La Capra Associates

NORTH CAROLINA'S RENEWABLE ENERGY POLICY

A Look At REPS Compliance To Date, Resource Options For Future Compliance, And Strategies To Advance Core Objectives

Technical Report

PREPARED FOR

North Carolina Energy Policy Council

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This Report was prepared by La Capra Associates, pursuant to a Contract with Advanced Energy on behalf of the Energy Policy Council. In the process of performing this work, the La Capra Associates Team engaged in an on-going dialog with the Energy Policy Council, funders and several stakeholders.

We are grateful to the dozens of stakeholders who graciously gave their time to answer questions and offer their perspective and suggestions. The La Capra Team appreciates the quality of inputs and collaboration from this process. In addition, the La Capra Team wishes to thank the North Carolina Energy Office and Advanced Energy for their oversight of this constructive process.

The La Capra Team recognizes that it was engaged to provide its independent expert views on issues which a variety of opinions are held. We performed this function to the best of our abilities and we hope that this is how our work has been received by the Energy Policy Group. That said, the opinions expressed in this Report are those of the La Capra Team and do not necessarily reflect those of any participant in the process described above. Also, in any project of this complexity, we run the risk of leaving names off the list. We did our best to capture all the organizations and lead participants; and we appreciate all who made contributions to this report.

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ACRONYMS/ABBREVIATIONS

Acronyms/Abbreviations	
Alternative Minimum Tax	AMT
American Council for an Energy-Efficient Economy	ACEEE
Appalachian State University	ASU
Balance-of-system	BOS
British Thermal Unit	Btu
Bureau of Ocean Energy Management, Regulation and Enforcement	BOEMRE
Capacity Factor	CF
Carbon dioxide	CO2
Carbon dioxide equivalent	CO2e
Carbon monoxide	CO
Clean Air Act	CAA
Clean Smokestacks Act	S.B. 1078
Combined Heat and Power	CHP
Commercial and Industrial	C & I
Compact Fluorescent Light bulb	CFL
Construction and Demolition	C&D
Construction Work in Progress	CWIP
Demand-side Management	DSM
Electric Membership Corporation	EMC
Energy Efficiency Resource Standard	EERS
Energy Independence and Security Act	EISA
Energy Information Administration	EIA
Energy Policy Act 2005	EPACT 2005
Electric Power Research Institute	EPRI
Energy Service Companies	ESCO
Environmental Protection Agency	EPA
Federal Production Tax Credit	PTC
Forest Inventory Analysis	FIA
Forest2Market (market information)	F2M
Georgia Environmental Finance Authority	GEFA
Gigawatt Hour	GWh
Greenhouse Gas	GHG
Green Ton	GT
Gross Domestic Product	GDP
Hydropower Evaluation Software	HES
Idaho National Engineering and Environmental Laboratory	INEEL

Acronyms/Abbreviations	
Integrated Resource Plan	IRP
Investment Tax Credit	ITC
Investor-owned Utility	IOU
Kilowatt	kW
Kilowatt hour	kWh
Landfill Gas Energy	LFGE
Landfill Methane Outreach Program	LMOP
Lawrence Berkeley National Laboratory	LBNL
Levelized Cost of Energy	LCOE
Megawatt	MW
Megawatt hour	MWh
Modified Accelerated Cost Recovery System	MACRS
Municipal Power Agency	Municipality
Municipal Solid Waste	MSW
National Ambient Air Quality Standards	NAAQS
National Energy Modeling System	NEMS
National Renewable Energy Laboratory	NREL
Net Present Value	NPV
Nitrogen oxides	NOx
North Carolina Eastern Municipal Power Agency	NCEMPA
North Carolina Energy Policy Council	EPC
North Carolina Municipal Power Agency 1	NCMPA1
North Carolina Renewable Energy Tracking System	NC-RETS
North Carolina State University	NCSU
North Carolina Utilities Commission	NCUC
Nuclear Regulatory Commission	NRC
One Million British Thermal Units	MMBTU
Operation and Maintenance	O&M
Particulate matter (<2.5 microns)	PM2.5
Power Purchase Agreement	PPA
Prevention of significant deterioration	PSD
Renewable Energy and Energy Efficiency Portfolio Standards	REPS
Renewable Energy Certificate	REC
Renewable Fuel Standard	RFS
Renewable Portfolio Standard	RPS
Request for Proposal	RFP
Research and Development	R&D
Selective Catalytic Reduction	SCR
Selective Noncatalytic Reduction	SNCR

Acronyms/Abbreviations	
Senate Bill 3	S.B. 3
Solar Photovoltaic	PV
Solar Renewable Energy Certificate	SREC
Southeastern Power Administration	SEPA
Southern Forest Resource Assessment Consortium	SOFAC
Sub Regional Timber Supply	SRTS
Sulfur dioxide	SO2
Tennessee Valley Authority	TVA
Timber Products Output	TPO
United States Department of Agriculture	USDA
United States Department of Energy	DOE
University of North Carolina at Chapel Hill	UNC

APPENDICES

LIST OF FIGURES AND TABLES

1. EXECUTIVE SUMMARY

The North Carolina Energy Policy Council (EPC) retained La Capra Associates to assess the Senate Bill 3 Renewable Energy and Energy Efficiency Portfolio Standard (REPS) and explore potential policy alternatives to address issues related to renewable energy, energy efficiency, greenhouse gas emissions, and economic development. In addition, the EPC directed La Capra Associates to determine the resource potential and costs of select technologies to provide a context for key policy considerations and to conduct a scenario analysis to examine a range of policy choices in North Carolina. Section 2 of the Study addresses REPS compliance to date, Section 3 provides our estimates for cost and potential by resource, Section 4 provides our baseline and scenario analysis and Section 5 discusses how we expect REPS compliance to perform over time and some policy considerations for the state of North Carolina.

The process of developing this report involved extensive research, analysis and stakeholder collaboration, including several meetings and discussions with environmental agencies, environmental advocates, gas and electric utilities, municipalities, cooperatives, renewable developers, the North Carolina Utilities Commission and Public Staff, and local University researchers (see Acknowledgements). La Capra Associates also accessed numerous reports and documents (see Bibliography) to develop the data and assumptions that informed the estimated potential and costs of various resource options. In addition, we developed a 15-year Baseline Analysis (Baseline) to represent the most likely course of compliance with REPS under the status quo.[1] We then constructed six scenarios designed to illustrate the effects of alternative policy choices with emphasis on minimizing electricity costs, increasing economic development in North Carolina, accelerating reductions of electric sector greenhouse gas emissions, expanding development of renewable energy sources, and aggressively pursuing development of energy efficiency measures.

The following are our key findings and conclusions:

1) There will be sufficient resources available to allow for cost-effective compliance with REPS.

The potential for renewable resources in and deliverable to North Carolina and the national renewable energy credit market provide ample resources to comply with the renewable energy requirements of REPS over the next decade. Utilities, although they must meet required set-asides, have flexibility to comply with REPS in a cost-effective manner. REPS requirements will

1 Our Baseline and scenario analyses relied on the use of a regional dispatch model which we developed for Virginia and the Carolinas to accurately characterize regional power system operations, simulate system dispatch, and track costs, emissions and fuel use.

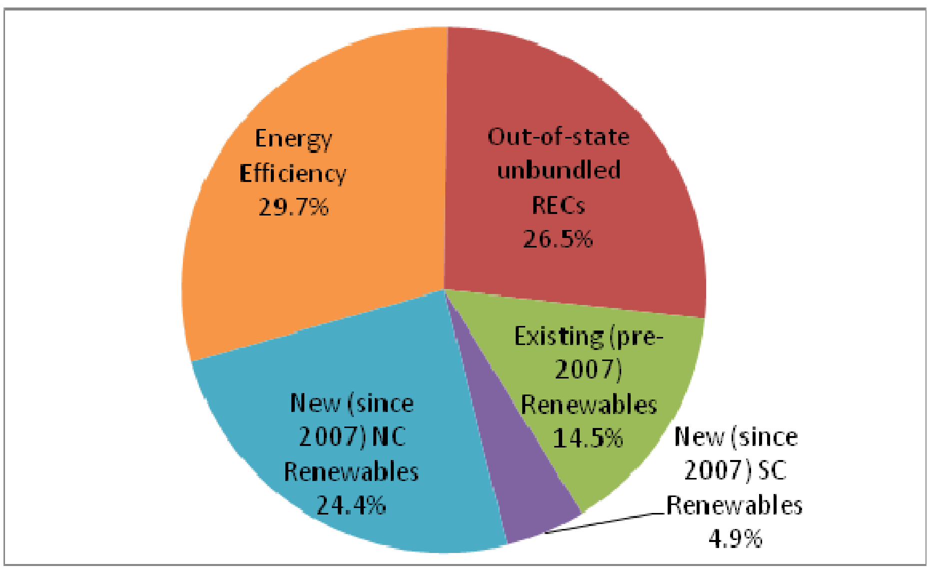
be met mostly by biomass and wind. We expect 22% of the biomass practical potential and 16% of the eastern onshore wind potential to be developed to meet these requirements. Western North Carolina wind resource development is not necessary to meet REPS goals over the next decade. (See Section 3 Figures 15 and 16 for resource potential and cost summaries.)

In addition to renewable resources, the potential for energy efficiency in North Carolina provides ample resources to comply cost effectively with a significant component of REPS. We estimate that the aggregate energy efficiency level to be implemented under the status quo will be 3.1% of total retail sales in 2020 or a roughly a quarter of the full REPS requirement. This level is less than half of our conservative estimate of achievable potential. (See Section 3.4 for further details on energy efficiency potential.)

2) REPS will be met fairly equally by new renewables, energy efficiency and out-of-state unbundled RECs.

Between 2010 and 2025, we estimate a cumulative total of 170 million MWh of energy or energy credits will be used to comply with REPS.

CUMULATIVE COMPLIANCE ENERGY SOURCES, 2010-2025 (BASELINE)



3) Since 2007, North Carolina has made progress towards the goals articulated in the legislation and more progress is expected over the next 15 years. (see Sections 2 and 5)

a) *Diversify the resources used to reliably meet the energy needs of consumers in the State*

North Carolina will diversify its resource base as more renewables are built and energy efficiency is achieved to meet REPS. By 2025, new renewable resources built in North

Carolina to comply with REPS will generate 3,700 GWh per year, or about 2.3% of projected retail sales for North Carolina electric power suppliers.

b) *Provide greater energy security through the use of indigenous energy resources available within the State*

Since REPS was implemented in 2007, 85 new renewable energy facilities have been built in North Carolina totaling 150 MW. By 2025, we project that about 85% of the 815 MW of new renewable capacity built to comply with REPS, or approximately 700 MW, would be located in North Carolina. The state has also experienced a significant increase in the development of energy efficiency programs since 2007, due, at least in part, to the cost recovery mechanism created as a result of S.B. 3.

c) *Encourage private investment in renewable energy and energy efficiency*

By 2025, we estimate that investments of more than $3.5 billion in investment in 2010 dollars will be made in North Carolina as a result of REPS compliance activities. Of this, roughly $2 billion will be invested in biomass, wind, solar, swine and poultry waste facilities. Over the next 15 years, total statewide investment in energy efficiency will be approximately $1.5 billion with cumulative energy savings of 60,000 GWh.

d) *Provide improved air quality and other benefits to energy consumers and citizens of the State*

Implementing REPS has helped North Carolina reduce SO_2, NOx and CO_2 emissions. Over time, as increased energy efficiency, wind, hydroelectric and solar power displaces fossil-fired generation, North Carolina's air quality will continue to improve.

4) The results of the analysis can have important policy implications.

A detailed discussion of policy considerations is included in Section 5 of this report.

REPS Observations

- REPS alone will not achieve substantial reductions in North Carolina's GHG emissions in the electric sector. Additional polices on low GHG resources will be needed if the North Carolina electric sector GHG emissions are to be significantly reduced.
- REPS alone will not lead to full utilization of North Carolina's potential cost-effective energy efficiency resources. If policymakers want to encourage more energy efficiency savings beyond the programs developed through the Integrated Resource Plan (IRP) process and REPS compliance, numerous policy options are available. These include policies already adopted in other states, such as amending REPS to require energy efficiency, establishing a

separate Energy Efficiency Resource Standard or employing other policy tools for achieving greater cost effective energy efficiency.

- In the long-term, REPS will not significantly impact electric power rates. In the near-term there may be some challenges associated with an increase in the residential cost cap and poultry set aside requirements.
- REPS-driven energy efficiency and renewable energy development have the potential to add a significant number of jobs and promote economic development in North Carolina. Many stakeholders believe the specific impact on the North Carolina economy and jobs should be the focus of further study and quantification.

Other Observations

- To support a residential solar industry in North Carolina over the long run, a more aggressive solar set aside would likely be needed. A set aside that ramps up evenly over time would allow the industry to grow and take advantage of the expected cost declines in future years.
- If North Carolina wants to develop offshore wind in the near future, a mandatory set-aside would be required. Given the high cost of offshore wind, it is unlikely that it will be developed in the next decade as a part of cost-effective REPS compliance.
- Whole tree sources add to the supply of biomass, increases options, and may reduce costs, but are not required to comply with the current REPs policy.

2. IMPLEMENTATION OF REPS

Session Law 2007-397 (Senate Bill 3 or S.B. 3)[2] was signed into law on August 20, 2007, making North Carolina the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). This legislation reflected a collaborative process by numerous stakeholders. Since the law was passed, the North Carolina Utilities Commission (NCUC) and the electric power suppliers subject to the law have undertaken the process of interpreting and implementing the REPS requirements. In this section of the report, we provide a summary of S.B. 3, as it relates to REPS, and a review of its implementation and compliance. We also identify key impacts, as well as stakeholder issues and concerns, regarding the implementation of North Carolina's REPS.

2.1 CONTEXT

2.1.1 *SUMMARY OF SENATE BILL 3*

Under S.B. 3, investor-owned utilities (IOUs) in North Carolina; including Duke Energy Carolinas ("Duke"), Progress Energy Carolinas ("Progress" or "PEC"), and Dominion North Carolina Power ("Dominion"); are required to meet 12.5% of their energy needs[3] with a qualifying mix of renewable energy resources and energy efficiency measures by 2021 and thereafter. Municipal utilities, including the members of North Carolina Eastern Municipal Power Agency (NCEMPA) and the members of North Carolina Municipal Power Agency 1 (NCMPA1), and Electric Membership Corporations/Cooperatives (EMCs) are required to meet 10% of their energy needs with qualifying resources by 2018.

The NCUC issued an order adopting final rules implementing S.B. 3 on February 29, 2008 and amended the final rules on March 13, 2008 to correct statutory references to reflect codification of the law.[4]

2 The full text of Senate Bill 3 can be found here: http://www.ncga.state.nc.us/Sessions/2007/Bills/Senate/PDF/S3v6.pdf.

3 Energy needs are based on the previous year's retail sales.

4 The February 29, 2008 order can be found here: http://www.ncuc.commerce.state.nc.us/selorder/rules/SW022908.pdf and the amended order can be found here: http://www.ncuc.commerce.state.nc.us/selorder/rules/KC031308.pdf.

2.1.2 *CURRENT OBJECTIVES*

Senate Bill 3 lists four key objectives for REPS:

1. Diversify the resources used to reliably meet the energy needs of consumers in the State;
2. Provide greater energy security through the use of indigenous energy resources available within the State;
3. Encourage private investment in renewable energy and energy efficiency; and
4. Provide improved air quality and other benefits to energy consumers and citizens of the State.

2.1.3 *RESOURCE OPTIONS*

Three types of resources can be used to meet REPS: 1) renewable energy, 2) energy efficiency, and 3) demand-side management (DSM).[5] The exact definitions of resources that can be used to meet REPS differ for IOUs versus EMCs and municipal utilities. They are summarized in Figure 1.

One important distinction between the two types of utilities is that municipal utilities and EMCs may use renewable facilities online before January 1, 2007 for compliance, while IOUs must use facilities online after January 1, 2007. The exceptions to this rule are hydropower facilities of 10 megawatts (MW) or less and renewable energy facilities that entered into NC GreenPower contracts prior to January 1, 2007, which are not subject to an online date restriction for the IOUs.

Another distinction between compliance for IOUs and for municipal utilities and EMCs relates to hydropower. IOUs may not use their hydroelectric facilities that are over 10 MW towards REPs compliance. For their facilities with a capacity of less than 10 MW, IOUs must use third party

[5] This analysis will use the terms "energy efficiency" and "demand-side management" as they are defined in Senate Bill 3:

'Energy efficiency measure' is defined as an equipment, physical, or program change implemented after 1 January 2007 that results in less energy used to perform the same function. 'Energy efficiency measure' includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources. 'Energy efficiency measure' does not include demand-side management.

'Demand-side management' is defined as activities, programs, or initiatives undertaken by an electric power supplier or its customers to shift the timing of electricity use from peak to nonpeak demand periods. 'Demand-side management' includes, but is not limited to, load management, electric system equipment and operating controls, direct load control, and interruptible load.

Although only cooperative and municipal utilities may use DSM (load management as defined by the legislation), load programs were not factored into the potential number because of the impact was determined to be minimal.

delivery or renewable energy certificates (RECs) to receive compliance credit.[6] Municipal utilities and EMCs are allowed to use their own hydroelectric facilities as well as facilities of all sizes for compliance.[7]

Electric power suppliers cannot meet more than 25% of their REPS requirement by buying RECs from facilities out-of-state. The remainder of the REPS requirement must be satisfied by renewable energy delivered to the electric power supplier's service territory or by energy efficiency. For IOUs, the renewable resources need not be located in North Carolina and could be located in a neighboring state, such as South Carolina or Virginia so long as their electrons are deliverable into North Carolina's electric power system.

Energy efficiency can be used by IOUs as well as municipal utilities and EMCs to meet a portion of their REPS requirement. IOUs may meet up to 25% of their REPS requirement with energy savings from energy efficiency through 2020 and 40% thereafter. Municipal utilities and EMCs may meet all of their REPS requirements with energy efficiency (after complying with set-aside requirements). IOUs are not allowed to satisfy any of their REPS requirements with demand-side management. Municipal utilities and EMCs can use DSM to satisfy their REPS requirements.

S.B. 3 created set-asides, which are the same for all utilities. The exact ramp-up schedules for solar, poultry waste and swine waste are included in Figure 1 and the final targets are as follows:

- Solar: 0.20% of retail load by 2018;
- Poultry Waste: 900,000 MWh by 2014; and
- Swine Waste: 0.20% of retail load by 2018.

The NCUC has ruled that electric power suppliers should prioritize the set-asides above other resources when complying.[8]

The NCUC has also ruled that the 25% out-of-state allowance also applies to the set-asides.[9] This means that electric power suppliers may buy solar, poultry waste and swine waste RECs

6 Renewable Energy Certificates (RECs) represent the renewable attribute of the resources unbundled from physical power delivery. This allows the RECs to be traded without regard to power delivery.

7 Docket No. E-100, Sub 113, Order on Public Staff's Motion for Clarification, 6/17/2009. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=BAAAAA86190B&parm3=000127195

8 Docket No. E-100, Sub 113, Order on Duke Energy Carolinas, LLC, Motion for Clarification, 5/7/2009. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=XBAAAA72190B&parm3=000127195

9 Docket No. E-100, Sub 113. Order filed 9/22/09. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=RAAAAA56290B&parm3=000127195

from facilities located outside of North Carolina that do not deliver power to their service territories.

FIGURE 1: REPS RESOURCES

		IOUs	Municipal utilities & EMCs
Renewable Energy	Included resources	▪ Solar PV ▪ Solar Thermal ▪ Wind ▪ Geothermal ▪ Biomass (includes Landfill Gas) ▪ Waste Heat from Renewable Resource ▪ Thermal energy at a renewable resource ▪ Hydrogen derived from renewable resource ▪ Hydro < 10 MW	▪ Solar PV ▪ Solar Thermal ▪ Wind ▪ Geothermal ▪ Biomass (includes Landfill Gas) ▪ Waste Heat from Renewable Resource ▪ Thermal energy at a renewable resource ▪ Hydrogen derived from renewable resource ▪ Hydro < 10 MW ▪ Hydro > 10 MW (limited to 30% of requirement)
	Online date	Online after January 1, 2007, except for hydro, which has no restriction	No online date restriction
	Out-of-State	Up to 25% of requirement if electric power is not delivered to a public utility that serves customers in the state[10]	
Energy Efficiency	Percentage	Up to 25% of requirement through 2020; Up to 40% of target 2021+	Up to 100% of requirement can be satisfied with EE or DSM once set-asides are fulfilled.
	Included Resources	Equipment, physical, or program changes implemented after January 1, 2007 that result in less energy to perform the same function. Includes energy produced from combined heat and power system that uses non-renewable energy resources.	
Demand Side Management		Not allowed	Actions to shift the timing of electric use from peak to non-peak demand periods.
Set-asides	Solar	0.02% of retail load by 2010; 0.07% of retail load by 2012; 0.14% of retail load by 2015; 0.20% of retail load by 2018	
	Poultry Waste	Collectively all IOUs, municipal utilities must supply: ▪ 170,000 MWh by 2012; ▪ 700,000 MWh by 2013; and ▪ 900,000 MWh by 2014.	
	Swine Waste	▪ 0.07% of retail load by 2012; ▪ 0.14% of retail load by 2015, ▪ 0.20% of retail load by 2018	

10 IOUs with less than 150,000 customers are not limited by this restriction and may comply with 100% renewable energy not delivered to the service territory. Dominion is the only IOU with less than 150,000 customers.

2.1.4 *REQUIREMENTS FOR INVESTOR-OWNED UTILITIES*

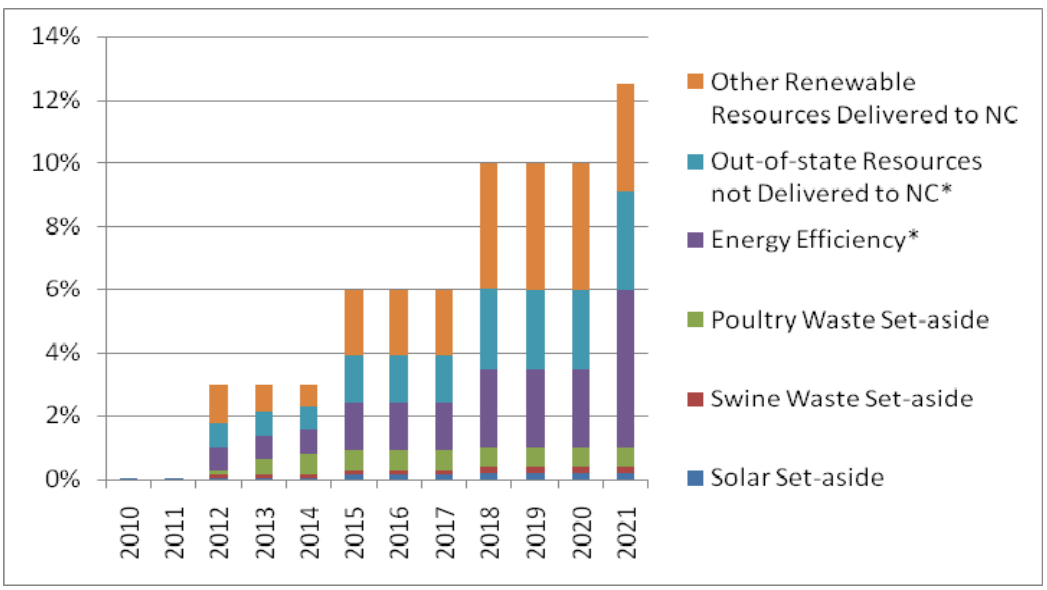
IOUs must procure 12.5% of 2020 retail sales as renewable energy and energy efficiency by 2021. Figure 2 below shows the interim requirements.

FIGURE 2: IOU REPS REQUIREMENTS

Calendar Year	REPS Requirement
2012	3% of 2011 North Carolina retail sales
2015	6% of 2014 North Carolina retail sales
2018	10% of 2017 North Carolina retail sales
2021 and thereafter	12.5% of 2020 North Carolina retail sales

Given the requirements described in the previous section, the IOUs have many options to satisfy their REPS requirements. The figure below shows the requirement by year for IOUs, the set-aside requirements and the energy efficiency and out-of-state options available to the IOUs.

FIGURE 3: IOU REPS REQUIREMENTS BY YEAR



* There is no required use of energy efficiency or out-of-state renewable resources for compliance. These proportions represent the maximum of the REPS requirement that can be satisfied by energy efficiency (25% through 2020, 40% thereafter) and out-of-state resources (25%).

2.1.5 REQUIREMENTS FOR ELECTRIC MEMBERSHIP CORPORATIONS AND MUNICIPAL UTILITIES

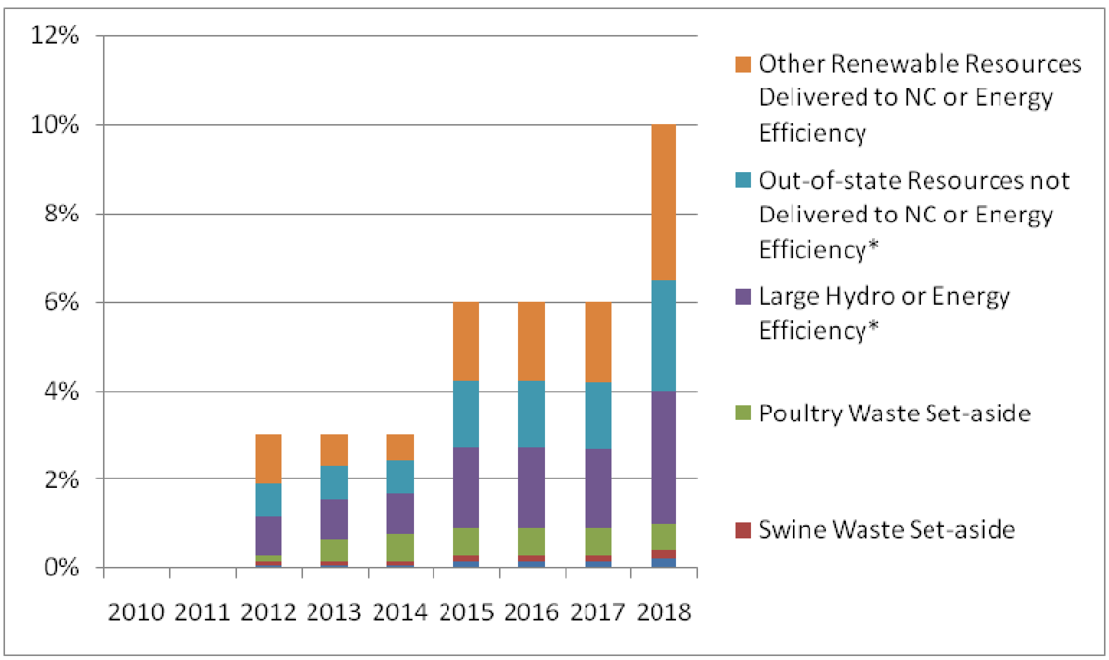
Municipal utilities and EMCs are required to procure 10% of 2017 retail sales as renewable energy and energy efficiency by 2018. Figure 4 below shows the interim requirements.

FIGURE 4: IOU REPS REQUIREMENTS

Calendar Year	REPS Requirement
2012	3% of 2011 North Carolina retail sales
2015	6% of 2014 North Carolina retail sales
2018 and thereafter	10% of 2017 North Carolina retail sales

Given the requirements described in the previous section, the municipal utilities and EMCs have many options to satisfy their requirements. Figure 5 below shows the requirements by year for municipal utilities and EMCs, the set-aside requirements and the hydropower and out-of-state options available to the municipal utilities and EMCs. Note that municipal utilities and EMCs may satisfy all of their requirements beyond the set-asides with energy efficiency.

FIGURE 5: MUNICIPAL UTILITIES' AND EMCS' REPS REQUIREMENTS BY YEAR



* There is no required use of large hydro, energy efficiency, or out-of-state resources. These proportions represent the maximum of the REPS requirement that can be satisfied by out-of-state resources (25%) and large hydro (30%). Municipal utilities and EMCs could also choose to satisfy all of their requirements beyond the set-asides with energy efficiency.

2.1.6 COST CAP

S.B. 3 establishes a per customer cost cap for REPS. If electric power suppliers reach the cost cap, they are considered in compliance even if they have not met the REPS requirement for that year. The NCUC has ruled that electric power suppliers need to prioritize the set-asides before other resources if they will exceed the cost cap. This means that electric power suppliers are expected to spend their money complying with the set-asides before complying with the general requirements.[11] The cost cap by year and customer type is included in Figure 6 below.

FIGURE 6: COST CAP (PER CUSTOMER PER YEAR)

Customer Type	2008-2011	2012-2014	2015 and thereafter
Residential	$10	$12	$34
Commercial	$50	$150	$150
Industrial	$500	$1,000	$1,000

2.2 REPS COMPLIANCE

In the REPS rulemaking proceeding, the NCUC adopted Rule R8-66, which requires that all renewable energy facilities intending to sell energy or RECs for REPS compliance register with the NCUC. Since the passage of the law in 2007, 176 new renewable energy facilities (as defined in the legislation) have registered with the NCUC.[12] These facilities need not be operational to certify their intent to sell RECs and, in fact, most that have been certified are proposed facilities. Of these, 119 registered facilities are located in North Carolina. Another 12 are located in South Carolina but would qualify as "in-state" if the "electric power is delivered to a public utility that provides electric power to retail electric customers in the state."[13] The remaining 45 facilities are located in western and mid-western states and would be eligible to sell RECs to North Carolina utilities subject to the maximum level of 25% of each supplier's REPS requirement.

While most of the individual facilities registered are located in North Carolina, the majority of the newly installed capacity is out-of-state and will sell unbundled RECs to North Carolina electricity suppliers (see Figure 7 below).

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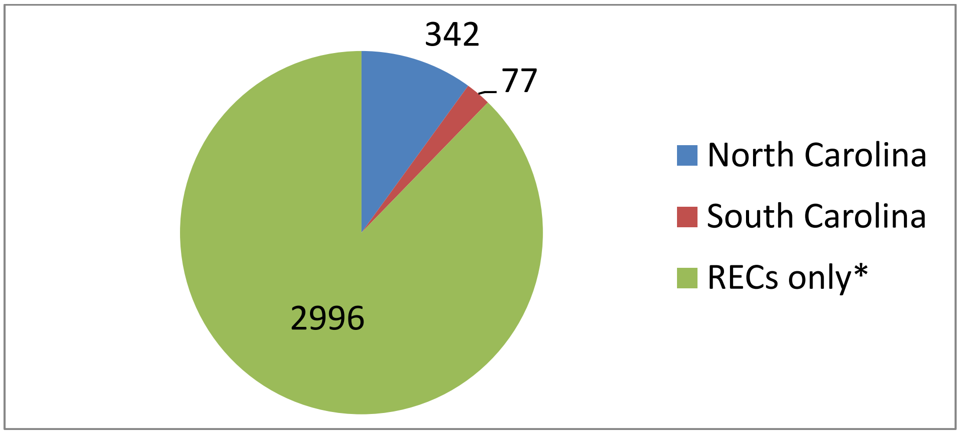
11 Docket No. E-100, Sub 113, Order on Duke Energy Carolinas, LLC, Motion for Clarification, 5/7/2009. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=XBAAAA72190B&parm3=000127195

12 Data as of December 1, 2010. *Renewable Energy Facility Registrations Accepted by the NC Utilities Commission.* Retrieved from: http://www.ncuc.commerce.state.nc.us/reps/reps.htm

13 General Assembly of North Carolina. Session Law 2007-397. Senate Bill 3. §62-133.7 (b)(1)d.

FIGURE 7: LOCATION OF NEW FACILITIES BY CAPACITY (MW)



*REC only facilities are registered for their entire capacity but may only sell a portion of their RECs in North Carolina.

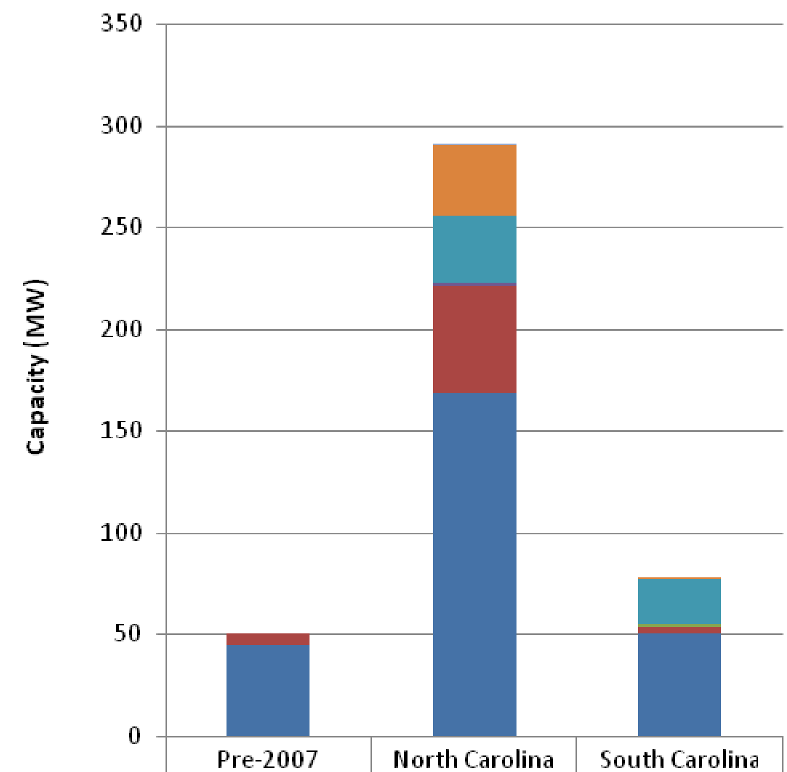
It is important to note that a facility must register its full capacity even if only a small portion of RECs will be sold to North Carolina utilities. Due to this requirement, the capacity of new out-of-state facilities may be deceptively high. Figure 7 should not be interpreted to indicate that the majority of renewable energy used for REPS compliance will be derived from purchases of out-of-state RECs. Such purchases are subject to the 25% maximum limit. The figures only demonstrate the scale of projects that have certified for the opportunity to sell RECs.

2.2.1 *REGISTERED IN-STATE NEW RENEWABLE ENERGY FACILITIES*

Since the passage of the REPS legislation, many newly constructed or planned renewable facilities located in North Carolina have registered with the NCUC. In addition, the law provides that, for IOUs, renewable energy from a facility located outside of the geographic boundaries of the state can still qualify as an in-state resource if the electricity can be delivered to North Carolina (see Section 2.2 above). Resources existing prior to 2007 which entered into a contract with NC GreenPower prior to January 1, 2007 also qualify as "new" resources for the purposes of REPS compliance.[14] Figure 8 below shows resources that have registered with the NCUC as new renewable energy facilities. The majority of new generating capacity is from biomass resources, but there are new solar photovoltaic (solar PV), wind, swine waste, poultry methane, landfill gas and hydro facilities as well.

14 NC GreenPower is an independent nonprofit organization which administers a program whereby ratepayers can voluntarily buy credits for 100 kWh of renewable energy. The organization in turn uses these funds to support renewable energy projects.

FIGURE 8: ACTUAL AND PROPOSED PROJECTS THAT HAVE REGISTERED AS NEW RENEWABLE ENERGY FACILITIES AS OF 12/1/10



	Pre-2007	North Carolina	South Carolina
Wind		0.1	
Solar PV		35.8	0.2
Hydroelectric		32.1	22.4
Swine Waste		1.6	
Poultry Waste			1.6
Biomass - Landfill Methane	5.3	53.1	3.2
Biomass	45.0	168.6	50.0

2.2.2 *OUT-OF-STATE NEW RENEWABLE ENERGY FACILITIES*

In order to provide options to minimize the cost of compliance, REPS allows utilities to buy unbundled RECs from out-of-state generators. Facilities located out of state that intend to sell RECs to North Carolina electricity suppliers must also register with the NCUC and are subject to the same requirement of being constructed on or after January 1, 2007. Of the 45 out-of-state facilities registered, the majority of the added capacity is from Texas wind power facilities (see Figure 9). The remainder of the out-of-state capacity consists of Midwestern wind facilities and a small amount of solar capacity.

FIGURE 9: OUT-OF-STATE RESOURCES REGISTERED AS OF DECEMBER 1, 2010

	Location	Capacity (MW)	Percentage of Total
Wind	Texas	2,195	73%
	Iowa	450	15%
	Dakotas	180	6%
	Kansas	149	5%
Solar	California	12	0.4%
	Illinois	10	0.3%
	Total	**2,996**	**100%**

Nationwide, wind power is typically the cheapest renewable resource and these out-of-state wind RECs represent the lowest-cost option for electric power suppliers to fulfill their general requirements. Duke noted in its 2010 REPS Compliance Plan: "The Company has found out-of-state wind RECS to be cost-effective when compared to in-state General Requirement resources. As such, the Company has entered into agreements to procure out-of state wind RECS up to the 25% out-of-state limitation."[15] Progress similarly notes that it "has purchased out-of-state wind RECs as allowed by S.B. 3. These RECs are the most cost effective options available, and they will allow PEC to balance its compliance each year while also helping to mitigate vendor performance risk."[16]

Electric power suppliers can fulfill up to 25% of their set-aside requirements with out-of-state resources. They are likely to maximize their purchase of low cost RECs from the registered solar projects in California and Illinois before developing new projects within the state.

2.2.3 *ENERGY EFFICIENCY*

While the use of energy efficiency for REPS compliance is optional, the cost of energy efficiency relative to other renewable sources is low and therefore an attractive option for REPS compliance. Figure 10 below lists the plans of the entities with the majority of electricity sales in North Carolina and the percentage of their REPS requirements that they plan to meet with

15 "Duke Energy Carolinas, LLC's 2010 Renewable Energy & Energy Efficiency Portfolio Standard Compliance Plan." Filed 9/1/2010, NCUC Docket E-100, Sub 128, p. 21.

16 "Progress Energy Carolinas Integrated Resource Plan, Appendix D: Alternative Supply Resources, NC REPS Compliance Plan." Filed 9/13/2010, NCUC Docket E-100, Sub 128, p. D-2.

energy efficiency for 2012. The values on the table include banked energy efficiency credits from 2008-2011.

FIGURE 10: PERCENT COMPLIANCE BY POWER SUPPLIER

Power supplier	% of Compliance (2012)
Duke	25%
Progress	25%
Dominion	17%
NCEMPA members	49% including banked credits*
NCMPA1 members	20% including banked credits *
Sales-weighted average	**26%****

* These estimates include the use of energy efficiency credits banked from 2008-2011. It is not expected that these entities will continue to utilize energy efficiency savings for this portion of the REPS requirement. These values also include energy efficiency and DSM. Municipal utilities and EMCs and are permitted to use DSM measures for REPS compliance, but IOUs are not.

** Sales-weighted average aggregates sales and energy efficiency credits used for the identified power suppliers.

2.2.4 *COMPLIANCE WITH 2010 SOLAR SET-ASIDE*

While most of the REPS requirements are not in effect until 2012, electric power suppliers are required to comply in 2010 with the solar set-aside equivalent to 0.02% of their 2009 sales. While the level of detail provided in REPS compliance plans varies by supplier, most either claim to have already acquired sufficient resources to fulfill the 2012 requirement or express confidence that they will fulfill the set-aside. For the larger suppliers, this includes a combination of facility development, Power Purchase Agreements (PPAs) and purchases of in-state and out-of-state RECs.

Duke, for example, has a solar PV distributed generation program which allows it to develop 10 MW of solar capacity at various sites owned by the utility or participating customers. In addition to those projects, Duke has contracted for in-state RECs and plans to maximize out-of-state REC purchases due to their relative lower cost.

Some electric power suppliers have unique challenges in complying with the set-aside. NCEMPA members, for example, have an existing wholesale partial requirements service agreement with Progress through 2017. The terms of the contract state that NCEMPA (and by extension its member municipal utilities) must purchase all necessary supplemental power from Progress and its members are contractually forbidden from entering into PPAs with renewable facilities or developing their own projects. Therefore, NCEMPA members are restricted to purchasing unbundled RECs to meet the solar set-aside requirements.

2.2.5 *COMPLIANCE WITH FUTURE REQUIREMENTS*

The compliance phase of the general REPS requirements, as well as the swine and poultry waste set-asides, begins in 2012. In the 2010 compliance plans, electric power suppliers were not required to present specific details regarding resources that will be utilized, but some conclusions can be drawn from the information provided.

A. Energy efficiency

Due to the low cost and existing cost-recovery and incentive mechanisms, North Carolina IOUs are actively developing energy efficiency programs. The state's two largest utilities, Duke and Progress, anticipate exceeding their 25% energy efficiency limit in order to bank credits for future years. Although municipal utilities and EMCs do not have a restriction on the amount of energy efficiency allowed for general compliance, current filings and recent stakeholder discussions suggest that few municipal utilities and EMCs achieve energy efficiency savings similar to utility levels. In fact, there are indications that the levels for municipal utilities and EMCs may be closer to 5-10% per year at the beginning of the compliance period and may increase to as much as 20% over time.

B. Out-of-state RECs

As previously discussed, most electric power suppliers will be using out-of-state RECs to fulfill the REPS requirement up to the maximum portion allowed. The use of these out-of-state facilities is a primary method of REPS cost-containment. Based on the data regarding new registered facilities (see Section 2.2) and national price REC market data, it is likely that these out-of-state resources will be predominantly wind facilities.[17] In addition, purchases of out-of-state solar RECs (subject to the 25% maximum) will likely be used to fulfill the set-aside requirement.[18]

C. In-state resources

The NCUC has determined that utilities must fulfill their set-aside requirements prior to the general requirements. Therefore, solar, swine and poultry waste resources will continue to be a key element in REPS compliance. Due to their high cost relative to other options, it is unlikely that utilities will procure energy or RECs from these facilities beyond their set-aside requirements.

In contrast, based on their relative low cost and high resource potential, biomass facilities will provide a significant portion of the in-state resources used for general REPS compliance. As of

[17] According to Spectrometer, RECs from states such as Texas and Illinois have been offered for around $1.00/MWh since the beginning of the year, and we do not see any reason to expect a major price increase.

[18] According to ICAP United, Inc, out-of-state solar RECs have an offer price of $11.00 currently (April 2011).

December 2010, new biomass facilities comprised 63% of the total capacity of new in-state-eligible facilities registered, but not necessarily operational, with the NCUC.

Another key element of electric power suppliers' general compliance strategies will be hydroelectric power. Municipal utilities and EMCs are allowed to fulfill 30% of their requirement with hydroelectric resources, including energy they already purchase from the Southeastern Power Administration (SEPA), so there would be no additional cost for this compliance measure. While there is minimal potential for new hydro development, IOUs may opt to pursue REC contracts with any qualifying hydro facility. As of December 2010, 39 hydroelectric facilities totaling 88 MW of capacity have registered with the NCUC.

2.2.6 *COST OF COMPLIANCE*

Costs the electric power suppliers incur to comply with REPS are recovered through the REPS rider. The REPS rider for the IOUs is approved by the NCUC. Costs recovered through the REPS rider include research and development costs and the incremental costs for renewable energy over the avoided cost rate of the electric power supplier. Energy efficiency is not included in the costs recovered under the REPS riders because energy efficiency costs are not incremental costs (energy efficiency is only considered cost-effective if it is below the avoided costs of a utility).

Duke and Progress have both filed REPS riders in 2010 which were approved by the NCUC.[19] Dominion has not yet filed a REPS rider with the NCUC. Additionally, the average REPS rider costs for the 22 EMCs whose REPS compliance is handled by GreenCo has been filed. The cost per customer is shown in Figure 11. The 2011 costs for Duke, Progress and GreenCo members are below the cost cap, with GreenCo members having the lowest costs per customer. One key question which will be explored later in this study is if electric power suppliers will be able to stay within their cost caps as set-asides and other REPS requirements increase.

[19] [Duke] Docket E-7, Sub 936. Application for Approval of REPS Cost Recovery, 3/2/2010, http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=RCAAAA46001B&parm3=000132163

[Progress] Docket E-2, Sub 974, Application for Approval of REPS Cost Recovery Rider, 6/4/2010. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=2AAAAA95101B&parm3=000132862

FIGURE 11: 2011 ANNUAL REPS RIDER COST VERSUS COST CAP

	Cost Cap 2011	Progress (12/2010-11/2011)	Duke (9/2010- 8/2011)[20]	GreenCo (Average of 22 Coops-2009 Costs)[21]
Residential	$10.00	$6.96	$3.24	$3.04
Commercial	$50.00	$35.16	$15.84	$15.21
Industrial	$500.00	$352.08	$158.52	$152.10
Percentage of Cost Cap		70%	32%	30%

2.2.7 *HOW IS REPS COMPLIANCE FARING RELATIVE TO STATED OBJECTIVES?*

A. Diversify the resources used to reliably meet the energy needs of consumers in the state

North Carolina will diversify its resource base as more renewables are built and energy efficiency is achieved to meet REPS. REPS will also add pressure to continue the coal retirements begun in response to other factors such as North Carolina's Clean Smokestack Act.

In recent times, North Carolina's energy mix has been dominated by coal and nuclear generation. In 2006, coal-fired resources provided roughly 60% of the state's generation and nuclear provided 32% (see Figure 13 below). Very little natural gas fired generation has been installed in North Carolina.

Prior to the passage of REPS in 2007, less than 5% of the state's electricity output came from renewable resources. Most renewable output (about 3% of the state's total) came from 1,900 MW of hydroelectric capacity. Another 1.5% of total output was generated by about 340 MW of biomass, landfill gas and other renewable capacity.

Since the REPS legislation was passed, approximately 150 MW of new solar, biomass and landfill gas renewable capacity has been developed in North Carolina.22 This new capacity is capable of generating almost 900 GWh of renewable electricity annually, which represents nearly 1% of North Carolina's total output in 2006.

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20 On March 11, 2011, Duke filed its REPS rider application for the 9/2011-8/2012 period. This analysis, as well as the values reported values in this table, reflects the REPS rider for the period ending 8/2011.

21 GreenCo average costs were calculated using the proportion of full compliance costs and total cost cap reported in its REPS compliance report. This proportion was applied to the cost cap for each individual customer class to yield the values presented in the table.

22 Based on registrations with NCUC as of December 1, 2010.

FIGURE 12: 2006 NORTH CAROLINA CAPACITY BY RESOURCE

	Capacity (MW)	Percentage Share
Coal	13,113	48.5%
Petroleum	563	2.1%
Natural Gas	5,997	22.2%
Nuclear	4,975	18.4%
Hydroelectric	1,954	7.2%
Other Renewables	338	1.2%
Pumped Storage	84	0.3%
Other	37	0.1%

Source: Table 4. Electric Power Industry Capability by Primary Energy Source, 1990 through 2008, North Carolina Electricity Profile, 2008 edition, released March 2010. U.S. Energy Information Administration.

FIGURE 13: 2006 NORTH CAROLINA OUTPUT BY RESOURCE

	Generation (GWh)	Percentage Share
Coal	75,487	60.3%
Petroleum	451	0.4%
Natural Gas	3,196	2.6%
Nuclear	39,963	31.9%
Hydroelectric	3,839	3.1%
Other Renewables	1,828	1.5%
Pumped Storage	131	0.1%
Other	319	0.3%

Source: Table 5. Electric Power Industry Generation by Primary Energy Source, 1990 Through 2008 (Megawatt hours), North Carolina Electricity Profile, 2008 edition, released March 2010. U.S. Energy Information Administration.

B. Provide improved air quality and other benefits to energy consumers and citizens of the state

New renewables and additional energy efficiency to meet REPS requirements have contributed to improving air quality.

North Carolina is subject to both federal and state laws regulating air quality. The National Ambient Air Quality Standards (NAAQS) under the federal Clean Air Act (CAA) sets limits for six "criteria" pollutants deemed harmful to public health and the environment: ground-level ozone, nitrogen oxides (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter smaller than 2.5 microns ($PM_{2.5}$), and lead. In addition, the North Carolina General Assembly passed the Clean Smokestacks Act (S.B. 1078) in 2002 requiring the state's two largest utilities, Duke and Progress, to reduce coal-fired plant NO_x emissions 77% by 2009 and SO_2 emissions 73% by 2013.

Prior to 2006, part or all of 22 counties in North Carolina were deemed NAAQS "nonattainment areas" for failing to meet the standard for at least one criteria pollutant. In recent years, however, North Carolina has been making significant improvements in its air quality. Since 2006, 12 counties have been re-designated from "nonattainment" to "maintenance" status under NAAQS. Duke and Progress have met the NO_x reductions mandated by the Clean Smokestacks Act and expect to meet the 2013 SO_2 reduction requirement with the planned retirement of one additional coal plant.[23]

The federal government began regulating greenhouse gas (GHG) emissions such as CO_2 for the first time in 2011. Although prospects for more comprehensive regulation through a federally legislated cap and trade or other similar program have dimmed in the short term, the Environmental Protection Agency (EPA) has begun to include GHG emissions in CAA permitting requirements for new and modified stationary sources under the prevention of significant deterioration (PSD) and Title V programs. The exact impact of this regulation is still uncertain due to evolving implementation issues and continued political opposition that threatens to rescind EPA's regulatory authority over GHG emissions.

