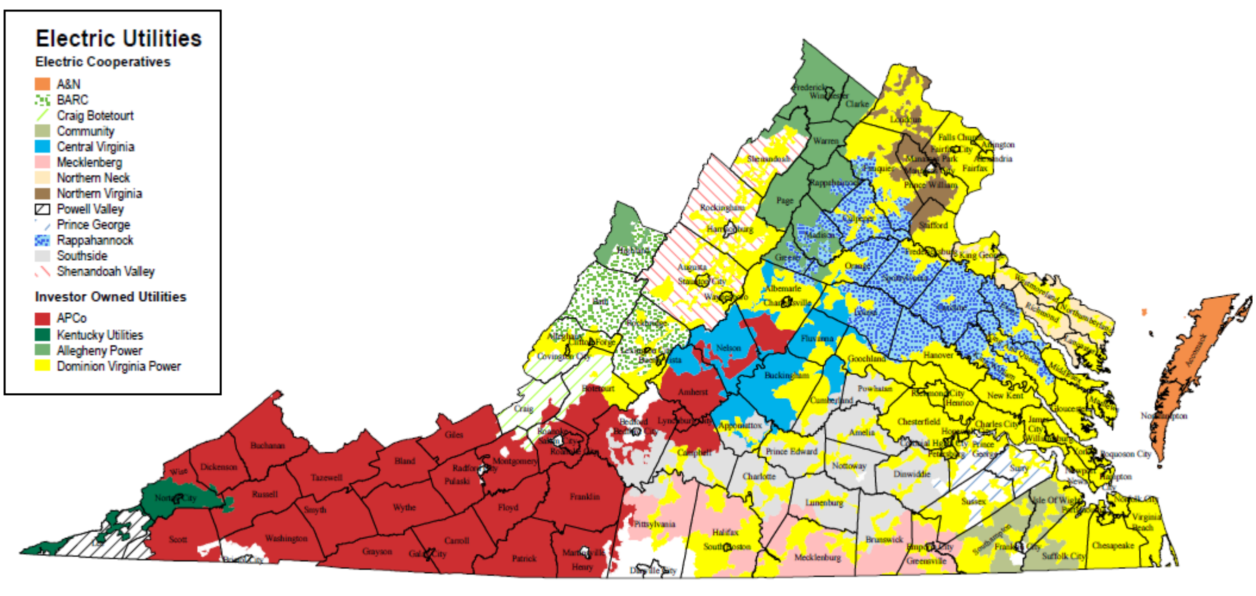
SECTION 2 - ELECTRICITY

Virginia's Electric Providers

- Electricity is provided to retail electric customers by:
  - Three investor-owned utilities providing 84.2 percent of retail sales;
  - Thirteen electric cooperatives providing 11.3 percent of retail sales; and
  - Eight municipal utilities providing 4.5 percent of retail sales.
- Investor-owned electric utilities include:
  - Dominion Virginia Power;
  - Appalachian Power (American Electric Power); and
  - Old Dominion Power (Kentucky Utilities).
- The 16 municipal electric utilities, serving customers located in their localities, include:
  - The Cities of Bedford, Bristol, Danville, Franklin, Harrisonburg, Manassas, Martinsville, Radford, and Salem;
  - The Towns of Blackstone, Culpeper, Elkton, Front Royal, Richlands, and Wakefield; and
  - Virginia Tech (serving the Town of Blacksburg).

Figure 2-1: Electric Utility Service Territories[1]



1 SCC, http://www.scc.virginia.gov/pue/elec/map.aspx, June 24, 2010. Shows Allegheny Power service territory which was transferred in 2010 to Rappahannock and Shenandoah Valley Electric Cooperatives.

Electric Consumption

- Virginians consumed 110 million megawatt hours of electricity in 2008.
- Electricity use has grown by approximately 3 percent per year over the last 10 years, with about two thirds of the growth attributable to new customers and one third to growth in use per customer.
- Growth is not uniform across the state, most being in the Northern Virginia, Hampton Roads, and Richmond areas.

Table 2-1: Electricity Sales by Type of Utility[2]

Item	Full Service Providers			Other Provider	
	Investor-Owned	Public	Cooperative	Energy	Total
Number of Entities	3	16	13	1	35
Number of Retail Customers	2,816,469	161,822	599,435	1,157	3,578,883
Retail Sales (thousand MWh)	92,727	4,960	12,404	16	110,106
Percentage of Retail Sales	84.21	4.50	11.27	0.01	100.00
Revenue from Retail Sales (million $)	6,970	418	1,418	2	8,809
Percentage of Revenue	79.12	4.75	16.10	0.02	100.00
Average Retail Price (cents/kWh)	7.60	8.44	11.44	10.50	8.00

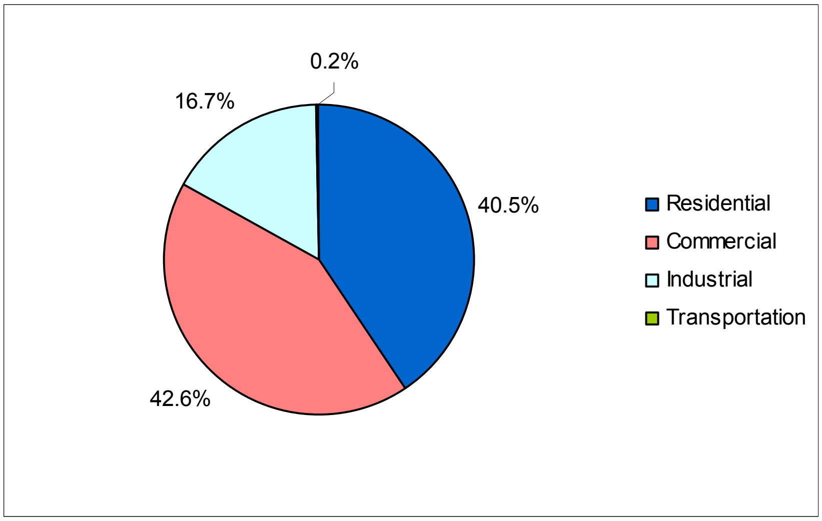
Table 2-2: Electricity Sales - Top Four Retailers of Electricity in Virginia[3]

Entity	Type of Provider	All Sectors	Residential	Commercial	Industrial	Transportation
1. Dominion	Investor-Owned	74,453	28,082	38,113	8,064	194
2. Appalachian Power	Investor-Owned	16,350	6,638	4,161	5,551	0
3. Rappahannock Coop	Cooperative	4,055	2,077	505	1,473	0
4. NOVEC	Cooperative	3,230	1,888	905	438	0
Total, Top Four		99,656	39,363	44,066	16,033	194
Total State Sales		110,106	44,597	46,878	18,438	194
% Total State Sales		91	88	94	87	100
(Thousand megawatt hours)						

[2] Adapted from EIA, State Electricity Profile, Retail Electricity Sales Statistics, 2008 http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept09va.xls, June 18, 2010. Data modified to show sales provided by cooperatives for customers formerly served by Allegheny Power.
[3] Adapted from EIA, State Electricity Profile, Top Five Retailers of Electricity, with End Use Sectors, 2008, http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept03va.xls, June 18, 2010. Data modified to show sales provided by cooperatives for customers formerly served by Allegheny Power.

- Virginia's utilities serve major military bases, one of the largest ports in the United States, and a large share of the computer infrastructure supporting the Internet and centralized computing. This results in a greater commercial load in Virginia than in many other states.

