in each hour.[134] (Solar plus storage, however, receives a higher ELCC than CERC at 70 percent.)

To provide a peak capacity equivalent to CERC requires a combination of generation and capacity from a combination of renewable, storage and demand-side resources adding up to a peak capacity of 620 MW.[135] AEC constructed an illustrative alternative resource portfolio based on the composition of renewable and storage additions in the Dominion IRP's Plan D (see the Appendix below for more detail on the construction of these portfolios). Plan D was chosen as it is the only portfolio that retires Dominion's carbon-emitting generation by 2045, while meeting the solar, wind, and energy storage targets of the VCEA.[136]

[133] (1) PJM. April 10, 2024. *Queue Reform and Current Statistics* [PowerPoint slides]. Available at: https://www.pjm.com/-/media/about-pjm/ensuring-a-reliable-energy-transition/queue-reform-and-current-statistics.ashx; (2) PJM. December 21, 2023. " New Interconnection Process Reaches Next Milestone." PJM Inside Lines. Available at: https://insidelines.pjm.com/new-interconnection-process-reaches-next-milestone/

[134] As a reminder, PJM's ELCCs for solar resources range from 9 to 14 percent; pairing utility-scale solar with storage increases the ELCC to 70 percent. Onshore and offshore wind have ELCCs of 35 and 62 percent respectively.

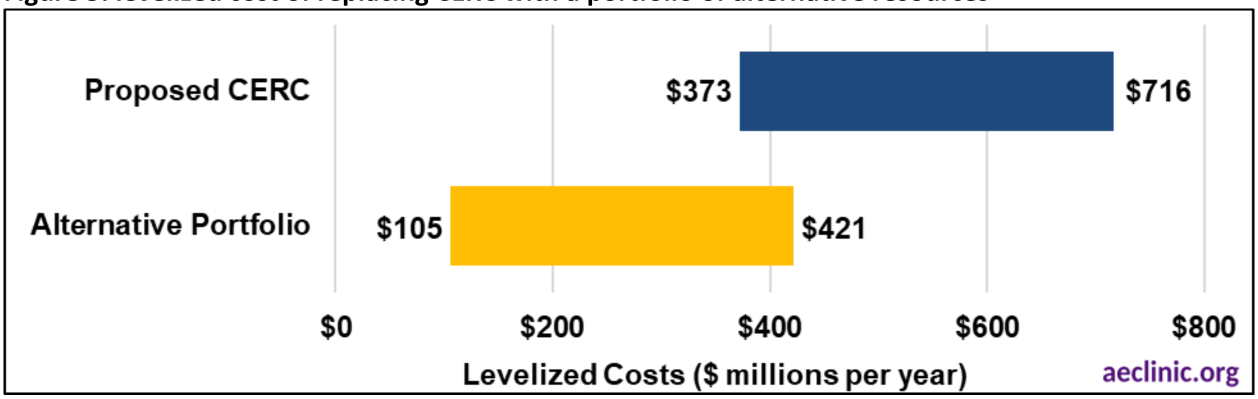
[135] CERC's peak capacity is calculated by AEC by multiplying its promised nameplate capacity (1,000 MW) by the ELCC assigned to gas-fired combustion turbine resources by PJM: 62 percent. Source: PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*

[136] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan*. p.24.

AEC's Alternative Portfolio provides 1,625 MW in total capacity compared to CERC's proposed capacity of 1,000 MW, while also matching CERC's peak capacity of 620 MW. The Alternative Portfolio produces 3.3 million MWh in annual generation compared to CERC's proposed generation of 3.2 million MWh (see Table 4 below).

The midpoint of the range of likely levelized costs[137] of AEC's Alternative Portfolio—composed of solar, wind, and storage resources—is 52 percent less expensive than that of Dominion's proposed CERC ($263 million versus $544 million, see Figure 5). The combination of solar, wind and storage meets CERC on peak capacity, beats CERC on annual generation, and would cost ratepayers just half of what Dominion wants to spend on CERC.

Figure 5. levelized cost of replacing CERC with a portfolio of alternative resources



Source: AEC calculations. See Appendix for data sources and a discussion of methodology.