REPS compliance will continue to contribute to reduced SO_2, NO_x and CO_2 emissions. Several of the resources that figure prominently in electric suppliers' compliance plans are virtually emissions-free, such as energy efficiency, wind, hydroelectric and solar power. Over time, as energy efficiency measures reduce load and low-emission renewable generation resources replace marginal fossil fuel-fired generation, North Carolina's air quality should improve. Although a relatively large share of out-of-state resources may be used for REPS compliance, to the extent renewables are from adjacent states, this still helps to reduce regional emissions that can impact North Carolina air quality.

There are a few cautionary notes, however. Unlike other renewable energy sources, biomass energy, which is expected to be a major part of the resource mix for REPS compliance, is not emissions-free. Biomass combustion does release NO_x and other pollutants. Depending on the

[23] Department of Environment and Natural Resources (2010). *Report on the Implementation of the Clean Smokestacks Act.* http://daq.state.nc.us/news/leg/2010_Clean_Smokestacks_Act_Report_Final.pdf. Accessed 1/11/2011.

fuel source and the method of life-cycle accounting, net GHG emissions can also be attributed to biomass combustion, though usually less than fossil fuel-fired alternatives. In addition, there is some concern that the combustion of poultry waste could result in arsenic air pollution.[24]

C. Provide greater energy security through the use of indigenous energy resources available within the state

The state has experienced an increase in renewable generation in North Carolina resulting from the implementation of REPS and we expect this to continue. Since REPS was implemented in 2007, 85 new renewable energy facilities have been built in North Carolina with 150 MW of renewable capacity. The majority of capacity is from three former coal facilities which have been converted to either exclusively biomass or a mix of coal, tires and biomass. The majority of facilities are solar PV and solar thermal units. Figure 14 summarizes the renewable resources online between January 1, 2007 and December 1, 2010.

FIGURE 14: NEW RENEWABLE ENERGY FACILITIES ONLINE BETWEEN JANUARY 1, 2007 AND DECEMBER 1, 2010

	Number of Facilities	Total Capacity (MW)
Landfill Gas	6	19
Hydropower	1	1
Solar Thermal	18	NA
Solar PV	57	36
Coal Conversion to Biomass25	3	94
Total[26]	85	150

D. Encourage private investment in renewable energy and energy efficiency

Energy efficiency

When S.B. 3 was enacted, utility activity with regard to energy efficiency was minimal. Progress offered rebates and loans to residential customers. Duke was in the process of seeking approval

24 Nachman, K.E., Graham, J.P., Price, L.B., and Silbergeld, E.K. (2005). Arsenic: A roadblock to potential animal waste management solutions. *Environmental Health Perspectives,* 113(9), 1123-1124.

25 Two of the plants burn a combination of biomass, coal and tires. The NCUC has ruled that 24% of the energy attributed to the burning of tires can be considered renewable, in addition to the biomass-fired energy. The capacity from these units has been prorated accordingly.

26 In our modeling described in sections 4 and 5, we assumed that only 140 MW was online by the end of 2010. The difference resulted from assuming that 10 MW of solar PV resources scheduled for 2010 would not come online until 2011.

of its Save-a-Watt Program when REPS was adopted. With the passage of S.B. 3, Progress, Duke, Dominion, and various EMCs and municipal utilities have filed for or received approval for a range of energy efficiency programs designed for all customer classes.

- According to its REPS compliance plan filed in September 2010, Progress anticipates achieving 181 GWh in savings from its energy efficiency programs, which represents 0.5% of forecasted sales. In 2012 this figure increases to 511 GWh, or 1.4% or retail sales. This exceeds the maximum energy efficiency that can be used to comply with REPS requirements, so Progress will be able to bank credits for compliance in future years.
- Duke's 2010 compliance plan notes that it plans to achieve more energy savings from its energy efficiency programs than can be used to fulfill the 25% portion of REPS requirements. Duke has been banking credits since implementing its energy efficiency programs in mid-2009 and expects to continue banking through 2012 and beyond.
- Dominion has recently received approval for several energy efficiency programs from the NCUC. In its 2010 compliance plan, Dominion forecasts achieving 10.4 GWh of savings from its programs in 2012, which represents 0.25% of its forecasted sales. Including credits from 2011 savings, Dominion anticipates fulfilling approximately 15% of its REPS requirement from energy efficiency, less than the 25% maximum.
- Various EMCs and municipal utilities have also developed energy efficiency programs. GreenCo, which administers the REPS compliance strategies for a group of 22 EMCs, has received approval in August 2010 from the NCUC for 11 energy efficiency programs, including offerings for the residential, non-residential, and agricultural sectors.

While S.B. 3 did not establish a minimum or maximum requirement for energy efficiency, it provided parameters for the optional use of efficiency savings for REPS compliance. Despite the lack of a firm requirement, the legislation's purpose, in part, was aimed at encouraging the development of cost-effective energy efficiency. As mentioned previously, the legislation does allow IOUs to use energy efficiency to meet up to 25% of their REPS compliance requirements and to begin banking energy efficiency RECs.

S.B. 3 directed the electric power suppliers to meet the electric needs of their customers with a least cost mix of supply or demand-side measures and directed the NCUC to approve an annual rider which allowed electric public utilities to "recover all reasonable and prudent costs incurred for adoption and implementation of new demand-side management and new energy efficiency measures."[27]

[27] G.S. § 62-133.9.(d) Cost recovery for demand-side management and energy efficiency measures.

In addition, the legislation allowed IOUs to capitalize their costs and for the NCUC to create incentives for the adoption and implementation of new demand-side and energy efficiency programs. This led to the creation of a regulatory structure which has established financial incentives for the IOUs to offer energy efficiency programs to their customers and a process by which programs are considered, approved, and reviewed.

Renewables

As mentioned above, since 2007 new renewables, in particular coal conversion to biomass and solar resources have been added to North Carolina. In order to comply with REPS we anticipate additional investment in renewables in the state, including wind. See Section 3 for further discussion on renewable resource potential and costs and Section 4 for analysis related to different future levels of renewables.

2.2.8 *KEY ISSUES RELATED TO IMPLEMENTATION OF REPS*

As mentioned in Section 2.2.2, North Carolina's REPS sets out four objectives. Our interpretation of these is as follows:

A. Diversify the resources used to reliably meet the energy needs of consumers in the state

As North Carolina meets future load growth and its REPS requirements, it will diversify its resources, adding additional renewables to its mix, but it must do so in a way that preserves and enhances the ability of the system to meet required standards of reliability.

B. Provide improved air quality and other benefits to energy consumers and citizens of the state

The individual energy resources and the overall power system performance must meet environmental standards set by federal and state law. REPS seeks to improve air quality by reducing SO_2, NO_X, mercury and greenhouse gas emissions. We have discussed with stakeholders "other" benefits during the development of this study but do not further interpret what this may mean as stated in the statute.

C. Provide greater energy security through the use of indigenous energy resources available within the state

North Carolina has many in-state renewable resources than can be utilized to enhance energy security by increased dependence on more diverse and local resources.

D. Encourage private investment in renewable energy and energy efficiency

Promoting investment in renewable and energy efficiency technologies is a key objective of REPS. Leveraging private capital to stimulate these markets will be an important aim.

Now that North Carolina had been implementing REPS for more than three years, the NCUC has reviewed and made rulings on various issues that have emerged. La Capra Associates reviewed the NCUC orders and engaged with numerous stakeholders to identify and garner feedback on the most critical issues to date, especially as they relate to the explicit and implicit objectives of the legislation.[28]

Our evaluation looks at performance against statutory objectives and the objectives that stakeholders are interested in today. It is clear that there are inherent tensions between emphasizing one objective relative to another. We aim to highlight these areas and related issues to help inform future policy discussions.

In addition to the four stated objectives in the legislation, in the course of our evaluation process stakeholders have articulated three key objectives upon which they would like to have future policy focus more directly.

1. **Reduce greenhouse gas emissions**

   In 2006, Congress was not yet considering climate legislation and the State was focused on meeting the Clean Smokestacks Act, which requires significant NO_x and SO_2 reductions. So although GHG emissions are part of the objective of improving air quality, several stakeholders expressed a desire for a policy with more of an explicit focus on reducing GHG emissions. In addition to using resources that would count towards REPS such as energy efficiency and renewables, some stakeholders also wanted to understand the potential impact of greater reliance on low carbon emitting baseload resources to achieve lower GHG emissions levels.

2. **Promote economic development in North Carolina**

   Promoting investment in renewables and energy efficiency technologies in North Carolina is a critical concern expressed by many stakeholders. S.B. 3 did not set economic development as an explicit objective. However, by promoting investment in renewables and energy efficiency, as well as the of use indigenous resources such as biomass, swine and poultry waste, there have been resulting economic benefits. North Carolina's current challenging economic environment and high level of state debt have increased the focus on investment in these resources as a way to encourage job creation.

3. **Provide stable and low electric power rates**

   In any economy, but particularly this one, keeping rates as low as possible is a priority. Consumers, particularly businesses, appreciate stable rates. Achieving REPS compliance in the most cost effective way, while ensuring stability of prices, is critical. The cost cap is meant to provide a mechanism to manage the costs of REPS.

28 Commission orders relevant to REPS policy are listed and summarized in Appendix B.

While several stakeholders support all of these objectives, stakeholders differ on which ones take priority and the best way to achieve them. Understanding the nature of these objectives and their impact on North Carolina's electric system is necessary to understanding the inherent trade-offs and better inform a dialogue on potential policy options. We outline some of those trade-offs below.

2.2.8.1 Providing a Low Cost Solution versus Promoting Local Investment

Various stakeholder groups articulated a strong desire to limit the cost of REPS compliance in order to avoid any hindrance of economic growth caused by increased electric rates. At the same time, one of the legislation's goals is to promote investment in renewables, which it achieves in part through set-asides. When these set-asides are met by in-state development of renewables, this promotes local economic development. These two positions are often at odds with one another.

The swine and poultry waste set-asides, for example, were established to promote the use of an indigenous waste product for electricity generation as well as to help address a waste concern in the state. While these set-asides are initiating new economic activity in North Carolina, they do so at a higher cost than other options available to meet REPS requirements. Energy from poultry and swine waste is significantly more costly than energy from biomass, another indigenous resource. In addition, compliance with these set-asides has proved to be the most challenging aspect of the legislation and has required the most planning and attention from electricity suppliers. Initially, utilities did not receive many responses to their Request for Proposals (RFPs), and some technological hurdles had to be overcome with generating energy from poultry waste.

Within REPS, the cost cap is meant to provide a mechanism to implement REPS at manageable costs. These set-asides have achieved their goal of in-state economic development in that they have spurred construction of new types of facilities. But due to the fact that set-asides must be fulfilled first, development comes at the expense of the other renewable industries. If the high cost of these resources causes suppliers to reach the REPS cost caps, it will effectively limit the overall amount of renewable energy in North Carolina. This also limits the suppliers from compiling the lowest cost portfolio of renewables and mitigating the legislation's impact on ratepayers.

Another issue related to the local development of renewables is the definition of "in-state" resources. The NCUC determined that resources out-of-state that can deliver energy to North Carolina customers qualify as "in-state" resources and are not subject to the 25% restriction. This ruling essentially permits energy generated by renewable resources in the South Carolina territory of Progress and Duke to contribute toward compliance. This features a similar trade-off discussed above; utilities may pursue lower cost renewables in South Carolina and limit ratepayer impact, but the amount of renewable projects developed in North Carolina may be diminished.

2.2.8.2 Promoting Investment in Energy Efficiency and Renewables

Investment in energy efficiency

Several issues were identified related to REPS' effectiveness in promoting investment in energy efficiency. The law contains a provision permitting the use of energy efficiency for compliance in order to encourage program development and to provide a low-cost compliance resource. The reality of implementation, thus far, has shown a 'disconnect' between goals and supplier actions.

According to REPS compliance plans and communication with suppliers, Duke and Progress will likely achieve energy efficiency savings in excess of the 25% allowed for REPS compliance, while municipal utilities and EMCs will achieve significantly less savings. This is despite the fact that municipal utilities and cooperatives are permitted to use energy efficiency to fulfill all REPS requirements other than the set-asides.

This difference has caused some stakeholders to voice concerns with the provision. First, the apparent ease with which the IOUs are already achieving the threshold amounts has raised questions about instituting more aggressive goals in order to further encourage investment.

Additionally, the difference between anticipated savings of IOUs and municipal utilities and EMCs indicates that program implementation is not based on potential but may be more dependent on available incentives and administrative feasibility. Regulated utilities can earn a return on their investments and have large customer bases which may allow for more efficient program administration.

This suggests that REPS may not be the best method of encouraging energy efficiency, leading some to question whether inclusion of energy efficiency in the REPS bill is the optimal method for achieving legislation's goal of increasing investment in energy efficiency. Later in this report we will discuss the trade-offs of developing a separate energy efficiency standard versus leaving energy efficiency within the existing REPS.

Investment in renewables

One issue that has been identified is the inherent tension between promoting low costs through enabling 25% of REPS to be met with out-of-state RECs and promoting more direct investment in renewables in North Carolina.

The REPS legislation includes a provision allowing up to 25% of the requirement to be fulfilled by the use of RECs purchased from out-of-state renewable facilities. The NCUC has been asked to address several issues regarding this provision and it remains a controversial issue.

A key issue is that the two largest IOUs in North Carolina operate multi-state integrated systems, meaning that for Duke and Progress, electricity generated at their plants in North Carolina and South Carolina both feed the states' combined demand and there is no grid separation. The statutory language anticipates this issue and deems all electricity that is generated by or delivered to a North Carolina public utility as "in-state" for the purposes of compliance.[29]

For those who look to promote job creation associated with renewable projects, it is an important distinction that the requirement is for delivery to the service territory. The significance of this provision is that it may reduce the economic development benefits that North Carolina would receive from the development of renewable facilities. In fact, a utility could technically fulfill all the requirements of the legislation without any renewable energy generated within the geographic boundaries of the state, although that extreme outcome is not occurring in practice.

As is detailed in Section 2.3, North Carolina has already seen considerable development of new resources and we do anticipate that additional resources will be developed within the state, in particular biomass, poultry and swine waste facilities.

The NCUC has also clarified that the 25% out-of-state limitation applies to the REPS general requirement as well as each set-aside individually. Various interveners in the issue argued that since the purpose of the set-asides is to develop North Carolina resources, set-asides should be fulfilled only by in-state resources. The NCUC initially agreed, but upon reconsideration, determined that applying the 25% limitation is the best approach to both promote indigenous resources and minimize cost of compliance.[30]

Finally, the NCUC was asked to clarify that, while electricity generated out-of-state and delivered to a North Carolina utility qualifies as in-state, thermal RECs derived from a combined heat and

29 See, e.g., G.S. 62-133.8(b):

(2) An electric public utility may meet the requirements of this section by any one or more of the following:

…

(d) Purchase electric power from a new renewable energy facility. Electric power purchased from a new renewable energy facility located outside the geographic boundaries of the State shall meet the requirements of this section if the electric power is delivered to a public utility that provides electric power to retail electric customers in the State; provided, however, the electric public utility shall not sell the renewable energy certificates created pursuant to this paragraph to another electric public utility.

30 "Order on Duke Energy Carolinas, LLC, Motion for Clarification." North Carolina Utilities Commission, Docket E-100, Sub 113. May 7, 2009

"Order on Dominion's Motion for Further Clarification." North Carolina Utilities Commission, Docket E-100, Sub 113. September 22, 2009 power (CHP) facility in South Carolina do not.[31] The NCUC determined that the language of the statute does not allow these thermal RECs to qualify as in-state, even if they are generated as part of the same process as electric power that does qualify as in-state.

Separately, a concern among some stakeholders is that the structure of the solar set-aside requirements does not effectively incentivize the development of strong solar industry in the state. For example, the solar set-aside requirement increases by large steps every three years beginning in 2012. This structure may foster a boom-and-bust solar industry, with high levels of development in the years preceding set-aside increases followed by two years of limited activity. This is not conducive to a strong, established solar installation industry that can consistently support a trained workforce. Already there are indications that enough solar has been developed so that, including banked credits, utilities will be able to meet their set-aside requirements through 2015 without additional development.

2.2.8.3 Price Stability

Achieving REPS compliance in the most cost effective way, while ensuring stability of prices, is critical. REPS, not withstanding some near term challenges associated with an increase in the residential cost cap and poultry set-aside requirements, will be effective at providing stable electric power rates. The cost cap increases significantly from 2013 to 2014, ($22 per customer), but the steep ramp-up of the poultry set-aside occurs between 2012 and 2013 when it increases from 170,000 MWh in 2012 to 700,000 MWh in 2013. The poultry set-aside increases another 200,000 MWh to 900,000 MWh in 2014.

31 "Order on Joint Motion to Determine Whether RECs are In-State or Out-of-State." North Carolina Utilities Commission, Docket E-100, Sub 113. July 13, 2009

3. RENEWABLE AND LOW CARBON RESOURCE OPTIONS IN NORTH CAROLINA

The North Carolina Energy Policy Council (EPC) commissioned this study to provide resource potential and cost information for its considerations of electric sector energy policy issues including the future of renewable energy, energy efficiency, and low carbon emitting energy resources. The EPC asked La Capra Associates to update and expand upon its 2006 assessment of North Carolina renewable energy potential and costs for this purpose.[32]

In this assessment, the EPC asked us to revisit our estimates of energy efficiency and renewable resources, including biomass, wind, hydro, and solar, and to expand this to consideration of potential low GHG emitting resources, specifically nuclear power and natural gas.[33]

Over the past five years, many changes have taken place that have impacted the cost and potential for renewable and energy efficiency resources. Among the factors are the implementation of S.B. 3 REPS, a recessionary environment, shifts in the natural gas market, technology advances and cost declines in some industries, and new regulatory policy, such as the introduction of state and federal efficiency standards.

This resource assessment was prepared based on independent research of published studies and La Capra Associates experience and expertise with these energy resources. We also considered input from many North Carolina stakeholders, including market participants, regulators and other interested parties, to identify recent credible data specific to North Carolina, including some of which is confidential. We have provided overall technical and practical potential for each resource as well as representative estimates of key resource metrics such as capacity factor, dispatch ability, reliability, emissions, capital costs and levelized costs. This section of the report provides a summary of this analysis, including key findings. Please see Appendix A for the Technical Supplement which outlines the approach and provides the full detail of results by resource and key findings for this research and analysis.

3.1 KEY FINDINGS

In determining the estimate of technical and practical potential for resources as well as associated costs there were a number of key findings which are outlined below.

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32 La Capra Associates, Inc, GDS Associates, Inc, and Sustainable Energy Advantage, LLC. (2006) Analysis of a renewable portfolio standard for the state of North Carolina. *Technical Report to the North Carolina Utilities Commission.*

33 An assessment of poultry and swine waste was not a part of the project scope.

3.1.1 *RENEWABLES*

3.1.1.1 Onshore Wind

- Onshore wind in North Carolina is a good resource. The Mountain Ridge Protection Act of 1983 (Ridge Law) is an obstacle to development in Western North Carolina.
- North Carolina will benefit from having its first wind farm built in the east, enabling better understanding of North Carolina specific development issues (e.g. hurricanes).

3.1.1.2 Offshore Wind

- There is enormous potential for offshore wind in North Carolina's waters. Its development is limited by its higher relative cost.
- North Carolina's offshore wind development efforts may benefit from experience in other east coast states which have projects underway.
- Offshore wind development in North Carolina, as well as other locations, may also benefit from technology advances in Europe, in particular a move to larger turbine sizes.
- The capital costs for offshore wind are expected to decrease over time due to industry learnings and greater efficiencies, but it will still take several years until offshore wind is competitive on a cost basis with onshore wind.

3.1.1.3 Solar PV

- Solar PV costs declined significantly in 2010 and the first quarter of 2011 and cost declines are expected to continue through the study period.
- There is an active solar industry in North Carolina, but this may contract as enough solar is currently under contract to meet REPS requirements through 2015.
- The resource potential for solar is quite large and North Carolina could support a larger solar set-aside. Based on our cost estimates, a set-aside would continue to be required as solar is not expected to be cost competitive with biomass and onshore wind in the 10-year horizon of this assessment.
- A set-aside that ramps up evenly over time would allow the industry to grow and take advantage of the expected cost declines in the later years.

3.1.1.4 Landfill Gas

- Landfill gas is a low cost renewable resource that has the added benefit of reducing emissions of methane, a potent greenhouse gas. While there is an opportunity to triple anticipated generation from landfill gas, full development would still represent a relatively small share of North Carolina renewable energy generation.

3.1.1.5 Biomass

- Under the current REPS policy, and assuming the definition of eligible biomass fuel includes whole tree chips, there is a practical potential to fuel more than 1,300 MW of electricity generation with forest, agriculture and urban waste biomass resources. Of that total, up to 787 MW could be co-fired with coal at existing plants.
- The true practical potential of biomass in North Carolina will be determined as much by assessments of environmental impacts as by economic and feasibility constraints. A full evaluation of the environmental trade-offs from utilizing various biomass resources is beyond the scope of this study.
- Inclusion of whole trees in the definition of eligible biomass fuel increases potential. However, it also introduces new issues such as the greenhouse gas impacts of dedicated energy harvests, competition with existing forest products industry, and potential for significant land use and forest management changes.
- Collaborating with researchers at North Carolina State University (NCSU), Duke and U.S. Forest Service, La Capra Associates used the Sub Regional Timber Supply model to estimate 1,000 MW of forest biomass potential in the North Carolina electricity supply region. Assuming logging residue recovery rates of 70% for hardwood species and 85% for softwood species, this potential can be obtained almost entirely with residues.
- If logging residue recovery rates do not reach these high levels, the expected potential for forest biomass would be lower. However, even if halved the potential would still exceed the expected demand from the current REPS policy.
- Our biomass potential forecast includes resources in South Carolina and Virginia. If renewable portfolio standard (RPS) policies enacted federally or in neighboring states add to regional biomass electricity demand, it is likely the practical potential for North Carolina would be significantly lower than projected.
- Dedicated energy crops, agriculture residues (not including manure) and urban wood waste have the practical potential to fuel another 350 MW of biomass electricity.
- Our co-fire potential estimate assumes that coal plants with selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) scrubbers can co-fire a maximum of 10% of heat input with biomass. Estimates vary on the feasibility of co-firing scrubbed plants.

3.1.1.6 Hydro

- The practical potential for new hydro is low – just over 100 MW. We do not foresee development of new hydro as a significant piece of the REPS compliance picture.

3.1.2 *ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT, AND COMBINED HEAT POWER*

- S.B. 3 laid the framework for North Carolina to begin to access the technical economic electric energy efficiency resources that had been identified as the potential in 2007. The NCUC has created a process and incentive system that make clear North Carolina's commitment to obtaining economic energy efficiency. The current structure of utility incentives, ability to receive REPS credit and the integrated resource planning is driving IOU's to actively pursue energy efficiency. Current IRP and other filings and hearings allow for periodic review of current avoided costs and overall compliance.
- In the three year implementation period of REPS, two utilities have significantly increased their efficiency program offerings. These utilities are funding program development, investing in the structure and planning, and are on a trajectory to achieve the 10 year economic energy efficiency potential.[34]
- Based on the available information, the economic energy efficiency potential range for North Carolina is 7-13%. Changes in and selection of avoided costs will significantly impact potential.[35]
- There is general agreement among stakeholders that the currently available potential studies are dated, not state specific and/or incomplete. In many instances, the available data for North Carolina is five or more years old.
- North Carolina's law allows all industrial and large commercial utility customers (that consume 1,000 MWh or more annually) to opt-out of utility programs and not pay the EE/DSM rider if they claim that they have implemented or plan to implement efficiency measures independently. The impact of this provision is considerable, and current opt-out levels represent approximately 15-30% of load.
- Cooperatives and municipal utilities, which represent 25% of the state's usage, have been able to secure RECs at a lower cost to their customers than energy efficiency programs.
- Demand-side management (DSM) is an eligible compliance resource for EMCs and municipalities. Due to the minimal impact on energy requirements, DSM is not expected to be a significant compliance resource.

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[34] Duke and Progress have a range of energy efficiency programs in place. Dominion filed for program approval and is expected to implement them in 2011.

[35] In the modeling, the low avoided cost used was the conventional avoided cost. The high avoided cost cases used the cost of renewables as the avoided cost.

- While somewhat limited in capacity, CHP is a good option for low-cost, high-efficiency generation. With strong development efforts, 600 MW is realistically achievable over 10 years.
- CHP could be an important component of a least-cost, low-emission portfolio, especially if paired the lowest-emission fossil fueled generation or if fueled using biomass.

3.1.3 *BASELOAD RESOURCES*

3.1.3.1 Nuclear

- Nuclear development is costly and there is little consensus on price estimates. Estimates have been escalating, but without a new project developed in the U.S., there will be little certainty on cost.
- Prospects for the development of nuclear power in North Carolina, as well as other places in the United States are highly uncertain due to safety concerns related to the impact of the recent earthquake and tsunami on the Fukushima-Daiichi nuclear plant in Japan.
- In addition, there is regulatory uncertainty especially given enhanced scrutiny of new designs and the lack of resolution to nuclear waste storage. The nuclear industry's history of cost overruns contributes to financing risk.

3.1.3.2 Natural Gas

- Natural gas combined cycle plants (CCs) are the preferred near-term baseload resource in the IOU IRPs.
- Stakeholders in North Carolina are currently investigating the potential for gas production in the western region. Even without in-state drilling, North Carolina has ample supply. Due to gas supply north and south on the Williams Transco pipeline, North Carolina is well-situated to take advantage of low gas prices for baseload power.

3.2 RENEWABLE RESOURCE POTENTIAL

3.2.1 *SUMMARY DISCUSSION OF RESOURCE POTENTIAL*

The potential of each renewable resource in North Carolina was assessed in terms of capacity potential, for both a "technical" potential and "practical" potential. These terms are defined as follows:

- **Technical Potential.** The technical potential is the total renewable resources, located within the state, with the potential for electric energy conversion.

- **Practical Potential.** This is the amount of capacity that we believe can be developed based on practical considerations. It is the potential that might reasonably be expected to be achieved based on currently available technologies and other screens specific to each resource. For example in the case of offshore wind, this would include a screen to limit practical potential to development at a certain water depth. Or in the case of woody biomass this would include screens for limitations on forest lands that are not harvestable. While we did consider some element of cost we have not employed pure cost effective analysis in constraining our estimates of practical potential.

Figure 15, below, shows the North Carolina resource potential for renewable resources. The assumptions behind the potential for each technology are discussed in detail in Appendix A. Figure 15 shows that there is almost 49,000 MW of technical potential and almost 18,000 MW of practical potential, not including solar PV potential which we have characterized as unlimited. Offshore wind is the biggest contributor to renewable potential followed by biomass and onshore wind.

FIGURE 15: RENEWABLE RESOURCE POTENTIAL

Resource Type	Technical Potential		Practical Potential	
	MW	GWh	MW	GWh
Onshore Wind				
Eastern	750	1,971	750	1,971
Western*	3,750	9,855	1,625	4,271
Total Onshore Wind	4,500	11,826	2,375	6,242
Offshore Wind	39,140	126,861	13,905	45,069
Solar PV				
Utility Scale	Unlimited	Unlimited	Unlimited	Unlimited
Rooftop	Unlimited	Unlimited	Unlimited	Unlimited
Total Solar PV	Unlimited	Unlimited	Unlimited	Unlimited
Biomass				
Biomass	3,242	24,140	1,373	10,223
Co-fire with coal**	747	5,562	747	5,562
Hydropower***				
Upgrades at existing generation sites	18	69	3	10
New generation with existing impoundment	781	3,080	82	324
Undeveloped sites	139	550	21	83
Total Hydropower	938	3699	106	417
Landfill Gas	72	538	68	503
Total******	**47,892**	**167,064**	**17,827**	**62,454**

* Assumes that the Ridge Law issues are resolved and development in Western North Carolina is possible. Without revision to the Ridge Law, there is very limited on-shore wind potential in Western North Carolina.

** Co-fire potential is a subset of overall biomass potential

*** Hydro technical potential includes sites that are greater than 10MW, but practical potential does not.

**** Does not include solar potential which is effectively unlimited.

3.3 RENEWABLE RESOURCE COSTS

3.3.1 *SUMMARY DISCUSSION OF COST PARAMETERS*

Figure 16 below, shows the cost parameters for each renewable, other low GHG emitting resources and CHP. This enables a comparative view of the cost of various renewable and other low GHG-emitting resource options in North Carolina and a basis for understanding future costs and potential rate impacts of various resource portfolios. Cost estimates are derived in part by the following parameters:

- **Capacity factor.** The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time to its output if it had operated at full nameplate capacity the entire time.
- **Modeled Project Size.** This is the size of project that we modeled and the size of project to which the costs correspond. Smaller projects would likely be more expensive.
- **Overnight Costs.** Overnight cost is the cost to construct the resource if no interest was incurred during construction, as if the project was completed "overnight."
- **Technology Decline Rate.** This is the rate at which we are assuming costs decline each year. This parameter is zero for many resources. Resources with declining costs are generally emerging technologies such as offshore wind.
- **Fixed O&M.** This is the fixed component of the operations and maintenance expense. It is not dependent on the plant output.
- **Variable O&M.** This is the variable component of the operations and maintenance expense of operating the renewable resource not including the fuel costs.
- **Fuel Costs.** This is the cost of fuel required for the resource.
- **Heat Rate.** A measure of efficiency of a power generation resource, the heat rate signifies the amount of heat energy required to produce one kWh of electricity. Lower heat rates indicate more efficient resources. Resources not requiring fuel (like wind) do not have a heat rate.

FIGURE 16: COST PARAMETERS ($2010)

Resource Type	Capacity Factor	Modeled Project Size (MW)	Overnight Costs ($/kW)	Technology Decline Rate (% in Real$)	O&M		Fuel Heat Rate (Btu/kWh)	Fuel Costs ($/MMBtu)
					Fixed ($/kW-yr)	Variable ($/MWh)		
Renewable Energy								
Onshore Wind	30%	100	$2,340	0%	$28	$-	NA	0
Offshore Wind	37%	400	$4,800	5%	$53	$-	NA	0
Solar PV								
Utility Scale	15%	2	$3,400	3%	$26	$-	NA	0
Rooftop	15%	0.5	$3,600	3%	$26	$-	NA	0
Biomass								
Co-firing	85%	20	$200	0%	$70	$1.00	12,000	$2.00
Dedicated Biomass	85%	50	$3,343	0%	$101	$3.00	13,500	$2.00
Hydropower								
Upgrades at Existing Generation Site	45%	2.5	$1,010	0%	$-	$5.00	NA	0
New Generation at Existing Impoundment	45%	2.5	$3,030	0%	$21	$5.00	NA	0
Undeveloped Site	45%	5	$4,030	0%	$21	$5.00	NA	0
Landfill Gas	85%	5	$2,450	0%	$119	$-	13,650	0
Other Low GHG Emitting Energy Supply Options								
Nuclear	90%	2236	$6,500	0%	$113	$2.59	NA	
Natural Gas								
CT – Conventional Peaking	5%	83	$905	0%	$7	$14.70	10,850	$6.47
CT - Advanced	5%	204	$673	0%	$7	$9.78	9,750	$6.47
CC – Current Technology	70%	530	$888	0%	$14	$3.43	7,050	$6.47
CC - Advanced	70%	389	$914	0%	$15	$3.11	6,430	$6.47

We developed levelized costs for both the renewable and low GHG mitigating resources to assess the associated annual costs for a portfolio of conventional resources and a portfolio that includes renewable resources. All levelized costs are in nominal terms and are calculated over a 20-year period where inflation is also taken into account, assumed to be 2.5% per year. The annual levelized cost for each type of resource modeled represents the cost for a resource installed in a particular year. Detail on the financial modeling is provided in the Technical Supplement to Section 3.

FIGURE 17: 2011 LEVELIZED COSTS

Resource Type	Levelized Cost (2010$/MWh)	
	Utility	Merchant
Renewable Energy		
Onshore Wind	$109	$101
Offshore Wind*	$193	$180
Solar PV**		
Utility Scale	$182	$162
Rooftop	$192	$170
Biomass		
Co-firing	$40	$39
Dedicated Biomass	$94	$99
Hydropower		
Upgrades at Existing Generation Sites	$24	$18
New Generation at Existing impoundment	$68	$54
Undeveloped Sites	$102	$101
Landfill Gas	$45	$43
Other Low GHG Emitting Energy Supply Options		
Nuclear	$140	$148
Natural Gas		
CT - Conventional Peaking	$376	$478
CT – Advanced	$368	$473
CC – Current Technology	$71	$78
CC – Advanced	$64	$70

* *We assume a technology cost decline rate for offshore wind of 5% per year over the study period.*

** *We assume a technology cost decline rate for solar PV of 3% per year over the study period.*

3.4 ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND COMBINED HEAT AND POWER

3.4.1 *ENERGY EFFICIENCY POTENTIAL*

As part of its analysis of the potential for renewable resources in North Carolina, La Capra Associates was asked to develop a 10 year potential estimate for energy efficiency based on existing studies.[36] Since energy efficiency is an eligible resource for REPS compliance, understanding it is an important component in the review of the legislation. This analysis is intended to help inform the role that energy efficiency can have as a resource.

This potential analysis is founded on existing estimates of technical potential. Potential is defined as achievable, cost effective energy efficiency that can be procured, measured, verified and attributed to utility energy efficiency programs. La Capra Associates screened this potential based on end-use measure costs to determine two levels of economical efficiency potential based on different avoided cost levels. This estimate was then revised based on several factors, including the impact of new legislation mandating certain efficiency improvements and La Capra Associates' analysis regarding reasonable penetration rates.

The Technical Supplement provides detailed information on the energy efficiency potential studies used and a framework for understanding our approach to developing a potential number for North Carolina. The Technical Supplement provides specific information on how the estimate was reached for North Carolina, including an overview of the resources used, factors taken into consideration and results of the energy efficiency potential number. We also include sections on demand-side management and combined heat and power (CHP).

[36] This analysis will use the terms "energy efficiency" and "demand-side management" as they are defined in S.B. 3. See Section 2, footnote 5.

FIGURE 18: ENERGY EFFICIENCY POTENTIAL ANALYSIS RESULTS

Scenario	Avoided Cost Threshold	Technical Potential (%)[37]	Economic Potential[38]	10-Year Potential[39]
Base EE	$0.05/kWh	32%	11%	7%
High EE	$0.10/kWh		16%	13%

3.4.2 *ENERGY EFFICIENCY PROGRAM COSTS/MEASURE COSTS*

The cost of energy efficiency varies widely program by program and measure by measure. Some measures, such as the replacement of incandescent bulbs with compact fluorescent light bulbs ("CFLs") can cost less than $0.01 per kWh saved. Other measures, such as appliance or air conditioner upgrades can cost much more. The price of a measure is dependent on several factors, including capital costs, quantity of energy saved, and life expectancy of the measure. Program costs include the costs incurred by the utility to implement the energy efficiency programs including incentives, marketing/communication, and the measurement/verification of savings.

The GDS study included estimates of measure costs, but did not include an accounting of the program costs. La Capra Associates referred to detailed estimates filed with the NCUC by the utilities to derive the cost estimates for base case measures. Costs are represented as a range due to the issues explained above.

Utilities have not implemented measures in the cost range represented in the high potential case. Therefore, these costs were estimated based on similar relationships between the avoided cost of the measure and the cost per kW or kWh.

37 Engineering estimates of energy savings if standard stock is replaced with most efficient measures. No consideration of economics, market or regulatory barriers.

38 Estimated savings from measures that have passed an economic analysis based on a $0.05/kWh utility avoided cost.

39 Includes adjustments for free ridership, achievable penetration rates, new federal appliance and lighting standards, and revised building codes. Potential does not reflect commercial/industrial opt-out provision.

FIGURE 19: MEASURE/PROGRAM COSTS

Scenario	Measure Costs		Program Costs	
	$/kWh	$/kW	$/kWh	$/kW
Base EE	0.005 - 0.059	430 - 2,175	0.007 - 0.071	852 - 3,222
High EE	0.06 - 0.10	1,075 - 5,437	0.057 - 0 .121	1,941 - 7,343

3.4.3 *DEMAND-SIDE MANAGEMENT*

The legislation creating North Carolina's REPS does not allow the three large utilities to use DSM programs to count towards REPS compliance, though the cooperative and municipal utilities are permitted to do so.[40] EPC asked La Capra Associates to offer a perspective on the role that demand response might play in reaching the goals articulated in S.B. 3.

DSM programs involve contracts with customers to reduce their electricity use at times of high wholesale market prices or when system reliability is jeopardized. DSM programs are generally thought of as capacity resources and, as such, they do not materially affect energy production in North Carolina. Demand-side management does have an important role in integrated resource planning as North Carolina looks for the best resource mix when multiple objectives are considered, including cost, reliability, environmental impact and economic development. Appendix A addresses these issues in further detail.

As the impact of DSM on energy is minimal, La Capra Associates does not expect it to be a significant factor in REPS compliance planning.

3.4.4 *COMBINED HEAT AND POWER*

Combined heat and power from a nonrenewable fuel is an eligible efficiency resource under REPS. La Capra Associates was asked to review the potential for CHP facilities to meet a portion of the North Carolina REPS requirements. The review of this potential was greatly enhanced by the Scenario Analysis of CHP Potential in North Carolina developed by ICF International in support of the U. S. Department of Energy's Southeast Clean Energy Application Center, based at the North Carolina Solar Center.[41]

40 As previously noted, recent legislation (S.75, signed into law 4/28/2011) has added "electricity demand reduction" as an eligible resource. Electricity demand reduction is equivalent to DSM or demand response. This analysis was completed prior to this legislation, but as noted in this section, demand response is primarily a capacity resource and is not expected to make a large contribution to energy or REPS compliance requirements.

41 " Target State CHP Analysis: Overview of Six State Scenario Analysis." ICF International. October 2010.

La Capra Associates' analysis found that there is significant CHP resource potential in North Carolina and that CHP is a highly cost-competitive resource. Figure 20 and Figure 21 provide the results of the potential and cost analysis. The Technical Supplement to Section 3 in Appendix A examines CHP in greater detail.

FIGURE 20. NORTH CAROLINA CHP POTENTIAL

	Technical Potential (MW)	Economic Potential (MW)	Achievable Potential (MW)	Achievable Potential (MW) in 5 years	Achievable Potential (MW) in 10 years
Reference CHP Capacity Potential	10,702	1,444	773	190	500
Reference CHP Demand Displacement	7,751	584	266	100	100

FIGURE 21. ASSUMPTIONS USED FOR MODELING LEVELIZED COST OF CHP

Technology Characteristic	CHP Capacity	CHP Demand Displacement
Capacity Factor	90%	90%
Modeled Project (MW)	25-50 MW	25-50 MW
Overnight Costs (2010$/kWh)	$1,018	$1,066
Technology Decline Rate	-	-
Fixed O&M (2010$/kW-yr)	$31.54	$31.54
Variable O&M (2010$/MWh)	-	-
Fuel Heat Rate (Btu/kWh)	5,222	5,388
Fuel Costs ($/MMBtu)	$6.47	$6.47

La Capra Associates used the assumptions summarized in Figure 21 to determine levelized costs for CHP of $0.05/kWh.

La Capra Associates concluded that, over the next 10 years, the penetration potential for CHP could be a significant portion of the achievable economic potential using the 35% investment tax credit (ITC) and through high inclusion in REPS implementation.

- There would be 600 MW developable in 10 years
- 100 MW would be consumed on site
- 500 MW would be exported to the grid

- The typical plant sizes would be 20-50 MW, although significantly smaller plants are not uncommon down to the 1 MW level or below.
- The cost of CHP electric energy would be approximately $0.05/kWh in large scale high thermal production applications which formed the basis of this potential.

4. ANALYSIS OF NORTH CAROLINA NEEDS AND RENEWABLE ENERGY AND LOW CARBON EMITTING RESOURCE OPTIONS

In addition to the evaluation of REPS to date in Section 2 and the updated renewable energy and low carbon resource potential assessment in Section 3, the EPC asked La Capra Associates to conduct a scenario analysis to examine a range of policy choices regarding renewable energy development, greenhouse gas emission reduction, and green economy development in North Carolina. We first developed a 15-year Baseline Analysis (Baseline) to represent the most likely course of compliance with S.B. 3 REPS under the status quo. We then constructed six scenarios designed to illustrate the effects of alternative policy choices with emphasis on minimizing electricity costs, increasing economic development in North Carolina, accelerating reductions of electric sector greenhouse gas emissions, expanding development of renewable energy sources, and aggressively pursuing development of energy efficiency measures.

We relied on the key objectives in the S.B. 3 REPS legislation and additional policy objectives identified by the EPC and stakeholders as a framework to develop the scenarios and associated resource portfolios. We then developed inputs and assumptions for six plausible but differing scenarios, including corresponding energy resource additions and retirement schedules, which take into account the resource technology cost and potential data discussed in Section 3 of this report. As a result, we show various technology mixes that could be developed through 2015, 2021 and 2025. Each scenario was evaluated using key metrics associated with each objective, such as cost of electricity, tons of carbon dioxide emissions, fuel mix, and investment in North Carolina resources.

Our baseline and scenario analyses relied on the use of AURORAxmp, a regional dispatch model, to accurately characterize regional power system operations; simulate system dispatch; and track costs, emissions and fuel use.

In the sections below we discuss our key findings from this analysis, our assumptions, approach, and results for these analyses.

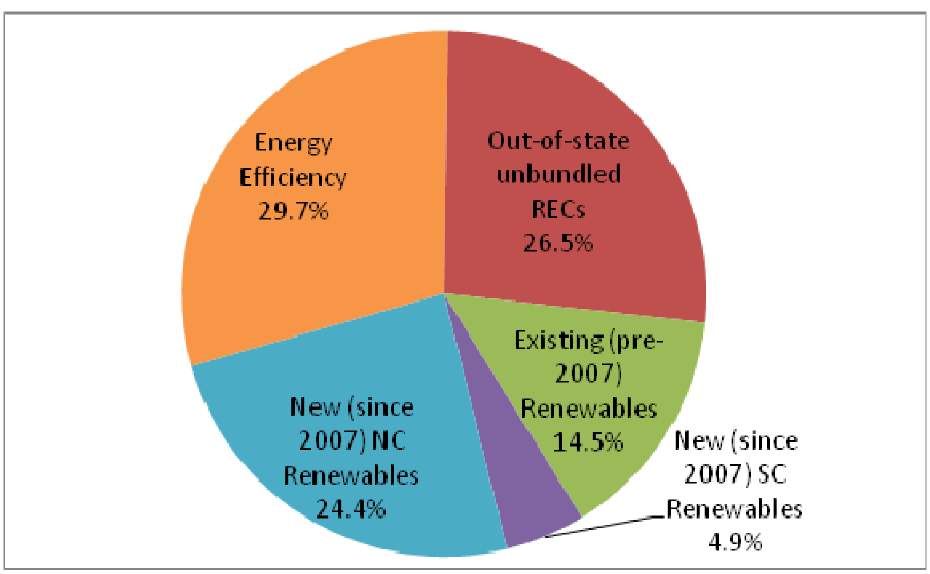
4.1 KEY FINDINGS

4.1.1 *BASELINE ANALYSIS*

- Our Baseline represents our best estimate of the compliance strategies of IOUs, EMCs and municipal utilities through 2025 if current REPS policy remains unchanged. Though economics of the different resource options was an important consideration, it was not the only factor. We also considered stakeholder input on the political climate and already announced compliance strategies to shape our forecast.

- We found that there is an abundance of low-cost RECs and SRECs (Solar Renewable Energy Certificates) available in other regions of the country, making it highly likely all utilities will maximize their use of out-of-state RECs for REPS compliance.
- We found that there is sufficient energy efficiency and existing (pre-2007) renewable energy capacity for EMCs and municipal utilities to comply with their general REPS requirements (excluding set-asides) without any new renewable energy generation.
- Based on our assessment of existing and potential qualifying resources and costs, we can find no reason that REPS compliance would present any undue challenges for utilities. The possible exception is the poultry waste set-aside. The relatively high target, the short ramp-up period, and the lack of existing development create compliance uncertainties. Analysis of these issues is beyond the scope of this study.
- We project that about 815 MW of new renewable energy capacity deliverable to North Carolina will ultimately be added between 2007 and 2025 as a result of S.B. 3, including 305 MW of biomass, 120 MW of onshore wind, 56 MW of landfill gas, 172 MW of solar, 46 MW of swine waste, and 114 MW of poultry waste resources.
- Between 2010 and 2025, we project that a cumulative total of 170 million MWh of energy or energy credits will be used to comply with REPS. Of that total, 30% will be energy efficiency credits, 27% will be out-of-state unbundled RECs, 15% will be energy generated by existing (pre-2007) renewable energy facilities, and 29% will be energy delivered to North Carolina utilities by new (since 2007) renewable energy facilities (see Figure 22).

FIGURE 22: CUMULATIVE COMPLIANCE ENERGY SOURCES, 2010-2025 (BASELINE)



- Resources built outside of North Carolina can still qualify as "in-state" if they deliver energy to an IOU with North Carolina customers. We project that 17% of new in-state renewable energy will be generated in neighboring states, although the proportion could theoretically reach as high as 50%.[42] All qualifying energy efficiency measures occur within North Carolina.

4.1.2 *SCENARIOS*

- Although adding significant new nuclear capacity results in the greatest degree of reduced carbon emissions, achieving a 30% reduction from Baseline levels by 2025, it also results in the highest total cost. This is due to the large size of nuclear facilities included in the analysis (nuclear capacity varied by more than 5,000 MW across the scenarios) and its relatively high cost.
- The most aggressive energy efficiency scenario has the second largest impact on reducing overall emissions by 2025. When compared to the high renewables build-out, it costs less and results in lower overall GHG emissions.
- Set-asides are the costliest component of REPS but have a minimal impact compared to baseload assumptions in achieving a lower cost portfolio.
- The high investment in renewables scenario results in an additional 5,000 MW of renewables compared to the Baseline, but also has associated $2 billion of net present value (NPV) of costs over the study period. There may be other end effects we have not captured.
- Scenarios with high levels of energy efficiency result in lower emissions overall (up to 12% by 2025 or average of 7% reduction from the Baseline).
- Significant amounts of cost-effective energy efficiency are available at a $0.05/kWh avoided cost. There is nearly twice as much energy efficiency potential available below the incremental cost of renewables and new nuclear power plants, or if fuel prices push up avoided cost.
- Nuclear development has a profound impact on cost for all scenarios as modeled. Given the degree of uncertainty regarding costs and the level of potential nuclear additions the exact impact may be more or less.
- There are large rate impacts in high (Scenario 1) and low (Scenario 3) nuclear scenarios.

42 To reach 50%, all future resources that have not already been built or registered with the NCUC would have to be built in neighboring states.

4.2 REGIONAL DISPATCH MODEL

For scenario analysis, La Capra Associates developed a simulation model of the southeast power system, using the AURORAxmp model by EPIS, Inc. as the dispatch simulation software. AURORA simulates economic dispatch of the power system to meet projected demand for electricity, incorporating the addition of new renewable and non-renewable resources as well as the modification of existing resources in the system, and tracking cost and environmental performance of the generation units in the region. The La Capra Associates model enabled analysis of system-wide costs and benefits of the various scenarios. Please see Appendix D for an overview of the model as well as the implementation methodology used by La Capra Associates.

4.3 MODELING THE S.B. 3 REPS - BASELINE

4.3.1 *KEY ASSUMPTIONS*

Our first step was to build a Baseline based on our assessment of the most likely compliance with REPS as it is currently set forth in legislation. To do this, we made assumptions about how electric suppliers would balance economic, political and feasibility considerations in complying with REPS.

A. Time frame

Although the initial period of focus requested for this study was 2011-2021, we extended our study timeframe to 2025 for a few reasons. We wanted to provide a wider window for some resources that would tend to appear further in the future due to long development lead times (e.g., nuclear and offshore wind) or declining costs (e.g., solar PV). Also, we wanted our model to extend beyond 2021, when the REPS requirements plateau as a percentage of retail sales, to reflect attainment of the full level of renewable energy and energy efficiency in the REPS requirements. Due to the banking of RECs allowed under REPS, requirements far in the future can have significant impacts on near-term buildout strategy.

B. Banking

North Carolina's REPS allows IOUs to bank compliance credits for up to seven years. We assumed that utilities will make use of this provision to optimize compliance strategies over multi-year periods rather than on an annual basis. Utilities have already been doing this by accumulating RECs since 2008 that will not be required until 2012 or later. As a result, during the early years when requirements are quickly escalating, total renewable energy output does not necessarily have to be at a level sufficient to comply with the current year's annual requirement. However, we assumed that by the end of the study period in 2025 when requirements level off (as a percentage of sales), utilities need to be generating enough compliance credits to comply with annual requirements without heavy reliance on banking.

C. Set-asides

The NCUC has ruled that the solar, poultry and hog waste set-aside provisions must be the first priority for compliance.[43] In our Baseline, we assume that the set-aside targets will all be met per their separate ramp-up schedules.

