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# The Economics of Four Virginia Biomass Plants

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## ABSTRACT

Global electricity generated from biomass more than tripled between 2000 and 2016, and it is forecast to grow at an increasing pace through 2050. Electricity generation from biomass is also expanding in the United States, particularly in the Southeast. Given the continued growth and policy support for biomass electricity generation, this paper assesses the economics of four Virginia biomass plants, three converted from coal plants in 2012 and one purchased and expanded in 2004. The goal is to estimate the levelized cost of electricity (LCOE) generated from the plants as a metric of their level of competitiveness with respect to alternative ways of meeting electricity demand in the region. The LCOE of the four plants range from $93 to $143/MWh, about 40-53% more expensive than new solar and wind today and is double the cost of energy efficiency. Even with the inclusion of federal subsidies and environmental credits, Dominion's biomass conversions are not competitive. Overall, our analysis underscores the risks associated with investing in large, long-lived generation assets at a time when technologies and markets are rapidly evolving.



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## 1. Introduction

Global electricity generated from biomass more than tripled between 2000 and 2016, and it is forecast to grow at an increasing pace through the year 2040 when it could account for 3.6% of the world's electricity (IEA, 2017, p. 257). In 2010, biomass generated 164 terawatt hours (TWh) of electricity and accounted for 1.1% of world electricity generation. In 2016 biomass generation rose to 566 TWh and accounted for 2.2% of world electricity generation (IEA, 2017, p. 257), with the United States leading, followed by China, Germany, Brazil (REN21, 2017). China and Brazil are becoming increasingly important producers thanks to support programs for biomass electricity generation, in particular from agricultural residues (Brown and Sovacool, 2014; IEA, 2017).

Electricity generation from biomass in the United States has grown significantly over the past decade, increasing from 54.3 TWh in 2005 to 62.6 TWh in 2016 (US EIA, 2017a, b). In 2015, electricity generation from biomass across all sectors accounted for 1.6% of total electricity generation. Almost half of this occurs at pulp and paper mills and other industrial cogeneration facilities managed outside of the electric power sector (Mayes, 2016). The remaining electricity produced from biomass is used as baseload or dispatchable power in the existing electric power sector (NREL, 2012). Much of the growth in biomass electricity generation is occurring in southern states such as Virginia, Florida, and Georgia and is baseload, dispatchable power (Mayes, 2016). In particular, of the 545 MW of current biomass capacity in the United States that has been converted from coal plants, 373 MW (68%) is located in the Southeast (Table A.1).

The Virginia Electric and Power Company (referred to as "Dominion") has contributed prominently to the expansion of biomass power in the Southeast.[1] In 2004, Dominion purchased a biomass facility located in Pittsylvania with a nameplate capacity of 83 megawatts (MW) and expanded it to 90 MW. In 2013, Dominion converted three of its coal plants (located in located in Altavista, Hopewell, and Southampton) to biomass, each rated at 51 MW. An industrial plant in Altavista also switched from natural gas to biomass as its primary fuel and upgraded capacity to add wood solids to its fuel mix.

These biomass conversions and expansions are part of Dominion's commitment to achieve Virginia's voluntary goal of 15% renewable electricity by 2025 (Dominion Energy, 2017, p. 56). Dominion also operates the Pittsylvania Power Station – an 83-megawatt biomass facility – and the 585-megawatt Virginia City Hybrid Energy Center, that utilizes up to 20% biomass for fuel. In 2012, Miller-Coors Brewing opened a biomass-based electricity plant in Elkton, Virginia, to dispose of brewing wastes. In 2013, the Northern Virginia Electric Cooperative (NOVEC) commissioned a 50 MW wood waste biomass plant in South Boston, Virginia (Mayes, 2016).

Given the continued growth and increasing interest in biomass electricity generation, this paper estimates the levelized cost of electricity (LCOE) generated from the Virginia biomass plants at Altavista, Hopewell, Southampton and Pittsylvania, to assess the level of competitiveness of these power plants with respect to alternative ways of meeting the demand for electricity services that these plants are currently providing.

In this paper, we estimate the cost of electricity generated from Dominion's four Virginia biomass plants, using the traditional cost-effectiveness metric, the levelized cost of electricity (LCOE). The LCOE is a per-MWh cost of electricity generation technologies, reflecting the net present value of all capital and operating expenses over the life of the investment. More recently, it has also gained credibility as a measure of the cost of saving energy (Brown and Wang, 2015) and energy storage (Belderbos, et al, 2017). It therefore allows utility planners and researchers to comprehensively evaluate the performance of various alternative energy resources.

The LCOEs for each of Dominion's four plants are then compared to four types of benchmarks:

- published estimates from the literature for new, stand-alone biomass facilities,
- the fixed O&M costs of alternative resources available for purchase in the PJM wholesale electric market,

[1] According to Bloomberg (https://www.bloomberg.com/research/stocks/private/snapshot.asp?privcapId=3027777), the Virginia Electric and Power Company is a regulated public utility, generates, transmits, and distributes electricity for sale in Virginia and North Carolina. It operates in two segments, Dominion Virginia Power (DVP) and Dominion Generation. The DVP segment engages in the regulated electric transmission and distribution operations, including customer service. The Dominion Generation segment is involved in generation operations.

- the levelized cost of competing electricity resources available today and in the near future (2022), including both supply- and demand-side alternatives, and
- the costs and benefits predicted by Dominion in the planning phase of the three coal plant conversions**.**

The results of these comparisons contribute to an assessment of whether Dominion's biomass investments have resulted in higher or lower costs to consumers. Have they proven more or less expensive than electricity available for purchase in the region? Are these resources competitive with other electricity resources that Dominion could purchase today and over the lifetime of these plants? And how do they compare to assumptions made during the planning phase?

## 2. Overview of Dominion's Biomass Plants in Virginia

Three of the Dominion plants (Altavista, Hopewell, and Southampton) were originally built as coal-fired power stations between 1989 and 1992. In 2013, they were converted to 100% biomass fuel and were uprated from a capacity of 51 MW to 71.1 MW today, which is a typical size for such plants (IRENA, 2012). In 2016, the full capacity of each of these generating units was available for power production between 63 and 78 percent of the hours of the year (Dominion, 2017, Appendix 3C). Their net capacity factors were similar, ranging from 63 to 68 percent, indicating that they were dispatched to produce electricity during most of the hours that they were available (Dominion, 2017, Appendix 3D). Based on their heat rates (Table 1), the efficiency of these units ranges from 22.3 to 22.5 percent.[2] This is relatively low compared with the typical efficiency of direct combustion in stoker boilers according to IRENA (2012, p. 38), which is estimated to be 36 percent.