[137] As a reminder, levelized costs include operational expenses, fuel costs, and capital costs—the costs of building the power plant spread out across the number of years it will operate.

Table 4. Analysis of an alternative portfolio for replacing CERC

Dominion's Proposed Chesterfield Energy Reliability Center (CERC)		
CERC: *Gas-Fired Combustion Turbine*	Capacity (MW)	1,000
	Capacity Credit (%)	62%
	Capacity on peak (MW)	620
	Capacity Factor (%)	37%
	Generation (MWh)	3,240,000
Alternative Portfolio		
Solar	Capacity (MW)	1,085
	Capacity Credit (%)	31%
	Capacity on peak (MW)	336
	Capacity Factor (%)	22%
	Generation (MWh)	2,091,260
Wind	Capacity (MW)	303
	Capacity Credit (%)	48%
	Capacity on peak (MW)	144
	Capacity Factor (%)	46%
	Generation (MWh)	1,228,970
Storage	Capacity (MW)	236
	Capacity Credit (%)	59%
	Capacity on peak (MW)	140
	Capacity Factor (%)	N/A
	Generation (MWh)	N/A
Total	**Summer Capacity (MW)**	**1,625**
	Capacity on Peak (MW)	**620**
	Generation (MWh)	**3,320,230**

Source: AEC calculations. See Appendix for data sources.

VI. Key Takeaways

Based on a misleading interpretation of evidence, Dominion claims that investment of ratepayer funds in the proposed CERC gas-fired combustion turbine is necessary to serve growing energy and capacity needs and manage extreme weather events. This AEC analysis, however, finds that a mix of solar, wind and storage can meet those same needs more cheaply.

In its 2023 IRP, Dominion claims that storage resources can only be built later in its planning period and that solar cannot provide sufficient black start capability. Both claims are false or misleading: Dominion argues that storage cannot be built until there are more renewables and that renewables cannot provide black start capability without storage. Taking these two critiques together, the Company finds—erroneously—that neither storage nor renewables can provide the energy services available from CERC. Dominion's critical error is its failure to consider the benefits that are possible when solar and storage are combined: Barring administrative obstacles, these resources can be brought online very quickly and can provide black start capability. Considered singly, renewables compare poorly to gas on peak capacity and storage provides no generation. Combined together, renewables and storage provide a low-cost, low-risk resource package that can meet growing customer demand and contribute to reducing greenhouse gas emissions from Virginia's electric sector.

Portfolios consisting of solar, wind, and storage resources cost less than it would to build and operate Dominion's proposed CERC facility. AEC examined an Alternative Portfolio combining solar, wind and storage designed to match CERC's peak capacity and slightly exceed its annual generation. The Alternative Portfolio is cheaper than CERC, costing between $105 to $421 million per year in levelized costs compared to CERC's $373 to $716 million. Notably, the Alternative Portfolio presented in this report includes neither energy efficiency nor demand response, both of which have the potential to lower costs still further. Investments in energy efficiency alone—made at levels similar to the annual investments common in numerous other states[138]—could obviate the need CERC by 2030 or sooner.

One challenge to bear in mind as new solutions and strategies are developed for investing in portfolios of renewables and storage will be the more intensive interconnection planning, design, infrastructure, and related labor needed to bring multiple solar, wind, and storage resources online (as compared to a single gas-fired resource). PJM's current process aims to increase efficiency in handling new service requests by moving away from a "first-come, first-served" approach to a ""first-ready, first-served" approach, and reduce wait times from 40 months down to 12 to 18 months.[139] Going forward, interconnection challenges will require creative and forward-thinking policy solutions working in conjunction with PJM for long-lasting, region-wide planning and implementation.

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[138] Subramanian, S., W. Berg, E. Cooper, M. Waite, B. Jennings, A. Hoffmeister, and B. Fadie. 2022. *2022 State Energy Efficiency Scorecard*. Washington, DC: ACEEE. Available at: www.aceee.org/research-report/u2206.