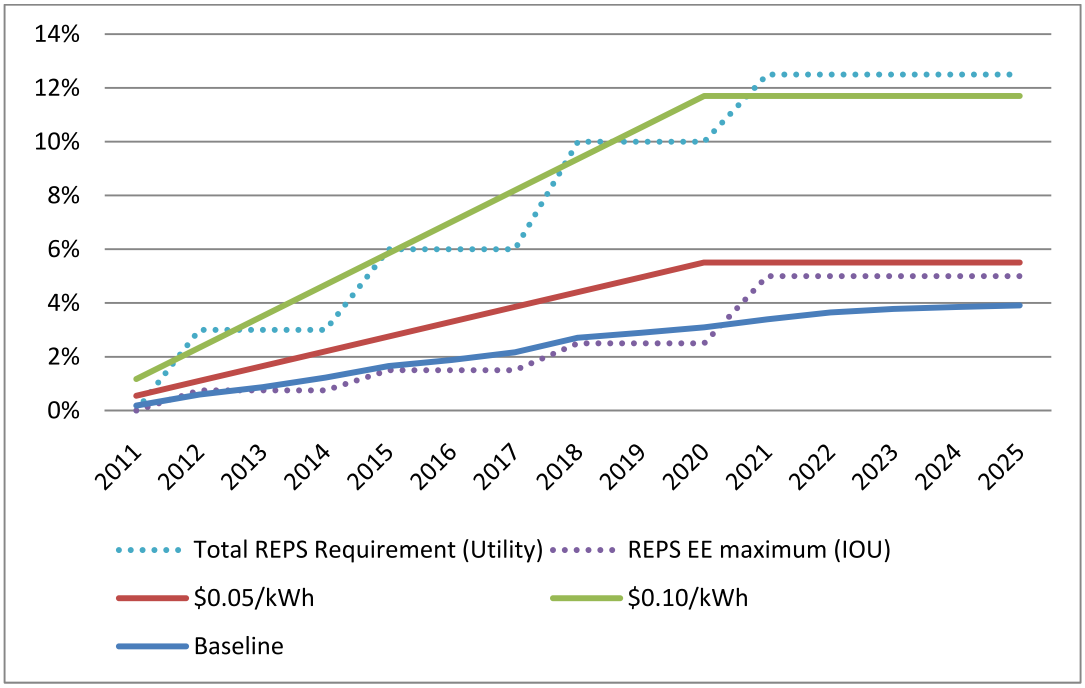
D. Energy efficiency

North Carolina's REPS allows electric suppliers to meet a portion of their requirements through energy efficiency measures. After the set-aside requirements, EMCs and municipal utilities are able to meet the rest of their REPS requirement through savings from energy efficiency and DSM measures. Based on compliance activity to date and information provided by EMCs and municipal utilities, our view is that they will utilize energy efficiency to meet 15% of the total REPS requirement (or 0.45% of retail sales) in 2012, escalating to 20% in 2017 (or a maximum of 2% of retail sales when their total requirement climbs to 10% in 2018).

IOUs are able to meet up to 25% of their total requirement with energy efficiency from 2012 through 2020, and 40% thereafter. As a percentage of retail sales, the allowance ranges from 0.75% in 2012 to 5% in 2021 and beyond. Given the low cost profile of EE, we assume IOUs will maximize their use of energy efficiency to meet REPS requirements. Based on the REPS compliance plans and confidential energy efficiency forecasts provided by the utilities, some utilities will exceed the 25% maximum in certain years. Therefore, for modeling purposes we assumed the utilities would achieve the forecasted savings included in the confidential disclosures. For municipal utilities and EMCs, La Capra Associates developed a set of assumptions based on public filings and conversations with stakeholders. The final input assumptions for energy efficiency in the region are a composite of these resources and the product of independent La Capra Associates analysis. The Baseline energy efficiency assumption is displayed in Figure 23 below along with the levels used in the scenario analysis (Section 4.4 below). The potential estimates developed by La Capra Associates and used in the scenario analysis assessed the 10-year potential. Although it is reasonable to assume that there will be further energy efficiency improvements after this time period, estimating savings beyond the 10 year study period was outside the scope of the analysis.

43 Docket E-100, Sub 113. Order on Duke Energy Carolinas, LLC Motion for Clarification, 5/7/2009. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=XBAAAA72190B&parm3=000127195

FIGURE 23: ASSUMPTIONS OF IOU ENERGY EFFICIENCY SAVINGS



E. Out-of-state option

All electric suppliers are allowed to satisfy up to 25% of their REPS requirements with the purchase of unbundled RECs from energy that is not delivered to North Carolina. Dominion, due to its small footprint in NC, is allowed to satisfy its entire requirement with out-of-state RECs. This allowance applies separately to the general requirement and to each individual set-aside. We assumed that all electric suppliers would maximize their use of this allowance for their general and solar set-aside requirements. It is highly unlikely that North Carolina resources will be able to compete with the abundant, low-cost RECs and SRECs available in other parts of the country.[44] For swine- and poultry-waste set-asides, however, we assume that all compliance comes from energy delivered to North Carolina utilities because it is not clear significant savings are available from out-of-state resources.

F. Large hydro and other existing resources

EMCs and municipal utilities are not required to use energy from new renewable energy facilities to meet the remainder of their general requirements. Instead, they can use energy from large hydro (including all SEPA allocations) and existing renewable facilities for compliance. We have determined that sufficient supply exists to meet the remainder of EMCs' and municipal utilities' general requirements after assumed energy efficiency measures. Therefore, we assume

44 E.g., Texas RECs are currently trading for about $1, according to Spectron Group's Spectrometer Report.

that no energy from new renewable energy facilities is needed to meet EMCs' and municipal utilities' REPS obligations.

G. New renewable build-out

For REPS energy requirements that are not fulfilled by assumed contributions from the above resources, we assume energy for compliance will be generated at new renewable energy facilities as defined by S.B. 3. We consulted the NCUC list of registered facilities[45] for the capacity of eligible resources that have come online since 2007, or are expected to come online by 2012.[46]

For biomass projects expected in the next two years, we also consulted Forisk Consulting's Wood Bioenergy 2010 data on announced wood biomass energy projects. Forisk submits announced projects to both a technology feasibility screen and a project status screen. We used their analysis to verify that our near-term biomass build-out assumptions are a reasonable representation of expected development.

Our biomass build-out includes existing and likely planned projects, with remaining additions in 2012 and beyond represented with generic units. The build-out was based on our view of the most likely development response to REPS as it is currently formulated.

For general requirements, we assumed that biomass-fueled projects would be heavily relied upon due to their favorable economics. Although co-firing with coal is a lower-cost resource than dedicated biomass (especially greenfield development), we assumed that the majority of new capacity added would be dedicated biomass facilities based on existing development patterns. We also assumed that any co-firing projects are likely to occur early in the study period.

Although biomass is the lowest-cost renewable resource with significant development potential remaining in the state, we assume that other resources will be included, as well. Based on our assessment of the political and development climate in North Carolina and the relatively small cost premium, we assumed that three 40 MW onshore wind farm projects will also be developed over the study period.[47]

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45 Renewable Energy Facility Registrations Accepted by the NC Utilities Commission. http://www.ncuc.commerce.state.nc.us/reps/reps.htm. Accessed 2/4/11.

46 Or were a part of the NC GreenPower program, and are therefore grandfathered into "new" status.

47 Note that Iberdrola filed an application for a Certificate of Public Convenience and Necessity to Construct a Merchant Plant on January 27, 2011 with the Public Utilities Commission for a 300 MW wind farm in Pasquotank and Perquimans Counties. This application was approved on May 3, 2011. (See filing by Atlantic Wind, LLC in Docket EMP 49 Sub 0.) The project still has additional hurdles to clear before it is constructed and if the project is

The timing of post-2012 resources was chosen with a preference to minimize capacity needed to comply with REPS energy requirements (see section 4.3.1(B), Banking).

4.3.2 *RESULTS*

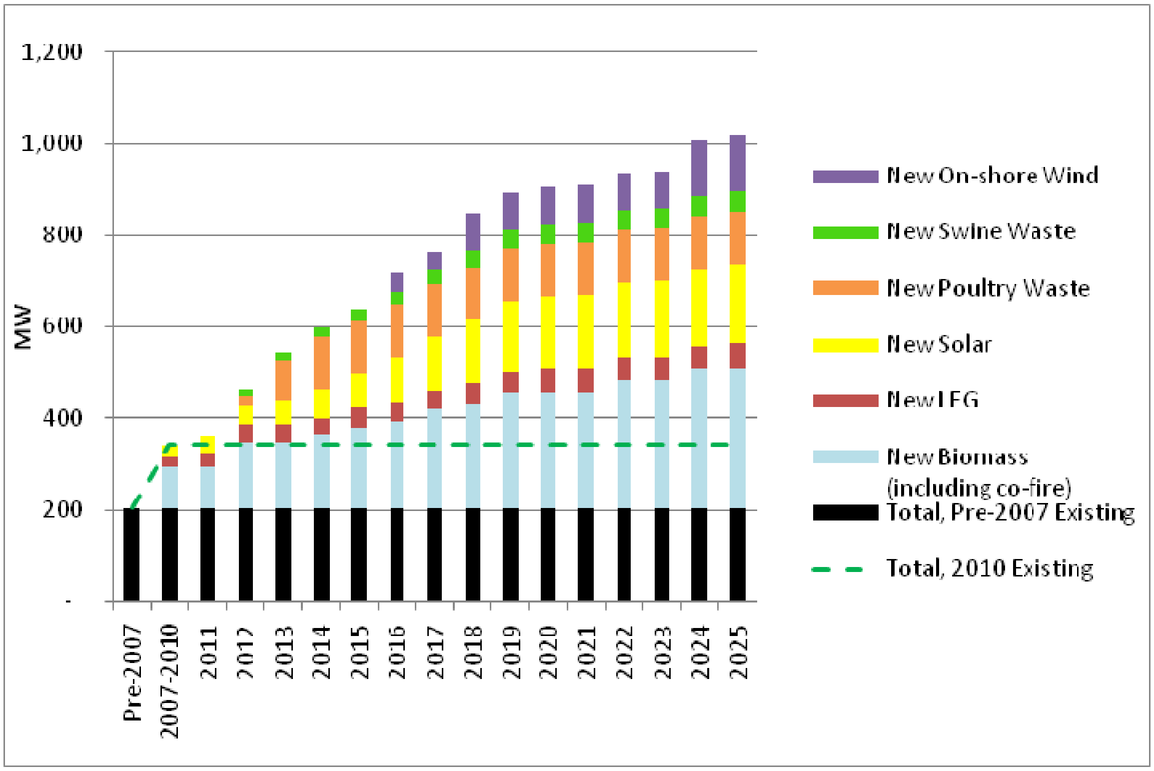
4.3.2.1 Renewable Projections

Figure 24 below shows the annual capacity of renewable energy facilities that deliver energy to North Carolina for compliance with REPS in our Baseline. Large hydroelectric facilities are not included in Figure 24 due to scale. At the end of 2010, just less than 350 MW of eligible capacity was online (excluding large hydro). By 2025, we expect more than 1,000 MW will be online to comply with REPS. Of that total, we assume that more than 800 MW of new renewable capacity will have been added since 2007, including 305 MW of biomass[48], 120 MW of onshore wind, 56 MW of landfill gas, 172 MW of solar PV, 46 MW of swine waste, and 114 MW of poultry waste resources.

constructed it is not certain that it will be the full 300 MW. For this reason, we have not included the entire project in our Baseline.

48 In the case of co-firing and retrofitting of existing coal plants, the new renewable capacity will replace existing fossil fuel-fired capacity rather than add new capacity. "New" biomass capacity reflects a mixture of capacity replacement and addition.

FIGURE 24: RENEWABLE ENERGY CAPACITY DELIVERABLE TO NORTH CAROLINA FOR REPS COMPLIANCE, BASELINE (LARGE HYDRO NOT SHOWN).

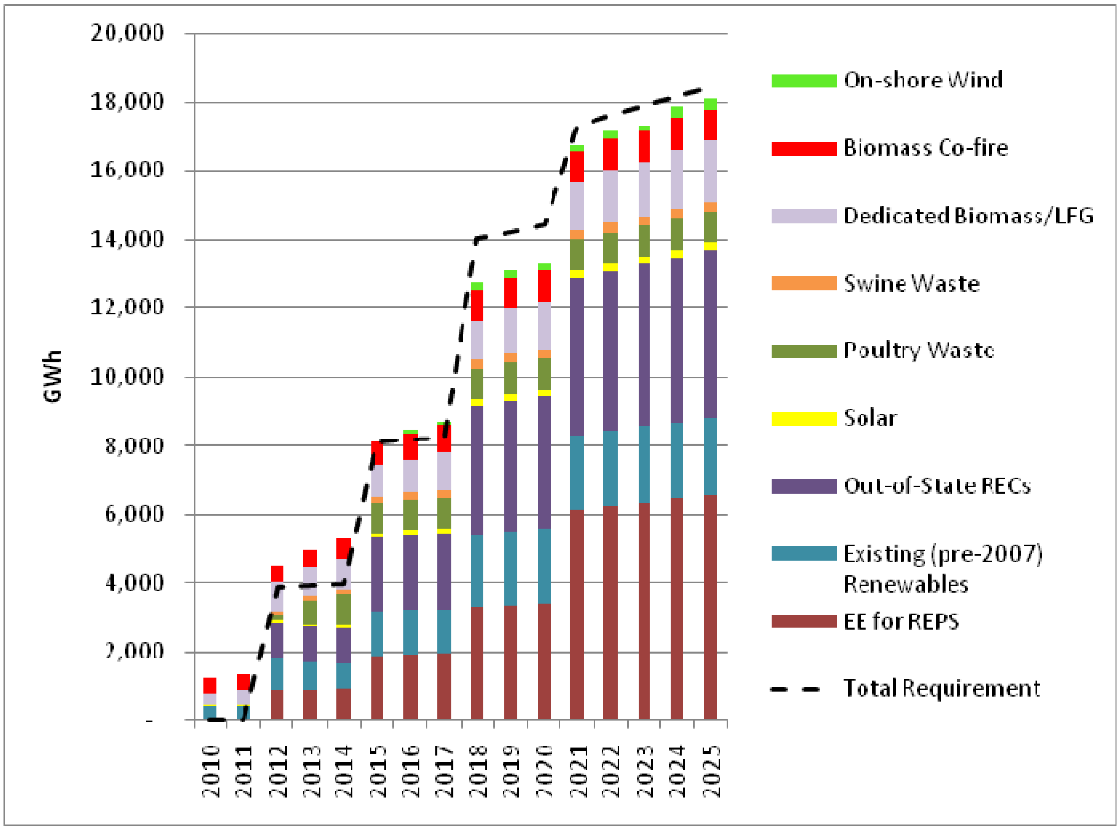


4.3.2.2 REPS Compliance

Figure 25 shows the expected sources of energy or energy savings used for REPS compliance on an annual basis by IOUs, EMCs and municipal utilities. Compliance is achieved largely through energy efficiency, existing (pre-2007) renewable resources, and out-of-state RECs.[49] This chart highlights the expected strategy by utilities to over-comply in the early years of the policy to mitigate large step increases in the requirements in later years.

49 Only EMCs and municipal utilities may use the existing (pre-2007) resources for compliance. The capacity of these resources (Figure 24) is constant, but the energy contribution (Figure 25) increases as the requirements for EMCs and municipals increases due to the ample capacity.

FIGURE 25: TOTAL REPS ANNUAL ENERGY REQUIREMENT AND SOURCES OF COMPLIANCE



4.3.2.3 GHG Emissions

All combustion-based methods of electricity generation emit gases that trap heat in the atmosphere, known as greenhouse gases (GHG). Carbon dioxide is the most abundant and well-known GHG, but others include methane, nitrous oxide and fluorinated gases. GHG emissions are typically measured in tons of carbon dioxide equivalent (CO_2e), which adds all GHGs together after adjusting for their relative global warming potential.

Figure 26 illustrates smokestack greenhouse gas emissions from electric generation sources in the VACAR South model subregion for the Baseline.[50] Total emissions increase slightly in the initial years, then remain relatively steady at about 110 million tons CO_2e per year through 2020, but thereafter fall significantly. By 2025, GHG emissions are roughly 20% below 2010 levels. The decline is due primarily to declining reliance on emissions-intensive coal-fired electricity as it is replaced by natural gas, nuclear and renewable generation resources.

50 Smokestack emissions refer only to the emissions generated and released into the atmosphere during the combustion process. This method of accounting does not take into account emissions generated or removed in the fuel production and collection process.

In addition to total amount, the source of GHG emissions shifts over the study period as well. The share of emissions coming from biomass and landfill gas account for 4.6% of total emissions in 2010, but their share climbs to 9.7% by 2025. [51] Although smokestack emissions from these renewable sources are comparable to fossil fuel-fired resources, a broader life cycle accounting often shows that these resources can also have positive GHG impacts that partially or completely offset their smokestack emissions. For instance, forest biomass fuel sources are GHG sinks prior to harvesting. Much of the GHG from landfill gas, animal waste, and forest or agriculture residues would have been emitted regardless of whether they are used as fuel for electricity production. The potential GHG emission benefits and offsets associated with these resources are not accounted for in the emissions levels shown in Figure 26.

Lifecycle GHG emissions accounting issues are subject to much debate, particularly as the EPA decides how to treat biomass under its new GHG regulatory authority.[52] However, few would argue that GHG impacts from generators fueled by landfill gas, animal waste, and biomass residues are significantly less than their smokestack emissions. Therefore, the reduction in GHG emissions is probably greater than what is shown in Figure 26.

For comparison, a linear trend line is shown in Figure 26 that represents a 75% reduction of GHG emissions from 2010 levels by the year 2050. This benchmark is loosely modeled on a GHG emissions reduction pact signed by New England Governors and Eastern Canadian Premiers, as well as the U.S. House-passed (but never enacted) Waxman-Markey Climate Bill.[53] In our Baseline, regional GHG emissions in 2025 are 12% above the linear projection to achieve 75% reductions by 2050.

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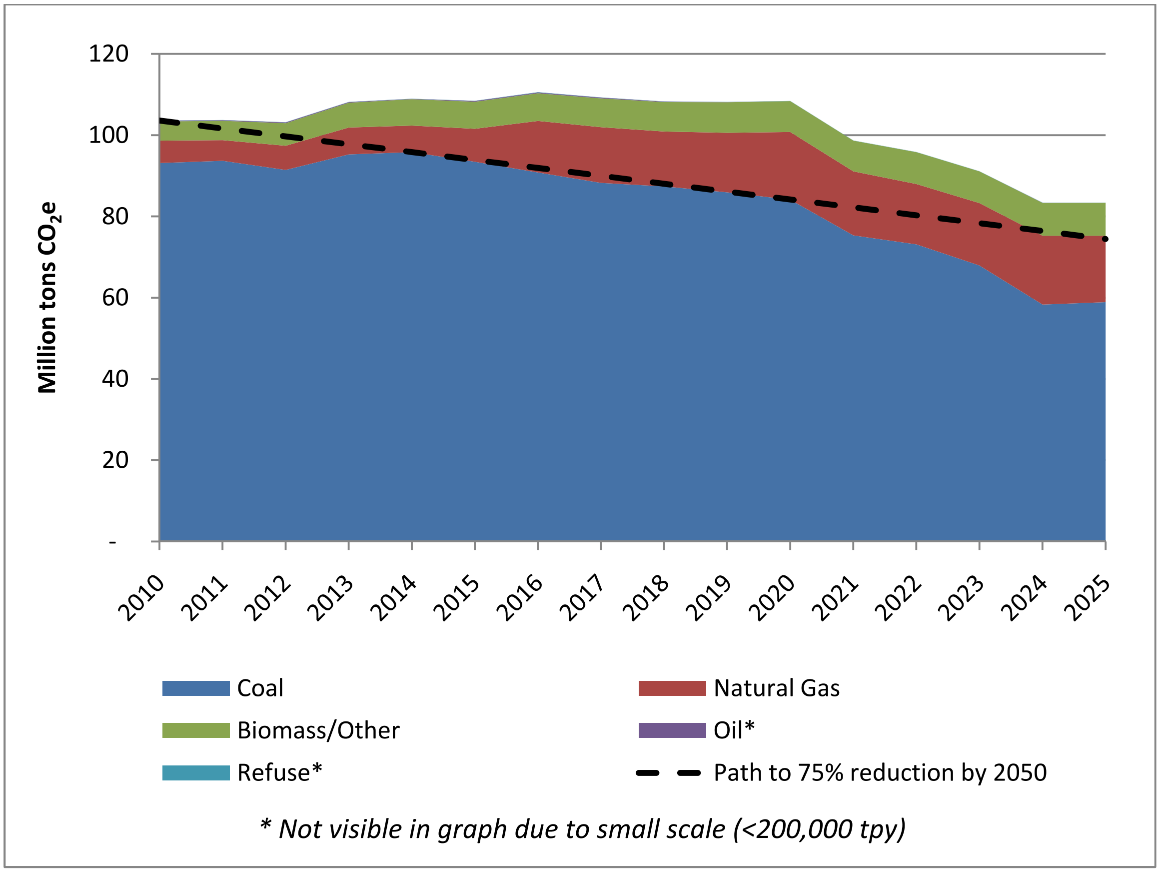
[51] Although the “Other” primary fuel category includes miscellaneous other fuel types, the vast majority of resources included are biomass and landfill gas.

[52] The EPA’s Final Tailoring Rule (May 2010), which set out the plan for implementing GHG permitting through the Clean Air Act beginning 1/2/11, would have treated emissions from biomass plants in the same manner as from any other stationary source. On January 12, 2011, the EPA announced that it was opening a reconsideration rulemaking, which it expects to be finalized by July 2011. The EPA signaled that the final rule would defer biomass inclusion in GHG permitting for 3 years, during which a scientific review would be completed and a final policy proposed.

[53] The 2001 New England Governors and Eastern Canadian Premiers’ Climate Change Action Plan calls for 75 – 85% reductions from 2001 emission levels by 2050. The American Clean Energy and Security Act of 2009 (commonly referred to as “Waxman-Markey”) proposed 83% reductions from 2005 levels by 2050.

FIGURE 26: GHG EMISSIONS BY PRIMARY FUEL TYPE FROM GENERATION RESOURCES LOCATED IN VACAR SOUTH SUBREGION, BASELINE



4.3.2.4 NOx and SO2 Emissions

Figure 27 shows NO_x and SO_2 emissions from generation resources located in North Carolina in our Baseline. Over the whole study period, NO_x emissions decline 40% and SO_2 emissions decline 76% from their respective 2010 levels.

The sharp decline in SO_2 emissions between 2011 and 2015 is primarily attributable to the retirement of several coal plants during that period. These are the plants lacking emissions control technology, so their retirement has a strong impact on overall emissions. The trend of GHG emissions from coal (Figure 26) does not have a similar downward trend during the same period because as these older units are being retired, Duke's new 825 MW Cliffside 6 unit comes online.

FIGURE 27: NO_X AND SO_2 EMISSIONS FROM GENERATION RESOURCES LOCATED IN NORTH CAROLINA, BASELINE

4.3.2.5 Costs

We also derived variable production costs for the Baseline. Importantly, these only incorporate variable costs, including fuel, O&M and emissions, and do not capture the capital or fixed O&M costs of the resource portfolio. To determine the embedded fixed costs of existing assets that are a component of the Baseline resource portfolio was outside the scope of this analysis. However, we did capture the incremental fixed costs of various portfolio options relative to the Baseline which we discuss in Section 4.4.3.2 below.

4.4 SCENARIOS

4.4.1 *DESCRIPTION OF SCENARIOS*

Like many comprehensive policies, REPS attempts to address multiple objectives. These are discussed in Section 2.

We designed six scenarios to highlight the impacts of changing the policy or the input assumptions to emphasize individual policy objectives. Employing this framework was a result of stakeholder input. The scenarios are designed to be plausible, but differentiated enough to place some of the benefit and cost trade-offs in sharp relief. The construction of each scenario was driven primarily by a single "what if" question.

4.4.1.1 Scenario 1: Reduce CO2 Emissions

What if the primary objective of a resource portfolio is to reduce carbon emissions?

This scenario places a greater emphasis on developing GHG emission-free resources as well as utilizing energy efficiency. We doubled the solar set-aside to 0.4% by 2018, and smoothed out the interim annual requirements to increase linearly. We assumed that onshore wind levels will be almost tripled from the Baseline to 350 MW. A 400 MW offshore wind farm is developed in this scenario, and comes online in 2020. All of these increases in renewable development are assumed to result from supplemental policies or requirements. Other renewable resources (biomass, hydro, swine and poultry waste, etc.) remain at the same levels as in the Baseline.

In order to reduce CO_2 emissions to the greatest extent possible, this scenario includes the implementation of energy efficiency measures to achieve La Capra Associates' estimated high economically achievable potential of 13% established in Section 3.4.1 of this report, achieved incrementally over 10 years. This scenario assumes that 1.3% of this potential is not realized due to an optimistic opt-out level of 10%, yielding a maximum energy efficiency level of 11.7%.[54] This level of energy efficiency includes all measures up to the $0.10/kWh cost threshold.

Despite levels of energy efficiency that achieve greater than 25% of REPS compliance, in this scenario utilities are only able to apply energy efficiency towards 25% of the overall requirement of 12.5% retail sales through 2020 and 40% thereafter.

This scenario also includes new nuclear development in addition to the 2,797 MW of nuclear plants already anticipated by the utility IRPs. In this scenario 2,200 MW of additional new nuclear is built in 2019 and a corresponding amount of coal generation is retired.

4.4.1.2 Scenario 2: Encourage Economic Development

What if the primary objective is to maximize economic development in North Carolina?

The key assumption made for this scenario is that only energy generated within North Carolina is eligible for REPS compliance. Unbundled RECs from energy not delivered to North Carolina and energy delivered to North Carolina customers from out of state are no longer eligible. We also assume that the solar set-aside is doubled to ensure continued development and job creation in North Carolina's budding solar industry. We assumed that a 400 MW offshore wind farm would be brought online in 2020, helping to establish a nascent offshore wind industry in North Carolina. We did not attempt to determine the most job-intensive renewable sources for

[54] In this, and all other scenarios, La Capra Associates operated under the assumption that the opt-out provision would remain a part of the energy efficiency/demand-side management rider regulation. The amount of load opting out is set at our judgment of a realistic minimum.

the remaining general requirement. A mix of onshore wind, dedicated biomass and biomass co-fire was assumed for the remaining post-2012 general requirement buildout.

Due to the economic development benefits of the implementation of energy efficiency measures, Scenario 2 assumes the same high potential, low opt-out case applied in Scenario 1, as well as the same statutory limitations for REPS compliance (i.e. 25% through 2020, 40% thereafter for IOUs).

There are no changes to baseload or non-renewable generation resources from the Baseline assumptions in this scenario.

4.4.1.3 Scenario 3: Low Cost

What if the focus is on the lowest cost to ratepayers?

One of the most commonly-cited trade-offs associated with policies to promote clean, renewable energy is the cost impact on ratepayers. This scenario places an emphasis on developing only the most cost-effective renewable energy and energy efficiency. All choices are made with an eye toward minimizing ratepayer impact, while meeting the total energy requirements of REPS.

Solar, poultry waste and swine waste resources are more expensive than other renewables currently, and are expected to be for at least the next ten years. Therefore, in this scenario, we assume that the set-aside provisions are removed from REPS.[55] After maximizing the allowances for energy efficiency, out-of-state RECs and existing renewables, we assumed that utilities would use a mixture of dedicated biomass and biomass co-fired with coal to meet their REPS requirements. Biomass energy is the lowest cost renewable energy source and has sufficient new development potential to meet the REPS requirements.

For this scenario, we assume an increase from the Baseline levels of energy efficiency to the "base case" estimate of energy efficiency potential established in Section 3.4.1. We also assume a more conservative opt-out level of 22.5% of load to mimic the current opt-out levels. This level of energy efficiency would consist of the full implementation of low cost energy efficiency measures (below $0.05/kWh).

The resource cost analysis outlined in Section 0 of this report found that the levelized cost of new CHP is lower than the levelized cost of new gas generation. Therefore this scenario also assumes the development of 600 MW of new CHP capacity in place of an equivalent amount of new gas generation planned in the utility IRPs

55 We note that such a sudden policy change would be inefficient and highly disruptive to the existing development pipeline. For modeling purposes, however, we ignore the sunk costs of projects planned or in development (but not yet on the NCUC registry) under the current policy.

Regarding baseload resources, Scenario 3 replaces the addition of nuclear generation as assumed in the utility IRPs with an equivalent amount of lower-cost gas combined cycle capacity.

4.4.1.4 Scenarios 4a & 4b: Promote Emerging Renewables

What if the primary objective is to promote emerging renewables?

These two scenarios place the primary emphasis on the development of new renewable power, especially technologies that may be relatively high cost now but expect to see cost declines as the technology matures. Solar and offshore wind are the two most prominent examples. Onshore wind is a relatively mature technology, but it has yet to be developed at utility scale in North Carolina, so it is included in these scenarios.

In Scenario 4a, we assume that an offshore wind set-aside is introduced that leads to the construction of a 400 MW offshore wind project in 2020. As in Scenarios 1 and 2, we assume that the solar set-aside is doubled to 0.4% by 2018 and the interim targets are smoothed and increase linearly. An onshore wind set-aside is also added that requires 0.05% of previous year sales in 2013, increasing to 1% by 2018. In addition to the set-asides, a mixture of dedicated biomass and biomass co-fire is added to meet the remaining general requirement.

This scenario adopts the same energy efficiency assumptions as the Baseline and makes no changes to baseload resources.

Scenario 4b is designed to extend the promotion of renewable resources to a greater degree. The onshore wind set-aside is the same as assumed in Scenario 4a. The solar set-aside is quadrupled, however, to 0.8% of previous year sales by 2026. There is also an offshore wind set-aside which requires 400 MW by 2018 and 4,000 MW by 2026.[56]

In order to accommodate these large set-asides, two other policy changes are assumed. First, out-of-state RECs are no longer allowed for a portion of compliance. Second, this is the only scenario that increases the overall REPS requirement. The requirements remain the same as current policy until 2021, but thereafter IOUs' requirements climb 2.5% per year until reaching 25% in 2026. EMCs and municipal utilities' requirements climb 1% per year over the same period to reach 15%. A mixture of dedicated biomass and biomass co-fire is added to meet the remainder of the expanded general requirements.

56 The set-aside is also assumed to set interim targets that increase by 450 MW per year between 2018 and 2026. This scenario assumes that transmission is built to accommodate the offshore wind resource. UNC's Coastal Wind for North Carolina's Future states that Dominion's existing system can accommodate 10 MW while Progress' system can accommodate 250 MW of offshore wind. Transmission improvements will be required for the 4000 MW of offshore wind assumed in this scenario.

This scenario adopts the same energy efficiency assumptions as the Baseline.

Due to the high levels of newly installed renewables in Scenario 4b, other types of capacity are retired. To compensate for the increased solar capacity, which typically produces energy during peak hours, 434 MW of gas combustion turbines originally planned in the utility IRPs is excluded from the buildout. Similarly, to compensate for the increased wind capacity, 2,400 MW of coal generation in addition to coal retirements in the Baseline is retired and 606 MW of gas combined cycle capacity is excluded from the IRP buildout.

4.4.1.5 Scenario 5: Promote Energy Efficiency

What if the primary objective is to promote energy efficiency?

The development of new energy efficiency measures accomplishes many of the goals of REPS, such as emissions reduction and economic development. This scenario explores the impact of enabling the use of energy efficiency savings above the maximum as defined in REPS for compliance. The high potential determined in the energy efficiency analysis, including a 10% opt-out level, reaches 11.7% in 10 years. This scenario models this level of implementation and full credit of energy efficiency savings towards REPS compliance.

With this level of energy efficiency except for the set-asides, which remain as currently formulated, no new renewable resources are required after 2012.

No changes were made to the baseload or non-renewable generation resources in this scenario.

More details about the exact specifications used in each scenario are in Section 4.4.2, below.

4.4.2 KEY INPUTS

4.4.2.1 Energy Efficiency

FIGURE 28: ENERGY EFFICIENCY SAVINGS AS A PERCENTAGE OF LOAD, BASE AND HIGH POTENTIAL

Scenario	2012	2015	2018	2021
Base Potential, 22.5% Opt-Out (Scenarios 1, 2)	1.10%	2.75%	4.40%	5.50%
High Potential, 10% Opt-Out (Scenarios 3, 5)	2.34%	5.85%	9.36%	11.70%

Energy efficiency levels used in the Baseline and Scenarios 4a and 4b were composed of confidential information and are not included in the table above.

4.4.2.2 Renewables

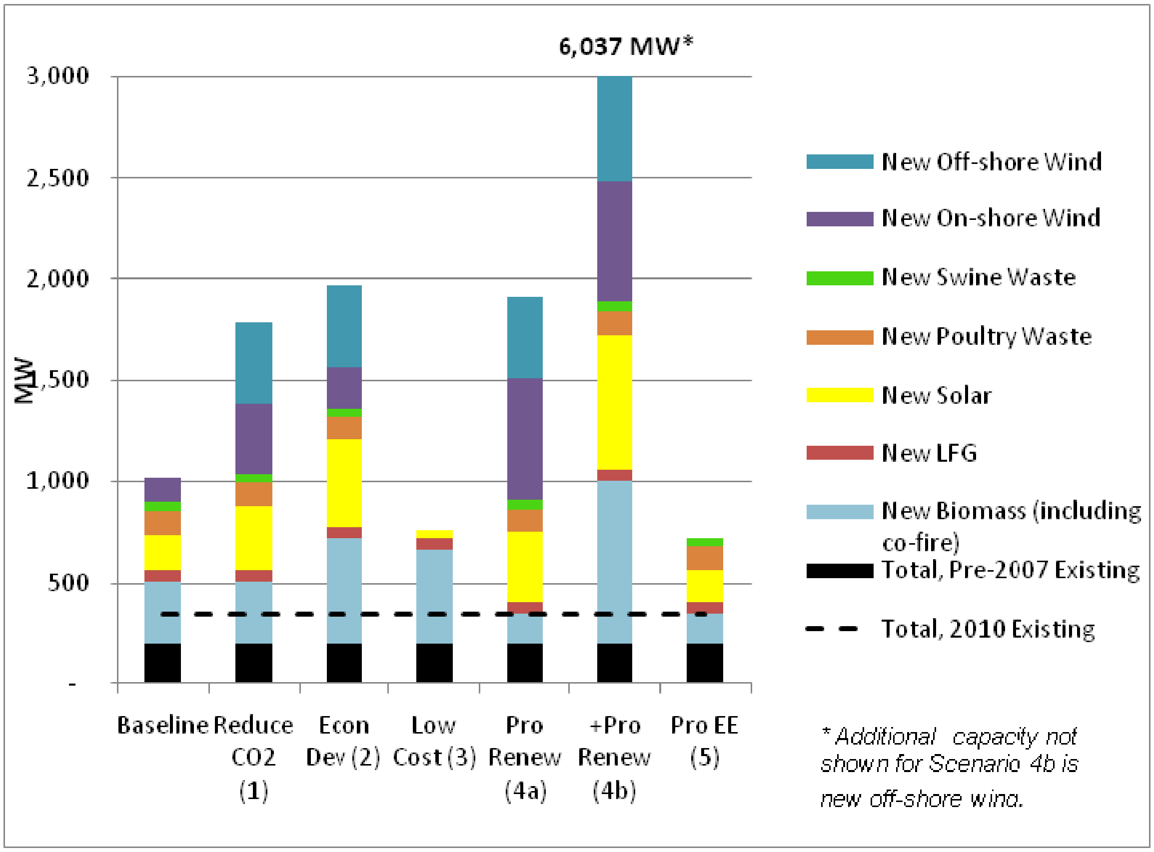
FIGURE 29: SCENARIO COMPARISON OF RENEWABLE SET-ASIDE AND ALLOWANCE ASSUMPTIONS ACROSS SCENARIOS

Resource	Reduce CO_2 (Scenario 1)	Econ. Development (Scenario 2)	Low Cost (Scenario 3)
Solar	0.4% by 2018, with linear ramp-up	0.4% by 2018, with linear ramp-up	None
Poultry/Hog Waste	Per S.B. 3	Per S.B. 3	None
Onshore Wind	350 MW	200 MW	None
Offshore Wind	400 MW in 2020	400 MW in 2020	None
Out-of-state RECs	Per S.B. 3	None	Per S.B. 3
In-state definition	Per S.B. 3	North Carolina only	Per S.B. 3

Resource	Emerging Renewables (Scenario 4a)	Emerging Renewables II (Scenario 4b)	Promote Energy Efficiency (Scenario 5)
Solar	0.4% by 2018, with linear ramp-up	0.8% by 2025, with linear ramp-up	Per S.B. 3
Poultry/Hog Waste	Per S.B. 3	Per S.B. 3	Per S.B. 3
Onshore Wind	0.05% in 2013, up to 1% by 2018	0.05% in 2013, up to 1% by 2018	None
Offshore Wind	400 MW in 2020	400 MW in 2018; 4,000 MW by 2026	None
Out-of-state RECs	Per S.B. 3	None	Per S.B. 3
In-state definition	Per S.B. 3	Per S.B. 3	Per S.B. 3

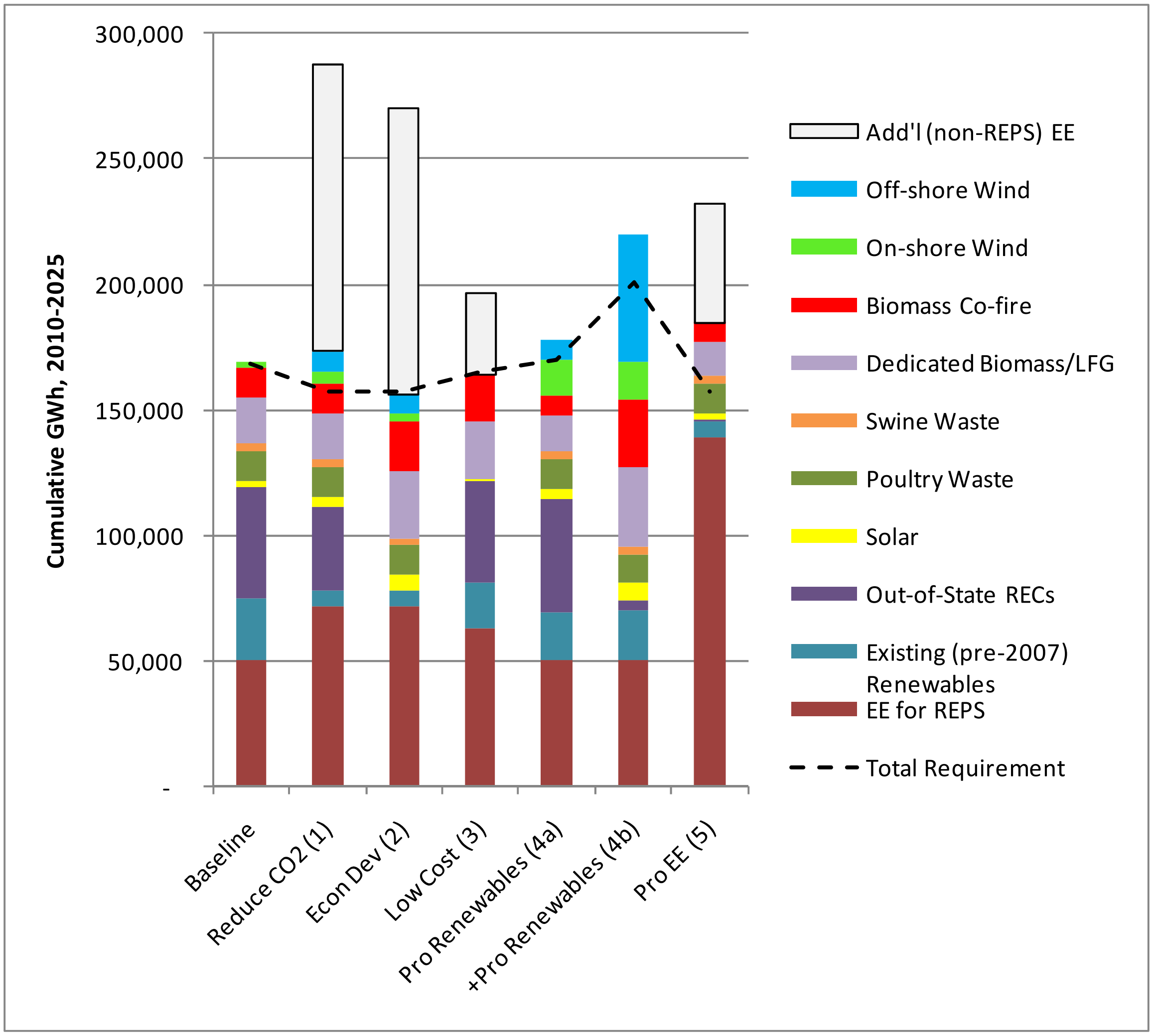
Build-outs were created based on these assumed parameters. Renewable capacity by resource for the 6 scenarios is shown in Figure 30 below. The renewable capacity used to meet REPS demand varies across the scenarios from less than 750 MW (Scenario 5) to more than 6,000 MW (Scenario 4b). The proportional mix of resources varies across scenarios as well.

FIGURE 30: COMPARISON OF RENEWABLE CAPACITY IN 2025 (EXCLUDING LARGE HYDRO) DELIVERABLE TO NORTH CAROLINA USED FOR REPS COMPLIANCE ACROSS ALL SCENARIOS



Compliance with REPS is determined by energy, not by capacity. Figure 31 shows the total REPS requirements and a breakdown of sources of compliance with REPS in each scenario on a cumulative basis. The figure shows total energy generated or saved over the entire 15-year study period. The empty (white) sections of the bar graphs in some scenarios represent energy efficiency measures that are not eligible to count toward REPS compliance.

FIGURE 31: COMPARISON OF CUMULATIVE (2010 – 2025) RENEWABLE ENERGY GENERATED OR ENERGY SAVED FOR COMPLIANCE WITH REPS ACROSS ALL SCENARIOS



4.4.2.3 Non-renewable Resources

Some scenarios included revisions to non-renewable resources including baseload and peaking units. These changes are noted in the scenario descriptions above and summarized in Figure 32 below.

FIGURE 32: SCENARIO ASSUMPTIONS, NON-RENEWABLE RESOURCES

Resource	Scenario 1	Scenario 2	Scenario 3	Scenario 4a	Scenario 4b	Scenario 5
Gas (CC)			Additional capacity built to account for nuclear not built		Retired units to offset increased renewables	
Gas (CT)					Retired units to offset increased renewables	
Coal	Retire equivalent capacity to offset new nuclear				Retired units to offset increased renewables	
Nuclear	Additional 2200 MW beyond IRP additions (2019)		Eliminated new units planned in IRPs			

4.4.3 *COMPARATIVE RESULTS*

4.4.3.1 Environmental Impacts

Figure 33 illustrates greenhouse gas emissions over the study period for each scenario. Each scenario results in a reduction in GHGs from the beginning of the period to the end, and all but one represent savings as compared to the Baseline. The scenario with the greatest emission reductions is Scenario 1, which contains additional nuclear capacity and the highest energy efficiency levels. Scenarios 2 and 5, which also assume the high efficiency levels, have similar emissions reductions. Of note is that these GHG reductions exceed those of Scenarios 4a and 4b, which emphasize renewable development. Scenario 3, which minimizes cost, contains an increase in emissions relative to the Baseline after 2021. This is primarily because this scenario does not include new nuclear generation and includes new gas CC capacity in its place.

FIGURE 33: VACAR SOUTH TOTAL GHG EMISSIONS BY SCENARIO

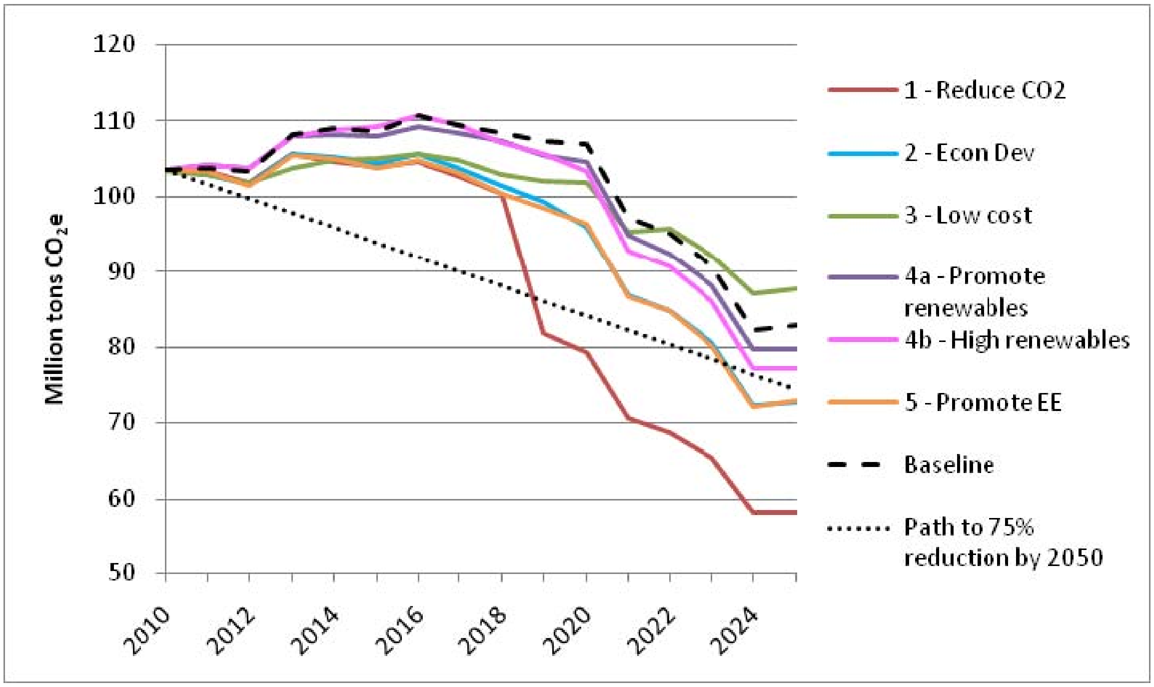


Figure 34 and Figure 35 demonstrate the differences in NO_x and SO_2 emissions by scenario. While there are significant differences between them, all scenarios are characterized by substantial emission reductions over the study period. Much of these reductions are attributable to the impact of the planned retirements of coal generation as a result of the Clean Smokestacks Act. This is particularly noticeable in the graph of SO_2 emissions, which decrease by at least 70% in all Scenarios.

Of the modeled scenarios, Scenario 1 features the most significant further reductions due to the additional coal retirements. The only scenario performing worse than the Baseline is Scenario 4b. This scenario shows an increase in NO_x emissions above the Baseline, principally due to the additional biomass capacity.