Figure 2-2: Percent of Retail Electric Sales by Customer Class, 2008[4]



Virginia's Electric Utility Regulatory Structure

- Virginia re-regulated electricity in 2007. Electricity is provided pursuant to a modified cost of service regulated monopoly system. Utilities serve exclusive territories and have an obligation to serve. Rates and terms of service for investor-owned utilities and electric cooperatives are subject to State Corporation Commission (SCC) review.[5]
  - Utilities are entitled to recover their reasonable and prudent operating expenses and earn up to a reasonable rate of return on the value of their capital investment in generating plants, transmission and distribution systems, and other facilities.
  - Calculation of a reasonable rate of return includes a comparison to the rates of return for peer electric utilities in the Southeastern United States.
  - Base rates are reviewed every two years.
  - Rates of return can be increased or decreased based on a utility's performance.
  - Additions to base rates are permitted through application of rate adjustment clauses which allow the recovery of costs for:
    - Fuel and purchased power (fuel adjustment clause);
    - Transmission, as approved by the Federal Energy Regulatory Commission;
    - Environmental and reliability improvements;
    - Energy efficiency programs;

[4] EIA, Virginia Electricity Profile, Table 8, Retail Sales, Revenue, and Average Retail Price by Sector, 1990 Through 2008. http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept08va.xls, May 7, 2010
[5] Virginia Electric Utility Regulation Act, Chapter 23 of Title 56 of the Code of Virginia, http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+TOC56000000023000000000000, June 19, 2010

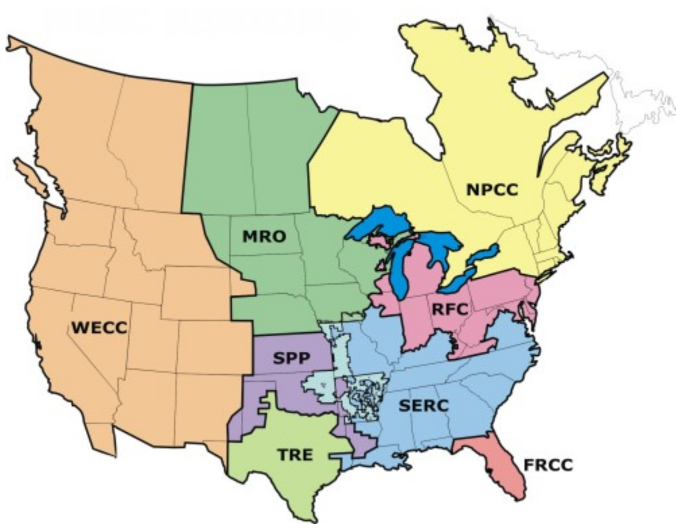
- Renewable energy needed to meet the state's renewable portfolio standard;
- Cost of new generating facilities; and
- A financial emergency.

- Electric cooperatives are authorized to increase or decrease rates by 5 percent in a three-year period (not including fuel factor adjustments) without SCC approval.
- Investor-owned electric utilities are also required to complete a 15-year Integrated Resource Plan (IRP) that sets out how the utilities will meet their customers' future demands for electricity and maintain adequate and reliable service. IRPs are to be updated every two years.[6]
- Electric utilities are required to be members of a regional transmission organization (RTO). The PJM Interconnection serves as the RTO for Virginia and areas to the north and west. PJM operates the largest centrally dispatched electric grid in the world by coordinating the movement of electricity in thirteen states.
- Rates and terms of service for municipal electric utilities are set by each City or Town Council.

Reliability Requirements

- Virginia's utilities must meet national standards established by the North American Electricity Reliability Council (NAERC) to ensure the reliability of electric service. Virginia is included in two regions of the North American Electricity Reliability Council.
    - The Southeastern Electric Reliability Council (SERC) that covers the Dominion region; and
    - The Reliability First Corporation (RFC, successor to the East Central Area Reliability Council) that covers the Appalachian Power region in Virginia.

Figure 2-3: North American Electric Reliability Council (NAERC) Regions[7]



[6] Electric Utility Integrated Resource Planning, Chapter 24 of Title 56 of the Code of Virginia, http://leg6.state.va.us/cgi-bin/legp604.exe?000+cod+TOC56000000024000000000000, June 24, 2010
[7] Solcomhouse, The US Power Grid, http://www.solcomhouse.com/uspowergrid.htm, June 19, 2010

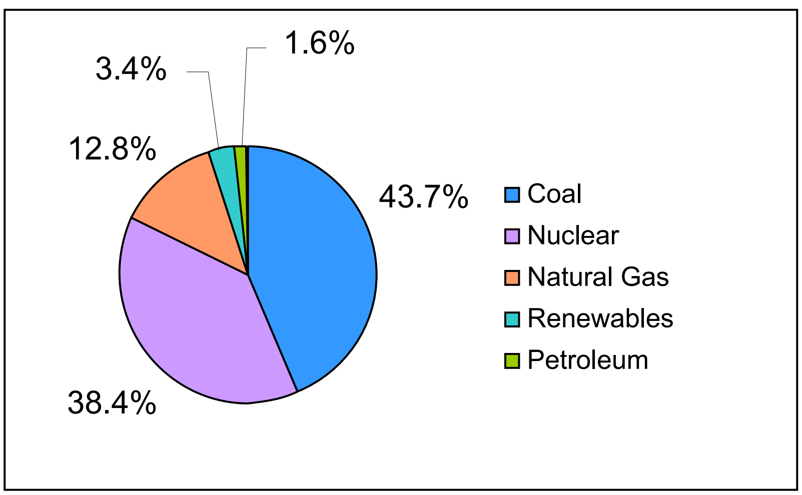
Electric Generation

- Virginia's utilities use a mix of utility-owned in-state generation, out-of-state generation, contractual purchases of electricity from in-state and out-of-state producers, and spot purchases of electricity from the PJM wholesale market to meet customer loads.
- Approximately one-third of Virginia's electric supply comes from power generated out of state. Most imports come from coal-fired plants located west and north of Virginia. A small amount of imports comes from renewable projects such as wind projects in West Virginia, Illinois, and Indiana.
- Electric generation is measured two ways, net generation and generation capacity.
  - Net generation is the amount of electricity generated over time. It is expressed in megawatt hours (MWh).
  - Generation capacity is the amount of electricity that can be generated at any one time. It is expressed in megawatts (MW).

Net Generation

- Virginia's electricity generation facilities produced 72,678,531 megawatt hours of electricity in 2008.
  - 59,780,402 megawatt hours (82 percent) were generated in plants operated by electric utilities; and
  - 12,898,129 megawatt hours (18 percent) were generated in plants operated by independent power producers and industrial combined heat and power facilities.
- Electricity is generated from diverse sources. Significant amounts of power come from coal, nuclear, and natural gas, with small amounts from renewable sources and petroleum.

Figure 2-4: In-State Net Generation by Fuel Type, 2008[8]



[8] EIA, State Electricity Profile, http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept05va.xls, May 11, 2010

Generation Capacity

- Dominion, Appalachian Power, and ODEC own power plants in Virginia with a combined peak generation capacity of 18,828 megawatts.
- Municipal utilities have very little generation capacity, purchasing almost all power through long-term, wholesale power contracts.
- Virginia's merchant and industrial cogeneration plants produce power for the wholesale marketplace and internal industrial use. These have a generation capacity of 4,648 megawatts.
- The ten largest power plants in size make up 60 percent of the generation capacity in the state.