**TABLE 1. KEY PLANT CHARACTERISTICS**

| | Year of Initial Commercial Operation | Year of Conversion or Purchase | Nameplate Capacity (MW) in Winter & Summer[1, 5] | Equivalent Availability Factor[2] (%) in 2016 | Net Capacity Factor[3] (%) in 2016 | Heat Rate (Btu/KWh) (2016)[1] | Biomass Fuel Type[1] |
|---|---|---|---|---|---|---|---|
| **Altavista** | 1992 | 2013 | 71.1 (2016) | 63 | 63 | 15,151 | Wood waste solids |
| **Hopewell** | 1989 | 2013 | 71.1 (2016) | 74 | 68 | 15,327 | Wood waste solids |
| **Southampton** | 1992 | 2013 | 71.1 (2016) | 69 | 66 | 15,247 | Wood waste solids |
| **Pittsylvania** | 1994 | 2004 | 90.0 (2016) | 60 | 20[4] | 17,357 | Wood waste solids |

Sources: [1] SNL Energy database (NRDC subscription); [2] Dominion (2017), Appendix 3C; [3] Dominion (2017), Appendix 3D.
[4] This is the average for the plant's two generators in 2016; in the prior two years, the average capacity factor was 40 percent when both generators were operating.
[5] The original nameplate capacities can be found here: https://www.dominionenergy.com/about-us/making-energy/renewables/biomass/pittsylvania-power-station
Notes: Equivalent capacity factor = the percent of the hours in a year that the full capacity of a generating unit is available.
Net capacity factor = the percent of a generating plant's nameplate capacity that was utilized.
Heat rate = the amount of energy in British thermal units (Btu) used by a generating unit to generate one kilowatt hour (kWh) of electricity.

[2] A generating unit's efficiency is calculated by dividing the equivalent Btu content of a kWh of electricity (3,412 Btu) by the heat rate.

Dominion's fourth plant in Pittsylvania is a larger biomass facility, with two generators each with a nameplate capacity of 45 MW, for a total capacity of 90 MW, uprated from 83 MW when it was purchased. It began operation as a biomass plant in 1994, and Dominion purchased it in 2004. In 2016, the Pittsylvania plant's equivalent availability factor was 60 percent – slightly less than the three biomass plant conversions. However, its net capacity factor in 2016 was only 20 percent: generator 1 operated at 40 percent capacity, but generator 2 did not any generate electricity that year. While the plant was available 90 percent of the time in 2014 and 2015, its average capacity factor in those prior years (when both generators were operational) was still relatively low (40 percent). The fact that Pittsylvania was available a majority of the year but was utilized less than half of the time, may be due to the plant's relatively high heat rate. The Btu/kWh ratios shown in Table 1 indicate that the Pittsylvania plant operates at an efficiency of 19.6 percent, which would make it less competitive to dispatch compared to the three biomass plant conversions. Pittsylvania also has relatively high non-fuel O&M costs (Table 2).

**TABLE 2. TRENDS IN PLANT GENERATION AND O&M COSTS**

| | Year | Net Generation (in MWh) [1] | Fuel Costs[2] $/MWh | Other Variable O&M Costs[2] $/MWh | Fixed O&M Costs[2] $/MW-year |
|---|---|---|---|---|---|
| Altavista | 2013 | 144,793 | $124 | $17 | $72 |
| | 2014 | 226,877 | $126 | $1 | $4 |
| | 2015 | 268,695 | $96 | $0 | $1 |
| | 2016 | 282,677 | $90 | $1 | $10 |
| Hopewell | 2013 | 117,113 | $100 | $26 | $46 |
| | 2014 | 265,667 | $53 | $0 | $6 |
| | 2015 | 262,577 | $50 | $0 | $4 |
| | 2016 | 306,059 | $54 | $1 | $4 |
| Southampton | 2013 | 85,393 | $107 | $33 | $36 |
| | 2014 | 253,411 | $52 | $7 | $23 |
| | 2015 | 290,307 | $53 | $0 | $2 |
| | 2016 | 296,083 | $54 | $1 | $2 |
| Pittsylvania | 2013 | 369,339 | $42 | $13 | $71 |
| | 2014 | 322,259 | $54 | $19 | $58 |
| | 2015 | 267,414 | $50 | $23 | $45 |
| | 2016 | 146,658[3] | $44 | $36 | $50 |

Note: Costs are in nominal dollars. Data sources: [1]US EIA (2017b); [2]SNL Energy database.

[3] This is the total for generator 1; generator 2 did not operate in 2016.

Table 2 shows trends in plant generation and operation and maintenance (O&M) costs from 2013 through 2016. The O&M costs that do not vary significantly with a plant's electricity generation are classified as fixed, including salaries for facility staff and maintenance that is scheduled on a calendar basis. The costs incurred to generate electricity are classified as variable, such as the cost of fuel and other consumable materials, as well as maintenance that may be scheduled based on the number of operating hours or start-stop cycles of the plant (US EIA, 2017c).

Generation from the three biomass plant conversions have increased over the four-year period as the plants became fully commissioned. By contrast, generation from the Pittsylvania plant has declined over time, again reflecting its relatively high non-fuel O&M costs and high heat rate.

Table 2 also shows trends in fuel costs, which comprise anywhere from 57 percent to 80 percent of total levelized costs (Table 4), depending on the plant. All four of Dominion's Virginia biomass plants examined in this paper have spreader stoker boilers. The relatively small-particle fuel specifications of these boilers can be met by a range of agricultural residues such as sawdust, non-stringy bark, shavings, end cuts, wood chips and pellets (IRENA, 2012). An estimated 3,300 tons of biomass feedstock or about 150 truckloads are unloaded each day at the three biomass conversion plants, totaling approximately 600,000 tons of biomass per year (Figure 1). The Pittsylvania plant consumes approximately twice that amount, totaling about 1.2 million tons annually.[3]

**FIGURE 1. FEEDSTOCKS USED TO FUEL DOMINION'S BIOMASS PLANTS**

| Delivering biomass feedstock to Dominion's biomass plants | Biomass feedstock at Dominion's biomass plants |
| --- | --- |

Source: https://www.dominionenergy.com/about-us/making-energy/renewables/biomass

While the fuel costs at the Altavista plant have declined in recent years, they remain higher than at the other three plants. This may explain why its net generation in 2016 was lower than at the other two converted biomass plants. The particularly high fuel costs in the early years of operation of these three plants may have been influenced by the rapid expansion of their supply chains and perhaps some initial stockpiling costs.

## 3. Levelized cost of Electricity of Dominion's Four Virginia Biomass Plants

### 3.1 Assumptions

LCOE is calculated by dividing the present value of a facility's costs by its discounted lifetime electricity generation (Equation 1).[4]

$$LCOE\ (\$/kWh) = \frac{\sum_{t=0}^{n}\left[(C_t + O_t + F_t - P_t - REC_t)/(1+r)^t\right]}{\sum_{t=0}^{n}\left[(E_t)/(1+r)^t\right]} \qquad [1]$$

- $C_t$ = Capital investment of conversion/purchase in year 0 (including financing)
- $O_t$ = Fixed operation and maintenance (O&M) expenditures in year t
- $F_t$ = Fuel expenditures and other variable O&M costs in year t
- $P_t$ = Production tax credit (PTC) in year t
- $E_t$ = Electricity generation in year t
- $r$ = Discount rate
- $n$ = Life of the system
- REC= Value of Renewable Energy Certificates (RECs)

[3] https://www.dominionenergy.com/about-us/making-energy/renewables/biomass/pittsylvania-power-station

[4] The discount factor in the denominator reflects the fact that electricity produced in the future has less value because the money that would be gained by "selling" that power would be acquired at a later time.

We assume a discount rate of 6.29 percent[5] and a facility lifetime of 25 years.[6] Costs and incentives in 2013-2016 are inflated to $2016, and all future costs are report in $2016; by using "real" dollars we do not need to consider the impact of inflation.