FIGURE 34: NO_X EMISSIONS FROM IN-STATE GENERATION RESOURCES, BY SCENARIO

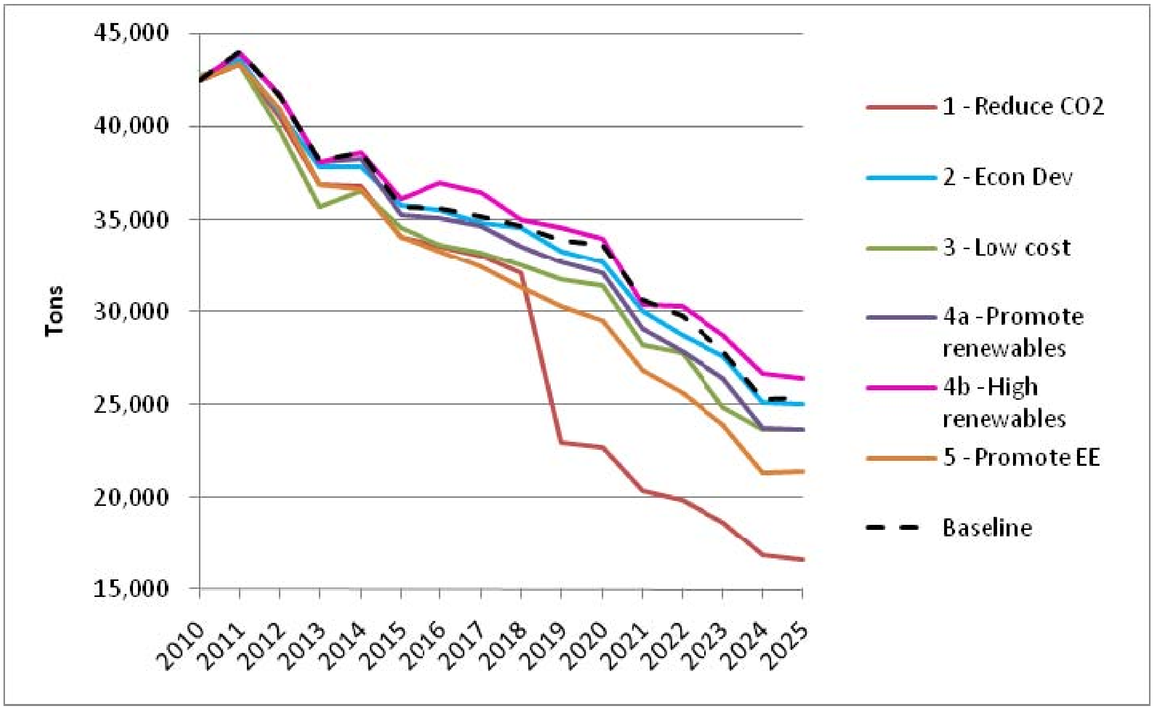
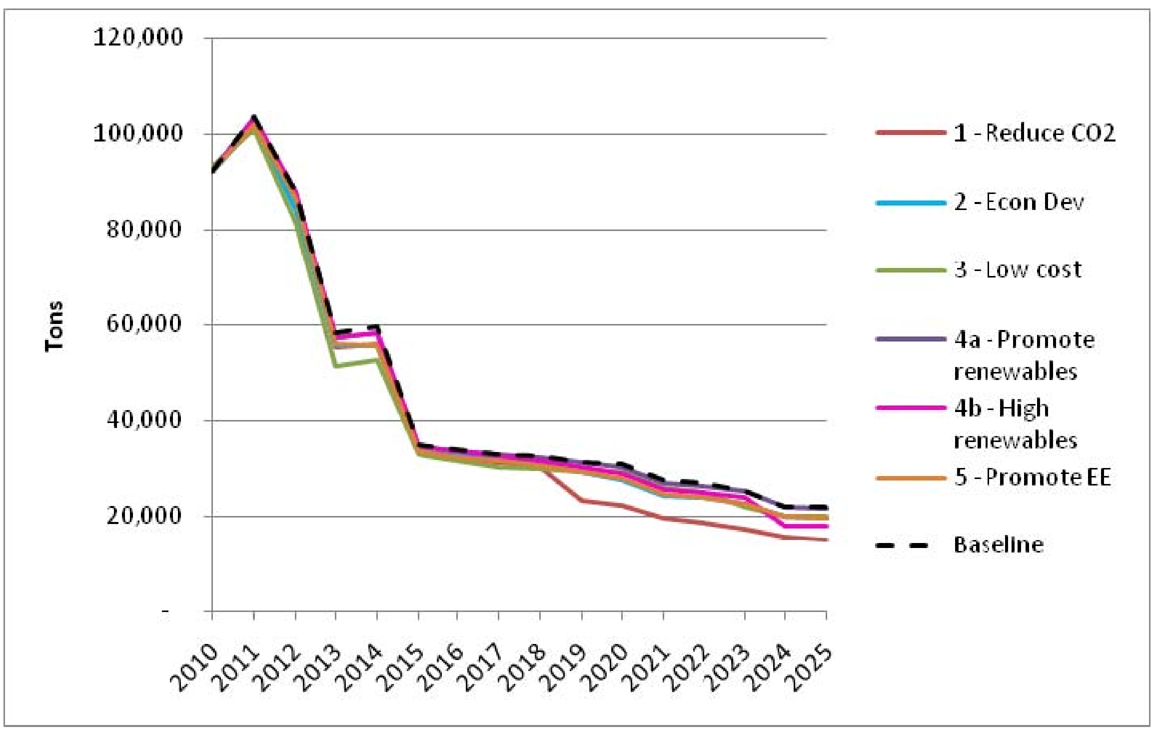


FIGURE 35: SO_2 EMISSIONS FROM IN-STATE GENERATION RESOURCES, BY SCENARIO



4.4.3.2 Differential Total Costs

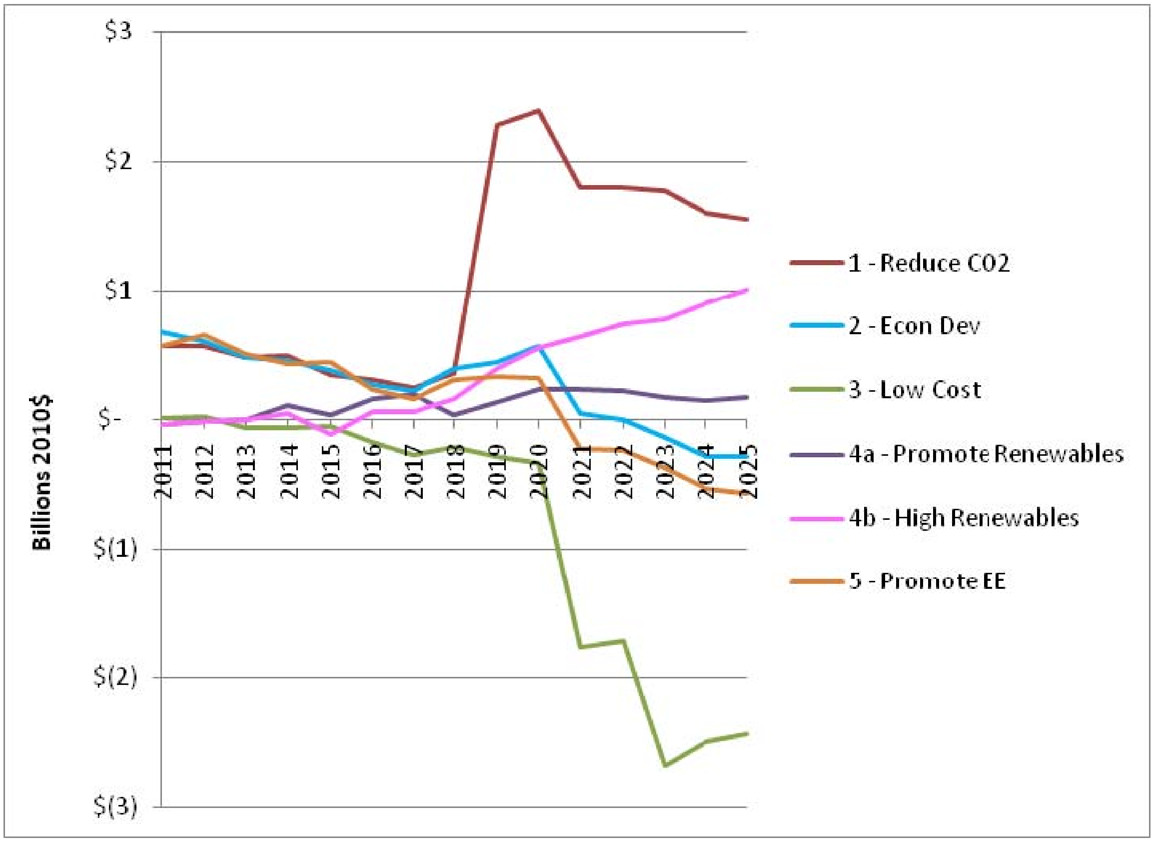
The cost of each scenario is made up of three categories of costs: fixed generation costs, variable production costs and energy efficiency costs. The differential variable production and energy efficiency costs were calculated by subtracting the Baseline costs from each scenario's costs. Differential fixed costs were determined by calculating the fixed costs of resource changes between each scenario and the Baseline. The sum of these three differential costs was the differential total cost, which tells us how the change in resource build-out for each scenario impacts costs relative to the Baseline. We did not calculate total costs for the Baseline or scenarios. The analysis was done for the entire VACAR South study area to account for any generation shifting within the utility service areas.

The costs were estimated as follows:

- Fixed generation costs. We used the financial model described in Section 3 of the report to calculate the annual fixed levelized cost for each generation resource. We then multiplied the levelized cost for each resource by its incremental capacity online each year relative to the Baseline.
- Variable production costs. As part of the Aurora model runs the variable costs for each resource were calculated for each scenario. These costs include the variable operations and maintenance costs and fuel and emissions costs. The Baseline variable costs were subtracted from all the other scenarios to derive the incremental variable costs.
- Energy efficiency. Costs of energy efficiency measures were calculated using two tiers of costs. All savings within the base potential (up to 7% of load) were assumed to have an average cost of $0.035/kWh. Any incremental savings above this level are within the high potential range. Costs for these savings were calculated assuming an average of $0.08/kWh. These costs were determined by taking the program costs, incentives, marketing and administration, plus the estimated costs for measurement and verification activities, and dividing the costs by the lifetime electric energy savings on a kWh basis assuming an average measure life of 12 years.

The differential total costs are shown in Figure 36 below. Those scenarios with more or less nuclear units than the Baseline differed the most in cost from the Baseline. Scenario 3 – Low Cost to Ratepayers – has the lowest costs and it has 2,800 MW less nuclear than the Baseline, while Scenario 1 has the highest costs and it has 2,200 MW more nuclear than the Baseline. Note that in calculating the cost for each scenario, we did not take potential transmission costs into consideration.[57] This is particularly relevant to Scenario 4b as the addition of offshore wind will require transmission investment.

FIGURE 36: DIFFERENTIAL TOTAL COST FROM BASELINE FOR VACAR SOUTH (BILLION 2010$)



4.4.3.3 Rate Impact

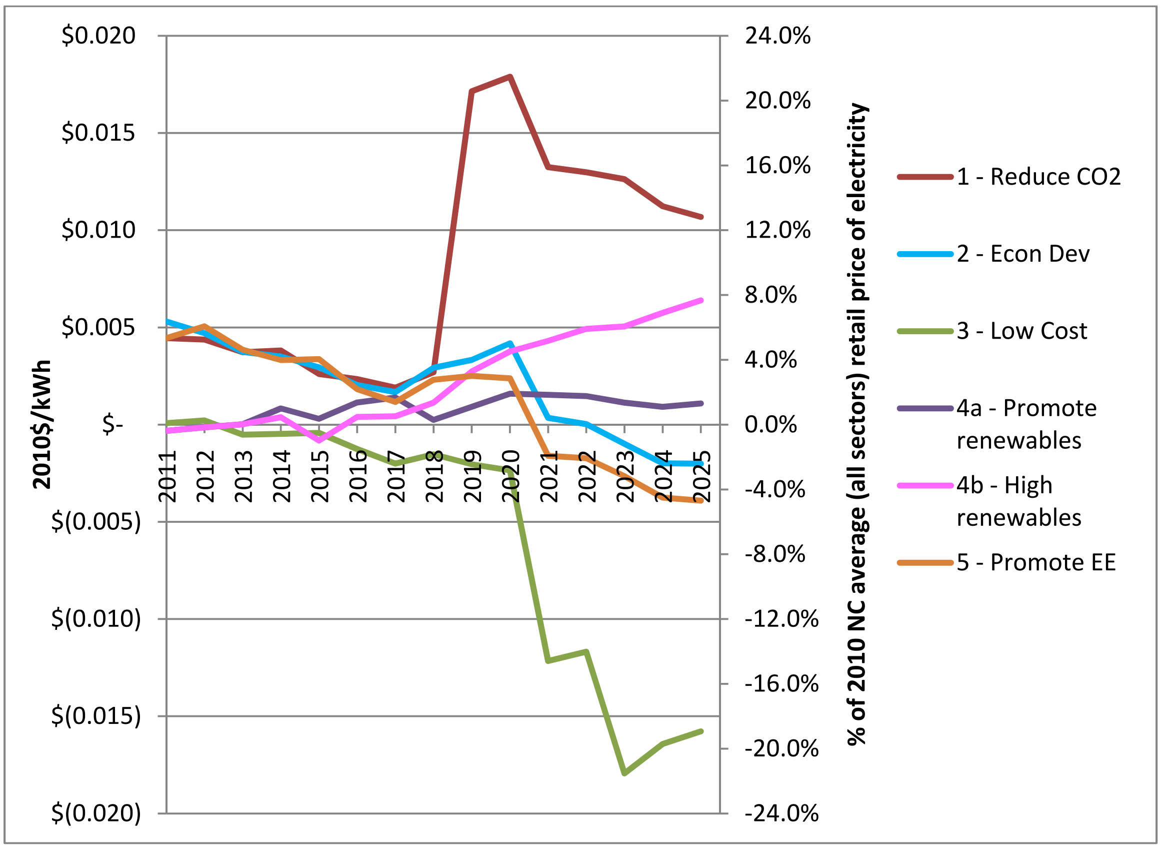
Finally, we estimated the impact of energy supply alternatives on electric power costs in North Carolina. For this analysis we took the VACAR South differential total costs for each scenario as described above and divided it by the projected North Carolina retail sales for that scenario.

The results of the rate impact analysis are shown in Figure 37 below. By 2025, rate impacts relative to the Baseline ranged from an additional 1.1 cents per kWh for Scenario 1 to a savings of 1.6 cents per kWh for Scenario 3. For context, the November 2010 average retail price of

57 A recent UNC study states that transmission improvements will be required to add more than 10 MW or 250 MW of offshore wind to Dominion or Progress systems respectively. University of North Carolina. Coastal Wind for North Carolina's Future. June 2009. http://www.climate.unc.edu/coastal-wind. Page 195.

electricity to end-use consumers in North Carolina was $0.0825.[58] The rate impacts of the scenarios relative to the Baseline range from an additional 13% of 2010 retail prices to a savings of 19% of 2010 retail prices by 2025. It should be noted, however, that we did not calculate rates in our Baseline, nor do we expect 2010 retail prices to remain constant throughout the study period.

FIGURE 37: RATE IMPACT: DIFFERENCE FROM REPS ($2010/KWH)



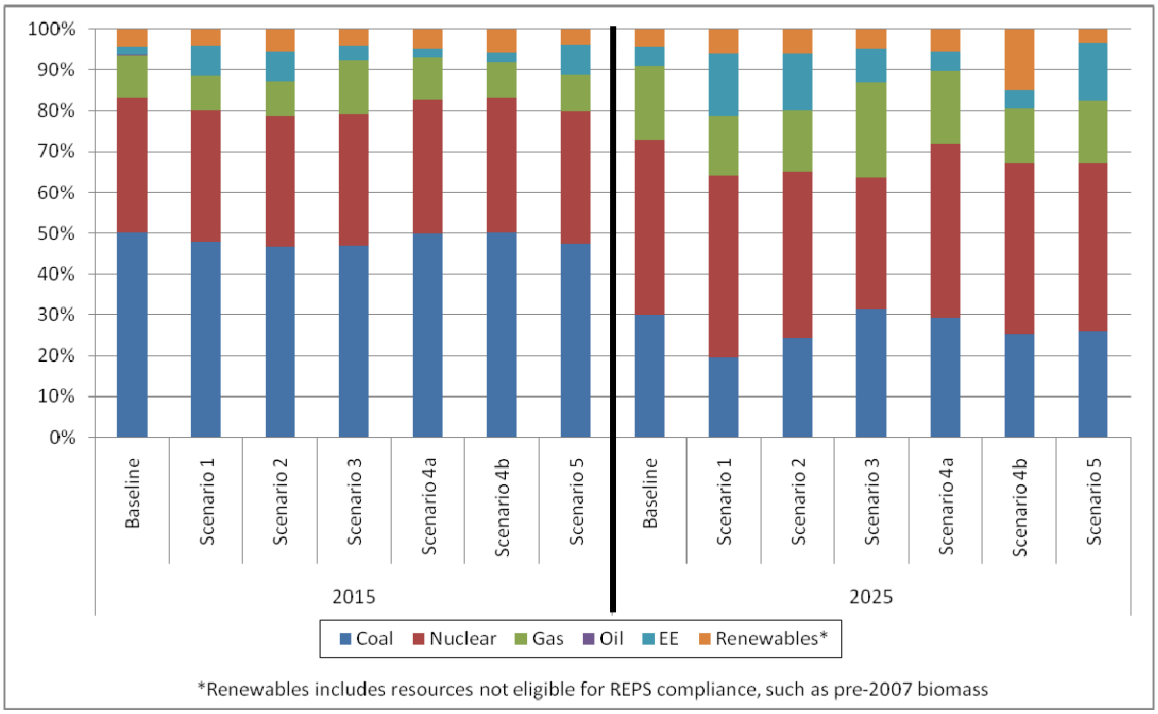
4.4.3.4 Price Stability – minimizing fuel price risk

In terms of price stability, there is greater resource portfolio stability if there is less exposure to fuel price risk, in particular gas prices which historically have experienced a fair degree of volatility. The low cost scenario (Scenario 3) has the largest amount of natural gas as gas replaces coal that is retired and less nuclear power is added. So although it is the lowest cost scenario, 24% of the portfolio is exposed to gas price risk in 2025 (Figure 38). Gas levels are fairly similar in the other scenarios, lowest in Scenario 4b, where it makes up 13% of the energy

58 U.S. Energy Information Administration, Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions Report."

mix in 2025. Renewables and energy efficiency have no fuel price and thus a portfolio with more of these elements in the mix has less price stability risk. Nuclear power fuel costs are a small component of the overall cost for nuclear plants and so also do not bear much fuel price risk, although clearly there exist capital cost risks, already discussed, associated with nuclear plants.

FIGURE 38: FUEL MIX BY SCENARIO, 2015 AND 2025



4.4.3.5 Cost Trade-offs

Given that the six scenarios were designed with different policy objectives in mind, we looked at the results of the model runs to understand how effective the scenarios were at achieving policy objectives relative to the Baseline. This analysis shows that there are clear trade-offs between achieving various objectives.

Specifically we looked at the following parameters:

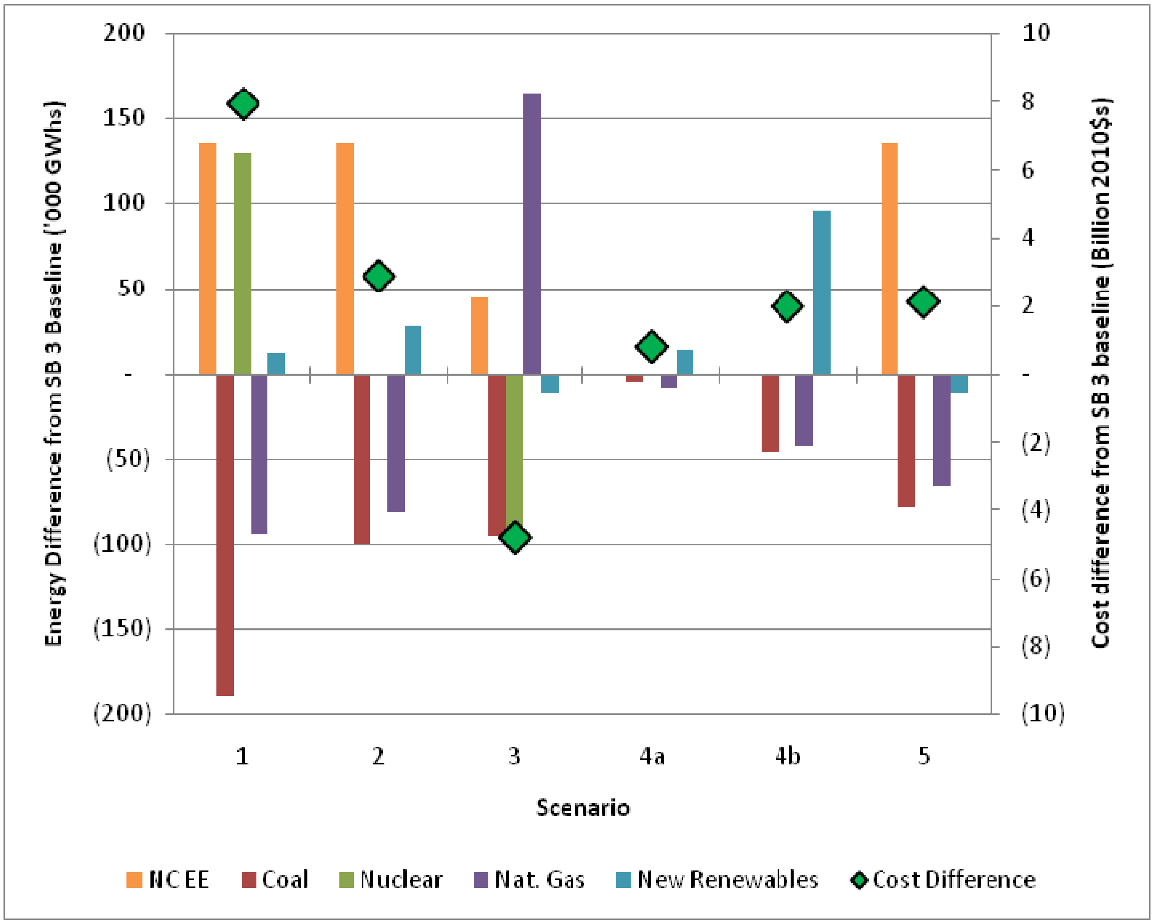
- Resource mix;
- Carbon emissions;
- Renewable capacity built; and
- Energy efficiency

The first thing we looked at was the difference in resource mix from the Baseline for the six scenarios versus the NPV of differential costs from the Baseline over the study period.

Figure 39 shows the difference from the Baseline in cumulative energy generation modeled in each scenario for the period 2010-2025 for five key resource categories: North Carolina-based energy efficiency measures; and electricity generated by coal, nuclear, natural gas, and new (post-2007) renewable energy facilities. The resources in these five categories meet more than 90% of the load in the modeled region. The same chart also shows the total cost differential from the Baseline for each scenario, which provides some context on the relationship between cost and resource mix.

Each scenario varies in its reliance on all five resource categories, making it difficult to make conclusions about individual resources' cost effects. The one exception to this seems to be nuclear. The two scenarios with the greatest total cost differential are Scenarios 1 and 3, which are also the only two with different nuclear generation assumptions than the Baseline. Scenario 1 has 2,200 MW more nuclear capacity than the Baseline and it is $8 billion dollars more expensive than the Baseline on an NPV basis. Scenario 3 has 2,800 MW less nuclear capacity than the Baseline and it is the $4.7 billion less expensive than the Baseline.

FIGURE 39: TOTAL CUMULATIVE (2010-2025) REPS ENERGY GENERATION AND COST DIFFERENCE FROM BASELINE, BY SCENARIO



Next, we looked at carbon emissions versus costs relative to the Baseline. Scenario 1, which includes additional nuclear generation, has the greatest carbon reduction, but also the greatest cost relative the Baseline. The cost per ton of carbon reduction was calculated and is shown in Figure 40 below. Scenario 5 has the lowest cost per ton of carbon abated, while the highest renewable energy scenario has the highest cost per ton of carbon abated.

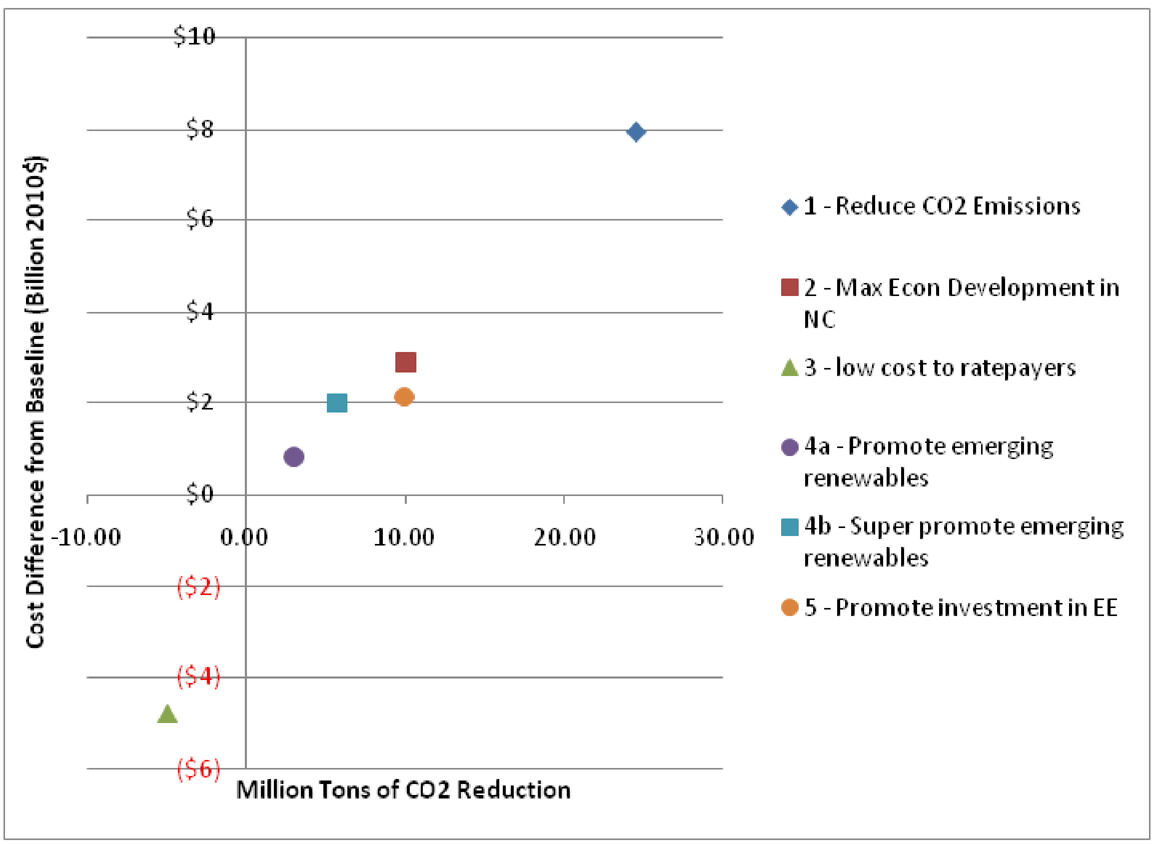
FIGURE 40: CARBON REDUCTION RELATIVE TO BASELINE

	Million Tons Difference from Baseline	NPV Cost Difference ($Billions)	Dollars per Ton Abated
1 - Reduce CO2 Emissions	24.5	$8.0	$324
2 - Max Econ Development in NC	10.0	$2.9	$289
3 - low cost to ratepayers	(4.9)	($4.8)	$983*
4a - Promote emerging renewables	3.0	$0.8	$268
4b - Super promote emerging renewables	5.8	$2.0	$348
5 - Promote investment in EE	10.0	$2.1	$215

* Scenario 3 results in a reduction in costs and increase in emissions relative to the Baseline, so this number represents the dollars saved per additional ton emitted.

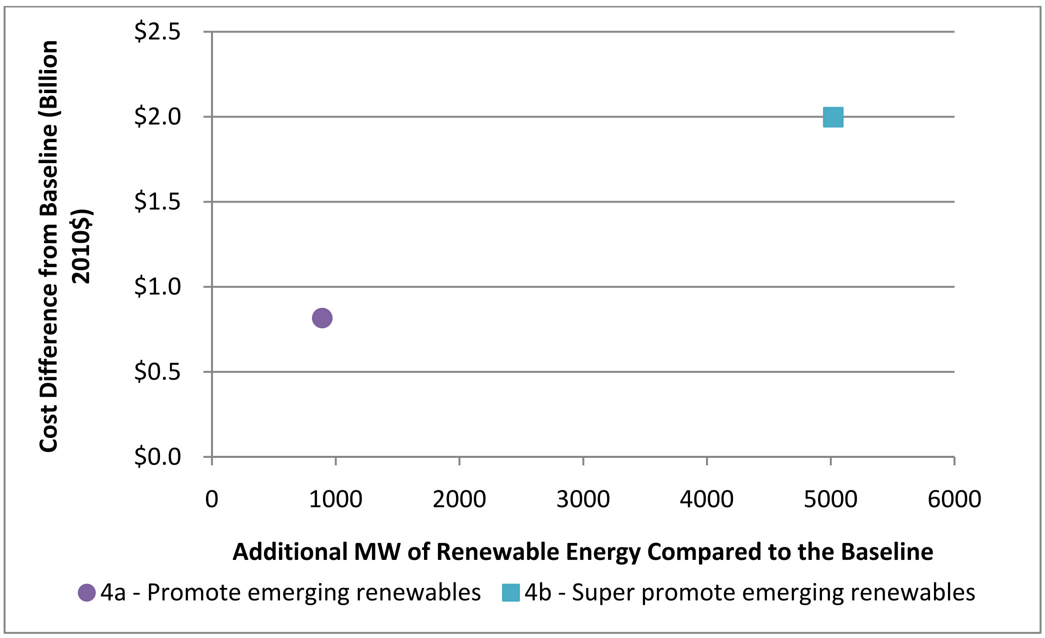
We plotted the carbon emissions reduction and cost relative to the Baseline in Figure 41 below. This illustrates the results shown in Figure 40 above.

FIGURE 41: CO_2 REDUCTION VERSUS COST DIFFERENCE FROM BASELINE



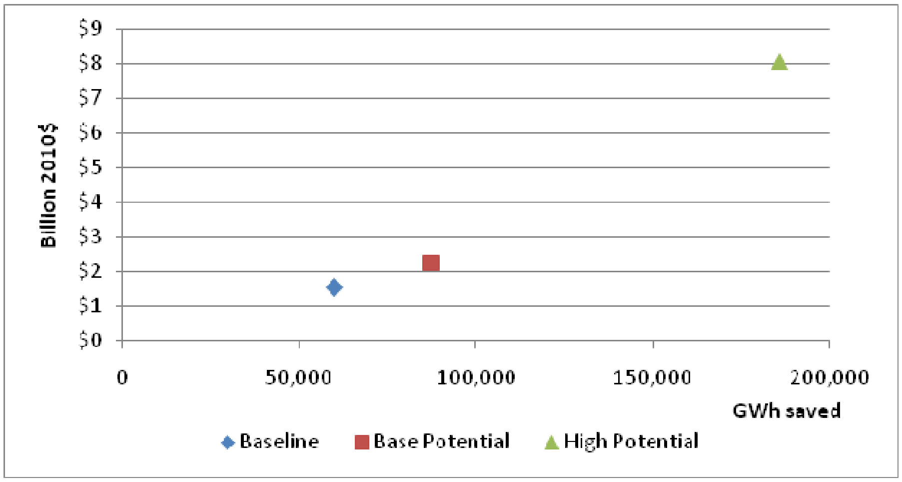
We also plotted additional renewable capacity and total differential costs relative to the Baseline for the two scenarios concentrating on renewable energy, 4a and 4b. This is shown in Figure 42 below. Scenarios 4a and 4b have about 900 MW and 5,000 MW more renewable energy than the Baseline, respectively. Even though Scenario 4b assumes an increase in renewable capacity over 450% greater than Scenario 4a, the differential total cost is only 145% greater.

FIGURE 42: ADDITIONAL RENEWABLE GENERATION RELATIVE TO BASELINE VERSUS ADDITIONAL COSTS



There are also trade-offs in the level of investment in energy efficiency. Figure 43 plots the net present value of investment in energy efficiency measures over 15 years and savings during the same time period for the three energy efficiency scenarios considered in this analysis. The High Potential scenario has significantly more savings, but at a higher average cost. This is due to the implementation of higher cost measures to achieve this level of efficiency.

FIGURE 43: ENERGY EFFICIENCY SAVINGS RELATIVE TO COSTS (TOTAL, 2011-2025)



5. POLICY CONSIDERATIONS

The electric sector is a central, complex and dynamic component of every state's economy and environment. With multiple objectives and numerous sector uncertainties such as energy costs and federal policies, states are challenged to determine which course will best serve their residents and businesses.

In the North Carolina EPC's deliberations on potential future policies for the electric sector, it has sought relevant information, informed analysis and stakeholder input. The EPC contracted with La Capra Associates to help assess the state's existing renewable energy policies and explore potential policy alternatives to address issues related to renewable energy, energy efficiency, greenhouse gas emissions, and economic development. Numerous stakeholders were engaged in the study process, raising additional questions regarding the effectiveness of S.B. 3 REPS in meeting its stated objectives, as well as other policy questions related to this legislation. In this section, La Capra Associates seeks to articulate the policy questions posed to us by the EPC and other stakeholders in this process and share our related observations based on the results of our investigation.

5.1 LEGISLATION OBJECTIVES

The EPC and several stakeholders with whom we spoke wanted to look at the performance of REPS relative to the four key objectives articulated in S.B. 3 REPS. They asked us to assess:

1. How REPS is performing thus far relative to the stated objectives which is addressed in more detail in Section 2 and;
2. The outlook for REPS performance over time, which is addressed below.

A. Will there be sufficient resources available to allow for cost-effective compliance with REPS over time?

Yes. The potential for renewable resources in and deliverable to North Carolina and the national renewable energy credit market provide ample resources to comply with the renewable energy requirements of REPS over the next decade. Utilities, although they must meet required set-asides, have flexibility to comply with REPS in a cost-effective manner. REPS requirements will be met mostly by biomass and wind. We expect 22% of the biomass practical potential and 16% of the eastern onshore wind potential to be developed to meet these requirements. Western North Carolina wind resource development is not necessary to meet REPS goals over the next decade.

In addition to renewable resources, the potential for energy efficiency in North Carolina provides ample resources to comply cost effectively with a significant component of REPS. We estimate that the aggregate energy efficiency level to be implemented under the status quo will be 3.1% of total retail sales in 2020 or a roughly a quarter of the full REPS requirement. This level is less than half of our conservative estimate of achievable potential.

B. Will REPS diversify the resources to reliably meet the energy needs of consumers in the state?

North Carolina will diversify its resource base as more renewables are built and energy efficiency is achieved to meet REPS. By 2025, new renewable resources built in North Carolina to comply with REPS will generate almost 3,700 GWh per year, or about 2.3% of projected retail sales for North Carolina electric power suppliers.

Since the REPS legislation was passed, approximately 150 MW of new solar, biomass and landfill gas renewable capacity has been developed in North Carolina. This new development represents a 44% increase in non-hydroelectric renewable generation capacity within just four years. By 2025 we expect that about 700 MW of new renewable capacity will have been built in North Carolina as a result of REPS, including 300 MW of biomass and landfill gas, 170 MW of solar, 120 MW of poultry and swine waste, and 120 MW of onshore wind.[59]

C. Will REPS provide greater energy security through the use of indigenous energy resources available within the state?

The state has experienced an increase in renewable generation in North Carolina resulting from the implementation of REPS and we expect this to continue. Since REPS was implemented in 2007, 85 new renewable energy facilities have been built in North Carolina totaling 150 MW. By 2025, we project that about 85% of the 815 MW of new renewable capacity built to comply with REPS, or approximately 700 MW, would be located in North Carolina. The state has also experienced a significant increase in the development of energy efficiency programs since 2007, due, at least in part, to the cost recovery mechanism created as a result of S.B. 3.

D. Will REPS improve air quality and other benefits to energy consumers and citizens of the state?

Implementing REPS has helped North Carolina reduce SO_2, NO_x and CO_2 emissions. Over time, as increased energy efficiency, wind, hydroelectric and solar power displaces fossil-fired generation, North Carolina's air quality should continue to improve. Although REPS contributes to improved emissions, the most significant driver in reducing emissions is 3,100 MW of coal

59 Iberdrola filed an application for a Certificate of Public Convenience and Necessity to Construct a Merchant Plant on January 27, 2011 with the Public Utilities Commission for a 300 MW wind farm in Pasquotank and Perquimans Counties. This application was approved on May 3, 2011. (See filing by Atlantic Wind, LLC in Docket EMP 49 Sub 0.) The project still has additional hurdles to clear before it is constructed and if the project is constructed it is not certain that it will be the full 300 MW.

retirements and the addition of 4,000 MW of nuclear power. In our baseline analysis, GHG emissions in the modeled region were reduced 20% from 2010 levels by 2025 to 83 million tons of CO_2. NO_x and SO_2 emissions from North Carolina generation resources were slashed 40% and 76%, respectively, over the same time period.

E. Will REPS encourage private investment in renewable energy?

REPS has been effective at incenting investment in renewables in North Carolina to date.

We expect roughly 815 MW of new renewable energy capacity deliverable to North Carolina to be built between 2007 and 2025 as a result of S.B. 3. On an installed basis, this equates to approximately $2 billion in investment in 2010 dollars by 2025. About 85% of the new capacity is expected to be built in North Carolina. [60]

F. Will REPS encourage private investment in energy efficiency?

North Carolina has seen a significant increase in investment in energy efficiency, due in part to the cost recovery provision in the Senate Bill 3 for energy efficiency and demand side management programs. While it is indisputable that there has been a significant increase in the development of energy efficiency programs since 2007, it is not as clear to what extent this development is due to REPS, the cost recovery mechanism also created by Senate Bill 3, utility incentives outside of REPS, or other factors, such as market forces.

Since 2007, IOUs, EMCs, and municipal utilities have implemented many energy efficiency programs and anticipate continuing this trend. Our analysis estimates that over the next 15 years total statewide investment in energy efficiency will be approximately $1.5 billion with cumulative energy savings of 60,000 GWh.

5.2 AREAS OF ADDITIONAL FOCUS

In addition to the four objectives specified in the legislation, the EPC asked us to specifically focus on the issues of reducing greenhouse gas emissions, promoting jobs and providing low stable rates to ratepayers. Related to these themes, the EPC asked us to conduct this study to inform their consideration of the following questions:

A. How effective will REPS be at reducing GHG emissions?

As discussed above, REPS will reduce all emissions, including GHG emissions. Although REPS contributes to improved GHG emissions, the most significant driver in reducing emissions is coal retirements and the addition of nuclear power. Although a relatively large share of out-of-state

[60] It is unclear from S.B. 3 REPS if "private" investment applies to utility as well as non-utility investments. We did not attempt to distinguish between these types of investment.

resources may be used for REPS compliance, any GHG emissions reductions benefit North Carolina equally, regardless of the location of the source.

B. How effective would strategies to encourage additional renewable and other low GHG emitting resources be in reducing GHG emissions compared to the current policy?

Strategies to achieve the greatest emissions reductions would involve increased renewable energy, extensive nuclear build outs, and energy efficiency maximized to its economically achievable level. In Scenario 1 we configured a resource portfolio that uses all three of these strategic elements to achieve maximum greenhouse gas emissions reductions. We assumed a doubling of the solar set-aside and an additional 630 MW of wind above the Baseline levels. We assumed an additional 2,200 MW of nuclear above the IRP levels. Energy efficiency is assumed to be achieved at 10.3% in 2025 compared to 4.0% assumed in our Baseline (see section 4.4.1.1 for more details about Scenario 1 assumptions). Together, these changes result in a 56% reduction in 2010 greenhouse gas emission levels for the VACAR South region by 2025. The 2025 annual emissions level of 58 million tons CO_2 achieved in Scenario 1 is 30% less than 2025 emissions in the Baseline.

C. How effective will REPS be as an economic policy tool?

The EPC has expressed interest in the economic development implications of the development of renewable energy and energy efficiency. REPS-driven energy efficiency and renewable energy development have the potential to add a significant number of jobs and promote economic development in North Carolina.

There are two important perspectives to consider. On the one hand, low electric rates arguably provide an engine for economic development. On the other, direct investment in indigenous renewable energy resources and energy efficiency act as a cluster development tool to incent manufacturing development and job creation.

There are trade-offs between these two perspectives. REPS legislation as currently written enables compliance through both purchasing RECs from out of state and purchasing renewable energy which is produced in facilities outside of North Carolina but delivered to the utilities' service territories. REC purchases are a low cost option but do not encourage local resource development. One would need to assess the direct economic impact and benefit of different levels of energy efficiency and renewables that could be developed in North Carolina relative to the additional costs incurred.

D. How would other policies that increase development of renewable and energy efficiency resources in North Carolina compare to REPS as an effective economic policy tool?

We developed a scenario (4b) which had the primary objective of realizing significant investment in new renewables. This scenario, which goes beyond the 12.5% requirement, results in an additional 5,000 MW of renewables compared to the baseline, but also has associated $2 billion of NPV of costs over the study period. We also developed a scenario (5) which had the aim of achieving a maximum level of investment in energy efficiency over the next ten years. This scenario results in an additional 6.4% reduction of 2025 load beyond the baseline and an additional $6.5 billion in costs over 15 years. The overall impact on North Carolina's economy was beyond the scope of this work, but is under consideration for supplemental analysis.

E. How effective will REPS be at providing stable and low electric power rates?

Achieving REPS compliance in the most cost effective way, while ensuring stability of prices, is critical. REPS, not withstanding some near term challenges associated with an increase in the residential cost cap and poultry set-aside requirements, will be effective at providing stable electric power rates. Cost effective resources exist to comply with REPS over the next 15 years without violating the cost caps established in REPS.

5.3 OTHER POLICY CONSIDERATIONS

In addition to the objectives outlined in the legislation and areas identified for more focus discussed above in section 5.1.2, stakeholders identified other policy-related questions specific to the resource options that can be used to meet North Carolina's REPS requirements. Below we articulate some of the questions posed to us in this process by various stakeholders and provide observations based on our analysis.

Energy Efficiency

A. Is REPS effective as a tool to achieve the maximum potential for energy efficiency?

Although the increased development of energy efficiency measures has coincided with the REPS legislation, it is not clear that the ability to use savings from these measures for compliance is spurring this development. The fact that some IOUs anticipate efficiency savings in excess of the 25% allowed for REPS indicates that the motivation for development may be connected more to the non-REPS incentives utilities are receiving for implementing efficiency measures. Even though some suppliers are rapidly developing energy efficiency programs, our analysis shows that the state as a whole will fall short of the La Capra Associates' base potential estimate. We estimate that the aggregate energy efficiency level to be implemented will be 3.1% of load in 2020, while our analysis suggests that the base potential in that year could be 7% of load assuming full implementation of low cost energy efficiency measures (below $0.05/kWh).

B. Is there additional potential in North Carolina for cost effective energy efficiency?

La Capra Associates performed a meta-analysis to examine the issue of potential and based on our analysis have concluded that, even on the current path, there is significant potential for additional cost effective energy efficiency. Our analysis suggests that depending on the measure cost threshold utilized, the 10-year cost effective energy efficiency potential is between 7% and 13%. The 13% level assumes a $0.10/kWh avoided cost level.

The energy efficiency provisions of REPS, along with cost recovery mechanisms and utility incentives are not encouraging the development of energy efficiency programs sufficient to access the maximum achievable potential. Based on supplier estimates and business-as-usual assumptions, we expect North Carolina's energy efficiency savings to be approximately 3.1% of load in 2020.

Importantly, the potential for energy efficiency savings will grow as new technology develops. Similarly, the definition of "cost-effective" is dynamic because the avoided cost of energy in North Carolina may fluctuate with capital costs of nuclear, gas and coal plants as well as fuel prices, particularly natural gas.

C. What are the options for achieving more of the energy efficiency potential?

Some stakeholders advocate for maximizing all cost effective energy efficiency while others question whether the state should be setting any requirements at all. Still others believe that the integrated resource planning process should be more thorough in evaluating energy efficiency as an alternative to new generation. If the state policymakers believe that current levels of energy efficiency are not sufficient and that the state, and individual stakeholders such as the utilities, will benefit environmentally or economically from more programs, they could consider other policy options to establish threshold levels of energy efficiency to emerge from the integrated resource planning process. These could include policies already adopted in other states, such as amending REPS to require energy efficiency, establishing a separate Energy Efficiency Resource Standard (EERS) or employing other policy tools for achieving greater cost effective energy efficiency.

i. What are the implications of amending REPS to require energy efficiency?

Based on the REPS compliance filings, Duke and Progress anticipate efficiency savings in excess of the 25% allowance for REPS compliance. Amending REPS to mandate the implementation of efficiency measures will likely impact municipal utilities and EMCs more profoundly, as they already see efficiency as a higher cost option for compliance.

If the intent of including energy efficiency as a required resource for compliance is to increase program development, the required levels would have to exceed these 25% levels. In the case of compliance by utilities, this action would decrease, potentially significantly, the amount of renewables required for compliance unless the overall REPS requirements were also increased.

ii. What are the implications of establishing a separate Energy Efficiency Resource Standard?

The impact of the development of an EERS, which would establish minimum efficiency requirements for all electricity suppliers, would likely have a considerable impact on REPS compliance. If energy efficiency is removed as an eligible compliance resource and the overall REPS requirements (i.e. 12.5% in 2021 for IOUs) are not reduced, it would result in necessary development of additional renewable resources. This would also likely increase the cost of REPS compliance because IOUs currently consider energy efficiency to be a least-cost method of compliance.

The development of an EERS would require extensive additional study and analysis to determine appropriate and achievable requirements.

iii. Are other policy tools available?

If North Carolina wants to maximize the achievement of economic energy efficiency, the state may want to explore ways to achieve and account for the energy efficiency that is outside of the control of the IOUs. This could mean establishing measurement and verification procedures for consumer-initiated measures, or establishing provisions allowing third party energy service companies (ESCOs) to implement efficiency measures and sell credits to IOUs, cooperatives or municipal utilities for their REPS compliance. ESCOs may be able to access customers and potential that are either not eligible for other programs or have opted-out of utility programs.

Renewable Resources

A. Are the set-asides creating cost pressures on REPS compliance?

Set-aside requirements for poultry waste have had a steep ramp-up, which means that most of the capacity must be built in a short amount of time. This also means that electric power suppliers will need to procure most of their requirement quickly and won't be able to take advantage of cost reductions that may come with the second generation of poultry facilities. Despite these challenges, it appears that compliance will occur at a level at or below the cost caps as stipulated.

Although solar power is more expensive than non-set-aside resources such as onshore wind, electric power suppliers have already built in-state facilities, contracted for energy, or identified low-cost out-of-state SREC markets sufficient to meet the set-aside requirements through 2015. We anticipate that compliance will occur at or below the cost caps.

B. Is the solar set-aside sufficient to sustain a solar industry in North Carolina?

North Carolina has an active solar industry, which has been stimulated by REPS. Currently enough solar is under contract to meet REPS requirements through 2015. The resource potential for solar PV is quite large. A larger solar set-aside would likely be needed to support a residential solar industry in the long run. Based on our cost estimates, a set-aside would continue to be required as solar, while declining in cost, is not expected to reach cost parity with biomass and onshore wind in the 10 year horizon of this assessment.

C. Does REPS require development of ridgeline wind in western North Carolina?

No. The REPS requirements can be met without developing any ridgeline wind in western North Carolina. There are sufficient other resource options available to afford the utilities flexibility in their compliance with REPS without needing to develop those wind resources. If the Ridge Law issues were resolved and development on ridgelines was allowed, as much as an additional 1,625 MW of practical potential could be available.

D. Will REPS spur offshore wind development?

No. Given the higher cost of offshore wind, it is unlikely that utilities will look to offshore wind to meet their REPS requirement. The current cost cap constraints under the REPS program are too low to incorporate offshore wind. The expected cost of off-shore wind in the near-term makes it unlikely that off-shore wind would be developed without a set-aside requiring it.

E. Are there sufficient biomass resources to comply with REPS without including whole tree chips?

The delineation of eligible biomass fuel sources requires a complex balancing of economic, environmental and technical feasibility factors. Some stakeholders believe that whole trees should not be harvested for energy due to environmental concerns; others believe that achieving renewable goals cost effectively is not possible if whole trees are ineligible. Our study is not intended to settle this debate.

- Whole tree sources add to the supply of biomass, increases options, and may reduce costs, but are not required to comply with the current REPs policy. Our analysis finds that the amount of biomass generation expected to meet REPS requirements – less than 300 MW – could be fueled entirely by forest residues and agriculture waste.

APPENDIX A – TECHNICAL SUPPLEMENT TO SECTION 3

The EPC commissioned this study to provide resource potential and cost information for its considerations of electric sector energy policy issues including the future of renewable energy, energy efficiency, and low carbon emitting energy resources. The EPC asked La Capra Associates to update and expand upon its 2006 assessment of North Carolina renewable energy potential and costs for this purpose.[61]

In this assessment, the EPC asked us to revisit our estimates of energy efficiency and renewable resources, including biomass, wind, hydro, and solar, and to expand this list to consideration of potential low GHG emitting resources, specifically nuclear power and natural gas.[62]

Over the past five years, many changes have taken place that have impacted the cost and potential for renewable and energy efficiency resources. Among the factors are: the implementation of S.B. 3 REPS; a recessionary environment; shifts in the natural gas market; technology advances and cost declines in some industries; and new regulatory policy, such as the introduction of state and federal efficiency standards.

This resource assessment was prepared based on independent research of published studies and La Capra Associates experience and expertise with these energy resources. We also considered input from many North Carolina stakeholders, including market participants, regulators and other interested parties, to identify recent credible data specific to North Carolina, some of which is confidential. We have provided an overall technical and practical potential for each resource as well as representative estimates of key resource metrics such as capacity factor, dispatchability, reliability, emissions, capital costs and levelized costs. This section of the report outlines the approach and provides the results and key findings for this research and analysis.

61 La Capra Associates, Inc, GDS Associates, Inc, and Sustainable Energy Advantage, LLC. (2006) Analysis of a renewable portfolio standard for the state of North Carolina. *Technical Report to the North Carolina Utilities Commission.*

62 An assessment of poultry and swine waste was not a part of the project scope.

KEY FINDINGS

In determining the estimate of technical and practical potential for resources as well as associated costs there were a number of key findings which are outlined below.

5.3.1 *RENEWABLES*

Onshore Wind

- Onshore wind in North Carolina is a good resource. The Mountain Ridge Protection Act of 1983 (Ridge Law) is an obstacle to development in Western North Carolina.
- North Carolina will benefit from having its first wind farm built in the east, enabling better understanding of North Carolina specific development issues (e.g., hurricanes).