[139] (1) PJM. "Interconnection Process Reform." Available at: https://www.pjm.com/planning/service-requests/interconnection-process-reform; (2) PJM. July 6, 2023. "Transition to New Interconnection Process Begins July 10." PJM Inside Lines. Available at: https://insidelines.pjm.com/transition-to-new-interconnection-process-begins-july-10/; (3) PJM. April 10, 2024. Queue Reform and Current Statistics [PowerPoint slides]. Available at: https://www.pjm.com/-/media/about-pjm/ensuring-a-reliable-energy-transition/queue-reform-and-current-statistics.ashx; (4) PJM. December 21, 2023. " New Interconnection Process Reaches Next Milestone." PJM Inside Lines. Available at: https://insidelines.pjm.com/new-interconnection-process-reaches-next-milestone/

Appendix: Methodology

To assess the costs of Dominion's proposed CERC facility, AEC constructed an Alternative Portfolio that adds solar, wind and energy storage resources to provide an equivalent peak capacity to CERC's 620 MW and meet (or exceed) its electric generation capabilities. CERC's capacity on peak was calculated by multiplying its capacity of 1,000 MW by PJM's ELCC 2025/2026 Class Ratings for a gas-fired combustion turbine of 62 percent.[140]

AEC based the resource mix for the Alternative Portfolio on the shares of resource additions in MW for solar, wind and storage from Plan D of Dominion Energy Virginia's 2023 IRP. The Alternative Portfolio uses the respective shares of Dominion's 15-year resource additions for solar (54 percent), wind (23 percent), and storage (23 percent).[141]

To estimate the peak capacity served by each resource (i.e., solar, wind, storage) in the Alternative Portfolio, AEC applied the resource mix to the peak capacity target of 620 MW.

To estimate the total installed capacity for each resource necessary to provide those levels of resource-specific peak capacity targets, AEC divided the capacity on peak (in MW) served by each resource by the corresponding resource-specific ELCC. ELCC's for solar, wind, and storage resources were estimated based on PJM's ELCC 2025/2026 Class Ratings.[142] For solar resources, AEC calculated a simple average ELCC of 31 percent based on PJM's ELCCs for distributed solar (9 percent), utility-scale solar (14 percent), and utility-scale solar plus storage hybrids (70 percent). For wind resources, AEC calculated a simple average ELCC of 48 percent based on PJM's ELCCs for onshore wind (35 percent) and offshore wind (60 percent). For storage resources, AEC utilized PJM's ELCC of 59 percent for 4-hour battery storage resources.

To calculate the total annual generation (in MWh), AEC multiplied the capacity for each resource by the corresponding capacity factors and the number of hours in a year (i.e., 8,760 hours). For solar resources, AEC estimated 22 percent by taking a simple average of the midpoint capacity factors reported in Lazard's April 2023 *Levelized Cost of Energy Plus* report for distributed solar (15 to 25 percent), utility-scale solar (15 to 30 percent), and utility-scale solar plus storage hybrids (20 to 27 percent).[143] For wind resources, AEC calculated a simple average capacity factor of 46 percent based on Lazard's capacity factors for onshore wind (30 to 55 percent) and offshore wind (45 to 55 percent).[144]

To calculate the annual costs of the proposed CERC facility and the Alternative Portfolio, AEC multiplied the annual generation (in MWh) estimated for each resource by the corresponding levelized costs of energy (in $ per MWh) reported by Lazard.[145] For the Alterative Portfolio, AEC estimated the annual costs associated with storage resources by multiplying the capacity (in MW) estimated for storage in each portfolio by the levelized cost of storage (in $ per kW-year) reported by Lazard.[146]

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[140] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction.*
[141] Dominion Energy Virginia. May 1, 2023. *Virginia Electric and Power Company's Report of Its 2023 Integrated Resource Plan.* Presented to the Virginia State Corporation Commission and the North Carolina Utilities Commission. p.28
[142] PJM. March 2024. *ELCC Class Ratings for the 2025/2026 Base Residual Auction*.
[143] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.37
[144] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.38
[145] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." pp.37-39
[146] Lazard. April 2023. "Levelized Cost of Energy+ (LCOE+)." p.42