We make the following assumptions about costs and incentives:

- The capital investment to convert the plants occurred in 2012 and were financed over a 15-year period at a rate or 6.38 percent.
- The initial year of electricity generation is 2013, and the facilities will operate for an additional 25 years.
- Fixed and variable O&M costs (including fuel costs) in 2017-2038 are the average of the fixed and variable O&M costs in the years 2013-2016.
- Annual electricity generation in 2017-2038 is the average of the electricity generation in the years 2013-2016.
- The Production Tax Credits (PTCs) for the three conversion plants are assumed to be $12/MWh for 10 years starting in 2013.[7] PTCs are assumed to be unavailable for the Pittsylvania plant since Dominion purchased it 10 years after its construction in 1994.
- In the base case, we assume that renewable energy credits (RECs) have no value. In the REC case, we assume a RECS value of $14.83/MWh, consistent with Dominion's IRP financial data.[8]

As described by EIA (US EIA, 2013), LCOE metrics focus on costs; however, where tax credits are available to utilities, EIA publishes estimates of "Total System LCOE" that exclude the tax credits and "Total LCOE Including Tax Credits" (US EIA, 2017d). Because Dominion considered the availability of tax subsidies for biopower generation when evaluating its biomass purchase and conversion projects, this paper reports LCOEs including tax credits. From a societal perspective, tax subsidies are simply transfer payments from government to business. As an alternative analysis, the value of RECS is considered. In these instances, we are comparing the cost value of what Dominion built (based on the value of RECs at that time) to what Dominion could be purchasing on the market today.

LCOEs can be applied to all types of electricity generation options and also can be used to evaluate the cost-effectiveness of energy-efficiency investments (Brown and Wang, 2016, Section 2.5). The flexibility of this metric is important to our analysis, since we seek to compare the investments in biomass facilities with a wide array of alternatives.

### 3.2 Definitions

**Capital costs** are assumed to be the cost of conversion to biomass for the three coal plants and the cost of purchase for Pittsylvania.

**Fixed O&M costs** include costs that do not vary significantly with generation, such as staffing and plant support equipment. They may also include major maintenance expenses such as expenses associated with environmental constraints (e.g., flue gas scrubbing systems).

**Fuel expenditures and other variable O&M costs** are production-related costs that vary with generation and include fuel costs (including the cost of transportation to the plant), water, chemicals, and other consumable materials and supplies.

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[5] Dominion uses this rate in its pubic IRP data analysis.

[6] 25 years of operation is used in the testimony of Diane Leopold, Senior Vice President, Business Development and Generation Construction for Virginia Electric and Power Company (Dominion, 2017).

[7] http://www.irs.gov/pub/irs-pdf/f8835.pdf.

[8] It is difficult to assess this assumed RECS value because there is little transparency and a great deal of volatility in RECS markets. Generally, voluntary REC prices are lower than compliance REC prices, but regional variability can also be significant. See: https://epicenergyblog.com/2016/04/27/the-role-and-prices-of-recs-and-offsets-in-climate-and-energy-plans/ https://gats.pjm-eis.com/gats2/PublicReports/BulletinBoard/PurchaseRequests

### 3.3 Data Sources

Sources of input data include public information from the Dominion IRP discovery process in the spring of 2017, the SNL Energy database which has O&M and fuel cost data for all of Virginia's plants, and EIA's Electricity Data Web Browser accessed in August, 2017.

The LCOE input data are shown in Table 3.

**TABLE 3. LCOE INPUT DATA AND ASSUMPTIONS FOR FOUR VIRGINIA BIOMASS PLANTS**

| | Altavista | Hopewell | Southampton | Pittsylvania |
|---|---|---|---|---|
| **Base Case:** | | | | |
| Capital Investment ($) | 73,393,545 | 71,011,637 | 69,407,788 | 48,200,140 |
| Fixed O&M Costs ($) [Avg. of 2013-2016] [1] | 1,113,054 | 777,601 | 810,520 | 2,325,700 |
| Fuel Costs ($) [Avg. of 2013-2016] [1] | 24,419,896 | 13,828,714 | 13,387,954 | 13,181,165 |
| Non-Fuel Variable O&M Costs ($) [Avg. of 2013-2016] [1] | 738,581 | 830,125 | 1,244,949 | 5,629,736 |
| Nameplate Capacity (MW) [1] | 71.10 | 71.10 | 71.10 | 90.00 |
| Capacity Factor (%) [1] | 63.1 | 68.0 | 66.0 | 20.11 |
| Electricity Generation (MWh/Year) [Avg. of 2013- 2016] [2] | 230,761 | 237,854 | 231,299 | 276,418 |
| Production Tax Credit ($/MWh) | 12 | 12 | 12 | 0 |
| Production Tax Credit Term (Years) | 10 | 10 | 10 | 0 |
| Discount Rate (%) | 6.29 | 6.29 | 6.29 | 6.29 |
| Financing Interest Rate (%) | 4.38 | 4.38 | 4.38 | 4.38 |
| Lifetime (Years) | 25 | 25 | 25 | 25 |
| Financing Term (Years) | 15 | 15 | 15 | 15 |
| **REC Case:** | | | | |
| Renewable Energy Certificates (RECs) ($/MWh) [3] | 14.83 | 14.83 | 14.83 | 14.83 |

Sources: [1]SNL Energy database (NRDC subscription); [2]EIA (2017b); [3]Dominion's Public IRP Data.
Note: All costs are in $2016

### 3.4 Results: Levelized costs for Dominion's four Virginia biomass conversions

The results of the LCOE analysis are shown in Table 4 and Figure 2.

In the base case, the LCOEs of the four Dominion biomass plants range from $93 to $143/MWh. Altavista has the highest LCOE largely because of its higher biomass feedstock costs. The Altavista plant also required a slightly higher upfront investment cost. It also has a lower capacity factor and slightly higher annual fixed O&M costs compared to the other two biomass plant conversions.

While the LCOE of the purchased biomass plant (Pittsylvania) is similar to two of the converted plants, the composition of its costs is quite distinct, with much higher fixed O&M costs and non-fuel variable costs due to the shutdown of the its second generator in 2016.