Offshore Wind

- There is enormous potential for offshore wind in North Carolina's waters. Its development is limited by its higher relative cost.
- North Carolina's offshore wind development efforts may benefit from experience in other east coast states which have projects underway.
- Offshore wind development in North Carolina, as well as other locations, may also benefit from technology advances in Europe, in particular a move to larger turbine sizes.
- The capital costs for offshore wind are expected to decrease over time due to industry learnings and greater efficiencies, but it will still take several years until offshore wind is competitive on a cost basis with onshore wind.

Solar PV

- Solar PV costs declined significantly in 2010 and the first quarter of 2011 and cost declines are expected to continue through the study period.
- There is an active solar industry in North Carolina, but this may contract as enough solar is currently under contract to meet REPS requirements through 2015.
- The resource potential for solar is quite large and North Carolina could support a larger solar set-aside. Based on our cost estimates, a set-aside would continue to be required as solar is not expected to be cost competitive with biomass and onshore wind in the 10-year horizon of this assessment.
- A set-aside that ramps up evenly over time would allow the industry to grow and take advantage of the expected cost declines in the later years.

Landfill Gas

- Landfill gas is a low cost renewable resource that has the added benefit of reducing emissions of methane, a potent greenhouse gas. While there is an opportunity to triple anticipated generation from landfill gas, full development would still represent a relatively small share of North Carolina renewable energy generation.

Biomass

- Under the current REPS policy, and assuming the definition of eligible biomass fuel includes whole tree chips, there is a practical potential to fuel more than 1,300 MW of electricity generation with forest, agriculture and urban waste biomass resources. Of that total, up to 787 MW could be co-fired with coal at existing plants.

- The true practical potential of biomass in North Carolina will be determined as much by assessments of environmental impacts as by economic and feasibility constraints. A full evaluation of the environmental trade-offs from utilizing various biomass resources is beyond the scope of this study.

- Inclusion of whole trees in the definition of eligible biomass fuel increases potential. However, it also introduces new issues such as the greenhouse gas impacts of dedicated energy harvests, competition with existing forest products industry, and potential for significant land use and forest management changes.

- Collaborating with researchers at NCSU, Duke and U.S. Forest Service, La Capra Associates used the Sub Regional Timber Supply model to estimate 1,000 MW of forest biomass potential in the North Carolina electricity supply region. Assuming logging residue recovery rates of 70% for hardwood species and 85% for softwood species, this potential can be obtained almost entirely with residues.

- If logging residue recovery rates do not reach these high levels, the expected potential for forest biomass would be lower. However, even if halved the potential would still exceed the expected demand from the current REPS policy.

- Our biomass potential forecast includes resources in South Carolina and Virginia. If RPS policies enacted federally or in neighboring states add to regional biomass electricity demand, it is likely the practical potential for North Carolina would be significantly lower than projected.

- Dedicated energy crops, agriculture residues (not including manure) and urban wood waste have the practical potential to fuel another 350 MW of biomass electricity.

- Our co-fire potential estimate assumes that coal plants with SCR or SNCR scrubbers can co-fire a maximum of 10% of heat input with biomass. Estimates vary on the feasibility of co-firing scrubbed plants.

Hydro

- The practical potential for new hydro is low – just over 100 MW. We do not foresee development of new hydro as a significant piece of the REPS compliance picture.

5.3.2 ENERGY EFFICIENCY, DEMAND-SIDE MANAGEMENT AND COMBINED HEAT AND POWER

- S.B. 3 laid the framework for North Carolina to begin to access the technical economic electric energy efficiency resources that had been identified as the potential in 2007. The NCUC has created a process and incentive system that make clear North Carolina's commitment to obtaining economic energy efficiency. The current structure of utility incentives, ability to receive REPS credit and the integrated resource planning is driving IOU's to actively pursue energy efficiency. Current IRP and other filings and hearings allow for periodic review of current avoided costs and overall compliance.

- In the three year implementation period of REPS, two utilities have significantly increased their efficiency program offerings. These utilities are funding program development and investing in the structure and planning and are on a trajectory to achieve the 10 year economic energy efficiency potential.63

- Based on the available information, the economic energy efficiency potential range for North Carolina is 7-13%. Changes in and selection of avoided costs will significantly impact potential.64

- There is general agreement among stakeholders that the currently available potential studies are dated, not state specific and/or incomplete. In many instances, the available data for North Carolina is five or more years old.

- North Carolina's law allows all industrial and large commercial utility customers (that consume 1,000 MWh or more annually) to opt-out of utility programs and not pay the EE/DSM rider if claim that they have implemented or plan to implement efficiency measures independently. The impact of this provision is considerable, and current opt-out levels represent approximately 15-30% of load.

- Cooperatives and municipal utilities, which represent 25% of the state's usage, have been able to secure RECs at a lower cost to their customers than energy efficiency programs.

[63] Duke and Progress have a range of energy efficiency programs in place. Dominion filed for program approval and is expected to implement them in 2011.

[64] In the modeling, the low avoided cost used was the conventional avoided cost. The high avoided cost cases used the cost of renewables as the avoided cost.

- Demand-side management (DSM) is an eligible compliance resource for EMCs and municipalities. Due to the minimal impact on energy requirements, DSM is not expected to be a significant compliance resource.
- While somewhat limited in capacity, CHP is a good option for low-cost, high-efficiency generation. With strong development efforts, 600 MW is realistically achievable over 10 years.
- CHP could be an important component of a least-cost, low-emission portfolio, especially if paired the lowest-emission fossil fueled generation or if fueled using biomass.

5.3.3 *BASELOAD RESOURCES*

Nuclear

- Nuclear development is costly and there is little consensus on price estimates. Estimates have been escalating, but without a new project developed in the U.S., there will be little certainty on cost.
- Prospects for the development of nuclear power in North Carolina, as well as other places in the United States are highly uncertain due to safety concerns related to the impact of the recent earthquake and tsunami on the Fukushima-Daiichi nuclear plant in Japan.
- In addition, regulatory uncertainty especially given enhanced scrutiny of new designs, the lack of resolution to nuclear waste storage, the nuclear industry history of cost overruns contribute to financing risk.

Natural Gas

- Natural gas CCs are the preferred near-term baseload resource in the utility IRPs.
- Stakeholders in North Carolina are currently investigating the potential for gas production in the western region. Even without in-state drilling, North Carolina has ample supply. Due to gas supply north and south on the Williams Transco pipeline, North Carolina is well-situated to take advantage of low natural gas prices for baseload power.

RENEWABLE RESOURCES POTENTIAL

5.3.4 *SUMMARY DISCUSSION OF RESOURCE POTENTIAL*

The potential of each renewable resource in North Carolina was assessed in terms of capacity potential, for both a "technical" potential and "practical" potential. These terms are defined as follows:

- **Technical Potential.** The technical potential is the total renewable resources, located within the state, with the potential for electric energy conversion.

- **Practical Potential.** This is the amount of capacity that we believe can be developed based on practical considerations. It is the potential that might reasonably be expected to be achieved based on currently available technologies and other screens specific to each resource. For example in the case of offshore wind, this would include a screen to limit practical potential to development at a certain water depth. Or in the case of woody biomass this would include screens for limitations on forest lands that are not harvestable. While we did consider some element of cost we have not employed pure cost effective analysis in constraining our estimates of practical potential.

Figure 44, below, shows the North Carolina resource potential for renewable resources. The assumptions behind the potential for each technology are discussed in detail in subsequent report sections. Figure 44 illustrates that there is almost 49,000 MW of technical potential and almost 18,000 MW of practical potential, not including solar PV potential which we have characterized as unlimited. Offshore wind is the biggest contributor to renewable potential followed by biomass and onshore wind.

FIGURE 44: RENEWABLE RESOURCE POTENTIAL

Resource Type	Technical Potential		Practical Potential	
	MW	GWh	MW	GWh
Onshore Wind				
Eastern	750	1,971	750	1,971
Western*	3,750	9,855	1,625	4,271
Total Onshore Wind	4,500	11,826	2,375	6,242
Offshore Wind	39,140	126,861	13,905	45,069
Solar PV				
Utility Scale	Unlimited	Unlimited	Unlimited	Unlimited
Rooftop	Unlimited	Unlimited	Unlimited	Unlimited
Total Solar PV	Unlimited	Unlimited	Unlimited	Unlimited
Biomass				
Biomass	3,242	24,140	1,373	10,223
Co-fire with coal**	787	6,350	787	6,350
Hydropower***				
Upgrades at existing generation site	18	69	3	10
New generation at existing impoundment	781	3,080	82	324
Undeveloped Site	139	550	21	83
Total Hydropower	938	3,700	106	417
Landfill Gas	72	538	68	503
Total****	47,892	143,405	20,528	55,994

* Assumes that the Ridge Law issues are resolved and development in Western North Carolina is possible. Without a permissive interpretation or revision to the Ridge Law, there is no on-shore wind potential in Western North Carolina.

** Co-fire potential is a subset of overall biomass potential

*** Hydro technical potential includes sites that are greater than 10MW, but practical potential does not.

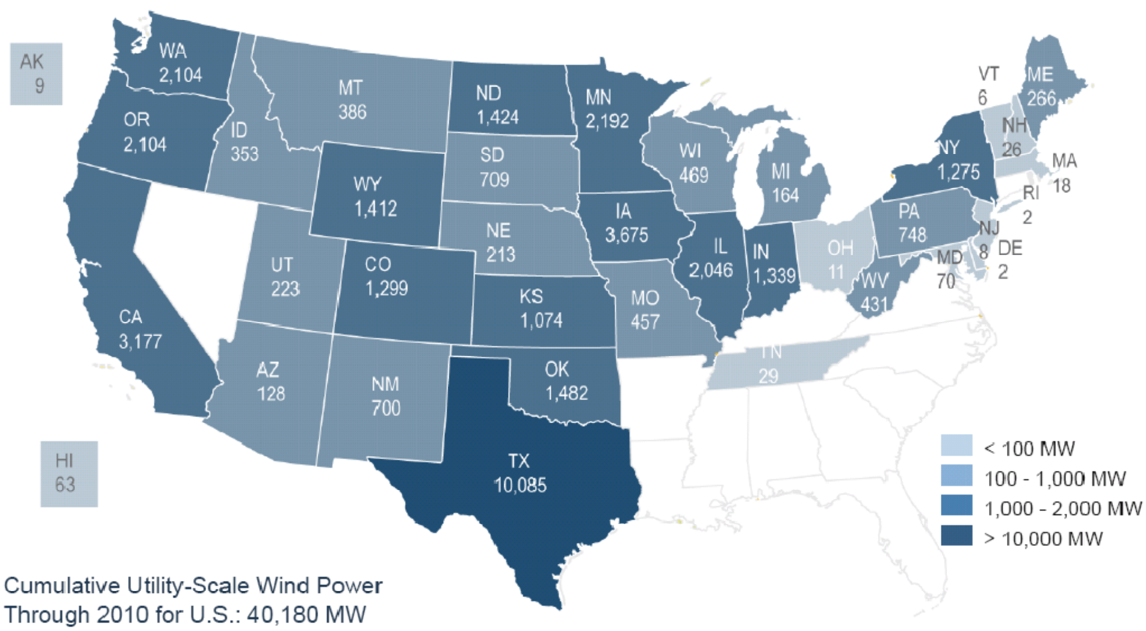
**** Does not include solar potential which is effectively unlimited.

5.3.5

5.3.6 *ONSHORE WIND*

Onshore wind energy generation is now a mature technology and serves as the backbone of many states' renewable portfolios. According to the American Wind Energy Association, there were over 40,000 MW of utility scale wind power capacity operating in the United States by the end of 2010.[65] About a quarter of U.S. development so far has occurred in Texas with most of the other development occurring in Midwestern or Western states. Figure 45, below, shows wind development by state through the end of 2010.

FIGURE 45: 2010 YEAR END WIND POWER CAPACITY BY STATE[66]



While North Carolina was one of the first states to install a utility scale wind turbine with the construction of a 2 MW turbine in Boone in 1979,[67] Figure 45 shows that no utility scale wind development has occurred in North Carolina since then through the end of 2010. Several developers are exploring projects in the state. Iberdrola filed an application for a Certificate of Public Convenience and Necessity to Construct a Merchant Plant on January 27, 2011with the NCUC for a 300 MW wind farm in Pasquotank and Perquimans Counties.[68] This application was approved on May 3, 2011.

65 AWEA. U.S. Wind Industry Association Year-End 2010 Market Report. January 2011. http://www.awea.org/learnabout/publications/loader.cfm?csModule=security/getfile&PageID=5083

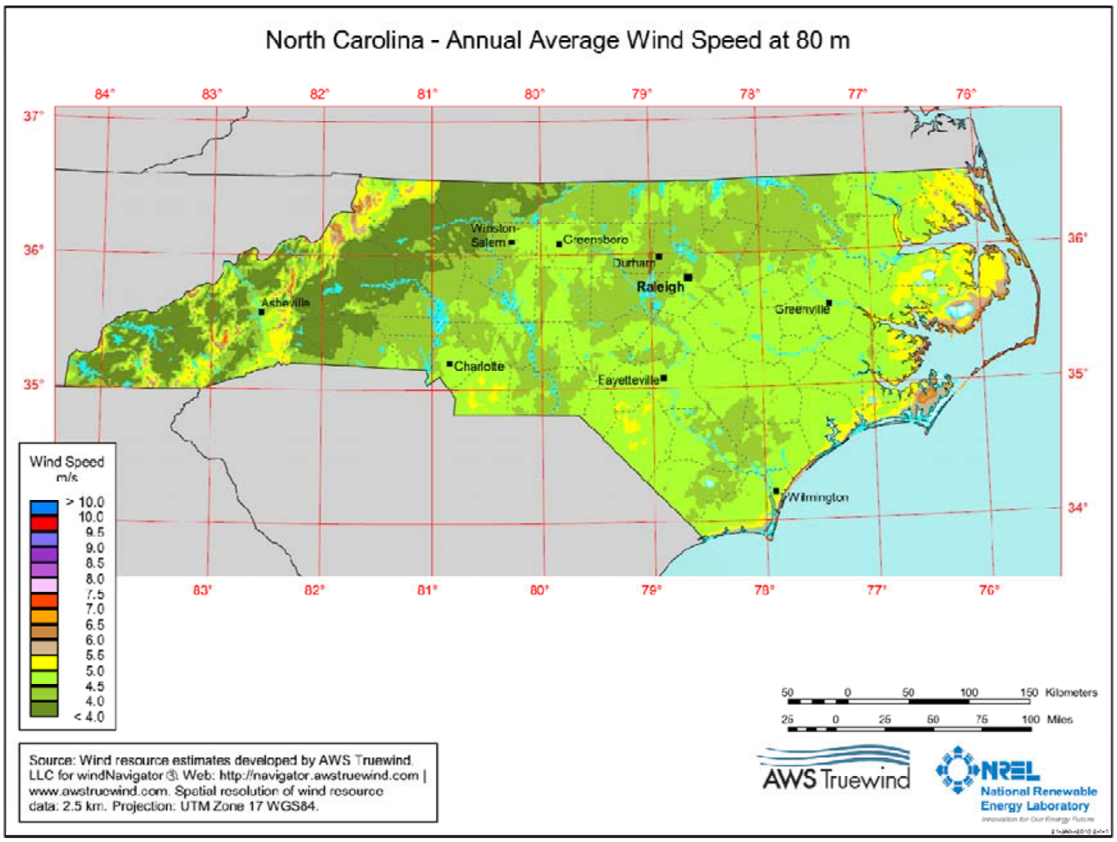
66 Ibid, page 5.

67 Passage of the Ridge Law in 1983 did not affect selection of this site.

68 Atlantic Wind, LLCs Application for a Certificate of Public Convenience and Necessity to Construct a Merchant Plant and Registration as a New Renewable Energy Facility. Filed on January 27, 2011 in Docket EMP 49 Sub 0 at the North Carolina Public Utilities Commission

The United State Department of Energy (DOE) Wind Powering America website has wind resources potential maps and estimates of windy land area and wind power potential development for every state. The wind resource potential map was developed by the Department of Energy and the National Renewable Energy Laboratory (NREL) using data from AWS Truewind. The wind resource map, shown below in Figure 46 illustrates that the best resource is either in the western mountains or close to the coast.

FIGURE 46: NORTH CAROLINA WIND RESOURCE[69]



Wind development in the western mountains of North Carolina is controversial because of the Mountain Ridge Protection Act of 1983 (Ridge Law). The Ridge Law was passed in 1983 in response to complaints about the Sugar Mountain Resort in Avery County. The law prohibits development higher than 40 feet on mountain ridges whose elevation exceeds 3,000 feet and whose elevation is 500 or more feet above the adjacent valley floor. The law exempts windmills, but there has been controversy over the intended definition of a windmill. Some

69 U.S. Department of Energy: Wind Powering America. North Carolina Wind Map and Resources Potential. Accessed March 10, 2011. http://www.windpoweringamerica.gov/images/windmaps/nc_80m.jpg

argue that this exemption should allow utility scale wind turbines while others argue that the exemption refers to a single wind turbine on a farmer's land for use by the farm.

In 2002 the Tennessee Valley Authority proposed to erect a wind farm partially located in the western mountains of North Carolina. While the North Carolina Department of Justice stated that the wind farm would be allowed under the Ridge Law, the State Attorney General issued a rebuttal stating that the Ridge Law would prohibit a the project in North Carolina.[70]

Developers with whom we talked all believed that wind development in the western mountains of North Carolina would not happen unless the Ridge Law issue is resolved. For this reason we have estimated the wind potential for the eastern and western portions of the state separately.

Potential Calculation

There are several sources of information on the wind resource in North Carolina. The Wind Powering America website includes a spreadsheet by NREL and AWS Truewind which gives wind resource data by state and capacity factor. The wind resource numbers are based off the data shown in Figure 46 above, and include the wind resource estimated by NREL for both 80 and 100 meter towers and for gross capacity factors of 30 percent and above.[71] The NREL and AWS Truewind data on the North Carolina wind resource are included in Figure 47 below.

FIGURE 47: NORTH CAROLINA WIND RESOURCE (MW) FROM WIND POWERING AMERICA WEBSITE[72] (MW)

Hub Height	30-35% Gross CF (26-30% Net)	35-30% Gross CF (30-34% Net)	>40% Gross CF (> 34% Net)	Total
80 m	611	110	86	807
100 m	1152	217	131	1500

For the western mountain region of the state, another source of wind potential is a paper from Appalachian State University (ASU).[73] The ASU work is based on an earlier NREL and AWS Truewind wind resource map than the wind resource potential given in Figure 49. The earlier data were for 50 meter towers instead of 80 meter towers, but is otherwise similar to more

70 Boaz, David. *North Carolina's Wind Energy Facilities Bill: The Debate Continues Over the Future of Wind-Power Generation in the North Carolina Mountains*. http://www.law.unc.edu/documents/clear/topic4boazfinal.pdf. Accessed April 27, 2011.

71 Net capacity factors are about 85 percent of gross capacity factors after accounting for transformer, transmission, line and wake losses, turbulence, availability, etc.

72 http://www.windpoweringamerica.gov/wind_resource_maps.asp?stateab=nc

73 Raichle, Brian. Method for Estimating Potential Wind Generation in the Appalachians. Appalachian State University, 10/24/2007.

recent data. The biggest difference between the ASU and NREL analyses (depicted in Figure 48) is that the ASU analysis calculated the wind potential from the miles of windy ridgeline available and the NREL analysis calculated the wind potential from the windy land area. Development practices in the western mountains support use of the ASU method instead of the NREL method.

The ASU study identified 300 miles of ridgeline which could potentially support wind development in western North Carolina. Assuming 12.5 MW per mile based on the spacing necessary for a GE 1.5 MW turbine, this would translate into potential capacity of 3,750 MW in the western mountains of the state.

FIGURE 48: WIND RESOURCE IN WESTERN NORTH CAROLINA

Wind Class	3	4	5	Total
Capacity Factor	25%	30%	35%	
Ridgeline (miles)[74]	170	72	58	300
Potential (MW)	2,125	900	725	3,750

The NREL data shown in Figure 47 is a good approximation for the flatter terrain of Eastern North Carolina. We chose the 100 meter data because developers mentioned that they would probably use the taller towers in North Carolina applications. We only included half of the NREL potential in our estimate of the Eastern North Carolina resource to ensure that we are not double counting western wind as they did not break out the west from the east and the west is about half of the total.

The technical and practical potential for onshore wind is shown below in Figure 49. We included all of the western North Carolina wind identified by ASU and half of the 100 meter potential identified by NREL in the technical potential. To estimate the practical potential in the west, we excluded sites with a capacity factor of less than 25% from the ASU data as it is less likely that this resource would be developed.

FIGURE 49: ONSHORE WIND POTENTIAL

	Technical	Practical
Eastern	750	750
Western*	3,750	1,625*
Total	4,500	2,375

[74] Estimate from Raichle 2007.

*Assumes Ridge Law issues are resolved

Because the in-state portion of the REPS requirement can be satisfied with energy delivered to the utilities service territory that is not located in North Carolina, we also collected information on wind energy potential for the neighboring states to North Carolina. This data comes from the Wind Powering America spreadsheet described above and also provides wind potential at 80 meter and 100 meter hub heights. We have not included this potential in the technical and practical potential, but it is possible that wind farms could be built in neighboring states and qualify for REPS as in-state resources. This potential is included in the tables below.

FIGURE 50: POTENTIAL IN NEIGHBORING STATES AT 80 METER HUB HEIGHT

	30-35% Gross CF (26-30% Net)	35-30% Gross CF (30-34% Net)	>40% Gross CF (> 34% Net)	Total
Georgia	100	25	6	130
South Carolina	182	2	1	185
Tennessee	245	48	17	309
Virginia	1,179	458	156	1,793

FIGURE 51: POTENTIAL IN NEIGHBORING STATES AT 100 METER HUB HEIGHT

	30-35% Gross CF (26-30% Net)	35-30% Gross CF (30-34% Net)	>40% Gross CF (> 34% Net)	Total
Georgia	216	62	16	294
South Carolina	1,197	17	2	1,215
Tennessee	674	114	29	817
Virginia	2,355	865	245	3,466

5.3.7 *OFFSHORE WIND*

According to the European Wind Energy Association there were 45 offshore wind farms totaling 2,946 MW installed in Europe by the end of 2010.[75] While there has been significant offshore wind development in Europe, there have not yet been any projects built in the United States.

75 European Wind Energy Association. The European offshore wind industry key trends and statistics 2010. January 2011, Accessed April 21, 2011. http://www.ewea.org/fileadmin/ewea_documents/documents/00_POLICY_document/Offshore_Statistics/110120_Offshore_stats_Exec_Sum.pdf.

This makes estimating offshore wind potential and costs in North Carolina more challenging than for resources where there is a history of development in the state.

Nationally, offshore wind has received a lot of attention as high profile projects such as Cape Wind in Massachusetts go through the permitting and contracting process. In February 2011, the United States Departments of Energy and Interior released a joint *National Offshore Wind Strategy*.[76] Under the *National Offshore Wind Strategy*, the Department of Energy is pursuing a scenario that includes deployment of 10 GW of offshore wind generating capacity by 2020 and 54 GW by 2030. The report released in February identifies wind development areas in the Mid-Atlantic region. It is expected that additional reports will be released in 2011 to specify wind development areas in the South Atlantic and New England Regions.

Offshore wind is a promising resource for states on the Atlantic coast because potential is high and the resource is located close to the urban load centers. Several studies have been published recently, which tout the environmental and job creation benefits of developing offshore wind.[77] Additionally, NREL published an assessment of the offshore wind potential for each state in its June 2010 report, "Assessment of Offshore Wind Energy Resources for the United States".[78]

Although offshore wind farms built in South Carolina or Virginia could deliver power to North Carolina, we have focused on the resource available in North Carolina. Because of the current high cost of offshore wind, it is assumed that offshore wind development would require a set-aside and it is likely that there would be an in-state requirement as part of such a policy.

In North Carolina, offshore wind has recently garnered a lot of attention. Governor Beverly Perdue of North Carolina created (by executive order) a Scientific Advisory Panel on Offshore Energy in September 2009. The stated purpose of this panel is to evaluate all offshore energy options (wind, tidal, natural gas, oil, etc.) and develop a comprehensive offshore energy strategy for the state. The panel is currently gathering written comments on the state's offshore energy future as well as direct input from coastal North Carolinians during three public meetings in Wilmington, Manteo and Morehead City.[79]

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76 US Departments of Energy and Interior. A *National Offshore Wind Strategy: Creating an Offshore Wind Energy Industry in the United States.* February 2011, Accessed April 21, 2011. http://www1.eere.energy.gov/windandhydro/pdfs/national_offshore_wind_strategy.pdf

77 Oceana and National Wildlife Foundation Reports

78 Schwartz, Marc; Heimiller, Donna; Haymes, Steve and Musial, Walt (National Renewable Energy Laboratory). (2010). *Assessment of Offshore Wind Energy Resources for the United States*. Retrieved from http://www.nrel.gov/docs/fy10osti/45889.pdf

79 In addition to actions by the Governor, the General Assembly is currently considering proposed legislation (S. 747) which would require the development of 2,500 MW of offshore wind capacity in the next 7 to 10 years.

In addition the Bureau of Ocean Management, Regulation and Enforcement (BOEMRE) has been working with the North Carolina Department of Commerce to develop a task force whose purpose is to facilitate intergovernmental communications regarding Outer Continental Shelf (OCS) renewable energy activities. As a part of this task force, they are looking at offshore wind energy potential development.[80] In terms of offshore wind potential, the University of North Carolina at Chapel Hill (UNC) prepared a report for the North Carolina General Assembly titled, "Coastal Wind: Energy for North Carolina's Future," which looks in depth at the feasibility of offshore wind development in both the Pamlico and Albemarle Sounds and in the ocean waters farther off the coast.[81]

Additionally, the Georgia Environmental Finance Authority (GEFA) is administering a grant for an offshore wind project from the U.S. Department of Energy which is facilitated by the Southern Alliance for Clean Energy.[82] The goal of the project is to create a thorough understanding of the infrastructure required to develop GW scale ocean renewable energy resources in an economic manner.[83]

To determine the technical and practical potential for offshore wind in North Carolina, we focused on the NREL and UNC reports mentioned above. Both reports start with similar wind resources maps, but the UNC report takes a deeper look at the feasibility of developing that resource including state-specific details. The UNC report looks at the following factors beyond wind resource:

- Environmental impacts;
- Use conflicts;
- Foundation considerations;
- Seafloor geology;
- Transmission; and

[80] http://www.boemre.gov/offshore/RenewableEnergy/StateActivities.htm#North_Carolina

[81] University of North Carolina. Coastal Wind for North Carolina's Future. June 2009. http://www.climate.unc.edu/coastal-wind

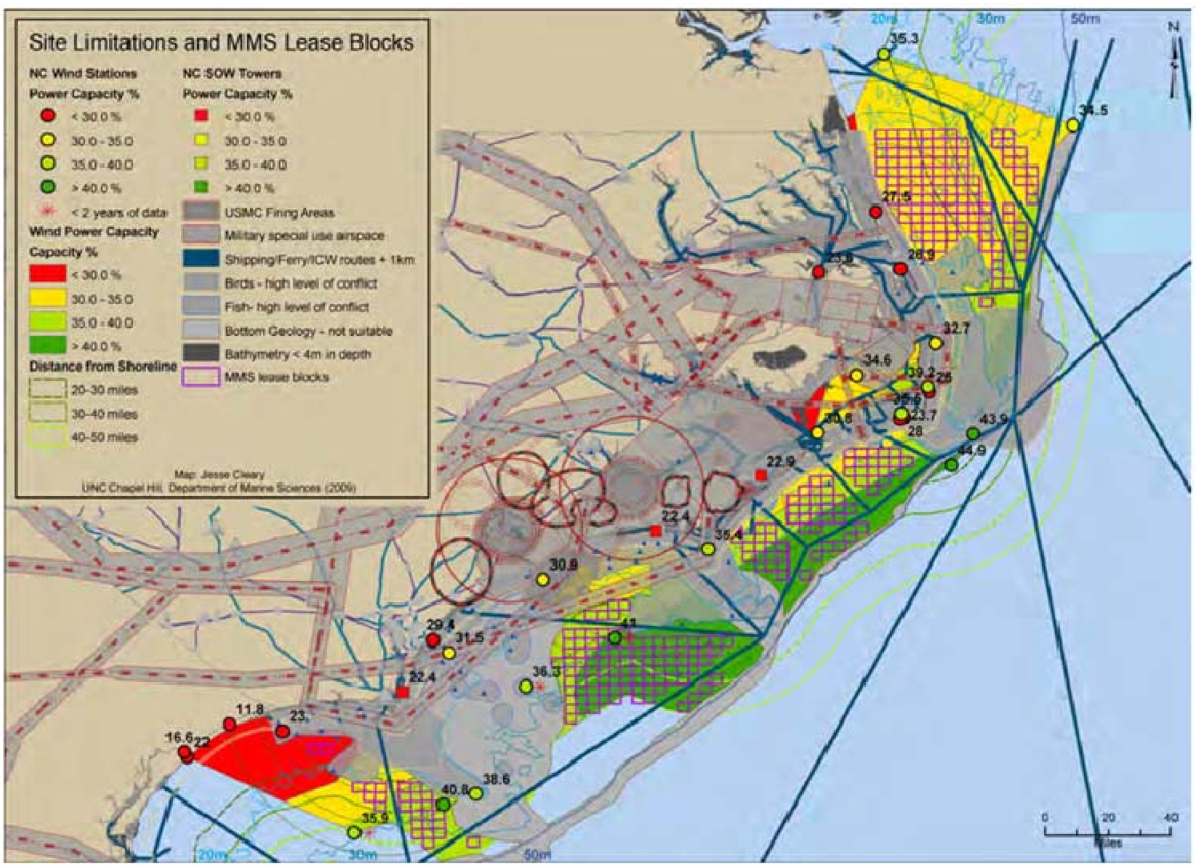
[82] Request for Proposals Southeastern Offshore Wind Energy Infrastructure Project. https://sites.google.com/site/requestforproposals2010/home

[83] This project is a collaboration among state, regional, and national agencies and involves three phases: 1) Siting analysis for offshore wind in North Carolina and Georgia; 2) Analysis of offshore wind generation output; and 3) Analysis of Transmission required for offshore wind. See the RFP website for more info: https://sites.google.com/site/requestforproposals2010/home/sobts.

- Legal and policy issues.

The UNC team eliminated a portion of the wind resource area because of conflicts with the issues in the list above. The team then produced an estimate of the viable area for wind development within state and federal waters off the North Carolina coast. For both state and federal waters, the report divides the resources by capacity factor and then gives the resource area in square miles, the average water depth of the resource area, the percentage of the area that would be suitable for different foundation types and the distance from shore. Figure 52 below shows the map UNC created of areas suitable for offshore wind development.

FIGURE 52: AREAS OF THE WIND RESOURCE SUITABLE FOR DEVELOPMENT[84]



To estimate the technical and practical potential of offshore wind in the state, we started with the estimates of windy area documented in the UNC report. We then calculated the capacity that could be installed in that area by using the MW per square kilometer given by NREL in its

84 UNC report page 356

estimate of offshore wind potential of approximately 13 MW per square mile.[85] The resulting number is the technical potential.

To calculate the practical potential, we reduced the technical potential in the following ways:

- **Capacity Factor.** We did not include any of the wind resource with a net capacity factor less than 30 percent;
- **Foundation Suitability.** The UNC report characterized the wind resource by what foundation type is possible: monopile or gravity based foundation or moderate feasibility (area between suitable and unsuitable geologic conditions). Moderate feasibility area was excluded from the practical potential.
- **Feasibility Multiplier.** The practical potential was further reduced by 50 percent by La Capra Associates because we did not believe it would be possible to develop more than half the available resource in the next 10 to 15 years. Getting even half the available resource permitted and funded will be difficult given the current relative high cost of offshore wind and challenges associated with permitting.
- **Transmission.** The UNC report states that the Dominion and Progress systems are capable of accommodating 10 MW and 250 MW offshore wind farms respectively without major upgrades.[86] Upgrades would therefore be required to achieve the practical potential in our analysis.

The tables below show the technical and practical potential for state and federal waters off North Carolina. The only area included in the state waters is Pamlico Sound which does not have strong resource potential for offshore wind. Also Duke Energy found that the water in the sound is too shallow for the barges required to construct a wind project.

The technical potential of state waters is 1,961 MW and the technical potential of the federal waters is 37,179 MW for a total North Carolina technical potential of over 39,000 MW. The practical potential includes 579 MW in state waters and 13,326 MW in federal waters for a total of 13,905 MW. Given that it is not likely to see this much offshore wind developed over the study time period, for all practical purposes, in terms of available sites, the offshore wind

[85] Schwartz, Marc; Heimiller, Donna; Haymes, Steve and Musial, Walt (National Renewable Energy Laboratory). (2010). *Assessment of Offshore Wind Energy Resources for the United States*. Retrieved from http://www.nrel.gov/docs/fy10osti/45889.pdf On page 12 of the report states the assumption of 5 MW per km^2, which is equivalent to 13 MW per $miles^2$. Note that NREL number was chosen over UNC (19.6 vs. 13) to be more conservative

[86] UNC report page 195

development potential is very large and will not be a limiting factor in terms of future development.

FIGURE 53: WIND RESOURCE IN NORTH CAROLINA STATE WATERS[87]

Capacity Factor	Area (Mi^2)	Avg. Depth (m)	Foundation Suitability[88]		Feasibility Multiplier	Technical Potential (MW)	Practical Potential (MW)
			Monopile	Moderate Feasibility			
<30%	38.80	5.7	81.1%	18.9%	0%	502	-
30-35%	87.18	5.8	84.4%	15.6%	50%	1,129	476
35-40%	25.45	5.2	62.2%	37.8%	50%	330	102
Total	151.43					1,961	579

FIGURE 54: WIND RESOURCE IN FEDERAL WATERS OFF NORTH CAROLINA[89]

Capacity Factor	Area (Mi^2)	Avg. Depth (m)	Foundation Suitability			Feasibility Multiplier	Technical Potential (MW)	Practical Potential (MW)
			Monopile	Gravity Based	Mod. Feasibility			
<30%	18	16.5	0.0%	0.0%	100%	0%	233	-
30-35%	1,143	26.9	78.0%	0.0%	22.0%	50%	14,802	5,773
35-40%	801	28.4	47.7%	0.0%	52.3%	50%	10,373	2,474
>40%	909	34.5	58.8%	27.5%	13.7%	50%	11,771	5,079
Total	2,871		0.0%	0.0%	100%		37,179	13,326

5.3.8 SOLAR

According to SolarBuzz, the global solar electric industry has grown by an average of 30 percent per year over the past 20 years. Over the same time period costs have declined due to economies of scale, and improvements in technology and solar cell efficiency. 7.3 GW of solar

87 Data on the area, average depth, and foundation suitability from table 10.1 on page 355 of the UNC report

88 Monopile foundation is a type of turbine foundation used in soft soil or shale, the monopile is driven 30-35 meters below the sea shore. Gravity based foundations are used on rocky bottoms. The gravity based foundation relies on its mass, including ballast material, to withstand the axial and lateral forces and the overturning moment generated by the local environment and the turbine. The Moderate Feasibility category refers to an area of transition between suitable and unsuitable geologic conditions for either gravity based or monopile foundations.

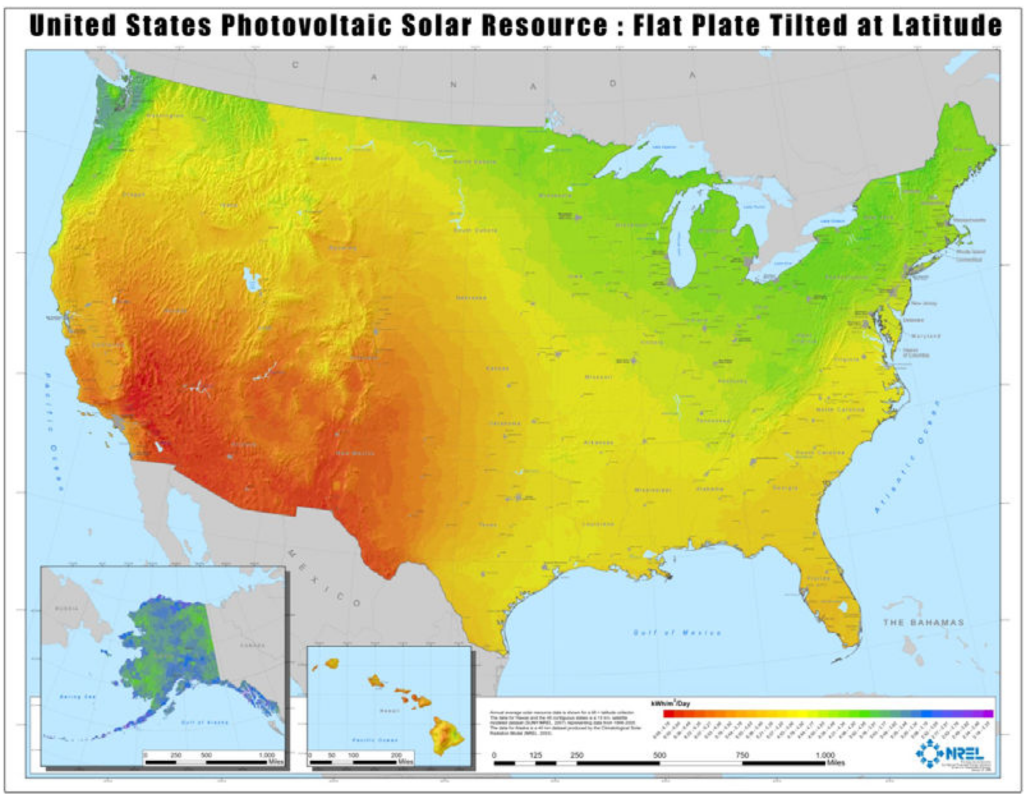
89 Data on the area, average depth and foundation suitability from table 10.2 on page 357 of the UNC report

PV was installed in 2009 worldwide and installations were expected to be more than 10 GW in 2010.[90]

The United States solar market is expanding quickly as well. Grid connected solar PV installations reached 878 MW in 2010 up from 435 MW in 2009, bringing the total U.S. installed capacity to 2.1 GW by the end of 2010.[91] North Carolina was one of the top ten solar markets in the United States with 31 MW installed in 2010 up from 8 MW installed in 2009.[92]

The map in Figure 55 below shows the solar resource in the United States for solar PV panels. It shows that North Carolina has a relatively good resource, but not one as strong as the solar resource in the southwestern United States.

FIGURE 55: NREL SOLAR PV RESOURCE MAP OF THE UNITED STATES[93]



90 SolarBuzz. Solar Energy Market Growth. http://www.solarbuzz.com/facts-and-figures/markets-growth/market-growth Accessed March 14, 2011.

91 Solar Energy Industries Association and GTM Research. US Solar Market Insight: 2010 Year in Review. Page 3, http://www.seia.org/galleries/pdf/SMI-YIR-2010-ES.pdf Accessed March 14, 2011.

92 Ibid, page 9.

93 National Renewable Energy Laboratory. Solar Maps. http://www.nrel.gov/gis/solar.html

5.3.9 *UTILITY PROGRAMS*

The solar set-aside under REPS began in 2010 and both Duke and Progress have been procuring solar resources to satisfy related requirements. According to Duke's 2010 compliance plan, it has implemented a 10 MW solar PV Distributed Generation Program, has signed a PPA with Sun Edison for a 15.5 MW facility in Davidson County, and has entered into a long term contract for RECs from solar hot water installations.[94]

Progress has procured some solar through its November 2007 RFP, implemented a commercial program for 5 MW a year and has filed for NCUC approval of a residential program to add 1 MW per year. Progress anticipates adding 6 MW per year through 2016.[95]

Solar PV Potential in North Carolina

The potential for development of solar PV in North Carolina is limited only by locations available to install solar panels. The consensus among developers and other stakeholders we spoke to was that there was no shortage of land or rooftops for solar PV in the state. To put it in perspective, about 10 acres of land is required for a 1 MW solar PV installation and there are about 31 million acres of land in North Carolina. If the 2021 REPS requirements were to be met entirely by solar PV in North Carolina, this would require 11 GW of solar PV and 110,000 acres of land or roughly 0.3 percent of the state.

Because the locations available for solar installation will not limit development, we have characterized the technical and practical potential for solar PV as unlimited.

Solar Hot Water Heating

Improvements in technology as well as continued concern regarding reducing GHG emissions have revived interest in the potential for solar hot water heating. The technical potential for solar hot water in North Carolina is vast. North Carolina has several military bases, agricultural facilities, hundreds of institutional structures such as prisons and university dormitories, and thousands of hotels in addition to millions of residential applications for solar thermal. Currently there is roughly 20 MW-equivalent of solar thermal hot water in the state. This 20 MW is based on providing hot water heating at only a small portion of one military base, one large poultry processing facility, and two dozen medium size commercial facilities. We conservatively estimate the practical potential to be 80 MW by 2020, or four times

94 Duke Energy. Duke Energy Carolinas, LLC's 2010 REPS Compliance Plan. Docket No. 100 Sub. 128. Filed September 1, 2010. Page 9.

95 Progress Energy. Integrated Resource Plan: Appendix D Alternative Supply Resources: North Carolina REPS Compliance Plan September 13, 2010, page D-3.

its current size. [96] Potential regulatory decisions regarding the solar set-aside as well as property assessment and financing issues are relevant factors that may impact how many installations are achieved.

5.3.10 *BIOMASS*

Biomass Potential Summary

FIGURE 56: BIOMASS FUEL POTENTIAL SUMMARY

Biomass Fuel Type	Maximum Deliverable by 2021 (million dry tons)	Total Fuel (million MMBtu)	Technical Potential (MW)	Practical Potential (MW)
Forest Biomass (technical potential scenario only)	14.5	245.8	2,539	N/A
Forest Biomass (SRTS model)	5.8	98.9	N/A	1,021
Urban Wood Waste	1.2	20.0	206	103
Crop Residues	1.8	28.5	295	147
Energy Crops	1.2	19.5	202	101
Total	**10.0**	**166.9**	**3,242**	**1,373**
Co-fire with Coal ***(subset of total biomass potential)***		**76.2**	**787**	**787**

Fuel Sources

Determining the technical and practical potential for biomass generation requires specifying how biomass resources are defined. The statute provides several examples of eligible biomass resources, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases and energy crops.[97]

[96] NREL estimates regional end-use energy consumption for water heating in the South Atlantic to be 31 billion kWh for residential and commercial users. The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States, P. Denholm, March 2007, page 4

[97] G.S. §62-133.8(a)(8)

The NCUC has interpreted the definition broadly, indicating that these examples are not to be taken as an exhaustive list of eligible biomass resources. Instead, the NCUC will determine biomass fuel eligibility on a case-by-case basis. The NCUC has ruled that at least in some circumstances the burning of whole trees can be considered a renewable resource.[98] There has not yet been a ruling on the eligibility of whole trees harvested specifically for biomass energy.

The practical biomass potential available to meet REPS is limited primarily by the availability of eligible biomass fuel that can be harvested or gathered and delivered to a generator economically. It is beyond the scope of this analysis to evaluate the environmental impacts, positive or negative, associated with the use of any particular biomass fuel source. The breadth of biomass resources eligible for REPS makes the estimation of biomass energy potential significantly more difficult. We have estimated biomass fuel potential in three broad categories: forest biomass, urban wood waste, and agriculture.

Forest biomass

Numerous studies have estimated the availability of forest residues for biomass electricity.[99] Forest residues are the tops, limbs, broken pieces, and unmerchantable species left behind by traditional roundwood harvests, or as a result of cultural operations (such as pre-commercial thinning) and timberland clearing. Although there is some divergence among the estimates, they all are a function of three key assumptions: the amount of residues generated by harvesting and thinning operations; the expected level of forestry activity over the study period; and the portion of residues that can be collected and delivered to generation resources feasibly, sustainably and economically. Only on this last assumption is there significant disagreement among studies.

When whole trees harvested specifically for biomass energy generation are added to the equation, the analysis becomes considerably more complicated – and the body of literature thinner. When considering only residues, whole tree harvest levels are usually assumed to be unaffected by biomass demand. This assumption is reasonable because biomass demand that can only be met with residues would not be expected to have a major impact on the market for roundwood products.[100]

98 Ruling is currently under appeal. NCUC Docket E-7, Sub 939 and 940. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=YAAAAA48201B&parm3=000132344

99 See, for example, Walsh 2000; Milbrandt 2005; La Capra Associates 2006; Galik et al. 2009, North Carolina Biomass Council, 2009. Full citations provided in the bibliography.

100 Roundwood products refer to products made from the stem (or trunk) of whole trees.

However, when demand for biomass fuel is allowed to compete directly with traditional users of roundwood products such as pulpwood (e.g. paper industry) and sawtimber (e.g., construction industry), the response of timber markets to biomass demand becomes a crucial factor. The response can include both displacement of traditional industry demand as well as increases in total harvest.

Technical potential

In these circumstances, technical potential of forest biomass is not a particularly helpful concept. Theoretically, the region's forests could all be clear-cut and replaced with fast-growing pine plantations, and existing demand from industries such as pulp and paper and construction could be completely displaced to produce massive amounts of fuel for biomass energy. Though such a scenario is highly unrealistic and undesirable, it is technically feasible.

For our estimate of technical potential, we chose a more "moderate" scenario in which all logging residues that can be collected and all pulpwood removals at historic levels are burned to generate biomass electricity. We assumed an 85% utilization rate for logging residues, which is at the high end of the spectrum in the literature. We relied on data from the 2009 Timber Products Output (TPO) study of the USDA Forest Service's Forest Inventory and Analysis (FIA) program. We averaged annual harvest data from 1995 to 2007 for all of North Carolina as well as the South Carolina counties in Duke or Progress' service territories.[101] Based on this approach, we conservatively estimate that more than 2,500 MW of electricity could be fueled by forest biomass (see Figure 57 below).

FIGURE 57: ESTIMATION OF TECHNICAL POTENTIAL FROM FOREST BIOMASS IN STUDY REGION*

	Historic Average Annual Amount (million dry tons)	Maximum Deliverable Amount[102] (million dry tons)	Available Energy @ 8,500Btu/dry lb (MMBtu)	Electric Potential @ 13,000Btu/kWh and 85% capacity factor (MW)
Logging Residues	7.91	6.73	114,367,798	1,182
Pulpwood	7.73	7.73	131,396,995	1,357
Total	**15.64**	**14.46**	**245,764,793**	**2,539**

** The study region includes all of North Carolina, some Virginia border regions, and South Carolina counties in Duke or Progress service territory.*

101 http://fia.fs.fed.us/program-features/tpo/

102 Assumes 85% utilization rate for logging residues.

Practical Potential

We assumed that *practical* potential is limited to forest biomass that can be harvested without causing unacceptable harm to forest resources or displacement of existing forest product industries, and delivered economically to a generation resource. To develop our estimate, we collaborated with Robert Abt, Professor in the Department of Forestry and Environmental Resources at North Carolina State University and a widely acknowledged expert on forest biomass resources in the South. Dr. Abt convened a team of experts[103] to work with La Capra Associates to develop input parameter scenarios for the Subregional Timber Supply (SRTS) model to produce forecasts of timber market prices and forest resource dynamics in response to different levels of REPS-driven demand for forest biomass.

Our assessment is that by the year 2021, roughly 1,000 MW of biomass electricity could feasibly and economically be fueled by forest biomass resources. With aggressive development of dispersed biomass generation and adoption of new harvest practices, virtually all of this potential could be met with forest residues. Our approach and conclusions are summarized below; for more detailed information on this modeling process, please see Appendix D.

The SRTS model

SRTS is an economic resource allocation model combined with a biological model that forecasts timber market dynamics, harvest activity and forest stocks across the South by zone, species, product, and forest type.[104] We used the model to predict the impact of various levels of REPS-driven demand for forest biomass-fired electricity on timber markets and forest resources within the utilities' service areas.

In SRTS model runs used to estimate forest biomass potential, user-specified biomass energy demand was assumed to be completely inelastic. In other words, any level of energy-related demand we entered would be supplied by the model, regardless of price. Our method for estimating practical forest biomass potential was to run SRTS multiple times with varying levels of assumed biomass energy demand until we found a maximum level that could be supplied within a feasible market equilibrium scenario. We then applied metrics to judge the feasibility of scenarios; specifically price effects, net harvest levels, and displacement of traditional wood industry demand.

Key assumptions

To estimate practical potential we made key assumptions regarding other biomass and traditional wood demand, residue utilization rates, location and sustainability. Our objective

103 The "SRTS Team" included Robert Abt; Christopher Galik, Research Coordinator for the Nicholas Institute for Environmental Policy Solutions at Duke University; and Karen Abt, Research Economist, USDA Forest Service.

104 For more detailed description of the SRTS model, see Abt, R.C., Cubbage, F.W., Abt, K.L. (2009). Projecting southern timber supply for multiple products by subregion. *Forest Products Journal,* 59(7/8): 7-16.

was to determine the maximum potential given these parameters. The summary table below illustrates this for two separate cases.