Figure 2-5: Virginia Electric Generating Capability (MW) by Fuel Type, 2008[9]

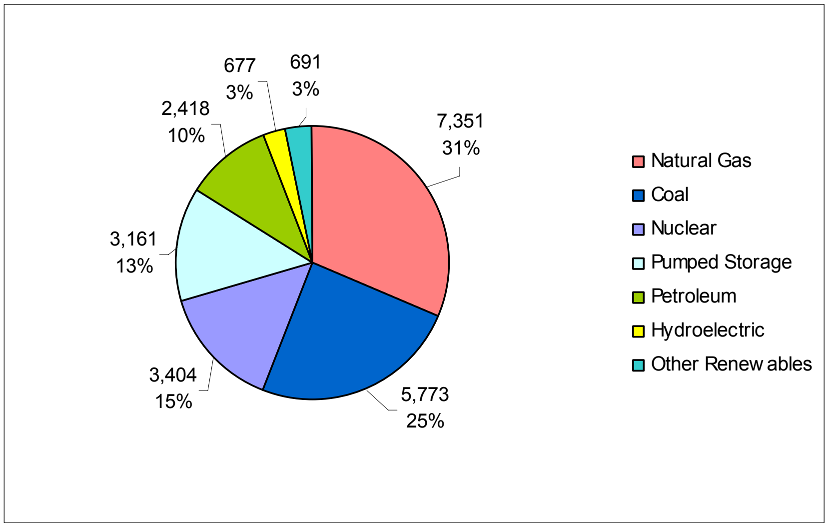


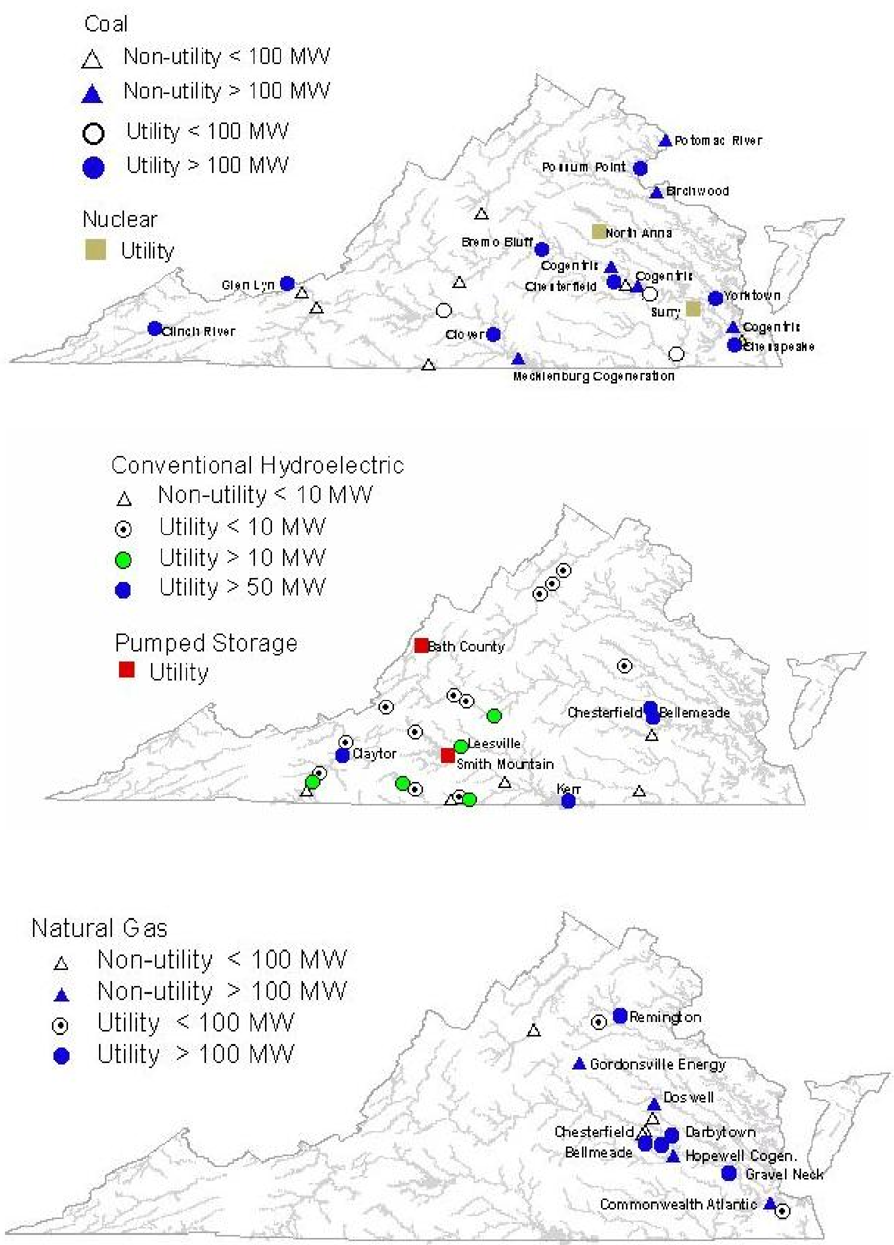
Table 2-3: Ten Largest Plants by Generation Capacity

Plant	Primary Energy Source or Technology	Operating Company	Net Summer Capacity (MW)
1. Bath County	Pumped Storage	Virginia Electric & Power Co	2,923
2. North Anna	Nuclear	Virginia Electric & Power Co	1,807
3. Possum Point	Gas	Virginia Electric & Power Co	1,733
4. Chesterfield	Coal	Virginia Electric & Power Co	1,632
5. Surry	Nuclear	Virginia Electric & Power Co	1,598
6. Yorktown	Coal	Virginia Electric & Power Co	1,141
7. Tenaska VA Gen Sta	Gas	Tenaska Virginia Partners LP	935
8. Clover	Coal	Virginia Electric & Power Co	865
9. Doswell Energy Center	Gas	Doswell Ltd Partnership	820
10. Chesapeake	Coal	Virginia Electric & Power Co	710
TOTAL			14,164

[9] EIA, State Electricity Profiles, http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept04va.xls, May 11, 2010

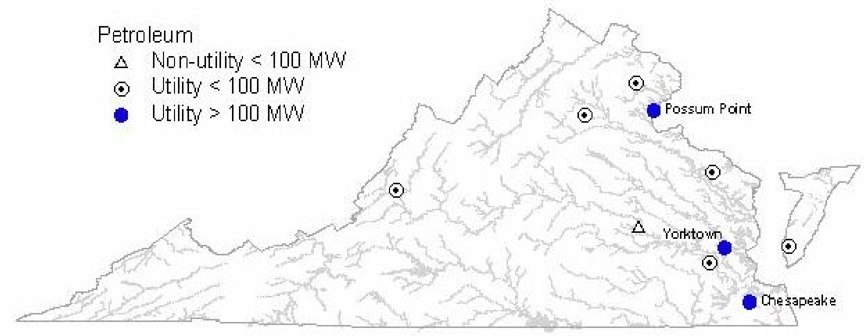
- Generation facilities are located across Virginia. Some are near population centers while others are located in remote areas requiring additional electric transmission to deliver the power to population centers.