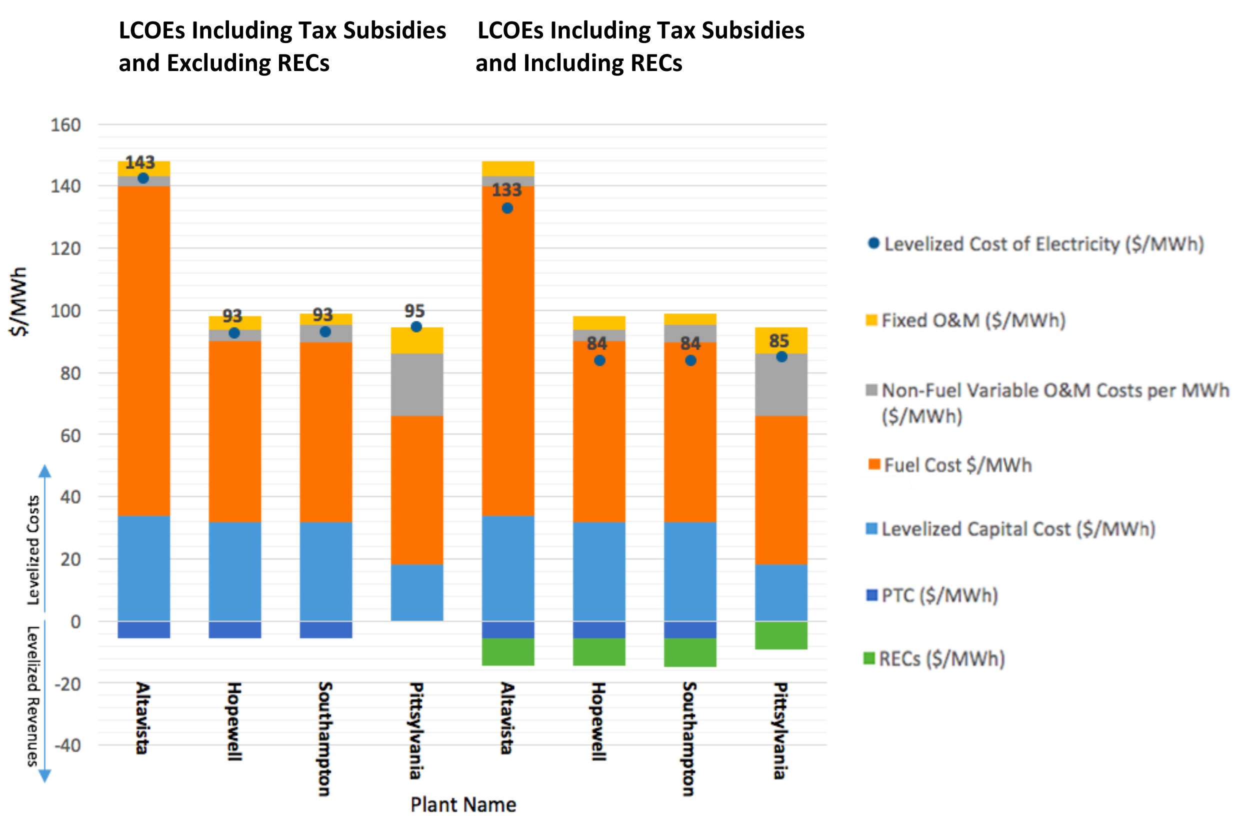
Including the value of RECs lowers the LCOEs to a range of $84 to $133/MWh.

**TABLE 4. LCOE RESULTS FOR FOUR VIRGINIA BIOMASS PLANTS IN $2016/MWh**

| | Altavista | Hopewell | Southampton | Pittsylvania |
|---|---|---|---|---|
| **Without RECs:** | | | | |
| Levelized Capital Cost ($/MWh) | 34 | 32 | 32 | 18 |
| Levelized Fuel Cost ($/MWh) | 106 | 58 | 58 | 48 |
| Levelized Non-Fuel Variable O&M Cost ($/MWh) | 3 | 4 | 5 | 20 |
| Levelized Fixed O&M COST ($/MWh) | 5 | 5 | 4 | 8 |
| Levelized PTC ($/MWh) | (5) | (5) | (6) | 0 |
| LCOE ($2016/MWh) | 143 | 93 | 93 | 95 |
| **With RECs:** | | | | |
| Levelized RECs ($/MWh) | (9) | (9) | (9) | (9) |
| LCOE with RECs ($2016/MWh) | 133 | 84 | 84 | 85 |

Source: Calculated from data shown in Table 3.

**FIGURE 2. BREAKDOWN OF THE LCOE OF DOMINION'S FOUR VIRGINIA BIOMASS PLANTS ($2016/MWH)**




Source: Drawn from data shown in Table 4.

Recall that these calculations are based on the same discount rate used by Dominion in its public IRP data analysis of 6.29 percent and a facility lifetime of 25 years (Dominion, 2017). A sensitivity analysis of our results to these two assumptions was completed by calculating LCOEs for each combination of five plant lifetime (15, 20, 25, 30 and 35 years) and five discount rates (3%, 4%, 5%, 6.29%, and 7%). For all four plants (Altavista, Hopewell, Southampton and Pittsylvania), the lowest LCOE value is produced by the scenario with the longest lifetime scenario (35 years) and the lowest discount rate (3%). The lowest LCOEs when RECs are included were: 121, 72, 73 and 78 for each plant, respectively, and the highest values were: 142, 92, 92, 90. None of these values differs by more than $12/MWh from the estimates shown on the right side of Figure 2.

## 4. Comparative Analyses

### 4.1 Comparison to published estimates from the literature

It is illustrative to compare these numbers for biomass conversion with published estimates from the literature for new, stand-alone biomass facilities. The estimated LCOEs of Dominion's four Virginia biomass plants ($93-143/MWh) are within the range of international estimates published by IRENA (2012, Table 1) for stand-alone spreader-stoker type biomass power plants ($66 to $231/MWh).[9] One of the four biomass plants (Altavista) falls above the $84.8-125.3/MWh range estimated by EIA (2017) for new plants in the United States entering service in 2022, where the range represents the minimum and maximum values across U.S. regions, subsidies are excluded, and the capacity factor is assumed to be 84 percent. EIA's regional estimate for the Virginia-Carolinas region for a new biomass plant entering service in 2022 is $101.3/MWh (Hammerschlag, 2017).

This EIA Virginia-Carolinas estimate does not include federal subsidies for new biomass. Excluding the $5.3-5.4/MWh PTC subsidies for the three coal-to-biomass conversions would make two of them comparable in cost to the EIA regional estimated LCOE for a new biomass plant entering service in the Virginia-Carolinas region in the year 2022. The same two plants and Pittsylvania also fall within the range of LCOE estimates of $60-101/MWh provided by Lazard (2016, p. 4) for biomass plants built in 2016 and receiving PTC subsidies.

By contrast, the LCOE estimate for the Altavista plant is higher than the high end of both the EIA and Lazard estimates, but it falls within the wider range of IRENA's cost estimates.

### 4.2 Comparison to PJM supply curve in 2016

In competitive electricity markets, the bids offered for different types of electricity resources are indicative of their cost-competitiveness. The PJM Interconnection operates one of the largest wholesale competitive markets in the United States, covering all or parts of 13 states including Virginia and the District of Columbia. Representing approximately one-fifth of the U.S. wholesale electricity market, where a plant falls on the PJM supply curve of bids would be a reliable indicator of its relative cost-competitiveness.

Because bids into the PJM market are confidential, we have developed a surrogate PJM supply curve for the year 2016 based on the variable O&M cost of power plants located in the PJM service territory. This supply curve serves as a rough proxy of the market competitiveness of Dominion's four Virginia biomass plants relative to other plants in the region (Figure 3). By combining fuel costs and non-fuel variable O&M costs, and by classifying and color-coding the observations into eight types of primary fuels, it is possible to visually examine the cost-competitiveness of different types of plants.[10]

As shown in Figure 3, the four Virginia biomass power plants are situated on the inside elbow of the PJM supply curve. There are approximately 170 GW of electricity with variable O&M costs that are lower, including solar, wind, and hydro costs that have essentially no fuel costs. Approximately 20 GW of electricity generation available to PJM costs more on a $/MWh basis than the four Virginia biomass power plants. This PJM wholesale market analysis shows that the four Virginia biomass plants have relatively high