FIGURE 58: KEY ASSUMPTIONS FOR SRTS MODEL INPUTS

SRTS Model Input	Case 1 (Maximum Potential)	Case 2
REPS-driven biomass demand	1,700 GWh in 2011, rising to 13,236 GWh by 2025.	1,444 GWh in 2011, rising to 10,370 GWh by 2025
Other biomass energy demand	Wood pellet demand based on existing and likely announced[105] project capacity. No RFS-driven demand for woody biomass.	
Maximum residue utilization rates	Softwood: 85% by 2015 Hardwood: 70% by 2015	
Study Area	All of North Carolina; some Virginia border region[106]; South Carolina counties in Duke or Progress service territory.	
Sustainability Screen	Based on occurrence of extant elements from NC Natural Heritage Program database. Exclusion ratio ranges by forest type: Deciduous: 1.3% - 3.7% Evergreen: 1.4% - 6.9% Mixed: 1.3% - 3.8% Woody Wetland: 1.2% - 9.4%	

We assumed that biomass energy demand is met first with all residues, and only begins competing for pulpwood and sawtimber when available residues are exhausted. We assumed that maximum average residue utilization rates would climb from 0% in 2010 to 70% for hardwood species and 85% for softwood species by 2015. These residue utilization rates are

105 From Forisk Consulting – only announced projects that have passed both their technology and status screens.

106 Virginia region included is same as was included in Abt, R.C., Abt, K.L., Cubbage, F.W., Henderson, J.D. (2010). Effect of policy-based bioenergy demand on southern timber markets: A case study of North Carolina. *Biomass and Bioenergy* 34: 1679-1686.

higher than most rates assumed in other studies, but are supported by ongoing research at North Carolina State University of timber harvesting in North Carolina.[107]

REPS is not the only driver of demand for biomass-fueled energy in North Carolina. One potential driver of demand for forest biomass is the federal Renewable Fuel Standard (RFS), which sets minimum standards for how much gasoline and diesel fuel must be produced from renewable sources each year. However, the initial announced targets have been steadily lowered in the face of shortfalls in production, and it is expected that energy crops and other sources would likely be preferred over wood feedstock for producing cellulosic ethanol.[108] Our model runs therefore assume no forest biomass is used to meet RFS-driven demand for biofuels.

Another potential driver of forest biomass energy demand is the wood pellet industry. In recent years, the South has seen an increase in existing and planned wood pellet production, primarily for export to European markets. The largest pellet production facilities in the world are located in the region. Green Circle Bio Energy Inc. opened a Florida facility in 2008 that produces a half million tons of pellets annually to be co-fired with coal in Western Europe.[109] RWE Innogy is now in the final stages of commissioning a Georgia plant that will convert 1.7 million green tons of wood and residuals into 827,000 tons of pellets per year for export to Europe, primarily the Netherlands.[110] A company with a long-term pellet supply contract with a Belgian utility has proposed a 330,000-ton annual capacity project in North Carolina.[111]

Our assumed level of wood demand for pellets was based on Forisk Consulting's estimate of demand for existing plants and proposed projects that have passed the status and feasibility screens[112] according to the June 2010 Wood Bioenergy South report.

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107 Hazel, D., Bardon, R., Megalos, M., Hopkins, C., and Osborne, N. (2009) *Estimates of Available Woody Residue Biomass from Timber Harvesting for Conventional Timber Products in North Carolina*. Project Completion Report to and Funded by the Biofuels Center of North Carolina.

108 2/23/11 conversation with Karen Abt

109 http://www.greencirclebio.com/plant.php. Accessed 3/14/11.

110 http://www.rwe.com/web/cms/en/86182/rwe-innogy/news-press/press/?pmid=4004685. Accessed 4/1/2011.

111 http://www.forest2market.com/f2m/us/f2m1/free/forest2fuel-archive/story/2011-Feb-Enviva. Accessed 3/14/11.

112 Technology screen is Forisk's assessment of whether the project is commercially viable today. The status screen indicates whether the project has received/secured/signed two or more of the following: financing, air quality permits, Engineering Procurement and Construction contracts (EPC contracts), power purchase agreements for electricity facilities, interconnection agreements for electricity facilities, and supply agreements.

Our assumed demand from other biomass energy drivers is on the conservative side so that we can estimate a maximum potential for REPS-driven biomass demand. To the extent any of these additional demands exceed our assumed levels, the potential for forest biomass-fired electricity will be reduced.

The study area included not only North Carolina, but also border counties of Virginia and the South Carolina counties in Duke or Progress Energy's service territory. Since it is generally not economic to deliver biomass fuel long distances (50 miles is a commonly cited maximum), we assumed this to be the potential fuel supply zone for biomass plants that could deliver electricity to North Carolina.[113] Although very few explicit harvesting guidelines or restrictions are currently in place for eligible biomass fuel, we assumed that REPS was not intended to result in overharvesting of sensitive forest areas. In order to model minimum standards with some logical relationship to geographic divisions and forest type distribution, Christopher Galik and the SRTS team developed a screen based on the relative occurrence of extant elements from the North Carolina Natural Heritage Program database.

Case 1 results

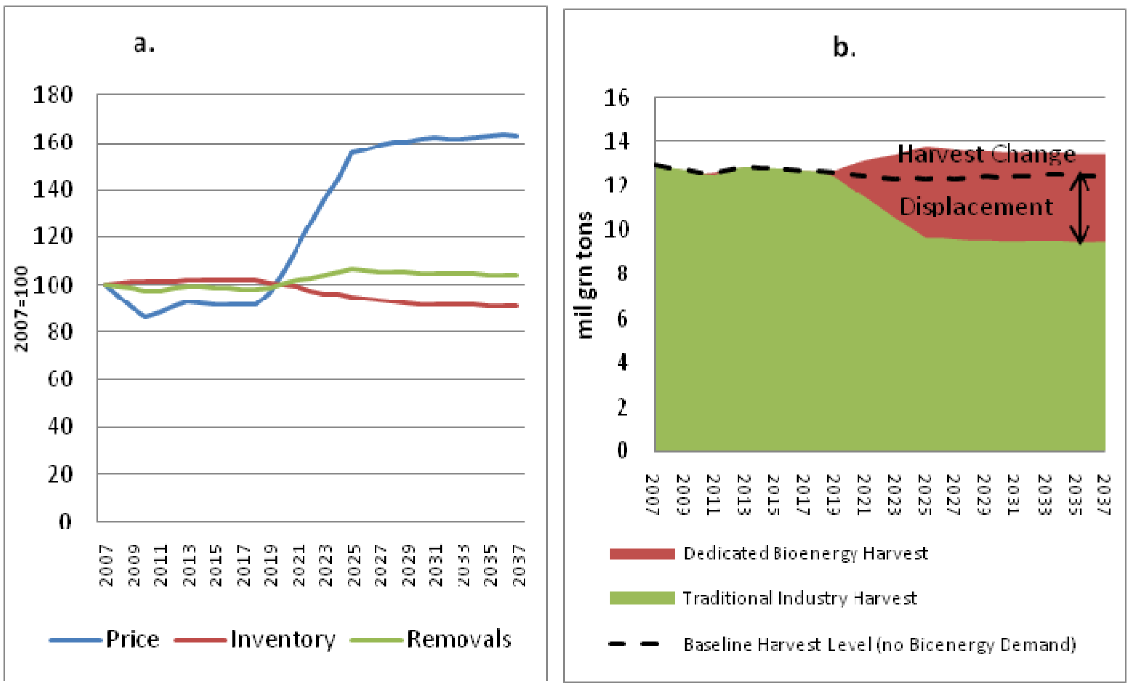
For our initial attempt at forest biomass electricity potential, we ran the SRTS model with 1,600 GWh REPS demand in 2011, increasing 776 GWh per year until reaching 12,457 GWh in 2025 ("Case 1"). This is roughly the level of energy generation needed for Duke and Progress to comply with their REPS requirements (excluding set-asides) entirely with forest biomass.[114] We concluded, however, that this level of production was not feasible because it resulted in a 60% price increase over 2007 levels for pine pulpwood by 2025 (see Figure 59a), as well as the displacement of nearly 24% of traditional industry demand for pine pulpwood when compared to a baseline scenario without biomass demand (see Figure 59b).[115]

113 We largely ignored Dominion in this analysis because they do not have any in-state requirement for renewable energy under REPS.

114 All biomass energy demand – REPS-driven and otherwise – is treated uniformly in the SRTS model. Therefore, the proportion of biomass energy demand in any particular case assumed to be for REPS-driven demand compared to RFS, pellet mills, and other bioenergy demand can be changed without affecting model output in any way.

115 Pine pulpwood is generally the least expensive roundwood product, and therefore the most likely to be used for energy production. In most model runs, impacts on sawtimber markets are minimal.

FIGURE 59: INITIAL BIOMASS DEMAND SCENARIO (CASE 1) RESULTS. (A) PRICE, INVENTORY AND REMOVAL TRENDS AND (B) HARVEST CHANGES COMPARED TO BASELINE (NO BIOMASS ENERGY DEMAND).



Case 2 results

Next, we reduced the amount of energy demand by 17% and ran the SRTS model again with all other assumptions held constant ("Case 2").The REPS-driven biomass demand in this case begins at 2.2 million green tons in 2011 and climbs to 15.9 million green tons by 2025. In 2021, the case supplies enough forest biomass to generate 7,600 GWh of electricity.

In the Case 2 SRTS model run, pine pulpwood prices increased only 35% over the entire 30-year study period. Using a 3-year (2006-2008) average of statewide pine pulpwood stumpage prices from Forest2Markets quarterly timber reports, we estimated a 2007 stumpage price of $6.08[116] per green ton. Using this as a basis, our Case 2 scenario projects pine pulpwood prices rising to just under $8.00 by 2025 and leveling off to about $8.20 by 2036. Using the simplifying assumption that stumpage price generally is about 36% of total delivered fuel cost for forest biomass,[117] this translates to a delivered price of $21.58 per green ton.

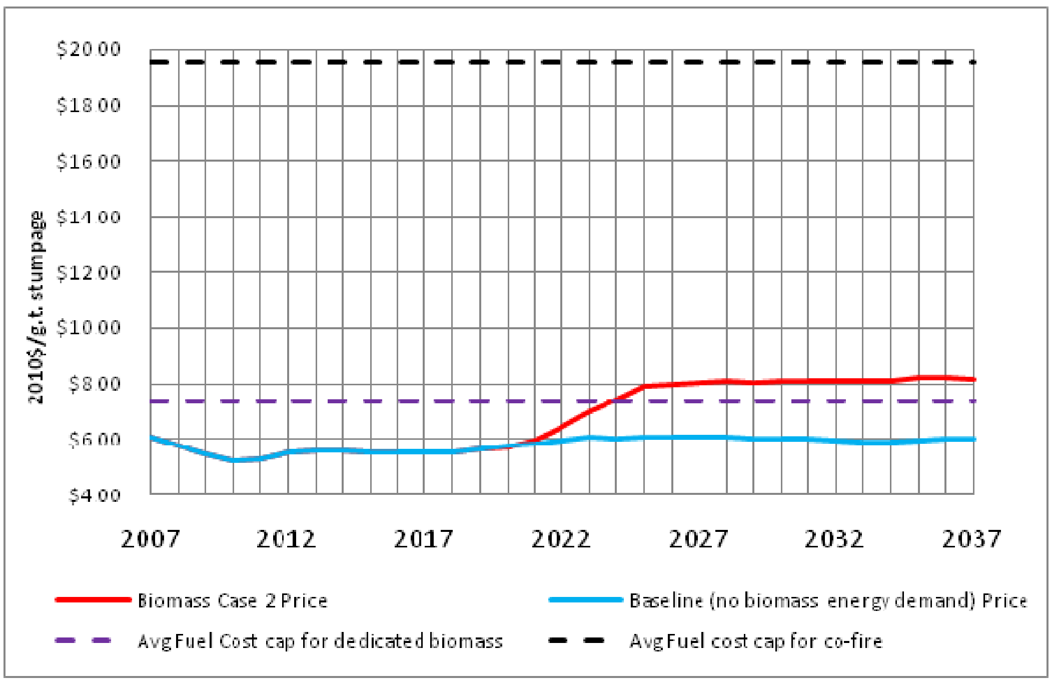
To determine if biomass electricity could potentially be generated with fuel prices rising to these levels, we first estimated an average cost cap on energy to meet general in-state REPS

116 All prices in this section are given in constant 2010 dollars.

117 Estimate from Robert Abt based on current market data.

requirements. Using public and confidential utility data, stakeholder input and La Capra Associates industry knowledge we estimated the maximum average incremental cost of compliance for the general in-state requirement[118] over the 2010 – 2025 time frame to be about $35/MWh. In order to produce biomass electricity within that cost cap, the price of fuel must average less than $7.34 per green ton stumpage ($20.40 delivered) for dedicated biomass plants or $19.58 per green ton stumpage ($54.40 delivered) for biomass co-fire plants. Figure 60 below illustrates that pine pulpwood prices remain below the dedicated biomass limit through 2024, and only exceed it slightly thereafter. Prices remain well within limits for co-fire. Based on these modeled prices we assessed that it is feasible for the biomass demand in Case 2 to be economically delivered to generation resources.

FIGURE 60: FORECASTED PINE PULPWOOD PRICE IMPACTS IN BIOMASS DEMAND CASE 2



Therefore, the REPS-driven demand for biomass energy modeled in Case 2 (and shown below in Figure 61A) is taken as the practical potential for forest biomass-fueled electricity delivered to North Carolina utilities. In 2021, the potential shown is 11.6 million green tons, which contains

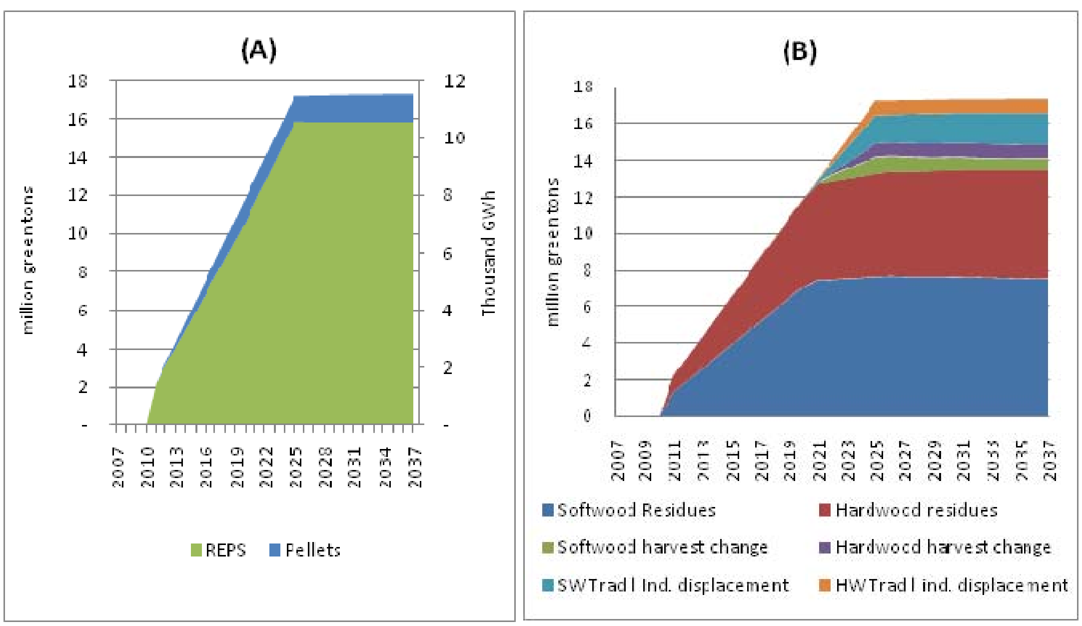
118 Less solar, poultry waste and swine waste set-aside requirements, out-of-state REC allowances, and assumed levels of energy efficiency. Costs for these portions of the requirements were estimated and subtracted from the total cost cap for the purpose of estimating the incremental cost cap of "general" REPS renewables.

enough energy to generate 7,600 GWh of electricity.[119] If we assume an average plant capacity factor of 85%, this amount of fuel is sufficient to supply 1,021 MW of biomass capacity.

Furthermore, as shown in Figure 61B, the majority of forest biomass supplied in this scenario is from residues. In fact, until 2021 the biomass energy demand is met entirely with residues. Only when demand climbs above 12 million green tons (enough to generate almost 8,000 GWh of electricity) are residues insufficient to fully supply energy demand. This result should be treated with some caution because our modeling assumptions for residue utilization rates were very aggressive. In order to achieve our assumed rates, biomass generation resources would need to be distributed throughout North and South Carolina by 2021, and residue collection rates would need to almost universally hit maximum achievable limits throughout the region. If these conditions are not met, the practical potential for forest biomass fuel from residues will be reduced.

Whether or not the full potential from residues is realized, our results indicate a large potential for forest biomass fuel even if dedicated harvests of whole trees were excluded from the definition of eligible biomass fuel.

FIGURE 61: BREAKDOWN OF BIOMASS ENERGY DEMAND (A) AND SUPPLY (B) IN CASE 2



119 Assuming energy content of 8,500 BTU/dry lb, and plant heat rate of 13,000 BTU/kWh.

Urban waste and agriculture

Biomass electricity can also be generated by burning urban wood waste, crop residues, and dedicated energy crops. Urban wood waste includes construction and demolition ("C&D") waste and municipal solid waste ("MSW"). Crop residues refer to stalks, husks, leaves and other remnants; corn stover and wheat straw are the most readily available for biomass use. Finally, some crops such as switchgrass and hybrid poplar can be cultivated specifically for biomass energy.

There have been several studies assessing the potential for each of these resources in North Carolina and the region, including the La Capra Associates 2006 report. After a review of existing literature, we did not find evidence that the picture has changed significantly since 2006. In fact, two recent papers to come out recently on the state's biomass potential cite the numbers used in La Capra Associates' 2006 report for urban wood waste, crop residue and dedicated energy crop potential.[120,121]

Studies differ in their assessment of practical potential based in part on differing assumptions about which resources might be available for biomass electricity. Some exclude municipal solid waste due to concerns about contamination and resulting harmful emissions. Others assume energy crops will be used to produce biofuels rather than biomass electricity. However, a review of several studies estimating the technical potential on an energy basis from these sources in North Carolina found that they fall within a range of roughly 51 to 61 million MMBtu of energy potential (see Figure 62).

120 North Carolina Biomass Council (2007). *The North Carolina biomass roadmap: Recommendations for fossil fuel displacement through biomass utilization.*

121 Abt, Abt, Cubbage & Henderson (2010).

FIGURE 62: COMPARISON OF ESTIMATES OF URBAN WASTE AND AGRICULTURE BIOMASS TECHNICAL POTENTIAL IN NORTH CAROLINA (1,000 MMBTUS)

Resource Type	Walsh 2000[122] (@ <$50/d.t. delivered, 1997$)	LCA 2006 Study/NC Biomass Roadmap (2007)	Milbrandt 2005
Urban Wood Waste			
Construction and Demolition waste (8,500 Btu/dry lb)	18,021	15,262	15,610
Municipal Solid Waste (8,500 Btu/dry lb)		14,225	
Agriculture – Crop Residues			
Corn Stover (7,400 Btu/dry lb)	9,706	14,260	25,690
Wheat Straw (7,800 Btu/dry lb)	7,409	942	
Agriculture – Energy Crops			
Switchgrass (8,000 Btu/dry lb)	26,113	4,210	10,176
Hybrid Poplar (8,500 Btu/dry lb)		5,149	--
Total, Urban Waste and Agriculture	61,249	54,049	51,476

Based on this review, we decided to use technical estimates from the 2005 National Renewable Energy Laboratory (NREL) study by Milbrandt.[123] NREL is a well-respected source, and the numbers for North Carolina were on the conservative end of the spectrum. Also, the Milbrandt study produced estimates for all 50 states, allowing us to include South Carolina resources in our potential estimates. Assuming that South Carolina does not have an RPS, we estimated that half of the potential resources in South Carolina could be available within the North Carolina utilities' service territories.

As shown in Figure 63, we estimate the technical potential for biomass electricity fueled by urban wood waste, crop residues and dedicated energy crops and delivered to North Carolina to

[122] Walsh, M.E., Perlack, R.L., Turhollow, A., De La Torre Ugarte, D., Becker, D.A., Graham, R.L., Slinsky, S.E., and Ray, D.E. (2000). *Biomass Feedstock Availability in the United States: 1999 State Level Analysis*.

[123] The Milbrandt study makes clear that it calculates technical potential, with no consideration of economic or theoretical availability (see p1).

be about 750 MW. Milbrandt's estimate of potential makes no consideration for economic or theoretical constraints on these resources. Such an analysis could not be found in the recent literature for North and South Carolina, and is beyond the scope of the current survey. Therefore, we applied the methodology used by Abt et al. (2010) in their recent case study of bioenergy demand in North Carolina. Their study assumes that 50% of technically available agriculture and municipal wastes become available for energy. Using this assumption, we estimated a practical potential for these fuel supply resources of about 375 MW.

FIGURE 63: TECHNICAL AND PRACTICAL POTENTIAL OF URBAN WOOD WASTE AND AGRICULTURE BIOMASS RESOURCES, BASED ON MILBRANDT 2005

	Technical Energy Potential, NC *(000 MMBtu)*	50% of Tech. Energy Potential, SC *(000 MMBtu)*	Technical Electric Potential[124] *(MW)*	Practical Electric Potential[125] *(MW)*
Urban Wood Waste	15,610	4,376	206	103
Crop Residues	25,690	2,846	295	147
Energy Crops[126]	10,176	9,356	202	101
Total	**51,476**	**16,578**	**703**	**352**

Biomass Generation

There are many different technologies for converting biomass fuel into electricity, including co-firing with coal or other fossil fuels in existing plants, direct combustion (including stoker boiler and fluidized bed technology) and gasification. For the purposes of our potential estimates, we assume that all of the above mentioned fuel resources can be burned in any type of biomass generation plant.

Dedicated Biomass

Dedicated biomass plants generate electricity primarily from biomass fuel. Stoker boiler and some fluidized-bed technologies are well-established and proven to be commercially viable at the utility scale. One prominent example that was built before 2007 is the 50 MW Craven

124 Assumes that the fuel will be burned at a plant with a 13,500 BTU/kWh heat rate and 85% efficiency.

125 See previous note.

126 Based on the potential for growing switchgrass on Conservation Reserve Program (CRP) lands.

County Wood Energy biomass plant in New Bern, North Carolina, which uses stoker boiler technology to burn a mix of wood waste and other biomass materials.

Biomass plants can be either "greenfield" projects built on new sites or "brownfield" projects that re-power retired coal or other fossil fuel-fired plants. Our potential estimate assumes the possibility of building biomass plants or re-powering fossil fuel-fired plants throughout the North Carolina IOUs' service territories in North and South Carolina. Since a large share of the cost of biomass fuel is transportation, it is unlikely that biomass of any type would be hauled more than 50 miles to a generator site. Of course, issues of permitting, financing and environmental review introduce a great deal of uncertainty in the development of any power plant. To the extent any barriers prevent widespread development of biomass, our potential estimates would need to be adjusted downward.

Co-firing

According to the most recent data from the U.S. EPA,[127] there is about 17,300 MW of coal-fired capacity located within North Carolina and the South Carolina service territories of Duke and Progress. Of that capacity, just over 4,200 MW is slated to be retired in the next five years, leaving more than 13,000 MW of existing coal power that might be co-fired with biomass.

In order to estimate a technical potential for co-firing, we simulated the methods and assumptions used by Abt, Galik and Henderson in their 2010 assessment of co-fire potential in the Southeastern United States.[128] Boiler level data from eGRID was screened for boilers with bituminous, sub-bituminous, lignite or synthetic coal as their primary fuel. We then eliminated boilers already co-firing with biomass or slated to retire in the utilities' 2010 IRPs.

Based on information from utilities' IRPs, we assumed that within a few years all remaining coal plants will have installed control devices[129] to reduce NO_x emissions. The alkali content of biomass ash can inhibit the operation of such devices, and some consider co-firing infeasible at plants with SCR or SNCR scrubbers installed. In contrast, Abt et al. cite studies that report successful co-firing at "scrubbed" plants at rates of up to 10%. We adopt this figure as our maximum co-fire rate, while acknowledging that if technical challenges associated with co-firing at SCR/SNCR-scrubbed plants prove greater than anticipated, practical potential for co-firing could be as low as zero.

127 eGRID2007 Version 1.1, based on 2005 data. Since this analysis was done, EPA has released eGRID2010 with 2007 data.

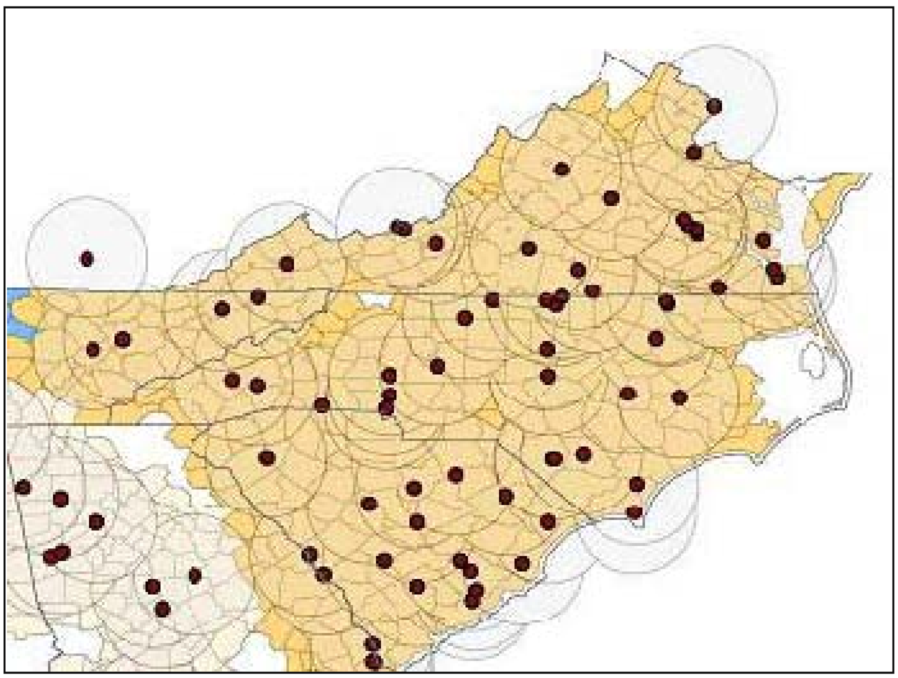
128 Abt, R., Galik, C. and Henderson, J. (2010) The near-term market and greenhouse gas implications of forest biomass utilization in the Southeastern United States. *Climate Change Policy Partnership*, *Duke University*

129 Either selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) reactors.

Unadjusted heat input numbers from eGRID for each eligible boiler were multiplied by the maximum co-firing rate of 10% to obtain an estimate of the maximum amount of biomass energy that can be co-fired. Our analysis showed that up to 76.2 million MMBtu, or about 787 MW of capacity, could potentially be co-fired in plants delivering power to North Carolina.[130]

Figure 64 shows the location of coal-burning facilities in North Carolina and the rest of the mid-Atlantic region, with 50-mile supply radii drawn around each. The map seems to indicate that the facilities are reasonably spread throughout the region, and would therefore draw from nearly the whole fuel supply region in the maximum co-fire scenario. Given a practical fuel potential to supply over 1,300 MW, we determined that 787 MW of co-firing as a subset of the total biomass potential is practical.

FIGURE 64: ADAPTED FROM ABT ET AL. (2010), MAP SHOWING COAL-BURNING FACILITIES WITH 50-MILE SUPPLY RADII FOR THE MID-ATLANTIC REGION[131]



[130] Assuming a heat rate of 12,000 BTU/kWh and a plant capacity factor of 85%

[131] Abt,. R., Galik, C. and Henderson, J. (2010) The near-term market and greenhouse gas implications of forest biomass utilization in the Southeastern United States. *Climate Change Policy Partnership*, *Duke University*

5.3.11 *HYDROPOWER*

Eligibility

A literal reading of S.B. 3 might lead to the interpretation that all hydro, regardless of age, ownership, or size, could be eligible for REPS compliance. However, subsequent NCUC orders have found that such an interpretation is contrary to the intent of the legislation, and has narrowed the definition. Small non-utility-owned hydro resources (<10 MW) that deliver power to North Carolina electric power suppliers qualify as new renewable resources regardless of when they were placed in service.[132] New and incremental additions (<10 MW) since 2007 of utility-owned hydro generation can qualify for REPS compliance. In addition, EMCs and municipal utilities can fulfill up to 30% of their REPS requirements with energy from large existing hydro resources (>10 MW), including their full allocations made by the Southeastern Power Administration (SEPA).[133]

New increments of additional hydroelectric power capacity of 10 MW or less will be regarded as new renewable energy facilities under NCUC's interpretation of REPS. Incremental additions can be an expansion or repowering of an existing hydroelectric power facility or the construction of a new facility. There are no restrictions on the type of eligible hydropower, e.g. run of river.

Increments of additional capacity greater than 10 MW can be eligible to fulfill a portion (up to 30%) of EMCs' and municipals' REPS compliance. However, since enough facilities exist already to fulfill this portion of the requirement, it is unlikely that any new increments would be developed as a result of REPS.

Potential Assessment

La Capra Associates' 2006 report relied on Idaho National Engineering and Environmental Laboratory (INEEL) data for hydropower potential analysis. We searched for updated data, but were unable to find any more recent sources of similar quality and sufficient granularity required for the analysis. We were also unable to find evidence of any new hydroelectric facilities built in North Carolina in the past 5 years. This analysis is therefore based on the same dataset as our 2006 potential estimate, but with updated assumptions to reflect the NCUC's current interpretation of resource eligibility under REPS.

132 In a 6/17/09 Order under Docket # E-100, Sub 113, the NCUC found that pre-2007 utility-owned hydro facilities are not eligible for REPS compliance.

133 NCUC Docket E-7, Sub 936 (8/13/10). The Commission ruled that EMCs and municipals can count their full SEPA allocation toward REPS requirements. Sources of SEPA energy include stream flow (traditional hydropower), pumping operations (hydropower generated through pumped storage operations), and "replacement energy" (energy SEPA purchases if its own generation is insufficient to meet contractual obligations to customers).

INEEL maintains a database of all potential hydropower sites in the United States, grouped into three main categories: sites with existing generation that could be upgraded; sites without generation but with existing impoundment structures; and undeveloped sites. Under REPS, new renewable hydropower facilities could be developed on any of these types of sites.

We used INEEL's Hydropower Evaluation Software (HES)[134] to evaluate 133 sites in North Carolina and northern South Carolina. HES assigns development likelihood factors (0.1 to 0.9) to each site based on environmental and other site attributes.[135]

To estimate technical potential for hydropower we used the HES-modeled potential, which is calculated by multiplying the nameplate capacity for each site by the HES likelihood factor. Our technical potential estimate of 938 MW includes sites larger than 10 MW.

FIGURE 65: TECHNICAL HYDROPOWER POTENTIAL

Site Type	Number of Sites	Technical Potential (MW)
Upgrades at existing generation site	8	18
New generation at existing impoundment	85	781
New generation at undeveloped site	40	139
Total	**133**	**938**

To estimate practical potential, we eliminated sites with less than 1 MW of potential because they would likely be too expensive to develop economically. We also eliminated sites larger than 10 MW because they would not qualify as new renewable energy facilities for REPS compliance. Finally, we eliminated sites judged by HES to be the least developable, with likelihood factors below 0.5. Using this approach, we estimated total practical potential to be 106 MW.

134 http://hydropower.inl.gov/resourceassessment/software/

135 These environmental attributes include whether a site has Wild and Scenic Protection or is on a tributary of a site with such protection, and other cultural, fishery, geologic, historic, recreational, or scenic attributes. The presence of threatened or endangered fish or wildlife influences the suitability factor. Other attributes include the potential project's location, including whether the site is within a national park, national grassland, national wildlife refuge, or another federal land.

FIGURE 66: PRACTICAL HYDROPOWER POTENTIAL

Site Type	Number of Sites	Practical Potential (MW)
Upgrades at existing generation site	1	3
New generation at existing impoundment	32	82
New generation at undeveloped site	5	21
Total	**38**	**106**

5.3.12 *LANDFILL GAS*

Under S.B. 3, energy generated by the capture and combustion of landfill gas, which largely consists of methane, qualifies as a renewable energy resource. Landfill gas energy ("LFGE") generators are cost-competitive with conventional sources of electricity, and several projects were already operational before REPS was enacted. According to the EPA's Landfill Methane Outreach Program (LMOP) database, which catalogs all open and closed landfills, there were 16 operational facilities at the beginning of 2007.[136] Eleven of these facilities generated useful heat only and five were generating electricity or were combined heat and power facilities. These five LFGE facilities represented 12.3 MW of installed capacity.

Landfill gas projects have several benefits. Methane gas is created as waste material breaks down in landfills. Methane itself is a greenhouse gas and has a global warming potential more than 20 times higher than CO_2. By preventing the natural release of the gas and using it instead to generate renewable energy, LFGE projects serve multiple purposes.

Current Status in North Carolina

According to the EPA's LMOP database, there are currently eight electricity-generating projects in North Carolina totaling 20.8 MW of installed capacity. Of these projects, three (8.5 MW) came online in 2007 or later, so only these three are eligible for REPS.

In addition to those online, there are four units under construction representing 11.2 MW of capacity.

Future Resource Potential

Discussions with various stakeholders suggested that the pace of development of LFGE projects has recently slowed, indicating that the number of remaining high potential sites may be

[136] Landfill Methane Outreach Program Database. U.S. EPA. Available online: http://www.epa.gov/lmop/

limited. To verify this La Capra Associates estimated landfill gas potential using the EPA LMOP database. For this analysis, landfills in both North and South Carolina were included.

From the 197 total entries in the database, 53 were removed because LFGE projects were operating at the site or were under construction. An additional 73 landfills were removed because they were closed more than ten years ago. Useable gas production from a landfill tapers off after approximately ten years, so these were removed due to the low likelihood of sufficient gas flow remaining.

The 71 landfills remaining represent all the landfills in North Carolina and South Carolina that have not yet constructed LFGE facilities and are either still open, or were closed within the past ten years. For each of these landfills, an electricity generation potential was calculated, using the EPA estimate of 0.78 MW of capacity per one million tons of waste in place.[137] This yields a technical potential of 72.2 MW.

Many of the landfills in this subset had low levels of waste in place, and thus would only support small LFGE projects. To determine practical potential, any landfills that could not support a project at least 0.5 MW in size were removed. The remaining 40 landfills represent a practical potential of 68 MW.

FIGURE 67: CURRENT STATUS OF LFGE PROJECTS/POTENTIAL

Operational	Under Construction	Technical Potential	Practical Potential
20.8 MW (NC only)	11 MW (NC only)	72 MW (NC/SC)	68 MW (NC/SC)

5.3.13 *NUCLEAR*

Nuclear generation holds tremendous potential for emission-free electricity for North Carolina. With no emissions of CO_2, NO_x, SO_2, or mercury, proponents argue that an increase in nuclear generation could help the State achieve many of its emissions reduction goals. Despite these benefits, the potential for new nuclear development remains uncertain.

Currently, nearly one third of the electricity generated in the state comes from nuclear facilities, and each of the three IOUs has plans to add new nuclear capacity to their portfolios. The first anticipated project is expected to go online in 2019 and by 2023 the utilities jointly anticipate more than 4,000 MW of new nuclear capacity. Additionally, one of the key cited benefits of the

137 "An overview of landfill gas energy in the United States." U.S. EPA Landfill Methane Outreach Program (LMOP). May 2010. Available online: http://www.epa.gov/lmop/documents/pdfs/overview.pdf

proposed merger of Duke and Progress is the increased ability to develop new nuclear.[138] In a notice to shareholders, Duke officials note that the merger will put the combined company in "a stronger position to build new nuclear generating facilities…"[139]

In terms of a practical potential, the limits to nuclear expansion in North Carolina will be a function of potential environmental issues, construction schedules, transmission access, financial constraints and public perception. Environmental questions remain regarding the large amount of water used for cooling, a particular concern in North Carolina given the recent prolonged drought. The storage and disposal of nuclear waste is another controversial environmental concern and one that continues to pose a challenge to the nuclear industry. Public perception can play a role as well. Recent events regarding a potential nuclear meltdown at the Fukushima-Daiichi nuclear power plant in Japan will need to be monitored to determine their potential impact on future nuclear development.

5.3.14 *NATURAL GAS*

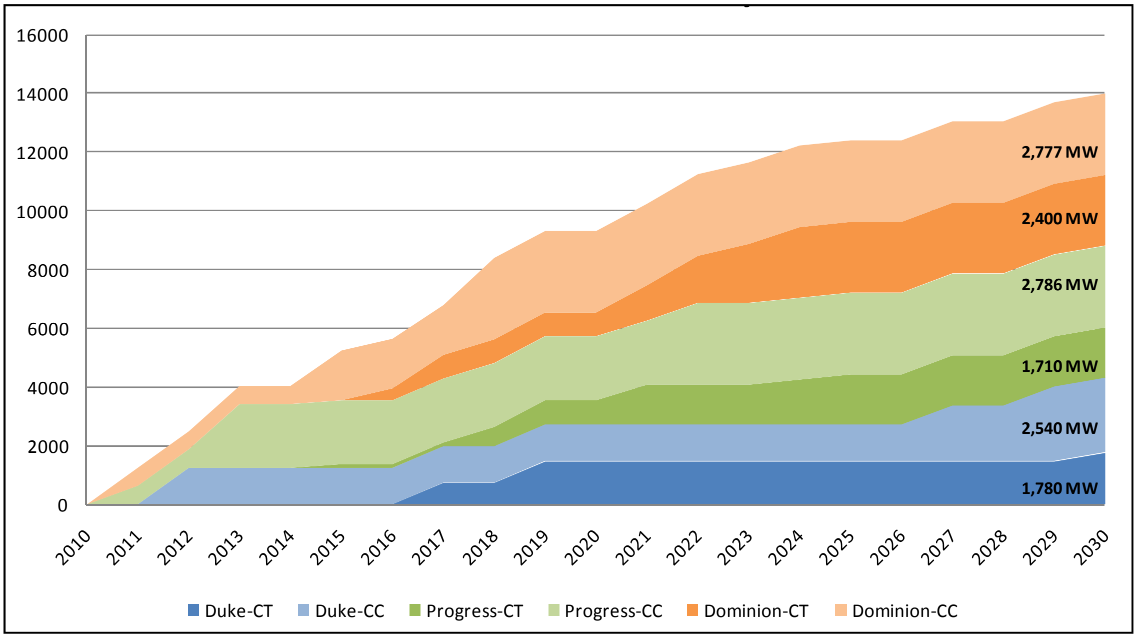
Historically, natural gas has been a relatively small part of North Carolina's generation mix. In 2000, electricity from natural gas represented less than 1% of total generation. This figure increased to more than 3% in 2008. Natural gas has typically been used to fuel combustion turbines, which are used intermittently to manage demand peaks and fluctuations. With the prospect for sustained lower natural gas prices as a result of the advent of shale gas and the development of high efficiency combined cycle plants, however, natural gas is becoming an increasingly integral part of North Carolina's generation portfolio.

North Carolina public utilities are planning to retire several coal-fired plants over the next four years and anticipate replacing them mostly with new combined cycle units. Over 4,000 MW of new combined cycle capacity is either under construction or has been approved by the NCUC. The figure below shows new natural gas capacity currently planned in the IOU IRPs.

138 "Duke Energy CEO calls for purpose-driven capitalism." Press release. March 2, 2011. http://www.duke-energy.com/news/releases/2011030201.asp

139 Duke Energy Corporation. U.S. SEC Form S-4, Registration Statement. March 17, 2011.

FIGURE 68: NEW GAS GENERATION IN IOU IRPS



Natural gas generation is less expensive than nuclear power and relative to nuclear represents a cost-effective carbon reduction strategy. Emissions of CO_2 per MWh are much lower for gas-fired units compared to coal units, so the switch from coal to natural gas will allow for a cleaner energy portfolio in North Carolina.

Potential

North Carolina has recently experienced an increase in possible development activity due to new estimates of shale gas deposits. Interested developers have begun leasing mineral rights in some areas despite the fact that current state law prohibits horizontal drilling and hydraulic fracturing ("fracking"), two common techniques of shale gas extraction.[140] There are ongoing efforts in the General Assembly to revisit these laws.

Despite the lack of in-state production, there is no resource constraint limiting the development of new natural gas facilities in North Carolina. Due to increases in domestic natural gas production as well as ample supply entering the Transco pipeline from the Gulf of Mexico and

140 Reid, Jeffrey, et al. "North Carolina Shale Gas – A Progress Report: Sanford Sub-basin, Deep River Basin, Lee, Chatham, and Moore Counties." North Carolina Geological Survey. February 28, 2011.

N.C. Gen. Stat. § 113-378 to § 113-415. "Subchapter V. Oil and Gas Conservation – Article 27."

15A NCAC 02C .0213. "Additional Criteria and Standards Applicable to Class 5 Wells."

new shale gas plays to the north in Pennsylvania and New York, North Carolina is well-situated to receive uninterrupted supply for the foreseeable future.

The only limits on the development of new natural gas generation, therefore, are construction time, expense, and load growth (i.e. whether or not new generation is needed).

RENEWABLE RESOURCE COSTS

5.3.15 *SUMMARY DISCUSSION OF COST PARAMETERS*

Figure 69 below shows the cost parameters for each of the resource options below. This enables a comparative view of the cost of various renewable and other low GHG-emitting resource options in North Carolina and a basis for understanding future costs and potential rate impacts of various resource portfolios. Cost estimates are derived in part by the following parameters:

- **Capacity factor.** The net capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time to its output if it had operated at full nameplate capacity the entire time.
- **Modeled Project Size.** This is the size of project that we modeled and the size of project to which the costs correspond. Smaller projects would likely be more expensive.
- **Overnight Costs.** Overnight cost is the cost to construct the resource if no interest was incurred during construction, as if the project was completed "overnight."
- **Technology Decline Rate.** This is the rate at which we are assuming costs decline each year. This parameter is zero for many resources. Resources with declining costs are generally emerging technologies such as offshore wind.
- **Fixed O&M.** This is the fixed component of the operations and maintenance expense. It is not dependent on the plant output.
- **Variable O&M.** This is the variable component of the operations and maintenance expense of operating the renewable resource not including the fuel costs.
- **Fuel Costs.** This is the cost of fuel required for the resource.
- **Heat Rate.** A measure of efficiency of a power generation resource, the heat rate signifies the amount of heat energy required to produce one kWh of electricity. Lower heat rates indicate more efficient resources. Resources not requiring fuel (like wind) do not have a heat rate.

FIGURE 69: COST PARAMETERS ($2010)

Resource Type	Capacity Factor	Modeled Project Size (MW)	Overnight Costs ($/kW)	Technology Decline Rate (% in Real$)	O&M		Fuel Heat Rate (Btu/kWh)	Fuel Costs ($/MMBtu)
					Fixed ($/kW-yr)	Variable ($/MWh)		
Renewable Energy								
Onshore Wind	30%	100	$2,340	0%	$28	$-	NA	0
Offshore Wind	37%	400	$4,800	5%	$53	$-	NA	0
Solar PV								
Utility Scale	15%	2	$3,400	3%	$26	$-	NA	0
Rooftop	15%	0.5	$3,600	3%	$26	$-	NA	0
Biomass								
Co-firing	85%	20	$200	0%	$70	$1.00	12,000	$2.00
Dedicated Biomass	85%	50	$3,343	0%	$101	$3.00	13,500	$2.00
Hydropower								
Upgrades at Existing Generation Site	45%	2.5	$1,010	0%	$-	$5.00	NA	0
New Generation at Existing Impoundment	45%	2.5	$3,030	0%	$21	$5.00	NA	0
Undeveloped Site	45%	5	$4,030	0%	$21	$5.00	NA	0
Landfill Gas	85%	5	$2,450	0%	$119	$-	13,650	0
Other Low GHG Emitting Energy Supply Options								
Nuclear	90%	2236	$6,500	0%	$113	$2.59	NA	
Natural Gas								
CT – Conventional Peaking	5%	83	$905	0%	$7	$14.70	10,850	$6.47
CT - Advanced	5%	204	$673	0%	$7	$9.78	9,750	$6.47
CC – Current Technology	70%	530	$888	0%	$14	$3.43	7,050	$6.47
CC - Advanced	70%	389	$914	0%	$15	$3.11	6,430	$6.47

5.3.16 *FINANCIAL MODELING*

Approach

As discussed in the previous section, we made assumptions regarding project size, capacity factor, and costs in 2010 dollars, specifically fixed and variable O&M costs overnight costs as well as where relevant heat rate assumptions for each resource type. These cost assumptions are summarized in Figure 69.

In addition we also made assumptions regarding depreciation, financing, and state and federal incentives.

Finally we developed two different models to capture two different ownership structures:

- Utility owned generation is modeled on a cost of service basis; and
- Merchant generation is modeled as a 20-year PPA.

La Capra Associates' models rely on these inputs to calculate a levelized cost for each resource type on both a utility owned and cost of service basis. Essentially annual revenue requirements are calculated to meet an expected level of return which then based on output determines a levelized cost.

Key Modeling Assumptions

In addition to the ownership structure, levelized costs of resources are greatly affected by several key modeling assumptions including federal and state tax incentives, depreciation schedules and financing assumptions. Each of these is described in detail below.

Tax incentives

Owners of these various resources can currently receive various state and federal incentives which have a meaningful impact on levelized costs. The incentives that we considered in our modeling were the Federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) and the North Carolina state tax Credit.

Federal tax credit

The PTC gives resource owners a tax credit for each unit of energy produced. The 2011 rates are 2.2 cents per kWh for wind, closed loop biomass and geothermal resources and 1.1 cents per kWh for other resources. Historically, the PTC has applied to wind and some forms of biomass projects. In the Energy Policy Act 2005 (EPACT 2005), resources such as hydropower were added to the eligibility list, and the PTC for closed-loop biomass resources was extended to ten years from five. Open-loop biomass, including landfill-gas and poultry litter projects, can now receive PTC at 50% of the full rate for ten years. The PTC is currently set to expire at the end of 2012 for wind projects and 2013 for other qualified resources.

The American Recovery and Reinvestment Act of 2009 allows resources eligible for the PTC to take the 30 percent ITC instead of the PTC if they choose. The ITC is a tax credit for 30 percent of the project cost which can be taken in the first year of operations. Because the 30 percent ITC is advantageous for most resources, we have assumed that all eligible resources will take the ITC instead of the PTC. We assume that the ITC will continue for all resources throughout the study period.[141]

The ITC for solar PV is systems placed in service between January 1, 2006 and December 31, 2016. The credit has a residential and a business classification, where the residential credit equals 30% of the solar PV project. A $2,000 cap on qualified solar electric property expenditure was removed for property placed in service after 2008. The bill allows individual taxpayers to use the credit to offset alternative minimum tax (AMT) liability, and to carry unused credits forward to the next succeeding taxable year. A $2,000 monetary cap on solar water heating property applies. The business credit has no cap and is for 30% of the project cost (after other credits are accounted for).[142] We have assumed that the ITC for solar will continue throughout the study period.

The American Recovery and Reinvestment Act of 2009 also allows resources eligible for the PTC and the ITC to take a cash grant of up to 30% of project costs. In order to be eligible for these grants developers must begin construction by the end of 2011 and projects must be placed in service before 2013 for wind, 2017 for solar and 2014 for other eligible technologies. We have not factored the cash grant into our analysis because of the requirement to begin construction before the end of 2011.

State tax credit

In addition, solar in North Carolina also benefits from a state tax credit for 35% of the cost installing renewable energy systems. The allowable credit cannot exceed 50% of the taxpayer's tax liability (less any other credits) for that year. If installed on a single-family dwelling, the credit must be taken in that year; for all other installations the credit is taken in five equal installments over five years.[143] Additionally, the credit for any specific project is capped at

141 In 2010, the PTC was 2.1 cents/kilowatt-hour. This incentive, the renewable energy Production Tax Credit (PTC), was created under the Energy Policy Act of 1992 (at the value of 1.5 cents/kilowatt-hour. Each year, the PTC increases with an inflation adjuster with the PTC rounded to the nearest $.001 per kWh.

142 Solar Energy Industries Association. *Frequently Asked Questions on the New Federal Solar Tax Credit. Retrieved from http://energy.maryland.gov/facts/renewable/solarroofs/SEIAsummaryEnergyAct05.pdf.*

143 North Carolina Solar Center. *Guidelines for Determining Tax Credit for Investing in Renewable Energy Property.* Retrieved from http://www.dor.state.nc.us/practitioner/individual/directives/renewableenergyguidelines.html.

$25,000 for residential customers and $2,500,000 for businesses. This tax credit was also made available to CHP in 2010.[144] This tax credit is currently available through the end of 2015.

Although we understand that there is the potential on a case by case basis for solar PV projects to receive this tax credit at the inverter level, in our calculation of levelized costs we have assumed solar PV projects receive this tax benefit based on the project size. For nuclear facilities, EPACT 2005 includes a PTC for the first 6,000 MW of new advanced nuclear plants built in the U.S. We do not assume that nuclear facilities developed in North Carolina would be able to take advantage of the PTC.