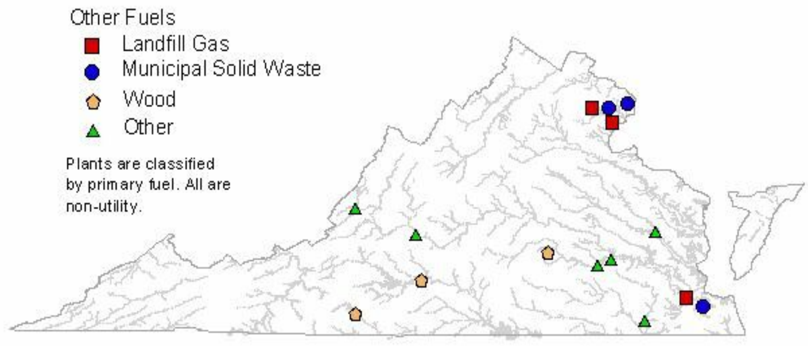
Figure 2-6: Location of Electric Power Generation Plants by Primary Fuel Consumed[10]



.[10] Virginia Energy Patterns and Trends. Location of Electric Power Generation Plants by Primary Fuel Consumed, http://www.energy.vt.edu/vept/electric/plantlocations.asp, June 19, 2010.

Note that the generation resources shown on these maps will be augmented by the new generation resources, including the coal/biomass Virginia City Hybrid Power Station in Wise County (to be online in 2012), and the natural-gas Warren County Power Station (to be online in 2015)





Renewable Portfolio Standard

- Virginia established a voluntary renewable portfolio standard (RPS) for investor-owned utilities to provide increasing amounts of electricity from renewable resources. Targets, measured against 2007 base load sales (total less sales attributable to nuclear generation), are:
  - 4 percent by 2010;
  - 7 percent by 2016;
  - 12 percent by 2022; and
  - 15 percent by 2025.
- A utility is eligible to earn an enhanced rate of return of up to 50 basis points if it meets the RPS targets and is not receiving a separate performance incentive for overall utility operations.
- Utility RPS plans and cost recovery are subject to SCC approval.

Table 2-4: Generation Needed to Meet RPS Targets (MWh)[11]

Utility	Base Line	2010 Target	2016 Target	2022 Target	2025 Target
Dominion	43,318,649	1,732,746	3,032,305	5,198,238	6,497,797
Appalachian	16,377,000	655,080	1,146,390	1,965,240	2,456,550

[11] Sourced from applications for approval of Renewable Portfolio Standards filed with the State Corporation Commission in case numbers PUE-2008-00003 (Appalachian Power) and PUE-2009-00082 (Dominion Power).

Generating Plant Loading Order

- PJM is the regional transmission organization (RTO) serving Virginia and areas to the north and west. PJM works with electric generators and utilities to operate the wholesale electric market and ensure reliable sources of electricity are available in the region.
- PJM selects which power plants are needed to meet electric loads based on plant availability and cost and capacity to deliver the electricity from the generating plant to load centers.
- Generation owners bid generation and demand side management capacity into the PJM marketplace. PJM selects the lowest cost resources first, and moves up the cost curve until the demand is satisfied.
- The cost bid for the last plant needed to meet demand sets the price for all electricity delivered during the bid period.
- This process results in the following mix of fuel types being used to supply power in the PJM system.

Table 2-8: PJM – Electric Generation by Fuel Type, CY 2009[12]

		GWh	Percent
Coal		349,818.2	50.5%
Nuclear		249,392.3	36.0%
Gas		67,218.9	9.7%
	Natural Gas	65,848.2	9.5%
	Landfill Gas	1,368.5	0.2%
	Biomass Gas	2.2	0.0%
Hydroelectric		14,123.0	2.0%
Waste		5,664.7	0.8%
	Solid Waste	4,147.0	0.6%
	Miscellaneous	1,517.7	0.2%
Wind		5,489.7	0.8%
Oil		1,568.1	0.2%
	Heavy Oil	1,383.7	0.2%
	Light Oil	162.9	0.0%
	Diesel	14.4	0.0%
	Kerosene	7.1	0.0%
	Jet Oil	0.0	0.0%
Solar		3.5	0.0%
Battery		0.3	0.0%
Total		693,278.7	100.0%

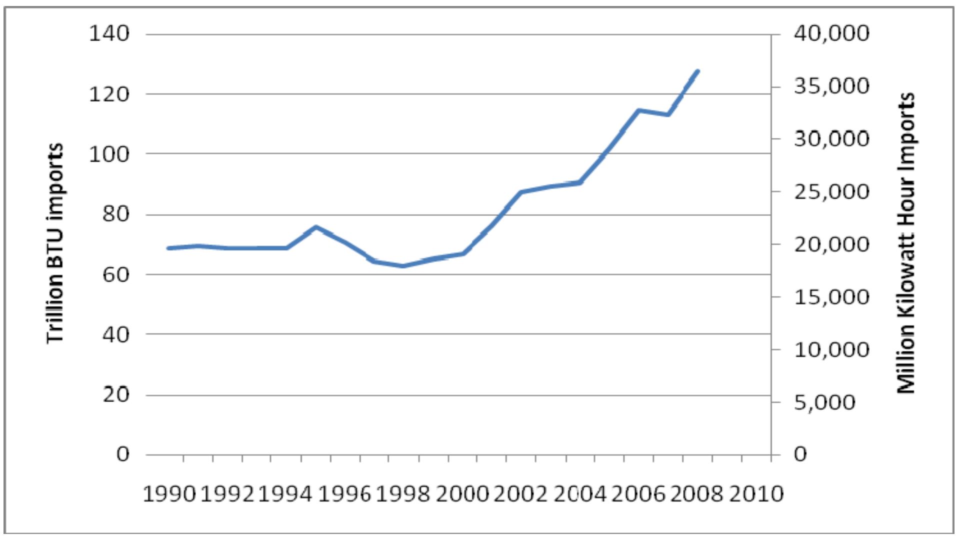
Electricity Imports

- Virginia utilities do not own in-state generation capacity sufficient to meet the state's peak load plus the reserve capacity required by federal regulation.
- It is sometimes less expensive to purchase electricity on the wholesale market than to generate the electricity at in-state, utility-owned facilities.

[12] PJM. 2009 Year in Review

- These factors resulted in Virginia importing 34 percent of electricity consumed in the state during 2008.
- As demand has grown faster than additions to generation, imports have increased by an average of 1.4 percent per year over the last 10 years.
- Virginia's imports come from:
  - Dominion's 1,632 megawatts Mount Storm electric generating station in West Virginia dedicated to serving Dominion's customers;
  - American Electric Power's generating plants dedicated to serving AEP customers;
  - Kentucky Utility's generating plants dedicated to serving KU customers; and
  - Generating plants not dedicated to serve only Virginia customers, primarily located in the PJM Interconnection area that runs from Virginia north to New Jersey and west to Illinois.

Figure 2-8: Virginia's Net Electricity Imports, 1990–2008[13]



Electric Rates

- Virginia's electric rates vary among the state's electric utilities[14], but on average have historically remained below the national average.