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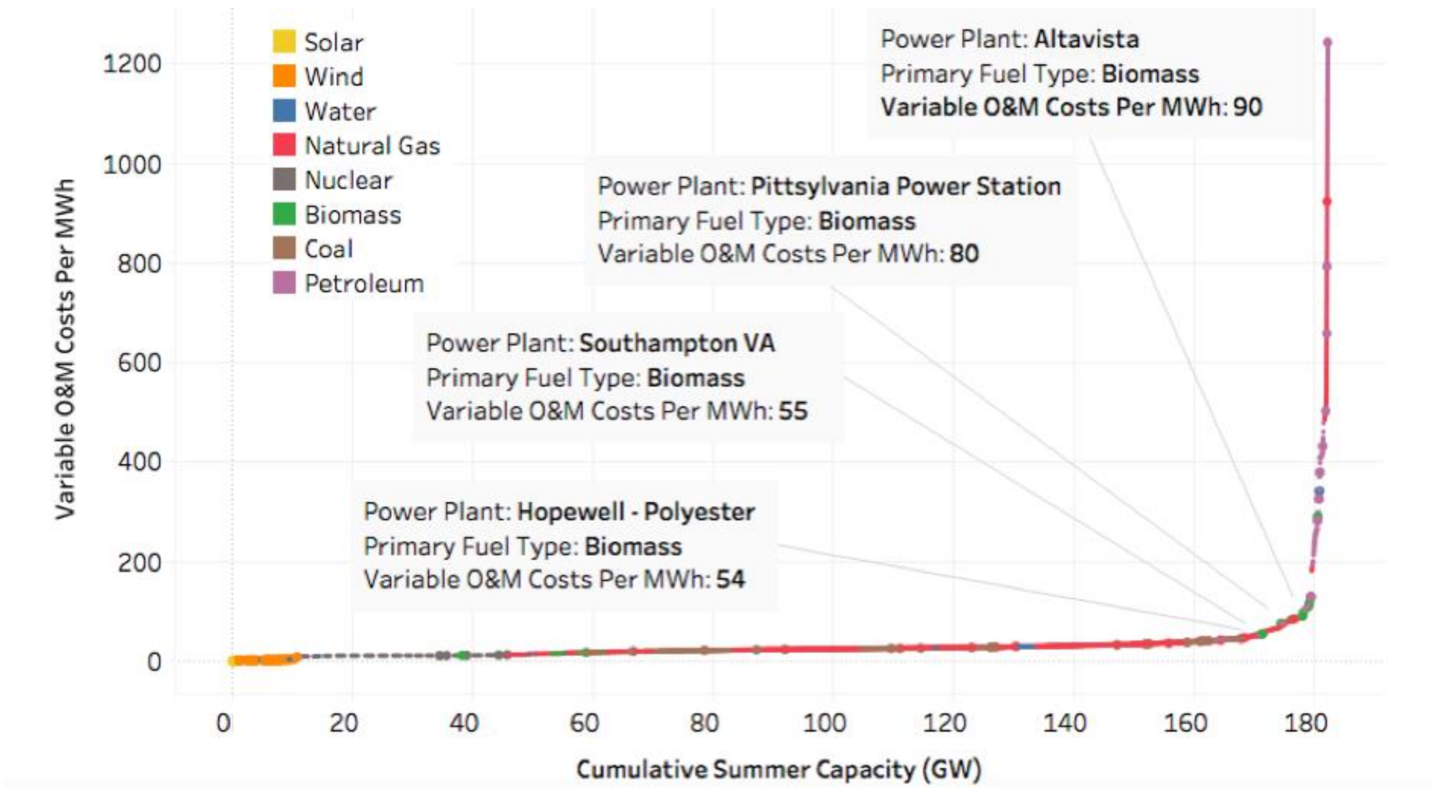
[9] Converted to $2016.

[10] In addition to solar, wind, and water (hydro), primary fuels are aggregated into the following five categories: natural gas (blast furnace gas, natural gas, other gases); nuclear; biomass (landfill gas, black liquor, municipal solid waste, wood waste solids); coal (bituminous, subbituminous, waste coal); and petroleum (distillate fuel oil, jet fuel, petroleum coke, residual fuel oil).

O&M costs compared to other electricity resources available for purchase in the region. For perspective, the summer peak demand served by the PJM Regional Transmission Operator exceeded 160 GW in only in three of the 17 years from 2000-2016.[11] Thus, if these four plants were forced to compete in the PJM market, they might not operate except during unusually hot summers.

**FIGURE 3. SURROGATE PJM SUPPLY CURVE IN 2016**




Source: Data from SNL (NRDC subscription). Note: Resource categories are ordered in terms of variable O&M cost per MWh based on the cost of the least expensive plant of a primary fuel type.

Solar, wind, and hydro plants occupy the least expensive left side of this supply curve, because they have essentially no fuel costs and therefore have very low variable O&M costs. After natural gas and nuclear enter the supply curve, biomass, coal, and petroleum are the sources that represent the next highest variable O&M costs in the PJM region.

This type of comparison is most useful when evaluating the competitiveness of existing generation relative to power that could be purchased in competitive markets. When considering options for the construction of new capacity, the scope of consideration needs to go beyond variable O&M costs to include all of the categories of costs and considerations included in Table 3. The potential role of demand-side resources should also be considered. Walton (2017) estimates that in 2016 the PJM market had approximate 8.1 GW of demand response participating in its capacity market. The following section compares alternative electricity resources based on applying the LCOE metric to alternative supply- and demand-side resources.

#### 4.3 Comparison to alternative supply-side electricity resources

In this section, we compare the costs of Dominion's biomass conversions to published LCOE estimates of non-biomass resources, including utility-scale solar and onshore wind. We rely on two sources that provide LCOE estimates for alternative electricity resources

[11] http://www.puc.state.pa.us/Electric/pdf/Reliability/Summer_Reliability_2017-PJM.pdf

in the United States, US EIA (2017) and Lazard (2016), and supplement those estimates with an estimate of the system integration costs associated with variable and nondispatchable technologies.

The US EIA (2017a) has published estimates for new generating plants entering service in 2022. EIA's analysis has recently been supplemented by Hammerschlag (2017), which compiles EIA's regional estimates for NEMS Region 16 ("Virginia-Carolina") that enable more appropriate comparisons for Dominion's Virginia biomass plants. These estimates account for federal subsidies to non-biomass technologies, where applicable.

In addition, Lazard (2016), provides LCOE estimates based on recently completed power plants in the U.S. Both EIA (2017) and Lazard (2016) are well documented and transparent in their assumptions. Other studies, such as the National Academies (2016) and Bloomberg New Energy Finance (2016), provide an assessment of the current marketplace for new electricity capacity. In aggregate, these studies provide comparable and consistent estimates for utility-scale supply-side electricity technologies in the Southeast today, including natural gas, onshore wind, solar, nuclear, and new biomass.

The LCOEs provided by US EIA (2017a) and Lazard (2016) for non-biomass options are summarized in Table 5.