Depreciation

La Capra Associates has modeled all of the resources with a 20 year book life, but has modeled shorter tax lives for renewable resources which are allowed to claim accelerated depreciation. The accelerated depreciation allows depreciation of the asset on a schedule faster than the book life, which gives a tax benefit to the project owner. The resources receiving accelerated depreciation in our models are:

- 5–year MACRS: Wind, Solar, and Combined Heat and Power; and
- 7-year MACRS: Hydroelectric.

Recently these technologies have been eligible to receive bonus depreciation, which allows the owner to depreciate 50 or 100 percent of the allowable basis in the first year. This was first allowed for under the federal Economic Stimulus Act of 2008 then by the American Recovery and Reinvestment Act of 2009 and renewed again in September 2010 by the Small Business Jobs Act of 2010 (H.R. 5297).

In the most recent legislation, enacted in December 2010, The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (H.R. 4853), eligible property placed in service after September 8, 2010 and before January 1, 2012 qualifies for 100% first-year bonus depreciation. For property placed in service in 2012, bonus depreciation will be 50% of the allowable basis.

As the economy improves, it is less likely that bonus depreciation will continue, so we have not included the bonus depreciation in our modeling.

Financing assumptions

Financing assumptions are especially critical to estimating the cost of renewable technologies, as many are capital intensive with little or no fuel costs. Renewable energy projects across the

[144] General Assembly of North Carolina. (2010). Session Law 2010-167, House Bill 1829. Retrieved from http://www.ncga.state.nc.us/Sessions/2009/Bills/House/PDF/H1829v7.pdf.

country have utilized multiple financing structures involving combinations of bank loans, equity investments, tax credits, and/or municipal bonds. The financing structure is project specific and dependant on a given project's owner, risk appetite, and its tax status.

A utility-owned project will be structured differently than one owned by an independent power producer or merchant developer. While there are structural differences between the two models, there are some constants. These are as follows:

- 50/50 debt to equity ratio;
- 6% debt rate;
- 6.8% discount rate; and
- Levelized cost escalates at 2.5% per year.[145]

Utility-owned generation

In order to properly reflect a utility-owned generator, we used a cost of service approach which assumes a utility allowed rate of return. We have assumed that the utilities would be seeking a 10 percent return on equity. The model takes the annual revenue requirement over the 20-year life of the asset and levelized cost in dollars per MWh which increases 2.5 percent each year.

Merchant generation

To model ownership by a merchant generator we assume that the output would be sold under a 20 year PPA at a fixed price escalating at 2.5 percent that is equivalent to a levelized cost which enables the owner to earn a market return on investment. The cost of the PPA will then be passed on to ratepayers.

For modeling purposes, a standard financing structure for a project developer is assumed to consist of a combination of debt and equity investments, where the debt is modeled as a mortgage-style fixed rate loan. The target debt-to-equity ratio depends on the coverage ratio required by the lender. The debt term is typically less than the expected economic life of the technology and reflects the perceived risk associated with the project, though debt terms will vary greatly depending on the project. Based on current market information, the cost of debt is assumed to be roughly 6%. The cost of equity for renewable project investors may range between 12 and 15% for a merchant project.

The model is designed to solve for a equity return of 15 percent and a minimum debt coverage ratio of 1.0. The levelized cost is the price that satisfies both the debt coverage and return on equity conditions.

[145] This refers to a contract with an initial price that escalates at 2.5% per year in subsequent years.

Levelized costs

We developed levelized costs for both the renewable and low GHG mitigating resources to assess the associated annual costs for a portfolio of conventional resources and a portfolio that includes renewable resources. All levelized costs are in nominal terms and are calculated over a 20-year period where inflation is also taken into account, assumed to be 2.5% per year. The annual levelized cost for each type of resource modeled represents the cost for a resource installed in a particular year.

FIGURE 70: 2011 LEVELIZED COSTS

Resource Type	Levelized Cost (2010$/MWh)	
	Utility	Merchant
Renewable Energy		
Onshore Wind	$109	$101
Offshore Wind*	$193	$180
Solar PV**		
Utility Scale	$182	$162
Rooftop	$192	$170
Biomass		
Co-firing	$40	$39
Dedicated Biomass	$94	$99
Hydropower		
Upgrades at Existing Generation Sites	$24	$18
New Generation at Existing impoundment	$68	$54
Undeveloped Sites	$102	$101
Landfill Gas	$45	$43
Other Low GHG Emitting Energy Supply Options		
Nuclear	$140	$148
Natural Gas		
CT - Conventional Peaking	$376	$478
CT – Advanced	$368	$473
CC – Current Technology	$71	$78
CC – Advanced	$64	$70

* *We assume a technology cost decline rate for offshore wind of 5% per year over the study period.*

** *We assume a technology cost decline rate for solar PV of 3% per year over the study period.*

5.3.17 *COST ASSUMPTIONS FOR POTENTIAL RESOURCES*

Onshore Wind

Although no utility scale onshore wind farms have been installed in North Carolina, onshore wind is an established technology with over 40 GW installed in the United States.

We spoke with several developers operating in North Carolina and the consensus is that the cost profile of a wind farm in North Carolina would be similar to that of a wind farm installed in other eastern states, such as New York, Pennsylvania or Maine. That said, wind project costs are site dependant and the potential for geotechnical issues at some sites and uncertainty about the wind resource quality could impact project costs.

We consulted numerous public sources, as well as confidential data from utilities and local wind developers, and decided to rely on recent Energy Information Administration (EIA) data as a reasonable estimate of wind costs in North Carolina. EIA published updated plant costs for all technologies in a November 2010 report entitled, "Updated Capital Cost Estimates for Electricity Generation Plants" ("AEO 2011"). The report contains an appendix by R.W. Beck and Science Applications International Corporation which is called a "Review of the Power Plant Cost and Performance Assumptions for the National Energy Modeling System (NEMS)."[146] This report provides state-specific cost information for each technology. The North Carolina specific onshore wind technology costs are in line with the expectation that North Carolina costs will be similar to other Eastern states.

Onshore wind is a mature technology, so we did not assume that costs will decline over time.

The overnight capital costs assumed for onshore wind were $2,340/kW in 2010 dollars and the levelized costs calculated were $101/MWh for a merchant plant and $109/MWh for a utility owned plant.

Offshore Wind

Predicting the costs of offshore wind is challenging because of the lack of development history in the United States. Several projects have received contracts for their power, but none have actually been constructed.[147] Although several offshore wind projects exist in Europe, their cost profile cannot be directly compared to potential United States projects, because the United States does not yet have the construction experience of Europe.[148] Special ships are needed to

146 U.S. Energy Information Administration. Updated Capital Cost Estimates for Electricity Generation Plants. http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf Accessed March 15, 2011.

147 Block Island (28 MW) received a PPA for 24.4 cents per KWh and Cape Wind (486 MW) received a PPA for 18.7 cents per KWh each with a 3.5% escalator

148 Europe currently has 2,946 MW from 45 wind farms in nine European countries. 10 wind farms, totaling 3,000 MW, are currently under construction.

construct an offshore wind farm and the Jones Act prohibits European ships from coming to the United States.

This lack of U.S. project data points makes it difficult to predict new plant costs and has yielded a wide range of cost estimates, from less than $2,800/kW[149] to more than $5,975/kW.

It is reasonable to assume that development in North Carolina would be similar in complexity to other locations on the Atlantic Coast. Further, North Carolina projects should be in a position to leverage economies learned during the first U.S. projects. In addition, North Carolina projects should benefit from lower construction costs relative to construction costs in the Northeastern states. In addition to conversations with offshore wind developers and other stakeholders, we examined a variety of sources to estimate offshore wind costs including the following government reports.

- **AEO 2011.** EIA estimated capital costs to be $5,975/kW on average in the United States and $5,418/kW in North Carolina identifying North Carolina as potentially one of the least expensive states to develop offshore wind in the United States. The 2010 EIA number is a significant increase over its 2009 estimate of $4,021/kW and the report states that the increase reflects the first-of-a-kind costs that would be encountered in developing the first project in the United States. Given that North Carolina is unlikely to build the first project in the United States, this may be overestimating the costs for development in North Carolina.
- **U.S. DOE Offshore Wind Strategic Work Plan.** This plan was prepared by the United States Department of Energy to outline the actions it will take to develop an offshore wind industry in the United States. This report shows a potential path to reduced offshore wind costs in 2030. It estimates 2010 costs at $4,259/kW and cites NREL as the source of this number.[150]

La Capra Associates estimates capital costs in 2010 dollars to be $4,800/kW based upon the sources above and discussions with stakeholders. We have based our estimates for fixed and variable operations and maintenance costs on those in the AEO 2011. Capital costs are more than double of onshore wind, due to larger turbine size and the costs of transporting and installing at sea. However, we expect similar to the onshore experience, these prices to decline over time as the industry grows, technology improves and more experience is gained.

For the cost of offshore wind to improve, cost declines will have to occur in key areas:

149 University of North Carolina. Coastal Wind for North Carolina's Future. Page 340, June 2009. http://www.climate.unc.edu/coastal-wind.

150 United States Department of Energy. A National Offshore Wind Strategy: Creating an Offshore Wind Industry in the United States. February 2011. Page 15. http://www1.eere.energy.gov/windandhydro/pdfs/national_offshore_wind_strategy.pdf

- As offshore wind develops in the United States, special purpose vessels to construct wind farms will need to be designed and built. The cost and efficiency of these vessels will affect project costs.
- Offshore wind components are currently built in Europe due to the greater development activity there. An industry that supports local manufacturing will have lower component costs by saving on transaction and transportation costs to ensure supply from Europe.
- Access to debt financing for a portion of the project will reduce costs compared to an all equity financed project.
- Cape Wind took 10 years to receive the required permits. Although BOEMRE has promised to make permit streamlining for offshore wind projects a top priority, this process needs to be sped up to reduce development costs.[151]

We have assumed a technology cost decline rate for offshore wind to reflect the expected cost declines as the industry grows. For an indication of how costs would decline over time, we looked to the onshore wind industry. The "2009 Wind Technologies Market Report", written by the Lawrence Berkeley National Laboratory and published by the United States Department of Energy, contains capital cost information for onshore wind over time. This information shows that onshore wind costs declined about 5 percent per year in the period from 1982 to 2002.[152] We have assumed that offshore wind costs will follow a similar trend and decrease 5 percent per year as well.

The levelized costs calculated for offshore wind were $180 per MWh for a merchant plant and $193 per MWh for a utility owned plant. Using the 5 percent per year cost decline rate, the cost of a utility owned plant would be $161 per MWh by 2015, $122 per MWh by 2021 and $103 per MWh by 2025 all in $2010 and assuming that existing incentives remain in place. At this assumed rate, the levelized cost offshore wind would be competitive with onshore wind between 2021 and 2025. The installed cost of offshore wind would still be higher than onshore wind, but the higher capacity factor of offshore wind would make the levelized cost competitive with onshore wind.

Solar PV

The market for solar PV is very dynamic, which can make it challenging to estimate the cost. However, according to multiple published and confidential sources solar costs have

151 *"Can the United States Really Get Its Act Together on Offshore Wind?"*, Peter Asmus — February 8, 2011. http://www.pikeresearch.com/author/peter-asmuspikeresearch-com?page=3

152 United States Department of Energy. 2009 Wind Technologies Market Report. Page 43. Accessed March 16, 2011. http://www1.eere.energy.gov/windandhydro/pdfs/2009_wind_technologies_market_report.pdf

demonstrated annual declines due to improved technology, solar cell efficiency and greater economies of scale.

Cost drivers

The installed costs of solar PV systems are influenced by many factors, including:

- The type of manufactured technology used in the solar PV module[153] (e.g., single crystal silicon or thin film);
- The type of module itself (flat plate or concentrator);
- The type of system installed (fixed-tilt, one-axis tracking and two-axis tracking, and roof-top or ground-mounted); and
- Whether the system is grid-connected or free-standing.

Solar PV module costs typically comprise 50-60 percent of the total installed cost. The remainder of the equipment and labor required to install a solar PV system is called the balance-of-system ("BOS"). Many items can be included on the BOS list. Typically, the term BOS is identified with the DC-to-AC inverter; the foundation and structure that mount the solar PV modules; and the electrical wiring and connection equipment. Internal electrical connections and module mounting techniques are critical determinants of panel cost, reliability, and endurance in an exposed environment. The BOS list can also include other solar PV system "soft" costs such as project management, engineering and design, testing, training, and operation and maintenance costs.

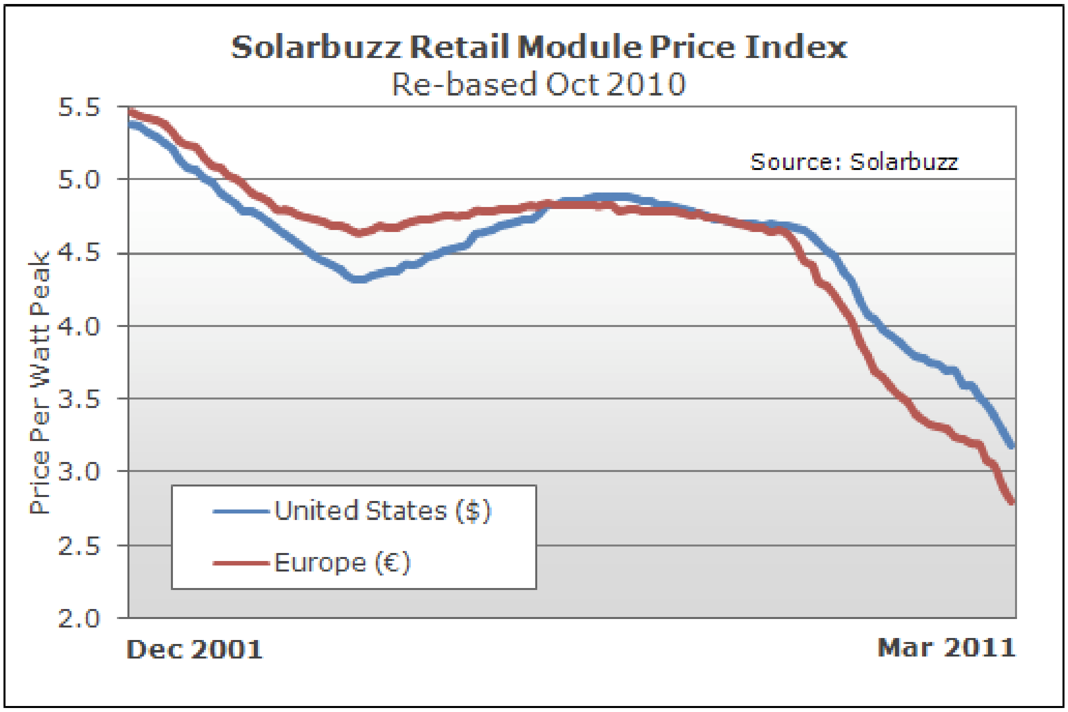
Solar PV panels can be installed as a fixed-tilt system facing south, or on a tracking device that allows the panel to follow the sun (one-tilt tracking and two-axis tracking), affecting both the installed cost and the energy production of the installation. Tracking the sun increases the energy output of the array, but at increased cost and complexity.[154] O&M costs are also higher for tilt systems as they involve moving parts.

Costs of solar PV systems have declined in recent years as the market penetration has increased. The SolarBuzz website tracks module pricing in both the United States and Europe. Figure 71 below shows the module pricing data from SolarBuzz, which shows that United States module prices have decreased from about \$5.4/watt in December 2001 to about \$3.2/watt in March 2011. This is a decline of about 5 percent per year.

153 The term "module" is used here to refer to the PV panels only. Other components of a PV system installation, such as land, mounting, control systems, electrical, and other balance of plant items are not included in the term "module".

154 Solar Electric Power Association, PV Basics: PV Facts Sheet, www.solarelectricpower.org/index.php?page=basics, 3/09

FIGURE 71: MODULE PRICES 2001-2011[155]



Another source of information on solar capital costs is a report by the Lawrence Berkeley National Laboratory which looks at installed costs for solar PV called "Tracking the Sun III". In developing the report, the authors compiled actual installed costs for solar PV projects throughout the United States in 2009 and some preliminary data for projects installed in 2010. Because the majority of installations have been in California the majority of installed cost data is from this state. The report states the average installed cost for systems 250 to 500 kW, 500 to 1000 kW and greater than 1000 kW was 7.1, 7.4 and 7.0 dollars per watt in 2009 respectively. The preliminary data from 2010 showed costs had dropped to 5.7 and 6.1 dollars per watt in New Jersey and California respectively for installations larger than 100 kW.[156]

The Solar Energy Industries Association and GTM Research have produced a report titled "U.S. Solar Market Insight: 2010 Year in Review." This report showed that utility scale projects had decreased in price from $4.80 per watt in the first quarter of 2010 to $4.05 per watt in the 4th quarter of 2010.[157]

155 SolarBuzz. Retail Price Environment: Module Pricing. http://www.solarbuzz.com/facts-and-figures/retail-price-environment/module-prices. Accessed March 17, 2011.

156 Lawrence Berkeley National Laboratory. Tracking the Sun III: The Installed Cost of Photovoltaics in the U.S. from 1998-2009. December 2010. Page 11, 15.

157 Solar Energy Industry Association and GTM Research. U.S. Solar Market Insight: 2010 Year in Review. Page 10.

Beyond published data, we spoke with several solar developers to get their prospective on solar costs in North Carolina. All the developers that we spoke with believed that the costs in the published sources were too high. The developers felt that the published sources did not capture all of the price declines that have happened in 2010 and the first quarter of 2011. They felt that a more realistic capital cost for solar is closer to $3.40 per watt for utility scale projects of about 2 MW and $3.60 per watt for rooftop projects in the 250-500 kW range.

There is a big disconnect between the published data and the information we received from developers. This can be explained in several ways. There was a large decline in price in the second half of 2010 continuing in to the first quarter of 2011, which was not captured in the published sources, particularly in the Tracking the Sun III report which only contains partial data for 2010. Also the data in the published sources was based on applications to state agencies for incentives. The applications may show higher costs than the actual installed costs to make sure the applicant has reserved the full incentive.

Our best estimates of overnight costs for solar PV is $3.40 per watt for utility scale installations of about 2 MW and $3.60 for rooftop installations of about 500 kW.[158] This translates into a utility owned levelized cost of $182 per MWh for the utility scale installations and $192 per MWh for rooftop applications. This cost estimate assumes that both the federal investment tax credit and state tax credit are utilized by the project owner.

Future cost declines

Given the large decline in solar PV costs that has occurred over the past year, we developed an estimate of future cost declines for the study period. This is challenging because a lot of the price fluctuation over the past several years has been related to commodity price fluctuations and policy decisions around the world. Price fluctuations related to market forces are likely to continue as is the general downward movement in price as the industry expands.

We looked at the historical price declines for an indication of future declines. The SolarBuzz chart in Figure 71 shows module prices declining from $5.4 per watt in January 2002 to $3.4 per watt January 2011 for a decline of about 5% per year. The Lawrence Berkeley National Laboratory (LBNL) report shows prices declining from $10.8 per watt in 1998 to $7.5 in 2009 (3% per year); including the preliminary 2010 number of $6.2 per watt, the annual decline has been around 5% per year. Much of this decline, however, can be attributed to global supply and demand dynamics and we do not expect continued annual declines at this rate. For this reason, we assume that solar costs decline by 3% per year going forward.

158 We chose to evaluate these size facilities based on stakeholder input. Some stakeholders have suggested that larger size installations should also be evaluated for costs and although as project sixe increases, costs will be lower it is important to note that the tax credit limit is only up to 2 MW. This may be an area that warrants further study.

Assuming a 3% decline each year a utility owned utility scale solar PV facility would have a levelized cost of $163 per MWh in 2015, $139 per MWh in 2021 and $125 per MWh in 2025 ($2010) assuming existing incentives remain in place. By 2025 solar will approach cost competiveness with onshore wind, but will still be more expensive.

Biomass

Biomass electricity is a mature technology that has been widely developed across the country at the utility scale. More than 150 MW of dedicated wood- and wood waste-fired biomass is already online currently in North Carolina.[159] As a result of this track record, data on biomass costs is more firm than for many emerging renewable technologies. However, significant variations exist between different biomass technologies. [160]

Dedicated biomass

To develop our cost estimate for dedicated biomass generation, we consulted a number of data points including EIA estimates, publicly available studies and confidential utility data. A comparison of the most relevant public data is summarized in Figure 72. Based on this data and corroborated by confidential data provided by North Carolina utilities, we concluded that the cost data from EIA's AEO2011 is a representative estimate of capital, fixed and variable O&M costs for dedicated biomass.

FIGURE 72: COMPARISON OF DEDICATED BIOMASS COST ESTIMATES

Data Source	Technology (Modeled size)	Capital Cost[161] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	LCOE ($/MWh)
		All costs in 2010$			
LCA 2006	Fluidized bed (25 MW)	$2,830 - 3,243 (IC)	$81	$11	$90 - 126
AEO 2011 (Beck Report)	Bubbling fluidized bed in Charlotte, NC (50 MW)	$3,343 (OC)	$101	$5	--
Lazard 2009[162]	Unspecified (35 MW)	$3,188 - 4,049 (IC)	$84	$11	$66 - 114

159 Form EIA-860 2009 Annual Electric Generator Database. Accessed 3/22/2011 from http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

160 Advanced biomass such as gasification and torrefaction are currently under development and not a focus of this study.

161 Some capital costs are given as overnight costs (OC), or the cost of building the plant without consideration for time of construction. Other capital costs are given as installed costs (IC), which take into account financing costs during the period of construction.

162 Lazard Levelized Cost of Energy Analysis – version 3.0 (February 2009). http://blog.cleanenergy.org/files/2009/04/lazard2009_levelizedcostofenergy.pdf. Accessed March 20, 2011.

The AEO2011 dedicated biomass costs contained in the Beck Appendix to the AEO 2011[163] are based on a 50 MW bubbling fluidized bed generator. Fluidized bed is something of a "middle of the road" technology – more efficient, emission-free and costly than other direct combustion technology such as stoker boilers, but less efficient, flexibly-fueled and costly than newer gasification technology.[164]

The Beck Appendix provides regionally-adjusted capital cost estimates that take into account possible geographic variations on cost inputs such as labor wages and productivity, construction materials and seismic design. The capital cost estimate for a plant located in Charlotte, North Carolina was $517 (13.4%) less than the base cost level.

We assume a fuel price of $2.00/MMBtu, which is in line with Lazard's estimate and roughly equivalent to the average price of pine pulpwood in North Carolina over the past four years.[165]

Biomass Co-fire

Co-firing biomass with another fuel such as coal generally requires capital investment for boiler modifications and fuel handling. To estimate costs associated with co-firing biomass fuel at existing coal plants, we once again reviewed a variety of publicly available studies and confidential utility data. The AEO 2011 did not provide an estimate of co-firing costs. However, co-fire capital costs were estimated for AEO2010.

163 U.S. Energy Information Administration. Updated Capital Cost Estimates for Electricity Generation Plants. http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf Accessed March 15, 2011.

164 AEO2011 estimates of costs for a 20 MW gasification plant are more than double for capital and triple for O&M.

165 Price data from Forest2Market Quarterly North Carolina Timber Reports. http://www.ces.ncsu.edu/forestry/resources/price_report.php. Accessed 1/23/2011. Assumes stumpage price is 36% of delivered price.

FIGURE 73: COMPARISON OF BIOMASS CO-FIRE COST ESTIMATES

Data Source	Technology (Modeled size)	Capital Cost[166] ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	LCOE ($/MWh)
		All costs in 2010$			
LCA 2006	Co-fire (20-69 MW)	$81 - 249 (IC)	$13	$5	$5 - 22
AEO 2010[167]	Co-fire (up to 15% of output)	$122 - 282(OC)	--	--	--
Lazard 2009	Co-fire (2%-20% of capacity)	$51 - 506 (IC)	$10 - 20	--	$3 - 37

We estimated capital costs of $200 for our modeling, well within the range of prices in our public and confidential sources.

Hydropower

Costs were developed for three types of hydropower facilities:

- Upgrades at existing generation sites;
- New generation at a site that doesn't have power, but does have an existing dam; and
- New generation at an undeveloped site.

The Idaho National Laboratory completed a hydropower resource assessment which located potential sites for hydropower development. This assessment included a cost estimate for each site.[168] To estimate the costs for development in North and South Carolina, we used the estimates in the Idaho National Laboratory database and escalated them to 2010 dollars. Our estimates for overnight and levelized costs are included in the table below. These estimates are for projects 10 MW and smaller.

166 Some capital costs are given as overnight costs (OC), or the cost of building the plant without consideration for time of construction. Other capital costs are given as installed costs (IC), which take into account financing costs during the period of construction.

167 Assumptions to the Annual Energy Outlook 2010. http://www.eia.gov/oiaf/aeo/assumption/electricity.html. Accessed March 22, 2011.

168 Idaho National Laboratory. Hydropower Resource Assessment. Accessed March 18, 2011. http://hydropower.inel.gov/resourceassessment/index.shtml

FIGURE 74: HYDROPOWER COSTS ($2010)

Type of Site	Overnight Costs	Levelized Costs
Upgrades at existing generation site	$1,550	$39
New generation at existing impoundment	$2,700	$71
New generation at undeveloped site	$4,525	$133

Landfill Gas

A cost estimate was developed for landfill gas facilities based on information in the 2010 EIA AEO and La Capra Associates' experience working with landfill gas developers. The 2011 Annual Energy Outlook does not contain information on the costs of landfill gas facilities, so we relied on the 2010 data.

The 2010 EIA AEO modeling data showed landfill gas overnight costs to be $2,599 in 2008 dollars or about $2,650 in 2010 dollars.[169] Because construction costs in North Carolina are lower than the national average, we have used $2,450 as our estimate of landfill gas capital costs. This translates into a levelized cost of $45 per MWh.

Nuclear

A key uncertainty regarding the development of new nuclear generation is its cost. Even with renewed interest and attention nuclear power has received in recent years, experts are still unable to reach a consensus on project costs. With no nuclear plants completed in the United States in more than a decade, cost estimates do not rely on recent domestic projects. This lack of recent evidence creates an inherent difficulty in predicting new plant costs and has yielded a wide range of cost estimates, from less than $3,000/kW to more than $10,000/kW.[170] Below we provide La Capra Associates' estimate of nuclear costs and outline the primary considerations accounting for the current range in estimates.

Relying on a variety of resources including utility, industry, and governmental estimates, as well as independent analyses, La Capra Associates estimates the overnight cost of new nuclear generation to be $6,500/kW. As an overnight cost, this figure includes capital expenditures such as materials (steel, concrete, etc.) and labor. Notably, the overnight cost estimate does not include the cost of financing during construction which can increase the final plant cost

169 Energy Information Administration. Annual Energy Outlook 2010. *Table 8.2 Cost and Performance Characteristics of New Central Station Electricity Generating Technologies.* http://www.eia.gov/oiaf/archive/aeo10/index.html. Accessed March 21, 2011.

170 Cooper, Mark. "The Economics of Nuclear Reactors: Renaissance or Relapse?" Institute for Energy and the Environment, Vermont Law School. June 2009.

considerably and is included in our levelized cost estimates. This is particularly true if original construction schedules are delayed, as they have been at reactors currently under construction in other countries. The overnight cost estimate also does not include any decommissioning costs.

Estimates of overnight costs for new nuclear plants have increased steadily in the past few years.[171] This is driven by multiple factors, including but not limited to scarce trained labor, higher costs of capital intensive technology, higher commodity prices, in particular steel, length of permitting and associated costs, as well as the lack of construction firms with the complete skill set to build new nuclear plants.

For nuclear power the cost of uranium is a relatively small portion of the cost of energy. Total fuel costs, including enrichment, typically represent less than 15% of the cost of energy. This may change, however, if enough new plants are constructed to impact the global commodity market. Conversely if several projects are cancelled or if existing units are retired, uranium costs could decline.

Due to the complexity of nuclear plants, O&M comprises a comparatively larger portion of nuclear costs. La Capra Associates estimates the fixed O&M cost of new nuclear generation in 2010 dollars to be $113/kW and the variable O&M cost to be $2.59/MWh.

In this analysis, La Capra Associates did not assume that North Carolina utilities would benefit from federal loan guarantees. The guarantees will primarily be secured by the first movers, and plans for a new nuclear plant by a North Carolina utility are not as advanced as those in other states.

Primary Factors Impacting Nuclear Cost Estimates

Cost overruns

During the 1970s and 1980s when the nuclear industry was rapidly expanding in the United States, projects frequently experienced large cost overruns. In addition, several high profile nuclear projects under construction internationally have developed cost overruns approaching 100% of initial project estimates.[172] Frequently initial cost estimates are updated to significantly

171 The EIA AEO 2011 estimates for a new generic nuclear plant are 37% higher than their 2010 estimate.

172 The OL3 reactor, currently under construction in Finland by AREVA SA, is reportedly experiencing cost overruns in excess of 90% of the original project estimates from 2005. Originally targeted for completion in 2009, the project is now expected to begin operation at the end of 2012. [Source: de Beaupuy, Francois."AREVA's Overruns at Finnish Nuclear Plant Approach Initial Cost" Bloomberg Business week. June 24, 2010. http://www.businessweek.com/news/2010-06-24/areva-s-overruns-at-finnish-nuclear-plant-approach-initial-cost.html]

In 2010, Électricité de France SA estimates that cost overruns at Flamanville reactor were equal to 25% of initial project estimates. The construction schedule has also been extended 2 additional years since construction began.

higher levels. For example, as a part of its 2008 IRP Duke raised the expected construction costs of its proposed Lee Nuclear Station to $11 billion, excluding financing costs. This was roughly twice the company's original estimates.[173]

This trend has led many to believe that current cost estimates from developers and utilities looking to construct new units understate actual project costs.

Financing and cost recovery

Nuclear power is extremely capital intensive. Given this and the long construction period, financing terms have a critical impact on the overall competitiveness of a given plant.

As previously mentioned, the cost of financing during construction is a major cost component for new nuclear generation. The sheer cost magnitude of new proposed projects – in the billions of dollars - and inherent development uncertainty have resulted in hesitation from investors. The federal government has attempted to allay these fears by offering various loan guarantees. Utilities in North Carolina, along with those in other states, have attempted to overcome some financing hurdles by requesting approval of a charge to ratepayers to recover the costs of construction work in progress ("CWIP"), and in some cases the costs of construction work not yet begun.

Potential issues impacting nuclear power costs and development

As the national and international spotlight on nuclear power continues, there are several issues that are important to monitor which could impact the cost and likelihood of new nuclear development in North Carolina:

- **Federal loan guarantees.** The Obama administration continues to support new nuclear development. Federal action, such as the creation of addition loan guarantees, could impact the likelihood of new construction and cost profile for projects that are able to incorporate this benefit.
- **Nuclear production tax credit.** The Energy Policy Act of 2005 established a nuclear PTC of $0.018/kWh per year for the first eight years of a new advanced nuclear project. This credit will only be granted to the first 6,000 MW of new capacity. In this analysis La Capra Associates has assumed that since potential nuclear developers in other parts of the country

[Source: Patel, Tara." EDF Said to Raise Flamanville Costs, Delay Reactor" Bloomberg Business week. July, 2010. http://www.businessweek.com/news/2010-07-29/edf-said-to-raise-flamanville-costs-delay-reactor.html]

In Ontario, Canada, the refurbishment of the Bruce Power nuclear facility was originally estimated to cost $2.75 billion in 2005. The most recent estimates cite $4.8 billion, an increase of 75%. The project timeline has also been extended almost 3 years beyond the original completion date. [Source: Jankowski, Paul. "Restart costs estimated to climb to $4.8B." QMI Agency. November 11, 2010. http://www.brucepower.com/uc/GetDocument.aspx?docid=3038]

173 Duke Energy Carolinas' Integrated Resource Plan. NCUC Docket E-100, Sub 118, November 3, 2008.

have more aggressive schedules than those presented by North Carolina utilities in their IRPs, it is not likely that any North Carolina plants will benefit from the PTC. If plans advance quickly and/or if the federal government expands these credits, this could change the cost structure for new nuclear development. However, it does not directly impact any initial project financing hurdles.

- **Legal challenges and delays.** Due to the controversial nature of nuclear power, new projects are particularly susceptible to costly legal challenges. Aside from the legal expenses, these challenges can delay projects and increase further the cost of financing prior to project completion.
- **Approval of new plant designs.** Several engineering plans for new Generation III+ reactors, such as the Westinghouse AP1000, are pending at the Nuclear Regulatory Commission.
- **Nuclear waste storage.** With the end of plans for a storage facility at Yucca Mountain, the issue of long-term storage will become a more important hurdle for the development of a new plant.
- **Small modular reactors.** The development of small (less than 200 MW) modular reactors could change the trajectory of nuclear development. If plans for such a reactor are approved, it could hasten the development of multiple plants because each facility would not have to undergo the same rigorous application process. Currently, several designs are in the pre-application phase, with the Nuclear Regulatory Commission (NRC) reviews underway. The NRC anticipates multiple applications for small reactor designs in 2012.

Safety concerns.

After the recent tsunami and nuclear incident in Japan, existing and proposed nuclear plants in the United States (and around the globe) will surely face increased scrutiny regarding system safety, though the full long-term impacts are not yet known.

Natural Gas

New natural gas plants are being constructed on an ongoing basis around the country and as a result there is a wealth of cost estimates for both CTs and CCs. Natural gas is a mature technology with less uncertainty in its cost parameters than, for instance, nuclear power and not surprisingly price estimates are relatively similar. For this analysis, La Capra Associates reviewed several industry studies as well as utility and developer information. We have adopted the cost estimate from the EIA's Annual Energy Outlook (

Figure 75 below). The table provides cost estimates for both conventional and advanced plants. It is expected that the planned natural gas capacity additions in the second half of the IRP planning period will likely consist of high-efficiency advanced units.

FIGURE 75: NATURAL GAS COST ESTIMATES

	Overnight Costs (2010$/kW)	Fixed O&M (2010$/kW-yr)	Variable O&M Costs (2010$/MWh)
Natural Gas CT – Conventional Peaking	$905	$7	$14.70
Natural Gas CT - Advanced	$673	$7	$9.78
Natural Gas CC – Current Technology	$888	$14	$3.43
Natural Gas CC - Advanced	$914	$15	$3.11

ENERGY EFFICIENCY

As part of its analysis of the potential for renewable resources in North Carolina, La Capra Associates was asked to develop a 10 year potential number for energy efficiency[174] based on existing studies. Since energy efficiency is an eligible resource for REPS compliance, understanding it is an important component in the review of the legislation. This analysis is intended to help inform the role that energy efficiency can have as a resource.

This potential analysis is founded on existing estimates of technical potential. Potential is defined as achievable, cost effective energy efficiency that can be procured, measured, verified and attributed to utility energy efficiency programs.[175] La Capra Associates screened this potential based on end-use measure costs to determine two levels of economical efficiency potential based on different avoided cost levels. This estimate was then revised based on several factors, including the impact of new legislation mandating certain efficiency improvements and La Capra Associates' analysis regarding reasonable penetration rates.

This section provides detailed information on the energy efficiency potential studies used and a framework for understanding our approach to developing a potential number for North Carolina. Section 3.2.3 provides specific information on how the number was reached for North Carolina, including an overview of the resources used, factors taken into consideration and results of the energy efficiency potential number. We also include sections on demand response and Combined Heat and Power (CHP).

174 This analysis will use the terms ' energy efficiency' and 'demand-side management as they are defined in S.B. 3. See Section 2, footnote 5.

175 For a broader discussion of potential, see: "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina." GDS Associates, Inc. Report for the North Carolina Utilities Commission. December 2006.

FIGURE 76: ENERGY EFFICIENCY POTENTIAL ANALYSIS RESULTS

Scenario	Avoided Cost Threshold	Technical Potential (%)[176]	Economic Potential[177]	10-Year Potential[178]
Base EE	$0.05/kWh	32%	11%	7%
High EE	$0.10/kWh		16%	13%

5.3.18 *ENERGY EFFICIENCY POTENTIAL STUDIES AND FACTORS IN DEVELOPING A POTENTIAL NUMBER*

Levels of Potential Studies

Potential studies for energy efficiency can be conducted with differing levels of detail, depending on their purpose. On one end of the spectrum, "top-down" studies are used for screening purposes. The potential study can be conducted at a fairly high level and focus on the societal level of benefits to determine whether the energy efficiency potential is significant enough to consider pursuing. At the other end of the spectrum are "bottom-up studies." These are detailed potential studies that focus on specific measures and are used for planning and program design. Such studies are much more time consuming and expensive but are invaluable and necessary for program planning and design.

In the middle of this spectrum are potential studies that are used for resource planning. These studies and analyses are conducted at a level such that energy resource planners and policy makers can be comfortable that the identified potential for energy efficiency resources can be relied upon to be realized as options to supply resources. La Capra Associates used this level of study to identify the energy efficiency potential for North Carolina.

Generally, potential studies are periodically updated to provide a snapshot of what is going on in the market. This enables potential numbers to better reflect the market including responses to changes in appliance and building standards, impact of existing programs, new technologies and changes in avoided costs or the point at which programs are considered cost effective. In many instances, the available data for North Carolina is five or more years old.

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176 Engineering estimates of energy savings if standard stock is replaced with most efficient measures. No consideration of economics, market or regulatory barriers.

177 Estimated savings from measures that have passed an economic analysis based on a $0.05/kWh utility avoided cost.

178 Includes adjustments for free ridership, achievable penetration rates, new federal appliance and lighting standards, and revised building codes. Potential does not reflect commercial/industrial opt-out provision.

Key Drivers

Identifying and understanding the assumptions within a given energy efficiency potential study helps explain why potential numbers vary so widely. Transparency of any underlying assumptions is critical to developing confidence in a potential number that is used in the development of energy policy.

- **Cost thresholds** – Selecting a number for determination of what is “cost effective” has a significant impact on potential. Obviously, the number of measures that are cost effective at 5 cents per kWh is much smaller than the potential at 10 cents per kWh.
- **Penetration rates** – The degree to which an energy efficiency measure or activity is adopted has a significant impact on potential. Most would agree that, unless legislated, reaching 100% of the market is impossible. Marketing programs for energy efficiency recognize the many barriers to reaching and converting consumers such as education level, financing, and available time and focus. Furthermore, given measure each has a different penetration potential. In selecting one potential number, a judgment must be made regarding how much of the market can be reasonably and economically reached.
- **Treatment of free riders** – Free riders are those program participants who would have adopted an energy efficiency measure or activity even in the absence of a program or policy that provides an incentive to do so. As energy efficiency measures are adopted and become the norm, utilities incorporate these changes into their load projections. Therefore, care must be taken not to double count (or not account for) free-ridership.

Legislative and Regulatory Policies and Structures

Many factors impact a state’s ability to reach its energy efficiency potential including the level of private and public investment, short-term vs. long-term impact on rates, market readiness, regulatory and legislative barriers, the economy, (dis)incentives to utilities and maturity of programs. Potential numbers can be used in a variety of ways, such as setting a minimum standard for utilities or as a stretch goal. The factors mentioned above, along with an understanding of what the potential number is, are critical to establishing effective policies.

Another category of factors impacting a potential number are legislative and regulatory structures, which can both increase and decrease achievable potential. By setting and supporting goals to stimulate energy efficiency, policymakers can stimulate demand for energy efficiency offerings, create incentives for utilities to promote energy efficiency and even require that utilities meet certain energy efficiency targets.

Other policies and structures can impact the achievement of energy efficiency potential. For examples, many states, including North Carolina, have provisions that allow businesses to opt out of paying for and participating in public energy efficiency programs. These opt-out provisions do not impact overall potential, but they do have an impact on the ability of utilities to reach all customers.

Influences Not Reflected in the Energy Efficiency Potential Number

In addition to the factors discussed above, a number of other conditions can impact potential that have not been specifically factored in to our potential analysis because they are not readily quantifiable, are outside of the scope of this effort, or are considerations in the marketing and implementation of programs but not as a means of determining potential.

Behavioral changes

The equipment-based energy efficiency approach to determining potential incorporates highly quantitative analysis of technical, marketing and consumer acceptance issues that occur in program development and implementation. Observers of energy efficiency resource potential also note that a substantial impact can be the behavioral changes surrounding energy consumption, which could be anything from temperature settings for heating and cooling, smart grid technologies (see section below), the consciousness in turning off lights, appliances and equipment, and the scheduling of work in industrial settings to minimize energy costs, not just labor. Many of these behavioral changes can be developed through the use of different rate design options. Often these behaviors change in conjunction with expansive equipment based energy efficiency. Sometimes the behavior enhances the equipment savings and in other times the greater efficiency can change a consumer's perspective and increase temperature settings for heating, as an example. We have not attempted to quantify behavioral change impacts beyond those captured within the potential studies reviewed. This does not mean that the energy and demand forecasts that the utilities and the State of North Carolina use for resource and environmental planning will be too high. The annual or bi-annual updates to the load forecasts will gradually capture trends in consumption as affected by behavioral changes by electric consumers, whether they be residential, institutional, commercial or industrial.

Drift

It is widely recognized that the efficacy of measures can diminish over time because of uninformed human intervention, poor maintenance or lack of proper installation – referred to as drift. Some advocates of efficiency call for programs that a check-up on all systems - hardware, software, and human, sometimes referred to as "commissioning."

Economy

The economy will always impact electric usage and the adoption of energy efficiency measures. In tough economic times, decision-makers may be more interested is economizing but investment funds may be less available for investing in energy efficiency.

Changes in marginal costs/rates

Electric utility rates paid by consumers and the marginal costs for the utility systems change over time. The result is that even for the same technology and measure costs assumptions, 1) the assessment of which measures are economical changes and 2) the investment choices customers make themselves in efficient or inefficient measures change. Both of these factors affect an assessment of economic potential. This is true whether the perception alone changes or actual levels of rates and marginal cost change.

Spillover

This term refers to the opposite of free-ridership. Spillover is when consumers make more energy efficiency purchases because the marketing of energy efficiency programs educates them or raises their awareness but they do not take advantage of the programs. This includes homeowners or businesses which intend to file for rebates but never complete the paperwork.

Smart grid

The development of smart grid technologies has the potential to drastically change trends of electricity consumption and impact technical efficiency, as well as spur behavioral changes. Several electricity suppliers in North Carolina are investigating smart grid technologies, including digital smart meters. Both Duke and Progress have active smart meter pilot projects, and several municipal utilities and EMCs have developed programs. Piedmont EMC, for example, has installed smart meters for all of its 31,000 customers.[179]

While the potential for consumption reduction is great, these technologies have not reached maturity and North Carolina is not yet experiencing wide scale adoption. In addition, the impacts of a smart grid are difficult to quantify due to the wide range of impacts and the lack of historical data in the region. For this analysis, smart grid technologies were not incorporated into efficiency potential.

Studies Reviewed in Meta-analysis[180]

For this analysis, several existing energy efficiency potential studies were reviewed. This section provides brief summaries of the primary resources utilized.

GDS Associates

In 2006, GDS Associates produced a feasibility study on the use of energy efficiency in an RPS for the North Carolina Utilities Commission.[181] Some of the results were incorporated into the energy efficiency section of the La Capra Associates 2006 report. The study provides a detailed end-use assessment of residential energy efficiency potential in North Carolina and a meta-analysis of commercial and industrial potential aided by a review of commercial and industrial (C & I) measures and costs. The GDS study was a primary resource for the La Capra Associates potential developed in this study.

179 "Smart grid, smart meters." John Murawski, Raleigh News & Observer. 1/24/2010. http://www.newsobserver.com/business/v-print/story/299551.html

180 A meta-analysis combines the results of several studies. Generally, a meta-analysis seeks to estimate an outcome more powerfully than might be possible from a single study under a given single set of assumptions and conditions. A meta-analysis is not necessarily superior to a well designed and carried out potential study.

181 "A Study of the Feasibility of Energy Efficiency as an Eligible Resource as Part of a Renewable Portfolio Standard for the State of North Carolina." GDS Associates, Inc. Report for the North Carolina Utilities Commission. December 2006.

Duke Energy Carolinas

Duke contracted a group of consultants to evaluate the potential for energy efficiency savings in its North Carolina service territory.[182] The group produced a final report in 2007 (the "Forefront study"). The bottom-up study evaluates numerous efficiency measures and establishes a technical potential which is then restricted by cost effectiveness. The study provides the utility with a recommended suite of energy efficiency programs for near-term implementation.

Progress Energy Carolinas

In 2009, ICF International produced a DSM potential study for Progress.[183] This study differs significantly from the GDS and Duke studies in that it does not attempt to identify total savings potential and apply restrictions. Instead, this bottom-up study identifies a selection of end-use measures based on cost-effectiveness tests and then determines a "realistically achievable potential" for those measures.

Dominion Power

Dominion provided La Capra Associates with some confidential materials related to EE/DSM potential. These materials were reviewed and incorporated into the La Capra Associates potential assessment.

ACEEE

The American Council for an Energy-Efficient Economy (ACEEE) is one of the foremost national organizations promoting the adoption of energy efficiency practices and measures. In 2010 the ACEEE released a report on energy efficiency potential and options for North Carolina.[184] Rather than an end-use measure analysis, the ACEEE study is purely a meta-study, reviewing various other potential analyses, including the GDS study. The ACEEE study was an important point of reference for this analysis, but as a meta-study it relied upon certain assumptions that were determined to be incompatible with the La Capra Associates analysis.[185]

Georgia Tech Meta-Review

In 2009 researchers at Georgia Tech produced a working paper reviewing 19 energy efficiency potential studies.[186] The study was focused on the South region and presented a comprehensive

182 "Duke Energy Carolinas DSM Action Plan: North Carolina Report." Forefront Economics Inc., H. Gil Peach & Associates LLC, PA Consulting Group. August 31, 2007.

183 "Progress Energy Carolinas DSM Potential Study: Final Report." ICF International. March 16, 2009

184 "North Carolina's Energy Future: Electricity, Water, and Transportation Efficiency." American Council for an Energy-Efficient Economy. Report Number E102. March 2010.

185 For example, the ACEEE study was based on studies that assumed very high penetration rates for efficiency measures. The importance of penetration rates is discussed below. The ACEEE study also included energy efficiency potential from sectors beyond the scope of this analysis, such as manufacturing, agricultural, and water efficiency.

186 Chandler, Sharon and Marilyn Brown. "Meta-Review of Efficiency Potential Studies and Their Implications for the South." Georgia Institute of Technology, Working Paper #51. August 2009.

review of recent energy efficiency potential evaluations. As with the ACEEE study, this meta-review was not used directly in the La Capra Associates analysis, but was utilized as a reference to benchmark the results.

EPRI

The Electric Power Research Institute (EPRI) released a nationwide study of energy efficiency potential in 2009.[187] The analysis includes a bottom-up study of residential and commercial potential, and a top-down review of industrial potential. While it is a nationwide study, results are disaggregated into region-specific potential figures (North Carolina is in the "South" region with 15 other states).

Appalachian State University

In 2007 the North Carolina State Energy Office sponsored an energy efficiency study completed by researchers at Appalachian State University (ASU).[188] This bottom-up study was a primary resource for the ACEEE study. The scope of the ASU study included a focus on thermal efficiency, so results are generally presented on a Btu basis. Where appropriate, the ASU study was used as a point of comparison for the La Capra Associates study.

Energy Efficiency in the South

A team of researchers from Georgia Tech and Duke University produced a regional energy efficiency potential analysis in 2010.[189] The study used a hybrid of top-down and bottom-up methodologies. Due to the regional nature of the study, results were not directly comparable. However, La Capra Associates reviewed this study for general reference.

La Capra Associates Methodology for Determining Energy Efficiency Potential

The following section outlines the methodology applied to develop the La Capra Associates 10 year base case potential for savings from energy efficiency (reported at the meter level). We have not looked beyond 10 years in our analysis. The energy efficiency potential studies review in our meta analysis do not attempt to forecast the subsequent generations of equipment energy efficiency improvements. However, we believe that most of the benefits of energy efficiency will be captured within the 10 year timeframe. History has shown in this industry that efficiency resource potentials identified do not decrease sharply with program implementations since new technology, or improved economics for efficiency investments

187 "Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S." Electric Power Research Institute. January 2009.