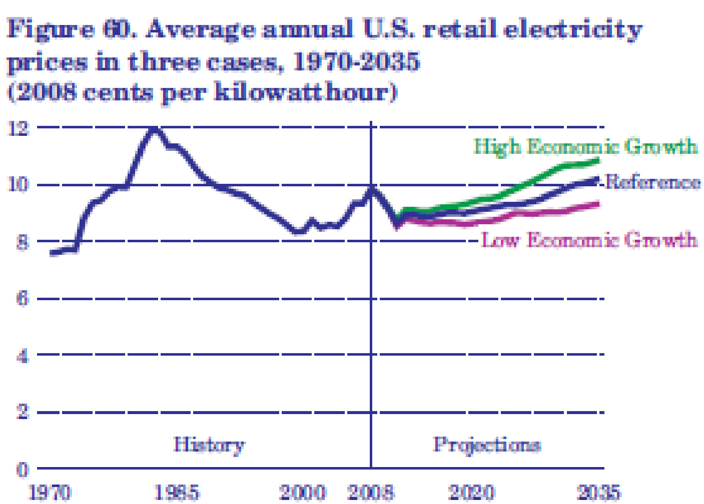
[13] EIA. State Electric Profiles, Virginia, http://www.eia.doe.gov/cneaf/electricity/st_profiles/virginia.html
[14] See http://dls.state.va.us/GROUPS/elecutil/12_14_09/rates.pdf for data on residential electric rates for individual Virginia electric utilities

Table 2-6: Average Retail Electric Rates by Customer Class (cents/kWh)[15]

Sector	1990	1995	2000	2005	2006	2007	2008	2009	YTD Thru Mar 2010
Residential	7.25	7.84	7.52	8.16	8.49	8.74	9.62	10.61	10.15
Commercial	6.06	6.07	5.65	6.05	6.21	6.38	7.32	8.10	7.78
Industrial	4.27	4.16	3.90	4.46	4.69	5.07	5.82	6.87	6.80
Transportation	5.31	5.21	5.05	6.81	6.81	6.73	7.80	8.42	7.82
All Sectors – VA	6.03	6.26	5.94	6.64	6.86	7.12	8.00	8.95	8.79
All Sectors – US	6.57	6.89	6.81	8.14	8.90	9.13	9.74	9.89	9.47
VA as % of US	91.78	90.86	87.22	81.57	77.08	77.98	82.14	90.5	92.82

- Future electric rates in Virginia will be affected by factors such as:
  - Utility operating costs;
  - Fuel costs;
  - Cost of capital;
  - Need for investments in new generation and transmission infrastructure;
  - Level of utility investments in energy efficiency and renewable portfolio standard projects; and
  - Rates of return for Virginia utilities.
- The federal Energy Information Administration (EIA) predicts that nationally, electric rates will fall through 2011 as fossil fuel costs and demand for electricity drops. Costs should then show a moderate increase through 2035 in response to rising fuel prices and the construction of new power plants.

Figure 2-7: EIA Electricity Price Forecast[16]



[15] EIA, State Electricity Profiles, http://www.eia.doe.gov/cneaf/electricity/st_profiles/sept08va.xls, June 24, 2010
[16] EIA, Annual Energy Outlook, 2010, Electricity Projections, http://www.eia.doe.gov/oiaf/aeo/pdf/trend_3.pdf, May 7, 2010

Factors Affecting Electric Generation Costs

- Electric generating costs vary based on the type and age of generating plants, the size of the plants, capital costs and the amount that has been depreciated, the cost of fuel and personnel, and other operational costs.
  - Older plants typically have lower costs. However, these plants may be more expensive if substantial environmental controls have to be added.
  - Larger plants generally offer an economy of scale due to spreading infrastructure and personnel costs over larger amounts of generation.
  - Fuel costs vary by fuel type. The relative cost of fuel also varies over time. Fuel costs are typically compared on a cost per million Btu input.
  - Differing types of electric generating plants require different amounts of manpower. Some plants, such as peaking natural gas plants, can operate with few, if any, workers present. Others, such as a biomass or coal plants, require larger numbers of workers to manage fuel, environmental controls, and ash.

Table 2-7: Average Wholesale Cost of Power by Power Plant Type (cents/kWh), 2008[17]

Plant Type	2008 Costs
Operation	
Nuclear	0.968
Coal, and Oil	0.365
Hydroelectric	0.578
Gas Turbine and Small Scale	0.298
Maintenance	
Nuclear	0.620
Coal and Oil	0.359
Hydroelectric	0.389
Gas Turbine and Small Scale	2.072
Fuel	
Nuclear	0.529
Coal and Oil	2.843
Hydroelectric	0
Gas Turbine and Small Scale	6.423
Total	
Nuclear	2.116
Coal and Oil	3.567
Hydroelectric	0.967
Gas Turbine and Small Scale	6.993

[17] EIA. Electric Power Annual. Average Power Plant Operating Expenses for Major U.S. Investor-Owned Electric Utilities, http://www.eia.doe.gov/cneaf/electricity/epa/epat8p2.html, June 19, 2010

Table 2-8: Average Delivered Cost of Fossil Fuel to Utility Power Plants ($/MMBtu), 2008[18]

Type of Fuel	Total All Sectors	Electric Power Sector	
		Electric Utilities	Independent Power Producers
Bituminous Coal	2.50	2.49	2.50
Petroleum	10.87	12.38	9.03
Natural Gas	9.02	9.15	8.94

Wholesale Electricity Pricing

- Wholesale electric prices in the PJM system are affected by the cost and availability of generation and the availability of transmission capacity to carry power from generating plants to load centers.
- Wholesale prices are higher in areas that do not have sufficient local generation or long-distance transmission capacity to meet peak electric loads as the demand in these areas must be met by local, more costly generating plants. This method of wholesale power pricing is called Locational Marginal Pricing (LMP).
- LMP in coastal areas with more congestion, such as Virginia, generally runs higher than in areas to the west, such as Illinois or Kentucky.
- Utilities in generation and transmission constrained areas must pass higher LMP along to their customers through higher retail rates.
- Wholesale electric costs in the PJM market vary over time as the demand for power grows or shrinks, as input costs such as for fuel change, and as new generation and transmission capacity is added to the region. For example, wholesale electric costs have dropped during 2009 and 2010 as demand and fuel costs have dropped.

[18] EIA. Cost and Quality of Fuels for Electric Plants 2007 - 2008 Edition, http://www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html, June 19, 2010

Table 2-9: Wholesale Electric Prices (LMP) by State ($/MWh), 2008-2009[19]

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$76.26	$40.80	($35.47)	(46.5%)
Illinois	$49.38	$29.05	($20.33)	(41.2%)
Indiana	$53.01	$33.08	($19.93)	(37.6%)
Kentucky	$53.80	$33.48	($20.32)	(37.8%)
Maryland	$79.75	$41.66	($38.09)	(47.8%)
Michigan	$54.07	$34.09	($19.98)	(36.9%)
New Jersey	$79.27	$41.08	($38.19)	(48.2%)
North Carolina	$71.69	$38.92	($32.77)	(45.7%)
Ohio	$52.64	$33.25	($19.39)	(36.8%)
Pennsylvania	$68.98	$38.47	($30.50)	(44.2%)
Tennessee	$54.36	$33.54	($20.82)	(38.3%)
Virginia	$73.20	$39.29	($33.91)	(46.3%)
West Virginia	$55.02	$34.60	($20.42)	(37.1%)
District of Columbia	$80.57	$42.98	($37.59)	(46.7%)

Table 2-10: Wholesale Electric (LMP) Prices in PJM ($/MWh), 1998-2009[20]

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)

[19] Monitoring Analytics, LLC. 2009 State of the Market Report for PJM, Table 2-57, Page 66
[20] Monitoring Analytics, LLC. 2009 State of the Market Report for PJM, Table 2-55, Page 65

Cost of New Generation

- Electric generators consider a variety of factors when deciding to build a new generating plant. These factors can be evaluated to calculate a levelized cost of power.
- Factors include:
    - Fuel costs and their expected change over time;
    - Risk associated with being able to successfully permit and construct each type of plant;
    - Time needed to construct the plant;
    - Expected life of the plant;
    - Cost of capital;
    - Capacity factor of the plant; and
    - Other.