We have added two columns in Table 5 that supplement these estimates to include system integration costs.[12] A substantial body of published research concludes that low penetration levels of solar and wind resources (<10%) have minimal integration costs. At higher penetration levels, the costs appear to be less than $10/MWh:

- A study by researchers at three DOE National Laboratories found that even at 17 percent solar penetration there are integration costs of $4.4/MWh, based on an analysis of Arizona (Wu et al., 2015).
- A recent analysis conducted by Duke Energy and PNNL focused specifically on solar energy found that integration costs in the Duke Energy footprint would remain below $10/MWh at penetration levels up to 19 percent of peak load.
- Additionally, a recent survey of the literature by the White House Council of Economic Advisors (CEA, 2016) found integration costs of less than $6/MWh, although many studies were focused on wind. The CEA report also found no correlation between levels of variable renewable penetration and ancillary service costs – an important real-world metric of potential integration costs.
- A PNNL study of NG Energy's southern Nevada system found that the annual cost of operating reserves needed to integrate 150 MW to 1000 MW of large PV and DG capacity ranges from $3 to $8 per MWh of PV and DG capacity (Lu et al., 2011).
- A study conducted for PJM by GE Energy Consulting (2014) examined 30 percent wind and solar penetration rates that would add more than 100 GW of renewable capacity. It concluded that 1,000 to 1,500 MW of additional regulation would be required compared to the amount needed for load alone.[13]
- Vivid Economics (2016; 2017) assumes system integration costs of 10£/MWh for the United Kingdom.

Based on this literature, and given the low penetration levels of solar and wind in VA we include an upper limit and conservative estimate of system integration costs for solar and wind of $10/MWh. Adding these estimates to the estimated LCOE for utility-scale solar and onshore wind produces our estimates for total levelized costs for alternatives new generation shown in Table 5.

**TABLE 5. ESTIMATED LCOE FOR NEW UTILITY-SCALE ELECTRICITY TECHNOLOGIES**

[12] It is also useful to consider a complement to LCOE – the levelized avoided cost of electricity (LACE). "LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for variable and non-dispatchable resources, such as wind or solar, that have substantially different duty cycles than the baseload, intermediate, and peaking duty cycles of conventional generators…. When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build" (EIA, 2017a). EIA's LACE methodology draws from a related body of literature that address the cost of integrating variable and non-dispatchable resources into the grid.

[13] Regulation includes generating units or demand response resources that are under automatic control and respond to frequency deviations. It is a category of PJM ancillary services.

| | Dispatchable Technologies: | | | | Non-Dispatchable Technologies: | | | |
|---|---|---|---|---|---|---|---|---|
| | Natural Gas Combined Cycle | Nuclear | Biomass Direct | | Wind-Onshore | Wind-Onshore + Integration Cost | Solar-Thin Film | Solar + Integration Cost |
| **Nation** | | | | | | | | |
| **Lazard: Low**[1] | 48 | 97 | 60 | | 14 | 24 | 36 | 46 |
| **Lazard: High**[1] | 78 | 136 | 101 | | 48 | 58 | 44 | 54 |
| **EIA: National Average**[2] | 57.3 | 96 | 102.4 | | 44.3 | 54.3 | 58.1 | 68.1 |
| **EIA: VA-Carolina**[2] | 57.2 | 96 | 101.3 | | 55.6 | 65.6 | 57.4 | 67.4 |

Sources: LCOEs including an upper limit for integration cost of $10/MWh estimated by the authors, drawing from the literature summarized in this paper and the sources listed below. Note: Costs are expressed in terms of net AC power available to the grid.
[1]Lazard (2016, pp. 2, 4) LCOEs are for plants constructed in 2016, including federal tax subsidies for biomass, wind, and solar.
[2]National estimates are published in US EIA (2017a), Table 1b. EIA's estimates for the Virginia-Carolina region are compiled in Hammerschlag (2017) based on EIA data. The EIA estimates do not include subsidies for wind and biomass because renewable production tax credits for these resources end in 2022. The LCOEs for both of these sources are for plants entering service in 2022.

Comparing the LCOE values for Dominion's four conversions from Table 4 with estimates of total LCOE for wind and solar from Table 5 produces the following findings.

The estimated total cost of producing electricity from wind and solar ranges from $65.6 – $67.4/MWh in the Virginia/Carolina region. These values represent the upper limit of LCOE estimates for these non-biomass sources based on Table 5; using a value of $5/MWh produces a LCOE range of $61.6 - $62.4/MWh. Dominion's lowest biomass conversion costs (namely those that exclude Alta Vista) are 84 - 85 $/MWh, when accounting for the financial benefits of RECs and federal subsidies.

In a less conservative scenario assuming system integration costs of $5/MWh and LCOE for solar and wind equivalent to the median value of Lazard's estimates, the cost to produce electricity from Dominion's three lower-cost conversions (excluding Altavista) are double those of wind and almost double the cost of solar. In the case of the Altavista plant, the cost to produce electricity is triple that of wind and solar.

#### 4.4 Comparison to energy-efficiency resources

To compare the cost of biomass or other electricity supply options with the cost of energy-efficiency resources, this study considers four types of costs: 1) the cost of any financial incentives needed to motivate consumers to use energy more efficiently, which is often benchmarked to the "energy-efficiency premium," the cost of the added increment of energy efficiency; 2) the cost of providing information and technical assistance, which in some cases may be the bulk of the program costs; 3) program administration costs; and 4) financing costs that apply to energy-efficiency programs, as well as to electricity generation projects (Brown and Wang, 2015). A complete assessment of this resource must also consider the role of the rebound effect as well as the market transformation impacts of energy-efficiency programs and policies.

The State of Virginia has not commissioned a comprehensive assessment of the cost of energy-efficiency resources in its state. However, the American Council for an Energy-Efficient Economy (ACEEE) has examined the availability of demand-side resources in the neighboring state of Maryland. Specifically, Baatz and Barrett (2017) evaluated the LCOE saved by the EmPOWER Maryland energy-efficiency programs from 2008 through 2015. They concluded that the programs produced 51 million MWh of energy savings at a levelized cost of $34/MWh.[14] These savings are more than twice the 20-year lifetime of electricity generation from the four Virginia biomass plants.[15]

Similarly, low LCOEs for energy efficiency have been documented by a range of programs implemented across the United States, addressing the energy waste in homes, businesses, and industry (Brown and Wang, 2015). A review of electricity energy-efficiency programs operating from 2009 to 2012 in 20 U.S. states provides estimates ranging from 1.3 to 5.6 cents/kWh, based on a 5 percent real discount rate. The simple average across the four years and 20 states produces a mean value of 2.8 cents/kWh (Molina, 2013). Because states vary in their commitments to exploiting demand-side versus supply-side resources, the American Council for an Energy-Efficient Economy has provided annual state report cards documenting variable levels of performance on energy-efficiency. In 2016, ACEEE estimated that the average state spent 0.66% of their electricity sales on energy-efficiency programs – ranging from a high of 3.0% in Massachusetts, to a low of 0% in Kansas. Virginia's expenditure of 0.9% on energy efficiency placed it sixth from the bottom…only five states spent less per capita. Virginia's energy-efficiency performance in 2016 received an overall rating of 29th, underscoring the limited commitment made to date to exploit the ability of energy efficiency to offset or postpone the construction of new power plants.

In sum, the results of a large body of research evaluating the cost-effectiveness of demand-side programs suggest that energy-efficiency resources would likely be less expensive than the cost of generating electricity from Dominion's four biomass plants in Virginia.

### 4.5 Comparison to Dominion's planning assumptions

In this section, we document Dominion's planning assumptions based on the testimonies of employees of Dominion and the Virginia State Corporation Commission (SCC). Most of the information in this section is drawn from Dominion's SCC docket for its three coal plant conversions.[16] The available information is limited in three important respects.

- It does not include a comparative analysis with a broad range of alternatives to biomass conversion.[17] The analysis of planned costs documented in Dominion's SCC docket focuses on the cost-effectiveness of converting the three Virginia coal plants to biomass compared to continuing to operate them as coal units.[18]
- It does not include LCOE estimates from the time when the biomass conversions were being planned. LCOE values may have been calculated by Dominion or its contractors during the planning phase of the coal plant conversions; however, we do not have access to them. [19,20]
- It does not include information about the assumptions that justified the purchase of the Pittsylvania biomass plant in 2004.

The testimonial evidence and Dominion's application in 2011 provide estimates of $388 million to $434 million "net present value savings" to customers when compared to continued operation of the coal plants.[21,22] According to a senior utilities analyst in the Virginia State Corporation Commission, these estimated savings do not necessarily infer a reduction in Dominion's future revenue requirements; they simply estimate that the company's future revenue requirements would be less than they would otherwise be if

[14] In addition, participants saved $4.1 billion on their utility bills over the lifetime of the energy-efficiency improvements. .

[15] From 2014-2016, the four Virginia biomass plants generated approximately 1 million MWh of electricity annually (see Table 2).

[16] http://www.scc.virginia.gov/docketsearch#/caseDetails/129845

[17] In its planning process, Dominion compared the cost of the biomass conversions to three alternative generating technologies: a pulverized coal unit without carbon sequestration, a natural gas combustion turbine, and a natural gas combined cycle plant. However, these cost estimates are redacted (Dominion, 2011, p. 14/58).

[18] The estimated savings simply indicate that Dominion projects future revenue requirements would be less than they would otherwise be if the conversions did not occur (Tufaro, 2011) and the units continued to operate as coal plants.

[19] Dominion refers to a report by Chmura Economics and Analytics in its Application, Direct Testimony, Exhibits and Schedules of Virginia Electric and Power Company Before the State Corporation Commission of Virginia, Case No. PUE-2011-00074, filed June 27, 2011, pp. 12-13. However, the report is not publicly available.

[20] Estimates of the net present value of savings to customers were provided by Dominion, but these cannot be converted into LCOE metrics because they place an unspecified value on the amount of electricity generated.

[21] Diane Leopold, Senior Vice President, Business Development and Generation Construction for Dominion Virginia Power, states that "The Biomass Conversions are expected to provide $388 million (NPV) in value to our customers" (Dominion, 2011, p. 35/54).

[22] Marc A. Tufaro, Senior Utilities Analyst in the Virginia State Corporation Commission's Division of Energy Regulation, notes that Dominion's application states that "estimated net present value savings include the value of PTCs, the sale of RECs, and carbon legislation" delivering a customer savings of approximately $434 million (Dominion, 2011, p. 16/58).

the plants continued to operate on coal (Tufaro, 2011). By narrowly delimiting their assessment to either conversions to biomass or continued coal plant operations, Dominion failed to reveal that more cost-effective options were available.[23] This limited vision appears to derive from the narrow emphasis on two outcomes.

First, the dockets and public documents make clear that Dominion saw coal-to-biomass plant conversions as delivering a significant improvement in functionality by switching three coal plants from peaking to baseload performance.[24] The three coal units served primarily as peakers, supplying electricity only 18 percent of the time, mostly when demand spiked significantly on hot and cold days. As biomass plants, Dominion testified that the units' availability factors were expected to increase to 92 percent (Ruppert, 2013). Based on recent operating data, this goal has been only partially achieved. Specifically, the net capacity factors of the three converted biomass plants ranged from 63 percent to 68 percent in 2016 (Table 1), higher than the coal peaking units, but significantly lower than the 92 percent forecast. The shortfall may be due to the biomass plants' lack of competitiveness relative to the PJM market.

Second, the expected value of PTCs and RECs was noted by Dominion in its application and testimonies as enabling the economic operation of the converted plants.[25] Based on our analysis, it appears that even with these public subsidies and environmental credits, Dominion's biomass conversions are not competitive with several other established sources of electricity.[26]

## 5. Conclusions

We estimate the levelized cost of electricity generated from Dominion's four biomass plants in Virginia: three that were converted from coal plants in 2012 and one that was purchased by Dominion in 2004. In the base case, which includes the value of PTCs, the LCOEs of the four plants range from $93 to $143/MWh. Altavista has the highest LCOE, largely due to its greater biomass feedstock costs and higher annual fixed O&M costs. As a result, unlike the other three plants, the LCOE estimate for Altavista falls outside the range of costs estimated by US EIA and Lazard for comparable new stand-alone biomass plants. The results of a sensitivity analysis focused on alternative assumptions about plant lifetimes and discount rates do not in any way invalidate or weaken these conclusions; indeed, they reinforce our findings.

Our analysis of the PJM wholesale market suggests that Dominion's four Virginia biomass plants are more expensive than electricity available for purchase from alternative sources in the region. Comparing variable O&M costs for the PJM capacity market in 2016, we find that the four Virginia biomass power plants are situated on the inside elbow of the PJM supply curve. There are approximately 170 GW of electricity that costs less, yet the summer PJM peak rarely exceeds 160 GW. Solar, wind, and hydro plants occupy the least expensive left side of this supply curve because they have essentially no fuel costs. After natural gas and nuclear enter the supply curve, biomass, coal, and petroleum represent the next highest variable O&M costs in the PJM region.

We also assessed whether Dominion's four biomass plants are providing competitive electricity resources compared with alternative resources that Dominion could purchase over the lifetime of these plants. In this comparison, we include an upper limit estimate of $10/MWh of integration costs for solar and wind based on values from the literature. Adding these costs to published LCOE estimates for utility-scale electricity technologies suggests that biomass is more expensive than natural gas combined cycle, solar, and wind power. Estimates of the LCOE for energy-efficiency resources indicates that demand-side resources are also less expensive than the cost of generating electricity from Virginia's four biomass plants.

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[23] For example, energy efficiency was an established low-cost energy resource in 2011 (National Academy of Sciences, 2010).

[24] Diane Leopold, Senior Vice President, Business Development and Generation Construction for Dominion Virginia Power, stated that "The Company will transform existing generation facilities that are not being fully utilized, modify them, and enhance their utilization and value to customers."

[25] Glenn A. Kelly, Director of Generation System Planning for Dominion, stated that "When repowered to operate on biomass fuel, the lower combined fuel and emissions costs, along with the expected federal Production Tax Credits (or "PTCs") and renewable energy certificates ("RECs"), are expected to enable the converted power stations to run economically at baseload capacity factors" (Dominion, 2011).

[26] Job creation and local economic development also were noted by Dominion to be motivating factors, as were the monetized environmental attributes of the biomass plant conversions. Dominion argued that because all three conversion units would operate selective non-catalytic reduction scrubbers, the coal to biomass conversions would benefit the environment by reducing emissions of nitrogen oxides, sulfur dioxide, particulate matter and mercury, as well as providing agricultural soil amendments, and job creation and local economic development were motivating factors (Dominion, 2017, p. 36).

A review of publicly available information led us to conclude that Dominion's planning process did not fully evaluate a broad range of alternatives to coal plant conversions to biomass. In addition, the plant conversions were seen as delivering a significant improvement in functionality by switching the plants from underutilized coal peaking units to baseload performance with biomass fuels, but the broader scope of costs and benefits from a wider array of alternatives received limited emphasis in public documents.