Table 2-11. Estimated Levelized Cost of New Generation Resources, 2016[21]

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2008 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	69.2	3.8	23.9	3.6	100.4
Advanced Coal	85	81.2	5.3	20.4	3.6	110.5
Advanced Coal with CCS	85	92.6	6.3	26.4	3.9	129.3
Natural Gas-fired						
Conventional Combined Cycle	87	22.9	1.7	54.9	3.6	83.1
Advanced Combined Cycle	87	22.4	1.6	51.7	3.6	79.3
Advanced CC with CCS	87	43.8	2.7	63.0	3.8	113.3
Conventional Combustion Turbine	30	41.1	4.7	82.9	10.8	139.5
Advanced Combustion Turbine	30	38.5	4.1	70.0	10.8	123.5
Advanced Nuclear	90	94.9	11.7	9.4	3.0	119.0
Wind	34.4	130.5	10.4	0.0	8.4	149.3
Wind – Offshore	39.3	159.9	23.8	0.0	7.4	191.1
Solar PV	21.7	376.8	6.4	0.0	13.0	396.1
Solar Thermal	31.2	224.4	21.8	0.0	10.4	256.6
Geothermal	90	88.0	22.9	0.0	4.8	115.7
Biomass	83	73.3	9.1	24.9	3.8	111.0
Hydro	51.4	103.7	3.5	7.1	5.7	119.9

[21] DOE EIA. 2010 Annual Energy Outlook. 2016 Estimated Levelized Cost of New Generation Resources, http://www.eia.doe.gov/oiaf/aeo/pdf/2016levelized_costs_aeo2010.pdf, June 19, 2010

Future Electric Demand

- PJM forecasts of summer peak demand and consumption predict:
    - Demand in Dominion's control area will grow on average 2.5 percent per year over the next 10 years. Consumption is forecast to grow by 2.4 percent per year.
    - Demand in Appalachian Power's control area will grow by 1.3 percent per year. Consumption is forecast to grow by 1.2 percent per year.
- Based on these growth rates, Virginia will need to add over 7,200 megawatts of capacity by 2020 to maintain the same electricity imports ratio of 38 percent as in 2008. Virginia will need to add 11,700 megawatts of capacity to meet 100 percent of projected growth.
- These growth forecasts may increase in the future as the state and national economy recovers, and as the electric market changes due to electric cars, added computing capacity, and other factors.

Table 2-12: Forecast of Peak Electric Demand in Virginia (MW)[22]

Year	Peak In-state Demand (MW)	Growth at 2.26%	In-state Generation Capacity (MW) at 38.3% Import Ratio	In-state Gross Consumption (MWh)	Growth at 2.16%	Consumption (MWh) from In-state Generation at 34% Imports
2008	38,052	0	23,476	110,106,000	0	72,679,000
2009	38,912	860	24,009	112,484,290	2,378,290	74,239,631
2010	39,791	879	24,551	114,913,950	2,429,661	75,843,207
2011	40,691	899	25,106	117,396,092	2,482,141	77,481,420
2012	41,610	920	25,674	119,931,847	2,535,756	79,155,019
2013	42,551	940	26,254	122,522,375	2,590,528	80,864,768
2014	43,512	962	26,847	125,168,858	2,646,483	82,611,447
2015	44,496	983	27,454	127,872,506	2,703,647	84,395,854
2016	45,501	1,006	28,074	130,634,552	2,762,046	86,218,804
2017	46,530	1,028	28,709	133,456,258	2,821,706	88,081,130
2018	47,581	1,052	29,358	136,338,913	2,882,655	89,983,683
2019	48,657	1,075	30,021	139,283,834	2,944,921	91,927,330
2020	49,756	1,100	30,700	142,292,365	3,008,531	93,912,961

Integrated Resource Plans

- Electric utilities in Virginia are required to complete an Integrated Resource Plan (IRP) to address how they will meet this growing demand over a 15-year time frame.
- Dominion's preferred IRP includes adding 7,900 megawatts of generation capacity, nearly 950 megawatts from demand side management programs, and market purchases.[23]
    - Projected new generation capacity would come from the Virginia City coal-biomass hybrid plant under construction and new plants including six natural gas combined cycle, four natural gas combustion turbine, the third North Anna nuclear, two biomass, and four wind facilities.

[22] Calculated based on EIA Electricity Profile Supply and Disposition historical data
[23] Virginia Electric and Power Company Integrated Resource Plan filed with the Virginia SCC on September 15, 2009

- Appalachian Power's IRP (East Zone) includes adding 4,168 megawatts of generation capacity and 1,346 megawatts from demand side management. This will be offset by planned unit retirements and retrofits lowering capacity by 5,093 megawatts for a net capacity addition of 422 megawatts.[24]
    - Projected new generation capacity would come from completion of the Dresden plant under construction in Ohio; capacity uprates at the Cook nuclear plant in Michigan; and construction of four new fossil fuel plants, biomass co-firing and two new biomass plants, and purchases or additions of wind and solar capacity.
- The Old Dominion Electric Cooperative (which provides wholesale power to its member retail electric cooperatives) is proposing constructing a new coal-fired power plant near Cyprus Creek in Surry County. The Cyprus Creek Power Station would have a capacity between 750 and 1,500 megawatts, and be completed at the earliest by 2018.

Transmission and Distribution of Electricity

- Electricity is delivered to end users through a network of high-voltage transmission and local distribution lines.[25]
    - Electric power is transmitted in Virginia through 230, 500, and 765-kV transmission lines constructed, owned, and operated by Dominion, Appalachian Power, Delmarva Power, and Allegheny Power.
    - Transmission lines are typically located above ground. The cost of burying high-voltage transmission lines underground is many times the cost of placing the lines overhead. Underground lines also present higher maintenance challenges and costs.
    - Electricity is distributed from the transmission network to end users through a network of smaller, lower-voltage lines and facilities.
    - Distribution lines are typically located above ground. Distribution lines can also be placed underground, typically in new development where the incremental cost of burying the lines is lower.
- Electric cooperatives and municipal electric departments do not own any transmission lines.
- Management of and additions to the regional transmission grid are directed by the PJM Interconnection to ensure reliability of the system.

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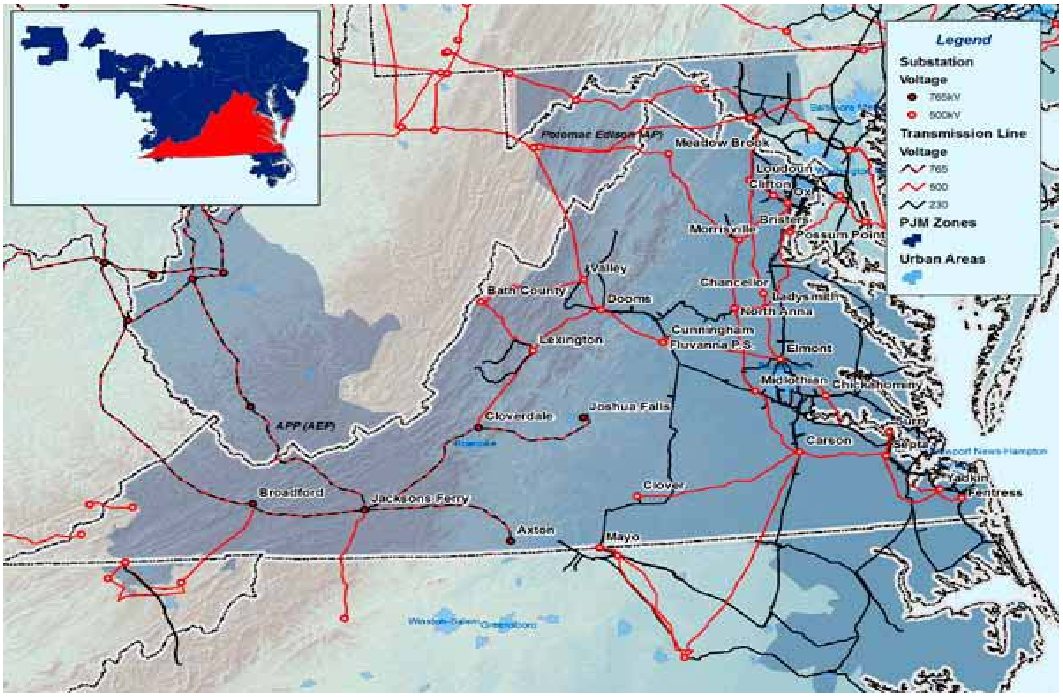
[24] Appalachian Power Company's Integrated Resource Plan filed with the Virginia SCC on September 1, 2009
[25] PJM 2009 RTEP Report – Section 12.12, Virginia, http://www.pjm.com/documents/reports/~/media/documents/reports/2009-rtep/2009-section12-12-va.ashx, June 18, 2010

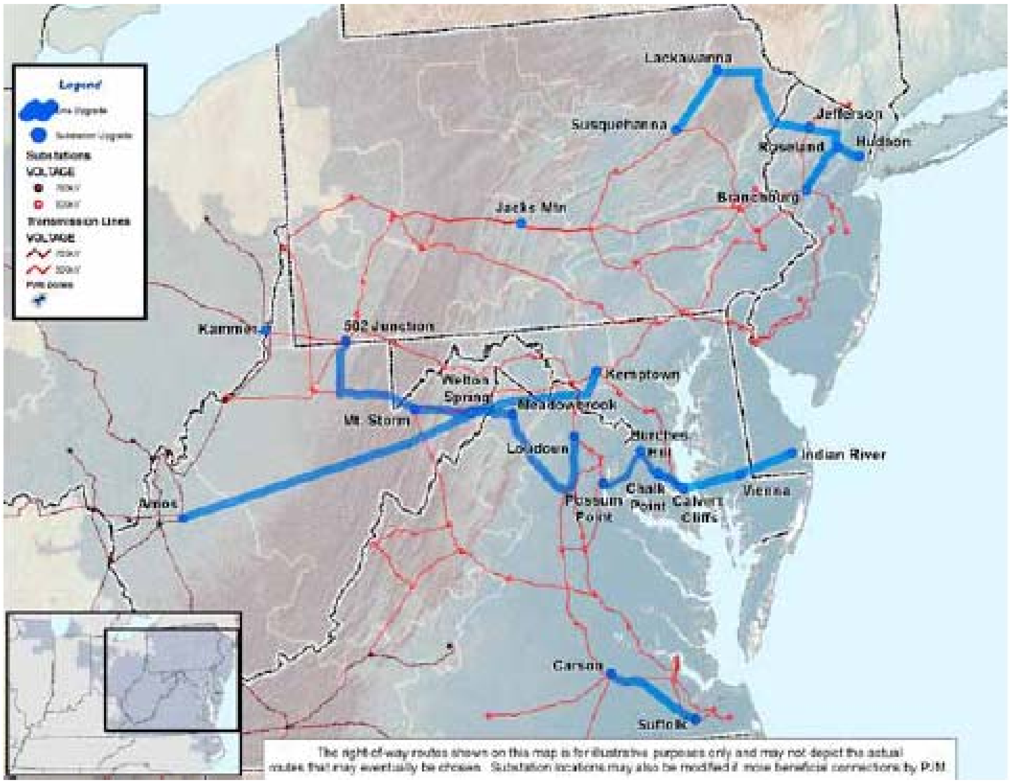
Figure 2-9. Virginia's Electric Transmission System[26]



- PJM creates a Regional Transmission Expansion Plan (RTEP) to identify the need for new transmission resources. The 2009 RTEP includes four high-voltage lines affecting Virginia.
  - o Allegheny and Dominion's 500 kV Trans Allegheny Interstate Line (TrAIL) from the 502 Junction in western Pennsylvania to Loudoun County;
  - o Dominion's 500 kV Carson to Suffolk line;
  - o Allegheny and Appalachian Power's 765 kV Potomac-Appalachian Transmission Highline (PATH) from Atmos, West Virginia, to Kempstown, Maryland; and
  - o Pepco's 500 kV Mid-Atlantic Power Pathway (MAPP) from Possum Point in Virginia to Indian River, Maryland.
- The Virginia SCC must determine and certify the need for and location of proposed new electric transmission lines. The SCC has approved the TrAIL and Carson-Suffolk lines.
- PJM has delayed the schedules for the PATH and MAPP lines due to the 2009-10 drops in electric demand.

[26] PJM. PJM 2009 Regional Transmission Expansion Plan, Section 12.12, Virginia RTEP Overview, Map 12-53, Page 321

Figure 2-10: PJM 2009 RTEP Approved 765 and 500 kV Facilities[27]



- The Federal Energy Regulatory Commission (FERC) regulates electric transmission rates. The charges are passed through to Virginia ratepayers on a dollar-for-dollar basis.
- FERC has the authority under the National Interest Electric Transmission Corridor (NIETC) legislation to designate priority electric transmission corridors in transmission constrained areas.
  - o Based on a U.S. Department of Energy study of transmission needs, FERC has designated two corridors in the Eastern United States with inadequate transmission, one crossing through Northern Virginia.
  - o If the SCC fails to act on a petition to build a new line in a designated corridor, the applicant to the line could petition FERC to take over jurisdiction for the line.

Conservation and Efficiency

- Electric efficiency actions can be used to reduce future growth in electrical demand.
- Substantial cost-effective investments in energy efficiency remain unmade as there are factors that undercut market forces. These include:
  - o Principal-agent barriers – the party responsible for the building improvements doesn't pay electric bills;

[27] PJM. PJM 2009 Regional Transmission Expansion Plan, Executive Summary, Map 1.2, Page 6

    - Information barriers – consumers don't have sufficient trusted information in order to act;
    - Transaction cost barriers – consumers cannot budget or borrow the up front investment needed for energy efficiency projects; and
    - Externality cost barriers – benefits of energy efficiency, such as lower utility costs from reduced peak demand, accrue to other people than those making the investments.