When Dominion first considered converting Virginia coal plants to biomass, U.S. markets were just beginning to see significant domestic supplies of low-cost natural gas, the cost of wind power was declining but not yet competitive, and solar systems were experiencing significant cost and performance breakthroughs. Large-scale energy-efficiency resources were well documented in national studies, but in the 2012 timeframe, few if any states in the Southeast had scaled-up their demand-side programs and documented their ability to offset or delay the construction of new power plants. It is likely that investing in natural gas plants would have resulted in lower revenue requirements and reduced costs to consumers in Virginia, but natural gas plants would not have contributed to Virginia's voluntary renewable energy goal.

Our results suggest that in today's energy marketplace, additional coal plant conversions to biomass in Virginia would likely not be prudent. The economics were not competitive in 2012 and they would be even more unattractive in today's marketplace with cheap natural gas, rapidly declining solar costs, and an abundance of affordable energy efficiency. Overall, our analysis underscores the risks associated with investing in large, long-lived generation assets at a time when technologies and markets are rapidly evolving.

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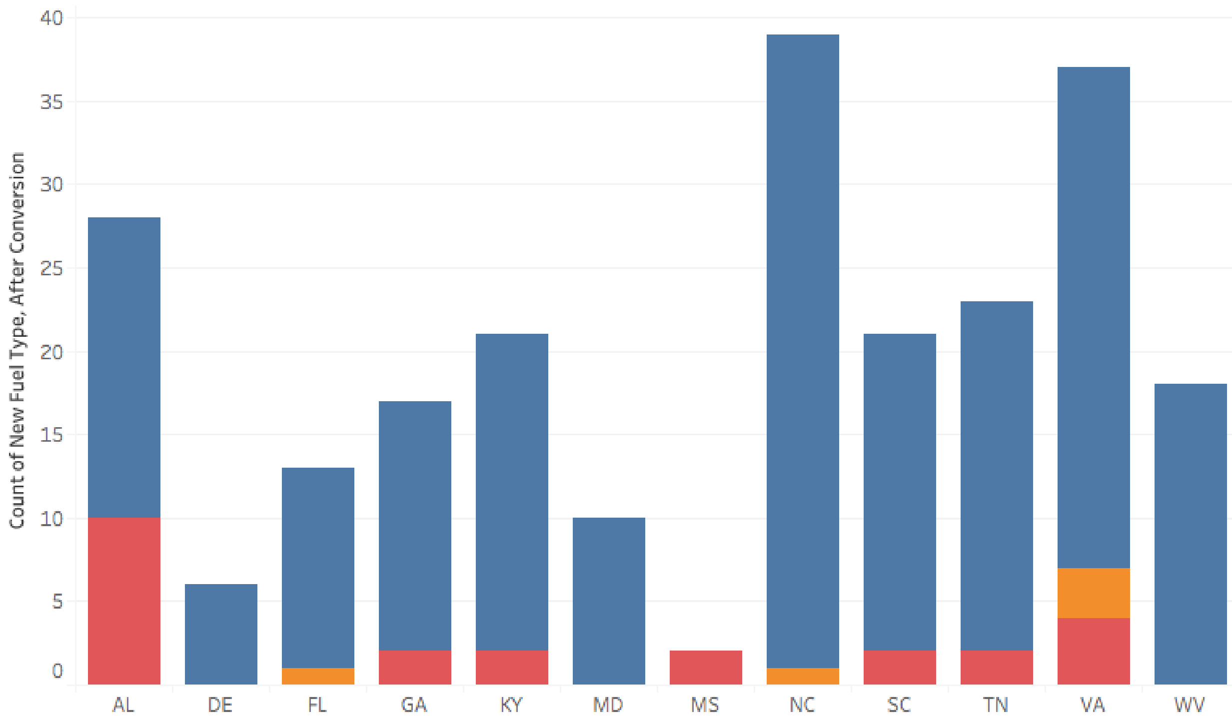
**Appendix A**

**FIGURE A.1 NATIONAL DATA ON COAL RETIREMENTS AND CONVERSIONS**




Count of New Fuel Type, After Conversion1 for each State. Color shows details about New Fuel Type, After Conversion1.

**New Fuel Type, After Conversion1**
- Retired Coal Plant
- Biomass
- Gas

Source: SNL Energy database (Sierra Club subscription)

**TABLE A.1 NATIONAL DATA ON COAL RETIREMENTS AND CONVERSIONS**

| Status | National Data | | Southeast Data | |
|---|---|---|---|---|
| | Sum of Nameplate Capacity (MW) | Percentage | Sum of Nameplate Capacity (MW) | Percentage |
| **Coal Retired** | 104,098 | 87.45% | 33,738 | 85.93% |
| **Coal to Biomass** | 545 | 0.46% | 373 | 0.95% |
| **Coal to Gas** | 14,279 | 12.00% | 5,152 | 13.12% |
| **Coal to other Nonrenewable** | 120 | 0.10% | 0 | 0.00% |
| **Total** | 119,042 | 100% | 3,9263 | 100% |

Source: SNL Energy database (Sierra Club subscription)

**TABLE A.2 LEVELIZED COSTS OF ELECTRICITY IN THE VIRGINIA-CAROLINAS SUBREGION, BASED ON EIA ESTIMATES FOR PLANTS ENTERING SERVICE IN 2022**

| | Capacity Factor (%) | Levelized Capital Cost | Fixed O&M | Variable O&M (including fuel) | Transmission Investment | Total System LCOE | Levelized Tax Credit | Total LCOE including Tax Credit |
|---|---|---|---|---|---|---|---|---|
| **Dispatchable Technologies** | | | | | | | | |
| **Natural Gas-fired Conventional Combined Cycle** | | | | | | | | |
| **National** | 87.0 | 13.9 | 1.4 | 40.8 | 1.2 | 57.3 | N/A | 57.3 |
| **VA-Carolinas** | 87.0 | 11.5 | 1.4 | 43.2 | 1.0 | 57.2 | N/A | 57.2 |
| **Natural Gas-fired Advanced Combined Cycle** | | | | | | | | |
| **National** | 87.0 | 15.8 | 1.3 | 40.8 | 1.2 | 56.5 | N/A | 56.5 |
| **VA-Carolinas** | 87.0 | 13,6 | 1.3 | 40.4 | 1.0 | 56.3 | N/A | 56.3 |
| **Biomass** | | | | | | | | |
| **National** | 83.0 | 44.7 | 15.2 | 41.2 | 1.3 | 102.4 | N/A | 102.4 |
| **VA-Carolinas** | 83.0 | 40.6 | 15.2 | 44.4 | 1.1 | 101.3 | N/A | 101.3 |
| **Non-Dispatchable Technologies** | | | | | | | | |
| **Wind-Onshore** | | | | | | | | |
| **National** | 39 | 47.2 | 13.7 | 0.0 | 2.8 | 63.7 | -11.6 | 52.2 |
| **VA-Carolinas** | 40.9 | 51.8 | 13.0 | 0.0 | 2.4 | 67.2 | -11.6 | 55.6 |
| **Solar PV** | | | | | | | | |
| **National** | 24 | 70.2 | 10.5 | 0.0 | 4.4 | 85.0 | -18.2 | 66.8 |
| **VA-Carolinas** | 24.1 | 58.6 | 10.3 | 0.0 | 3.7 | 72.6 | -15.2 | 57.4 |