- State government has taken a number of actions to overcome these market barriers, including:
    - Adoption by the General Assembly of voluntary goals to reduce electric use by 2022, through conservation and efficiency, by an amount equal to 10 percent of 2006 use;
    - An Energy Star appliance sales tax holiday over Columbus Day weekend in October;
    - An income tax exemption for sales tax paid on certain energy efficiency improvements;
    - $15 million in American Recovery and Reinvestment Act (ARRA) State Energy Program funding for energy efficiency rebates;
    - $7.4 million in ARRA funds for Energy Star appliance and equipment rebates;
    - $94 million in ARRA funds to expand the Weatherization Assistance Program, under which efficiency improvements are made to homes of families earning up to 60 percent of the state medium based on family size;
    - $200 million in energy efficiency improvements made to state government facilities;
    - Completion of carbon emission inventories and plans to lower carbon emissions. Energy efficiency actions are a primary strategy of these plans; and
    - Authorization for local governments to provide property tax and other incentives for:
        - Energy Star buildings (at least 20 percent more efficient than minimum building code requirements);
        - Buildings with green roofs and solar energy systems; and
        - Property Assessed Clean Energy (PACE) or Home Performance with Energy Star programs.

- Virginia's consumers also benefit from federal incentives and programs that encourage efficiency, such as:
    - Federal energy efficiency income tax credits;
    - Strengthened minimum equipment efficiency requirements; and
    - Expansion of the Energy Star program.
- Conservation and efficiency can offset a portion of future electric load growth. If Virginia's consumers can meet the state goal to reduce its electricity use by 10 percent, the forecasted peak electric generation capacity would be reduced by 3,285 megawatts.

Table 2-13: Electricity Generation Scenarios for Virginia (Demand/Generation Capacity)

Scenario	Year	In-State Electrical Demand (MW)	Energy Efficiency Goal Percent	Energy Efficiency Goal (MW)
Base Case	2008	38,052	0%	0
1	2020	49,756	0%	0
2	2020	46,471	9%	3,285
	Scenario Description			
Base Case	Base historical year – 2008 - Based on Energy Information Administration data			
1	No conservation and efficiency impacts, no new generation			
2	10% conservation and efficiency impacts, no new generation			
Energy Efficiency goal based on 10% reduction from 2006 base year by 2022 as provided in Chapter 888 (HB 3068), 2007 Virginia Acts of Assembly. 2006 base consumption was 118,365,000 MWh, with an approximate 36,500 MW peak demand. (2006 data source - State Electricity Profiles 2006, 11/21/07). http://tonto.eia.doe.gov/ftproot/electricity/stateprofiles/06st_profiles/062906.pdf.				

Adequacy of Electric Infrastructure Siting Requirements

- Permitting for new electric facilities is a complex and lengthy process.
- Multiple federal, state, and local permits are required to address issues such as need for the project, cost, and impact on ratepayers; environmental impacts; safety; and local land use impacts.
- The permits establish performance requirements in multiple environmental and public safety areas.
- These processes provide for multiple opportunities for public comment, in writing and orally.
- For example, an applicant for a proposed fossil-fuel power plant must apply for permits or approvals from:
    - The Department of Environmental Quality (DEQ) for air, water, and waste discharges, including:
        - Air permits to address use of Best Available Control Technology to maintain compliance with the National Ambient Air Quality Standards (NAAQS) and Maximum Achievable Control Technology for hazardous air pollutants;
        - Water permits to address withdrawals from and discharges to surface and groundwater;
        - Wetland permits (issued jointly with the U.S. Army Corps of Engineers and Virginia Marine Resource Commission) to address construction affecting wetlands; and
        - Waste permits to address management of solid wastes, typically bottom and fly ash from combustion.
    - The Department of Conservation and Recreation for erosion and sediment control and stormwater management;

    - The Departments of Game and Inland Species and Agriculture and Consumer Services for threatened or endangered plant, animal, or insect species;
    - The Department of Historic Resources for state and federally-protected historic or other natural or cultural resources;
    - The Department of Transportation for access to public highways;
    - The SCC which must issue a Certificate of Public Convenience and Necessity showing the need for the project, that the power plant is in the public interest, and that it would not have an excessive rate impact;
    - Multiple federal agencies for environmental controls, such as:
        - The Environmental Protection Agency (EPA);
        - The Army Corps of Engineers;
        - The U.S. Fish and Wildlife Service; and
        - The U.S. Forest Service.
- Virginia has taken a number of actions to facilitate permitting of new electric infrastructure.
    - Applicants for new electric generation or transmission projects, or natural gas transmission lines or storage facilities, may use a pre-application planning and review process with agencies within the Secretary of Natural Resources to provide a plan that will provide for an efficient and coordinated review of the proposed energy facility. The plan includes:
        - A list of the permits or other approvals likely to be required based on the information available;
        - A specific plan and preliminary schedule for the different reviews;
        - A plan for coordinating those reviews and the related public comment process; and
        - Designation of points of contact, either within each agency or for the Commonwealth as a whole, to facilitate this coordination.
    - The DEQ is drafting permits by rule for renewable energy projects of 100 megawatts or less in size (such as land-base wind projects) and of 20 megawatts or less if the project results in air emissions (such as biomass projects) to provide a streamlined permitting process for smaller renewable projects.
    - The SCC, in considering its Certificate of Public Convenience and Necessity for electric generating plants and associated facilities, cannot impose additional conditions with respect to environmental protection, building codes, transportation plans, and public safety when a separate permit is granted by a federal, state, or local government entity.
- A long permitting process makes it more difficult to finance the large capital investments required for generating facilities.
- To help reduce the financial risk, Virginia provides, subject to SCC approval:
    - An increased rate of return for utility investments in new, clean-technology generating plants; and

    - Construction work in progress cost recovery to reduce the regulatory lag in recovering capital investments in new plants.

- EPA has taken steps under the Clean Air Act to regulate carbon emissions as a regulated emission. This will require a change in how utilities permit new fossil-fueled generation plants.
- Virginia lacks a process to permit carbon capture and storage that might be part of a new generation project. Items to be addressed before widespread carbon sequestration is possible include:
    - Testing technology and permanence of sequestration in unminable coal seams;
    - Addressing the rights and liabilities of owners of lands used for sequestration; and
    - The potential of saline aquifers in Central and Eastern Virginia to serve as underground carbon sinks.

Future Direction

- To meet the projected growth in electric demand and the need to replace aging generation capacity, we must :
    - Construct new, large centralized generation facilities and smaller-scale independent power projects;
    - Expand distributed generation;
    - Construct new transmission facilities; and
    - Expand conservation and efficiency actions.
- EPA's decision to regulate carbon dioxide as a pollutant, or federal carbon legislation that would supersede EPA regulation requiring more stringent emission standards, may make older fossil fuel facilities more expensive to operate. In response, utilities may retire such units and increase reliance on more expensive power purchased on the wholesale market.
- The threat of cap and trade regulation creates substantial uncertainty that may discourage investment in new fossil-fueled generation.
- The greatest potential for renewable electric generation and new jobs comes from onshore and offshore wind, waste or biomass-to-energy facilities, and solar. However, renewable projects are typically smaller and are unable to substitute for new base-load generation.
- Hydropower is limited due, to the few locations in Virginia without a major environmental impact.
- The unknown rate of penetration of electric vehicles into the marketplace may require additional generation capacity expansions.
- Smart meters have been subject to complaints by some regarding their accuracy. There may need to be a longer history of use before public acceptance improves and the savings from voltage control attributable to smart meter use has been proven.