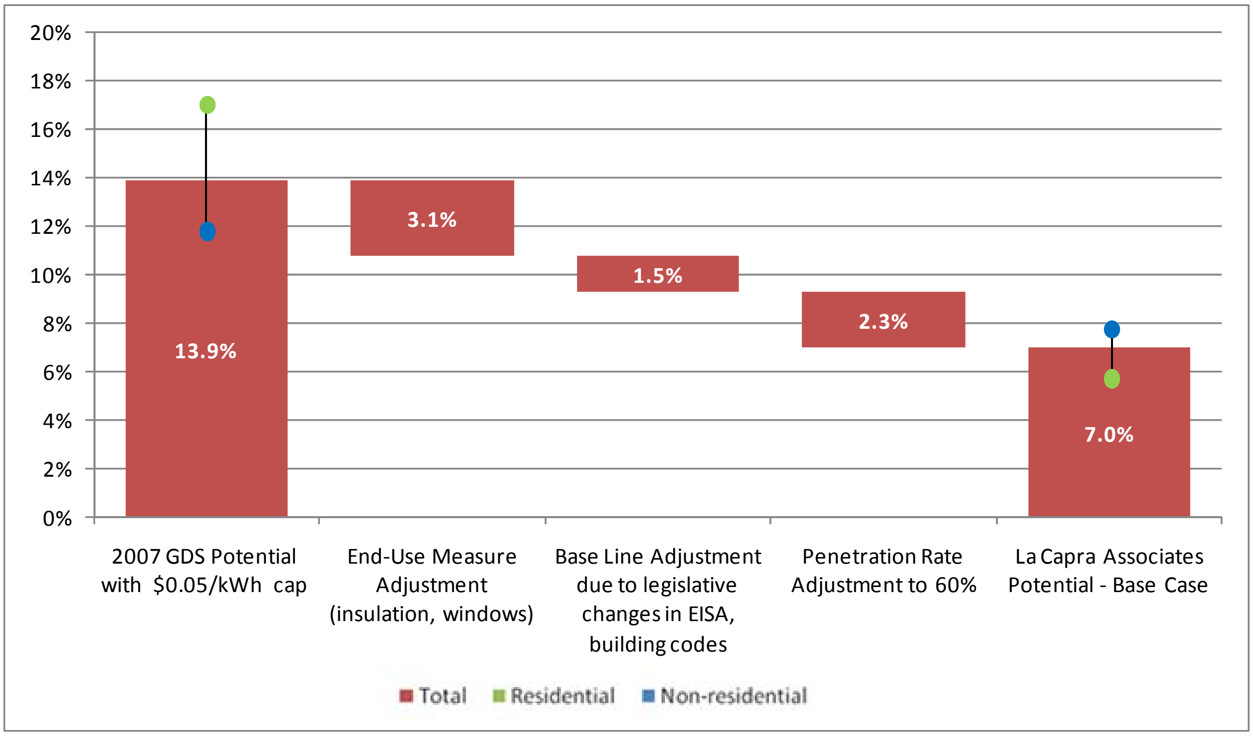
188 Tiller, Jeff. "Energy Efficiency Opportunities for North Carolina Buildings and Industrial Facilities." Appalachian State University Energy Center and Department of Technology. February 2007.

189 Brown, Marilyn A., et al. "Energy Efficiency in the South." Georgia Institute of Technology and Duke University. Published by: Southeast Energy Efficiency Alliance. April 2010.

which are currently not economic, continue to replenish the depleted inventory of energy efficiency opportunities.

Beginning with an initial potential estimate drawn from the GDS study, several adjustments were made to derive La Capra Associates' final estimate. Figure 77 illustrates these adjustments, which are explained below. While the analysis of potential was performed for all sectors combined, the estimated total impact to residential and non-residential sectors is presented below for reference.

FIGURE 77: SUMMARY OF ADJUSTMENTS TO ENERGY EFFICIENCY BASE CASE POTENTIAL



Basis of analysis

This analysis is grounded in the results of the GDS study in context with the utilities studies. This was selected because it provides a detailed, comprehensive, and state-specific potential estimate. Although the study is now somewhat dated, it provides sufficient details for applying appropriate adjustments in order to develop a current, accurate potential.[190]

[190] Standard industry practice is to renew detailed end-use potential analysis approximately every three years. This frequency allows potential numbers to reflect the market including responses to changes in appliance and building standards, impact of existing programs, new technologies and changes in avoided costs or the point at which programs are considered cost effective.

Avoided cost threshold

The La Capra Associates base case potential utilized an avoided cost value of $0.05/kWh. This represents only a portion of the measures examined by GDS. For example, residential measures ranged from $0.003/kWh to $2.338/kWh.

The $0.05/kWh level was used for the base case potential because it represents a conservative threshold for measure implementation. GDS refers to this estimate as the "Achievable Cost Effective Potential," and gives a value of 13.9%.

End use measure adjustment

While it is beyond the scope of this analysis to perform a detailed measure-by-measure analysis of energy efficiency potential, the La Capra Associates team reviewed the estimated savings for each of the residential measures in the GDS study. During this analysis, it was determined that the projected savings of certain measures significantly exceeded estimates for these same measures within other potential studies.

Specifically, the GDS study attributes 59% of all savings in the residential sector to weatherization, insulation, and the use of Energy Star windows. Due to the high capital cost for these measures, the low success rate of major retrofit measures, and the prevalence of natural gas heating in North Carolina, it was determined that the savings from these measures should be reduced.[191] Our team felt that the estimated level of savings was too high and assumed 20% would remain as a proxy for lower cost measures and other residential opportunities. Therefore, the estimate of savings from these measures was reduced by 80% in order to develop a more realistic potential estimate. This reduction equates to a 3.1% reduction in overall potential.

It is important to note that in addition to those measures addressed above, there are other instances where savings potential from certain measures would be higher or lower than the estimates in the GDS study. Similarly, due to the vintage of the study, there are several measures which were not included that have been proven cost-effective. While La Capra Associates did not intend to perform a detailed review on a measure-by-measure basis, the measures adjusted above were identified for additional scrutiny due to their disproportionate influence on overall potential. This highlights the need for a new comprehensive end-use potential study.

191 This determination represents a conservative estimate of potential. As noted elsewhere, due to the relative immaturity of the energy efficiency programs in North Carolina and a regulatory structure that does not incentivize the development of programs by EMCs and municipal utilities, amongst other reasons, La Capra Associates developed these assumptions. Higher estimates of potential that assume higher penetration rates and an expanded suite of possible measures may also be credible and would represent a more aggressive view.

Adjustment for recent legislation

Over the past several years there have been multiple pieces of state and federal legislation that will impact the future of energy efficiency gains and programs. On the federal level, the Energy Independence and Security Act (EISA) of 2007 was a landmark bill mandating drastic improvements in the efficiency of residential and commercial appliances, as well as improvements in lighting efficiency.

These changes will have a great impact on electricity consumption as the provisions are phased in over the next several years. While these measures will still contribute to a more efficient electric system, they will essentially be mandated by federal regulations. Since consumers will be required to implement these measures, utilities will not be able to offer optional programs to entice customers to adopt them. Therefore, it is not appropriate to include them in an analysis determining achievable energy efficiency potential for electricity suppliers in North Carolina.

Similarly, the North Carolina Building Code Council has recently approved new building standards in December 2010. The new codes call for an efficiency improvement of 30 percent in commercial buildings and 15 percent in residential buildings.[192] Although there is currently some uncertainty related to these building code revisions, for the purposes of this analysis, we have assumed that the codes approved by the council will be implemented at the 30 percent and 15 percent levels.[193]

The GDS study was completed prior to the passage of either piece of legislation. Due to the potential overlap between measures, the GDS potential was reduced to account for the fact that these legislative measures will capture some of the potential that was assumed in the GDS study.

For the new North Carolina building codes, the adjustment is based on estimates provided in the ACEEE study. That study estimated that, by 2020, savings from the revised building codes would equal 2% of load. The study was released in March 2010 before the building codes were approved by the North Carolina Building Code Council. At that time, the codes being considered would have improved residential and commercial building efficiency by 30%. The codes that

192 "NC Building Code Council Approves Compromise on Energy Conservation Code." North Carolina Sustainable Energy Association. Press Release. December 14, 2010. Available online: http://energync.org/blog/ncsea-news/2010/12/14/nc-building-code-council-approves-compromise-on-energy-conservation-code/

193 The codes approved by the council in December reflected a compromise between the Governor's office, the N.C. Homebuilders Association, and various interest groups. Since the compromise was reached, there have been certain political and legislative challenges to the new codes that may jeopardize their adoption. At this time, the General Assembly is considering H 801, which would adopt the new building codes approved in December.

In addition to the legislative challenges, various analyses completed subsequent to the approval of the codes have estimated that the residential code changes may only yield efficiency improvements of 8-15%, depending on location in the state. As noted, for the purposes of this analysis we have assumed 15%.

were actually passed, however, were the result of a compromise requiring a 30% improvement in commercial buildings and only a 15% improvement in residential structure.

Due to this change, it is appropriate to reduce the ACEEE estimate to eliminate half of the anticipated savings from residential structures. Based on the calculations demonstrated in Figure 78 below, it was determined that the ACEEE estimate of 2% should be adjusted to 1.6%.

FIGURE 78: ENERGY SAVINGS FROM RESIDENTIAL STRUCTURES[194]

	Residential (GWh)	Commercial (GWh)	Total (GWh)	Portion of 2020 Load (%)
2020 Savings based on 30%-30% building codes	1,235	1,705	2,940	2.0%
2020 Savings based on 15%-30% building codes	617	1,705	2,322	1.6%

This potential was removed from the GDS potential because with a regulatory mandate for these savings, it is not appropriate to include them in a utility potential estimate.

The GDS study was also adjusted to reflect the provisions of the EISA legislation. The ACEEE study estimates that the regulations contained in the act will reduce electricity consumption in North Carolina by 1.2% by 2025. These provisions will be fully implemented in 2014, which means the average annual savings will be 0.11% per year. Since the La Capra Associates estimate of potential is based on 2021 load, we estimate that the impact of the EISA regulations in 2021 will be 0.77%.

As with the building codes, these savings should be removed from the potential estimate because the savings will not be attributable to utilities.

The combination of these adjustments would be a 2.37% reduction in overall potential. However, since all the provisions of the legislation do not come into effect until 2014, it is possible that utilities could develop programs in the short term that would yield attributable savings. Due to the timing of the legislation, the legislative adjustment was reduced by 30% to 1.66%.

194 Sector savings based on ACEEE estimate of residential-commercial breakdown as 42% and 58%, respectively. See ACEEE 2010, p. 28.

This adjustment was further reduced due to potential overlap between measures covered by each piece of legislation. Specific breakdowns of savings by measure within the legislation were not available, so this overlap effect was estimated at a minimal value of 10%.

Our team determined that while the legislation could warrant a larger adjustment to the energy efficiency program potential, by applying all the factors discussed above, only a 1.5% adjustment due to legislation should be made to the prior study.

Penetration rate adjustment

The GDS study assumed a maximum penetration rate of 80% on equipment burnout for residential measures, so the net penetration rate in the 10 year study varies depending on measure life. While penetration rate estimates typically vary by measure, an average rate of 80% is at the high end of estimates of maximum penetration. The recent EPRI study, for example, cited long-term residential implementation factors ranging from 5% for dehumidifiers to 100% for lighting. For commercial measures the range of values was from 30% to 100%. In order to develop a realistic achievable potential, the La Capra Associates estimate contains an adjustment reducing the average long-term penetration rate of residential measures to a more practically achievable level of 60%.

Since the GDS study based the commercial and industrial potential estimates on a meta-review, rather than an end-use measure assessment, the penetration rate for these sectors is not as explicit. After reviewing the source studies included in the meta-review, it was determined that an equivalent penetration rate adjustment is appropriate for the commercial and industrial potential as well. Three of the studies were completed by GDS and used the same 80% penetration rate. Of the remaining studies that explicitly cited maximum penetration rates, most ranged from 70%-80%. This review confirmed the initial presumption that GDS provided a commercial/industrial potential estimate that is consistent with the same fundamental approach to achievable potential as their more detailed residential analysis.

The adjustment to reduce the penetration rate from 80% to 60% for all sectors results in an overall potential reduction of 2.3%.[195]

Final potential

Beginning with the original GDS potential of 13.9%, the adjustments described above yield a final potential of 7%. This figure represents the realistically achievable 10 year potential.

195 The penetration rate adjustment described in this section represents a conservative view of energy efficiency potential. Some studies have shown that an 80% penetration rate is achievable and reasonable. Also, a more aggressive view of potential would anticipate that even if an 80% rate is not realized, new low cost measures would be introduced to have the same overall impact. For this analysis, La Capra Associates chose a more conservative and justifiable estimate due to the relative immaturity of the efficiency market in North Carolina.

Development of High Potential Case

By making some changes to certain assumptions and adjustments, La Capra Associates also developed a "high potential" case. Rather than a separate analysis, this scenario provides an estimate of the potential with a more aggressive implementation of a larger suite of economically-qualifying measures.

There are two primary differences between the base and high cases. First, the high case includes all measures below a $0.10/kWh avoided cost threshold. The GDS estimate at this level is 19.4%.[196] The $0.10/kWh threshold is especially valid if policy makers are considering trade-offs between higher cost new generation, such as renewable and nuclear, and energy efficiency. The base estimate assumes program economics are based on avoided costs of the operation of conventional, existing fossil fueled generation at $0.05/kWh. The cost associated with new fossil generation is somewhere in between the two threshold levels.

The second difference between the base case and high potential cases is the penetration rate. For the high case a maximum rate of 70% was used, which would be achievable with increased marketing, outreach, and incentives. The increase in penetration rates was viewed as reasonable on average since for many programs the additional avoided cost assumption will allow higher program expenditures, including incentives while still maintaining favorable program economics. The other adjustments to the GDS potential in the base case were also applied in the high case. Using this methodology, the 10 year potential is calculated as 12.7%.

The same methods and a corresponding set of assumptions were applied to the values in the Duke potential study. Beginning with a total potential of 20.6% (assuming 100% penetration and the same $0.10/kWh threshold), the same adjustments for legislation and maximum penetration were applied. These adjustments resulted in a potential of 13.3%.

The final La Capra Associates estimate of high potential combined the results from the GDS and Duke analysis to yield a final potential of 13% over 10 years.

Potential Estimate Benchmarking

The final estimates for the base case and high case energy efficiency potential were compared to recent estimates produced elsewhere. The Georgia Tech meta-review (described in section 3.5.2.5 above), provides a recent and comprehensive review of 19 energy efficiency potential studies produced since 1997. The review focuses on the South region and includes mostly region-specific studies, as well as several national studies, such as the EPRI analysis (2009). This study was selected for benchmarking purposes because it is region-specific and includes the majority of the most recent potential studies. The average and range of estimates for efficiency

196 The GDS study cites an "Achievable Potential" of 20.1%, which includes all examined measures regardless of cost. This figure was reduced to include only measures below the $0.10 threshold.

potential in the electricity sector is provided below. The values are presented as savings potential percent per year.[197]

FIGURE 79: RANGE OF EFFICIENCY ESTIMATES IN GEORGIA TECH META-REVIEW

	Minimum	Average	Maximum
Moderate Achievable	0.37%	0.88%	1.75%
Maximum Achievable	0.50%	1.18%	2.01%

The La Capra Associates estimates of 0.70% per year for the base case and 1.3% per year in the high case are comparable to the averages and ranges from the Georgia Tech meta-review.

Impact of Opt-out Provision

One important factor not considered in the development of these potential numbers is the opt-out provision. The potential numbers include estimates for all customer classes. In establishing the mechanism for cost recovery of DSM/energy efficiency programs, Senate Bill 3 allows industrial and "large commercial"[198] customers to opt-out of a utility's energy efficiency programs if they have implemented, or plan to implement, energy efficiency measures independent of the utility programs. This provision can have a profound impact on the portion of the identified potential that can be achieved by energy efficiency programs run by the utilities. The percentage of utility loads in North Carolina eligible to opt out is estimated to be more than 40%, and estimates of current levels of opt-outs are between 15% and 30% of total load.

The impact of the opt-out provision was not included in the La Capra Associates estimates, meaning our estimates include the savings potential for all customer sectors. The potential for these savings exists regardless of policy regarding which customers are eligible for utility-sponsored programs. In the scenario development, however, various levels of opt-out were modeled. In the base case, La Capra Associates assumed 22.5% of the total load opts-out. The more aggressive scenarios assumed only 10%.

Strategies for incorporating the impact of the opt-out provision in policies will be discussed later in this report with policy recommendations.

[197] Chandler and Brown, 2009, p. 25

[198] The NC Utilities Commission has determined that "large" customers are defined as those purchasing 1,000,000 kWh per year or more.

Program Costs/Measure Costs

The cost of energy efficiency varies widely program by program and measure by measure. Some measures, such as the replacement of incandescent bulbs with compact fluorescent bulbs ("CFLs") can cost less than $0.01 per kWh saved. Other measures, such as appliance or air conditioner upgrades can cost much more. The price of a measure is dependent on several factors, including capital costs, quantity of energy saved, and life expectancy of the measure. Program costs include the costs incurred by the utility to implement the energy efficiency programs including incentives, marketing/communication, and the measurement/verification of savings.

The GDS study included estimates of measure costs, but did not include an accounting of the program costs. La Capra Associates referred to detailed estimates filed with the NCUC by the utilities to derive the cost estimates for base case measures. Costs are represented as a range due to the issues explained above.

Utilities have not implemented measures in the cost range represented in the high potential case. Therefore, these costs were estimated based on similar relationships between the avoided cost of the measure and the cost per kW or kWh.

FIGURE 80: MEASURE/PROGRAM COSTS

Scenario	Measure Costs		Program Costs	
	$/kWh	$/kW	$/kWh	$/kW
Base EE	0.005 - 0.059	430 - 2,175	0.007 - 0.071	852 - 3,222
High EE	0.06 - 0.10	1,075 - 5,437	0.057 - 0.121	1,941 - 7,343

Demand-side management

The legislation creating North Carolina's REPS does not allow the three large utilities to use demand –side management (DSM) programs to count towards REPS compliance, though the cooperative and municipal utilities are permitted to do so.[199] EPC asked La Capra Associates to

199 As previously noted, recent legislation (S.75, signed into law 4/28/2011) has added "electricity demand reduction" as an eligible resource for IOUs. Electricity demand reduction is equivalent to demand response.

The NCUC is currently considering the issue of determining a method of measurement and verification of reduced energy consumption. See: Docket E-100, Sub 113. Order Requesting Comments on Measurement and Verification of Reduced Energy Consumption, August 24, 2010. http://ncuc.commerce.state.nc.us/cgi-bin/webview/senddoc.pgm?dispfmt=&itype=Q&authorization=&parm2=CAAAAA63201B&parm3=000127195

offer a perspective on the role that demand response might play in reaching the goals articulated in S.B. 3.

DSM programs involve contracts with customers to reduce their electricity use at times of high wholesale market prices or when system reliability is jeopardized. The nature and role of DSM programs in the electric system planning and operation help explain the intersection, or lack thereof, between demand response programs and North Carolina's goals. Demand-side management programs:

- Are designed to be one of the last resources deployed to meet or lower the electric demand.
- Tend to be dispatched significantly less than peaking generation, which operate 10% of the time or less (10% being just under 900 hours).
- Interrupted customer load for extended periods would still operate less than 100 hours per year.

DSM programs are generally thought of as capacity resources and, as such, they do not materially affect energy production in North Carolina. Since DSM is a new capacity resource, if it is used as a resource, energy will continue to be supplied over almost all the hours by existing dispatchable resources, generally fossil fueled. Utilizing DSM as new capacity as compared with other new generating resources could actually increase the use of older non-renewable generation to supply electric energy. If emissions during peak periods are of particular concern due to air quality issues, DSM may be environmentally beneficial. Since the focus of the analysis in this report is to examine and consider various resources and configuration of resources that can provide material portions of North Carolina's electric "energy," DSM programs are outside of the scope of this analysis.

Demand-side management does have an important role in integrated resource planning as North Carolina looks for the best resource mix when multiple objectives are considered, including cost, reliability, environmental impact and economic development. DSM can be a low cost capacity resource. Development is dependent on customer location, which may make it a good candidate for a capacity resource to enhance reliability in an area where it is harder to site generation and thus avoid transmission investments.

Although there is no direct job creation or property tax benefits from DSM, it creates economic development in two ways:

- The programs provide credits that lower the bills of participating retail customers, helping make the state more cost competitive and therefore a more attractive location for business.
- Demand response frees up sites that would have been needed for generation capacity making them available for economic development.

Combined Heat and Power

La Capra Associates was asked to review the potential for combined heat and power (CHP) facilities to meet a portion of the North Carolina REPS requirements. The review of this potential was greatly enhanced by the Scenario Analysis of CHP Potential in North Carolina developed by ICF International in support of the U. S. Department of Energy's Southeast Clean Energy Application Center, based at the North Carolina Solar Center.[200] This study included extensive sensitivity analysis to test the magnitude of changes in conditions and incentives to help promote CHP as an effective component of the state's energy plan and as a contributor to reliable electric infrastructure.

FIGURE 81. NORTH CAROLINA CHP POTENTIAL

	Technical Potential (MW)	Economic Potential (MW)	Achievable Potential (MW)	Achievable Potential (MW) in 5 years	Achievable Potential (MW) in 10 years
Reference CHP Capacity Potential	10,702	1,444	773	190	500
Reference CHP Demand Displacement	7,751	584	266	100	100

Many CHP installations exist in North Carolina with a combined electric capacity of 1,504 MW and over 15,000 MMBtu of coincident thermal output capacity.[201] These CHP systems are in use mainly at industrial facilities and at institutional facilities such as university campuses, where effective fuel efficiencies reach upwards of 75%. CHP is eligible as an energy efficiency technology under the North Carolina REPS and when fueled by biomass, is eligible under the general pool of renewable RECS.

The study conditions were developed under the premise that while CHP is a viable electric generation resource with a competitive levelized cost, certain policy changes and market signals that improve market access and inclusion in resource planning and would have a positive effect on investment.

Preliminary analysis and input data

The ICF study considered existing CHP, technical potential by size and application from existing facilities and estimated growth over the forecast period (20 years), electric and gas prices today and over the forecast period, and CHP technology cost and performance today and over the forecast period.

200 "Target State CHP Analysis: Overview of Six State Scenario Analysis." ICF International. October 2010.

201 A database of existing CHP installations in North Carolina is maintained by ICF with support from the Southeast Clean Energy Application Center and can be accessed online at http://www.eea-inc.com/chpdata/States/NC.html

Modeling

The CHP potential study modeled CHP payback analysis by technology, size, and application. Analysis was conducted two ways: assuming all CHP power production would be consumed on-site and the other allowing for exporting CHP power to the grid. The modeling reflected the market acceptance as a function of payback and considered market penetration over time and summarized the outputs.

La Capra Associates analysis

La Capra Associates analyzed the various results for economic potential and penetration rates. Technical potential to install CHP capacity was found to be very high for North Carolina.

1. 7,751 MW no export, i.e. all power consumed on site.
2. 10,702 MW when allowing export of CHP output to the grid.

Economic potential through 2020, when accounting for market acceptance and penetration over time, results in significantly lower estimates for realizing CHP as an economic resource. La Capra Associates review focused on the Base Case analysis and the sensitivity that assumed the 35% investment tax credit, inclusion in the North Carolina REPS and high market acceptance through education and technical assistance provided by the Application Center.

Base Case

- 91 MW no export, i.e. all power consumed on site
- 428 MW when allowing export of CHP output to the grid

Sensitivity with Case 35% Investment Tax Credit (ITC), North Carolina REPS and high market acceptance

- 902 MW no export, i.e. all power consumed on site
- 2,092 MW when allowing export of CHP output to the grid

La Capra Associates used the assumptions summarized in Figure 82 below to determine levelized costs for CHP of $0.05/kWh.

FIGURE 82. ASSUMPTIONS USED FOR MODELING LEVELIZED COST OF CHP

Technology Characteristic	CHP Capacity	CHP Demand Displacement
Capacity Factor	90%	90%
Modeled Project (MW)	25-50 MW	25-50 MW
Overnight Costs (2010$/kWh)	$1,018	$1,066
Technology Decline Rate	-	-
Fixed O&M (2010$/kW-yr)	$31.54	$31.54
Variable O&M (2010$/MWh)	-	-
Fuel Heat Rate (Btu/kWh)	5,222	5,388
Fuel Costs ($/MMBtu)	$6.47	$6.47

La Capra Associates concluded that, over the next 10 years, the penetration potential for CHP could be a significant portion of the achievable economic potential using the 35% ITC and through high inclusion in REPS implementation:

- There would be 600 MW developable in 10 years
- 100 MW would be consumed on site
- 500 MW would be exported to the grid
- The typical plant sizes would be 20-50 MW, although significantly smaller plants are not uncommon down to the 1 MW level or below.
- The cost of CHP electric energy would be approximately $0.05/kWh in large scale high thermal production applications which formed the basis of this potential.

APPENDIX B – SUMMARY OF NCUC ORDERS RELEVANT TO REPS

Date order issued	Docket #	Summary of key findings relevant to REPS
1/31/2011	E-100, 113	Revises rules R8-64 to R8-69 to streamline and clarify administration of REPS, and finalizes the Renewable Energy Tracking System (NC-RETS) operating procedures for issuing and tracking REPS compliance credits.
12/10/2010	E-100, 113	Extends deadline for obtaining RECs for more than two years' worth of historic generation data to 6/1/2011.
11/23/2010	E-100, 113	Clarifies that utilities will be able to recover the cost of procuring energy to satisfy the collective swine and poultry waste set-asides, even if the unbundled RECs are sold to another NC utility.
10/11/2010	E-7, 939-940	Wood fuel derived from whole trees through primary harvests are considered eligible biomass resource for REPS. Biomass types in statute are examples, not exhaustive list. Declined to issue a comprehensive definition, affirming commitment to evaluate proposed biomass resources on a case-by-case basis.
10/8/2010	E-100, 113	Thermal energy generated from poultry waste is not eligible to satisfy poultry set-aside.
8/13/2010	E-7, 936	Municipal utilities and EMCs can count all power (including pumped storage hydropower) from Southeastern Power Administration toward REPS compliance (subject to 30% limit).
6/25/2010	E-100, 113	Allows collaborative efforts among electric providers to fulfill poultry litter set-aside (similar to swine waste)
3/31/2010	E-100, 113	Approved a pro-rata allocation mechanism (as proposed by PEC) for meeting poultry and swine waste set-asides. Mechanism divides suppliers' shares of obligation according to share of NC retail electricity sales.
2/12/2010	E-100, 113	Approved joint RFP process for electric suppliers to collectively meet swine waste set-aside. Electric suppliers withdrew their petition to delay and modify the set-aside pending review of the responses to the joint RFP.
1/20/2010	E-100, 113	For facilities using anaerobic digestion of a mix of organic material, only energy generated by the portion of methane gas actually produced from poultry and swine waste is eligible to satisfy those set-asides.
9/22/2009	E-100, 113	Clarified that 25% out-of-state limitation applies to the general REPS obligation and to each of the set-asides *individually*. Dominion is exempt from 25% limitation.
7/27/2009	E-100, 113	Clarified that a utility-owned renewable energy facility in service before 1/1/2007 does not qualify as "new". Nonutility-owned facility in service before 2007 can only qualify as "new" if it had contract with NC GreenPower prior to 2007.

Date order issued	Docket #	Summary of key findings relevant to REPS
7/13/2009	E-100, 113	Clarified 5/8 order: for out-of-state CHP facility, electricity delivered to NC utility can be considered in-state, but thermal energy is out-of-state.
6/17/2009	E-100, 113	a. Existing (pre-2007) utility-owned hydro does not qualify, regardless of size or type. New small hydro (increments <10MW) does qualify. b. Tennessee Valley Authority (TVA) distributors and out-of-state headquartered EMCs that have retail customers in NC are subject to REPS requirements. University-owned electric suppliers are not.
5/7-5/8/2009	E-100, 113	a. Solar, swine and poultry set-asides have priority over general requirements when the cost cap comes into play. All set-asides have equal priority. b. Set-asides must be fulfilled with energy generated by or delivered to a NC electric power supplier. Unbundled RECs from qualifying energy can be used to satisfy set-asides. c. Allow power supplies to meet swine and poultry set-asides collectively, determining among themselves how best to do it. d. Electricity generated out of state (including customer-sited generation) can only be considered "in state" if it is delivered to utility with NC customers. Out-of-state thermal energy cannot be considered "in state". e. RECs can be held and sold indefinitely by municipal utilities and EMCs, and up to 7 years by IOUs. However, can only be applied to NC REPS up to three years after creation.
11/26/2008	E-100, 113	Clarifies that each year's REPS requirements (both general and set-asides) are based on the previous year's actual sales, not forecasts for the current year.
2/29/2008	E-100, 113	Order adopting final rules implementing S.B. 3

APPENDIX C – FOREST BIOMASS POTENTIAL ESTIMATION METHODOLOGY

OVERVIEW

5.3.19 *MODELING TEAM*

For the purpose of modeling forest biomass potential, we contacted Robert Abt, Professor in the Department of Forestry and Environmental Resources at North Carolina State University and a widely acknowledged expert on forest biomass resources in the South. Dr. Abt convened a team of experts to work with La Capra Associates to develop input parameter scenarios for the Sub Regional Timber Supply (SRTS) model to produce forecasts of timber market prices and forest resource dynamics in response to different levels of REPS-driven demand for forest biomass. The "SRTS Team" included Christopher Galik, Research Coordinator for the Nicholas Institute for Environmental Solutions at Duke University; and Karen Abt, Research Economist, USDA Forest Service.

5.3.20 *THE SRTS MODEL*

SRTS is an economic resource allocation model combined with a biological model that forecasts timber market dynamics, harvest activity and forest stocks across the South by zone, species, product, and forest type.[202] The U.S. Forest Service, Forest Inventory and Analysis (FIA) database provides baseline levels of inventory, growth, removals and acreage grouped by forest type, ownership, species and age class. The model determines market equilibrium harvest levels and timber prices based on input projections of timber-price-constant demand and assumed demand and supply price elasticities. Timber removals from one period are then entered into the biological model to determine the inventory in the succeeding period. The SRTS model framework is currently supported largely by Southern Forest Resource Assessment Consortium (SOFAC) at NCSU.

The SRTS model is not capable of directly solving for a potential forest biomass supply limit. Energy demand for biomass is assumed to be totally inelastic – that is, completely price insensitive. Therefore, the model will supply whatever level of demand is input, regardless of market forces or environmental impact. Our method for estimating a maximum potential was to run the model with a very high level of REPS-driven biomass demand. We then assessed the timber market and inventory impacts to determine if the model's market equilibrium solution is practical. We then reduced our assumed biomass energy demand level until the model

202 For more detailed description of the SRTS model, see Abt, Cubbage and Abt (2009).

produced an equilibrium we deemed feasible based on price, industry displacement, forest inventory and management change and other metrics.

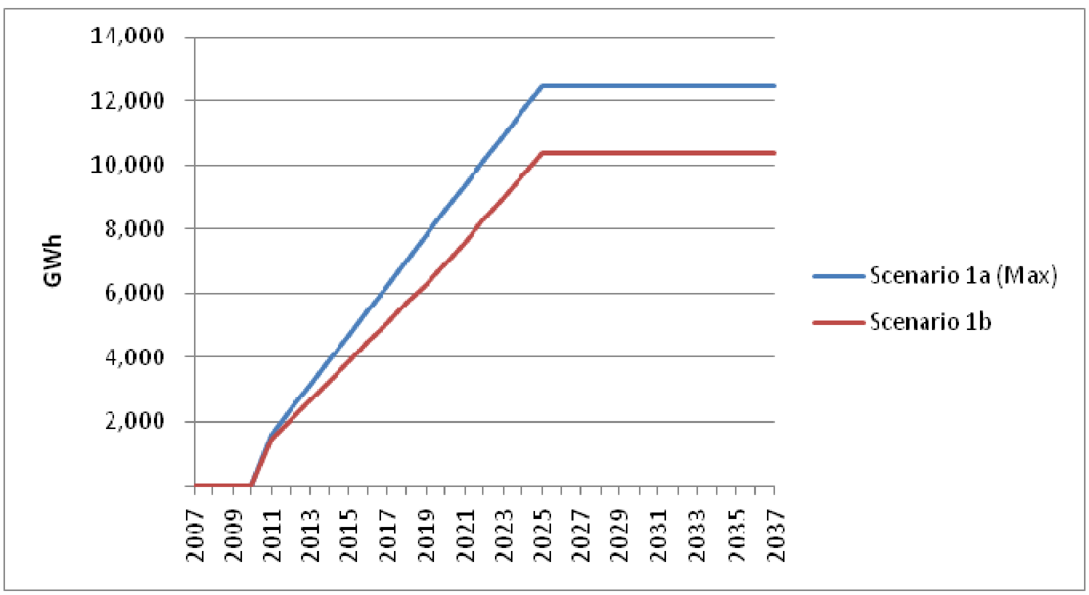
INPUT ASSUMPTIONS

The equilibrium solution reached in any particular SRTS model run is heavily influenced by a number of assumptions that are made as parameter inputs. Some key assumptions made in our modeling runs are described below. For the most part, all other parameter inputs and assumptions not mentioned below were the same as those used by Abt et al. (2009).

5.3.21 *MAXIMUM REPS-DRIVEN FOREST BIOMASS DEMAND*

In order to obtain a high level of demand to test in our model, we assumed an initial scenario in which the state's two largest utilities, Progress and Duke, comply with their non-set-aside REPS requirements entirely through forest biomass-fueled electricity generation. We also assumed that the utilities would make use of REPS' banking provision to smooth year-to-year energy requirement increases over the study period (see Figure 83).

FIGURE 83: ASSUMED REPS-DRIVEN FOREST BIOMASS ENERGY DEMAND, BY SCENARIO



5.3.22 *OTHER BIOENERGY DEMAND*

REPS is not the only driver of demand for biomass-fueled energy in North Carolina. One potential driver of demand for forest biomass is the federal Renewable Fuel Standard (RFS), which sets minimum standards for how much gasoline and diesel fuel must be produced from renewable sources each year.

Another potential driver of forest biomass energy demand is the wood pellet industry. In recent years, the South has seen an increase in existing and planned wood pellet production, primarily for export to European markets. The largest pellet production facilities in the world are located in the region. Green Circle Bio Energy Inc. opened a Florida facility in 2008 that produces a half million tons of pellets annually to be co-fired with coal in Western Europe.[203] RWE Innogy is now in the final stages of commissioning a Georgia plant that will convert 1.7 million green tons of wood and residuals into 827,000 tons of pellets per year for export to Europe, primarily the Netherlands.[204] A company with a long-term pellet supply contract with a Belgian utility has proposed a 330,000-ton annual capacity project in North Carolina.[205]

In our modeling, the SRTS team developed high, medium and low cases for biomass demand from pellets and liquid fuels. In order to estimate a maximum practical potential for REPS-driven forest biomass electricity, our model runs used the low case for other bioenergy demand. To the extent any of these additional demands exceed our assumed levels, the estimated fuel potential for forest biomass-fired electricity would be reduced on a ton-for-ton basis.

Our assumed level of wood demand for pellets in the low case was based on Forisk Consulting's estimate of demand for existing plants and proposed projects that have passed the status and feasibility screens[206] according to the June 2010 *Wood Bioenergy South* report (see Figure 87).

According to Forisk, producing cellulosic ethanol from woody biomass is not yet commercially viable.[207] Therefore, RFS-driven demand for forest biomass is not included in our low case. We believe this is a defensible assumption based on the track record of RFS implementation to date. The initial targets announced have been steadily lowered in the face of shortfalls in production, and woody biomass in the region has not been used as a major feedstock for ethanol production to this point.[208]

5.3.23 *ROLE OF RESIDUES*

Forest residues are the limbs, tops, and non-merchantable trees generally left behind after commercial harvests, as well as the non-growing stock that is removed during commercial thinning operations. FIA data provides species and survey unit-specific residue factors per total

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203 http://www.greencirclebio.com/plant.php. Accessed 3/14/11.

204 http://www.rwe.com/web/cms/en/86182/rwe-innogy/news-press/press/?pmid=4004685. Accessed 4/1/2011.

205 http://www.forest2market.com/f2m/us/f2m1/free/forest2fuel-archive/story/2011-Feb-Enviva. Accessed 3/14/11.

206 Technology screen is Forisk's assessment of whether the project is commercially viable today. The status screen indicates whether the project has received/secured/signed two or more of the following: financing, air quality permits, Engineering Procurement and Construction contracts (EPC contracts), power purchase agreements for electricity facilities, interconnection agreements for electricity facilities, and supply agreements.

207 Forisk Consulting (2010) Wood Bioenergy US, 2:9. http://www.forisk.com/UserFiles/File/WBUS_Free_201010.pdf. Accessed 2/24/11.

208 Abt, K. Personal communication, 2/23/11.

volume of growing stock removals. SRTS in turn uses the FIA factors to model logging residue production.

The rate at which residues can actually be utilized is subject to much debate. A lack of widespread economic uses for residues in the United States means that actual utilization rates are quite low. However, it is assumed that in the event of new market incentives to collect and sell residues (such as REPS-driven demand for biomass fuel), timber harvesters would make the capital investments and harvest practice changes necessary to significantly increase utilization rates.

Researchers differ on the maximum feasible utilization rates, but recent studies put the rate anywhere between 50% (Galik et al. 2009, Abt et al. 2010) and more than 90% (Perlack 2005). The utilization rate is an average across all harvests, and so is a function both of the maximum portion obtainable per harvest site as well as how widespread the collection of residues becomes.

Residue utilization rates are a critical input to these SRTS model runs because biomass energy demand is assumed to be met, to the extent possible, exclusively with residues. If there are insufficient residues to meet biomass energy demand, the excess demand is met with dedicated energy harvest of whole trees that either displaces existing demand (e.g. from the pulp and paper industry) or increases net harvest totals.

For our model runs, we assumed utilization rates would climb from 0% in 2010 to 85% for softwood species, and 70% for hardwood species by 2015. These rates were taken from midrange estimates suggested by Dennis Hazel, Associate Professor in the Department of Forestry and Environmental Resources at North Carolina State University, and based on ongoing research he and others are conducting into residue generation and collection potential from conventional timber harvests in North Carolina (Hazel et al., 2009). The high estimates are based primarily on two key findings: first, some evidence that the FIA residue factors underestimate the amount of residues generated by typical North Carolina harvesting operations; and second, the common use of “tree-length” logging systems in the Piedmont and Coastal Plain regions of North Carolina that make residue collection easier and more efficient.[209]

[209] In much of the U.S., loggers remove limbs and tops in the forest where the trees are felled before hauling the merchantable stems to a log deck. In a “tree-length” logging system, both merchantable and non-merchantable trees are hauled intact to a log deck, where the merchantable trees are delimbed and topped. This reduces the need to glean residues from the forest floor across the entire harvest site.

FIGURE 84: "TREELENGTH" LOGGING SYTEM IN ACTION IN NORTH CAROLINA.

Grapple skidders (left) haul bunches of cut trees with limbs and tops intact to a log deck (center), where they are delimbed and topped. This system, common in the Piedmont and Coastal Plain regions of North Carolina, makes it possible to collect residues very efficiently. Photo courtesy of Dennis Hazel.

Our residue assumptions, which fall on the high end of the spectrum found in the available literature, introduce a number of caveats to any conclusions about biomass potential drawn from our model runs. First, our high residue collection assumptions would require aggressive residue-harvesting practices to be almost universally adopted throughout the study area. Since it is not generally economic to transport biomass fuel long distances, such practices could only be supported by geographically well-distributed generation resources located throughout the study area.

A second caveat is that our model likely underestimates roundwood impacts from REPS-driven biomass demand due to the assumption that residues are exhausted prior to any use of whole trees for bioenergy. Past experience and utilities' stated compliance plans indicate that whole trees, if included as an eligible biomass fuel source, will likely be used prior to the exhaustion of available forest residues.

5.3.24 *TRADITIONAL FOREST PRODUCTS DEMAND*

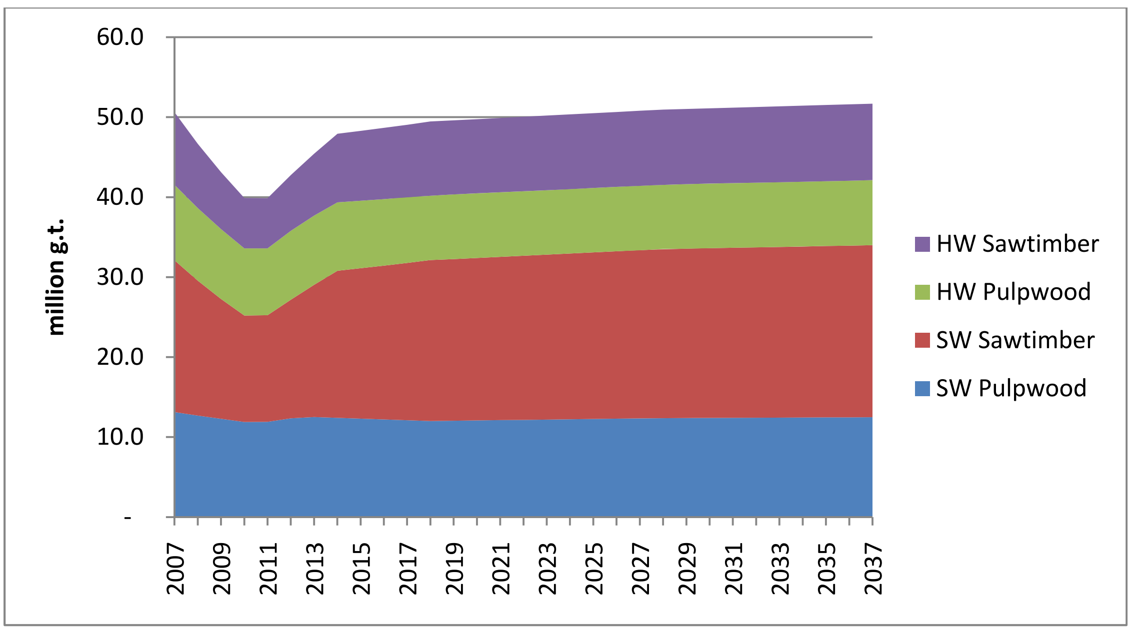
Traditional wood demand (e.g. pulp and paper, sawtimber, etc.) is estimated in SRTS by beginning with exogenous projections of price-constant wood demand for the different product categories. Using assumed price and inventory elasticities, SRTS equilibrates supply and demand to estimate final demand at the market price in each period. We assumed the same market data-based demand elasticities as were used in Abt et al.'s North Carolina case study (2010).

Karen Abt developed our projection of price-constant wood demand to initialize traditional demand in our SRTS runs. The projection begins with actual FIA data for 2007. Then Bureau of

Labor Statistics 2008-2018 industrial output projections were used to drive the forecast to 2018. However, to capture recession impacts, demand levels were downscaled from 2007-2010 proportional to observed decreases over the same period in the value of shipments in the paper and wood products industry (U.S. Department of Commerce, Bureau of the Census, 2011). After bottoming out in 2010-2011, we assumed the traditional demand rebounds and returns to the pre-recession BLS sector trajectory by 2014. After 2018, we assumed demand for the four products basically levels off, with product-specific annual demand growth rates ranging between 0.0% and 0.5% (see Figure 85).

This projection was designed to be on the high end of the spectrum. High traditional demand results in higher level of harvest, and therefore increased supply of residues available. Due to the primary role residues play in supplying biomass energy demand, assuming a higher level of traditional demand increases the maximum potential for REPS-driven biomass. If North Carolina's traditional wood products demand does not meet this projection, the potential estimate from these model runs will likely be overly optimistic.

FIGURE 85: PRICE-CONSTANT TRADITIONAL DEMAND PROJECTIONS ASSUMED FOR SRTS MODEL RUNS



5.3.25 *SUSTAINABLE HARVESTING*

According to a recent NCUC ruling, whole trees can be eligible for use as fuel for REPS-compliant biomass energy.[210] Many other states with renewable portfolio standards that include whole tree biomass also place sustainability requirements or other restrictions on the harvesting of eligible biomass fuel to ensure that the policy does not result in unintended ecological damages

210 North Carolina Utilities Commission Docket No. E-7, Sub 939 and 940. Order accepting registration of new renewable energy facilities. Issued 10/11/2010.

and deforestation. The North Carolina definition of "renewable" whole tree biomass remains ambiguous and subject to NCUC interpretation on a case-by-case basis.

We assumed that the intention of the REPS policy is not to cause inappropriate or excessive harvesting that damages valuable natural resources or threatens the sustainability of forest resources. Therefore, we attempted to include screening parameters in our scenario that would simulate at least minimum sustainability standards for harvesting of forest biomass.

It was beyond the scope of this analysis to develop screening parameters that would place restrictions on the SRTS-modeled harvests directly analogous to any particular sustainable harvesting guidelines or policies. In any event, the lack of clarity on biomass eligibility would make choosing the model for such a screen an arbitrary exercise.

In order to model minimum standards with some appropriate relationship to geographic divisions and forest type distribution, Christopher Galik and the SRTS team developed a screen based on the relative occurrence of extant elements from the North Carolina Natural Heritage Program database.

The Natural Heritage Program, part of the North Carolina Department of Environment and Natural Resources, documents and classifies natural areas of national, state and regional significance. Using GIS data from the Natural Heritage database, the SRTS team mapped the areas in North Carolina with medium to high likelihood (>20%) of extant occurrences of rare and endangered species populations, exemplary or unique natural ecosystems (terrestrial and palustrine) and special wildlife habitats. Overlaying this map on a map of the state's forests produced ratios of areas with such occurrences to total forest area by type (deciduous, evergreen, mixed and woody wetland) across four subregions (see Figure 86 below). These ratios were then entered into the SRTS model as generic exclusion ratios.

FIGURE 86: PERCENT OF FOREST AREA EXCLUDED FROM HARVESTING IN SRTS MODELING DUE TO SUSTAINABILITY SCREEN

	Deciduous	Evergreen	Mixed	Woody Wetland
NC1 – Western Mountains	2.9%	6.9%	3.7%	8.6%
NC2 – West Piedmont	2.1%	2.7%	2.1%	9.4%
NC3 – East Piedmont	1.3%	1.4%	1.3%	1.2%
NC4 – Coastal Plain	3.7%	3.5%	3.8%	2.8%

It should be noted that extant occurrences from the natural heritage database should be taken only as a proxy for high conservation value areas rather than literal "no harvest zones". There are certainly areas containing extant occurrences of natural heritage elements that would be perfectly appropriate sites for forestry activities. We assume such examples are balanced out by other high conservation value areas (such as riparian buffers) not captured by the chosen database elements. The exclusion ratios were ultimately applied generically to entire subregions and forest types within the model (see Figure 86, above), losing their direct connection to specific locations.

We believe this screen is relatively conservative. It excludes less than 4% of forest areas in most zones, with slightly higher exclusion rates in some western mountains and wetland zones. The use of the natural heritage database elements as a proxy for high conservation value areas is admittedly crude, but provides at least some approximation of the geographic distribution of such areas. We developed the screen as neither a representation of, nor recommendation for any particular sustainability policy.

5.3.26 *HARVEST AREA*

The area included in the demand and supply calculations of the SRTS modeling included all of North Carolina and the Virginia border region capable of supplying North Carolina demand (from Abt et al. 2010). The counties in South Carolina that are part of the service territories of Duke Energy Carolinas and Progress Energy Carolinas were also included. These counties were included because biomass energy produced there and delivered to one of the North Carolina IOUs' customers would be considered in-state under the REPS law. When possible, we break out the percentage of biomass resources that are obtained from areas outside North Carolina.

FUEL COST CAP CALCULATION

If we ignore competition from other forms of renewable power, the limit on biomass is largely an economic constraint – whether enough biomass fuel can be delivered to generation resources at a price which allows sufficient energy to be generated below the REPS cost cap. Since the SRTS model assumes REPS-driven demand for biomass energy is perfectly inelastic – that is, completely price insensitive – the model is incapable of making this distinction. We calculate a maximum delivered fuel price above which biomass power could not be developed without exceeding the REPS cost cap structure.

5.3.27 *KEY ASSUMPTIONS IN FUEL COST CAP CALCULATION*

Perfect banking from 2011-2025: We assume that utilities add resources in such a way that they maximize their use of the annual cost cap for all years.

Maximum Energy Efficiency: Since REPS compliance through energy efficiency measures is recoverable through a separate process and doesn't count toward the renewable energy cost caps, we assume that utilities maximize their use of energy efficiency for compliance. As a result of this assumption, only IOUs are considered because EMCs and municipal utilities can meet their requirements entirely through EE.

Maximum out of state: Because out of state renewable resources are so much lower cost than most resources available in North Carolina (Texas RECs are currently trading at about $1.00), we assume that utilities maximize purchases of out of state RECs for REPS compliance. One repercussion of this assumption is that only Duke and Progress are assumed to potentially develop in-state biomass, since Dominion is permitted to use all out-of-state RECs for compliance.

CALCULATING A FUEL COST CAP FOR UNDESIGNATED INCREMENTAL ENERGY

Total cost caps for Duke and Progress were calculated based on projected customer numbers from the IRPs' 2010 IRPs. Progress' IRP projected research and development (R&D) and administrative costs, which were subtracted from the total cost caps. Since Duke did not provide similar information, we assumed that the same percentage of the total cost cap would be for R&D and administration, and subtracted that as well. The remaining total represents the cap for incremental REPS energy cost. The cap was converted to real 2010 dollars using the gross domestic product (GDP) chain-type price index from AEO2011.

We estimated incremental costs for set-aside resources and out-of-state resources based on confidential utility data and La Capra Associates industry knowledge. These costs were subtracted from the incremental cost cap to obtain an incremental cost cap on undesignated resource requirements. For our scenarios, this is equivalent to a cost cap on forest biomass-fueled energy.

Because the energy requirements and cost caps under REPS are "lumpy", we did not calculate annual cost caps but rather an average cost cap for the whole period 2010 – 2025. This assumes that utilities will use the banking provisions of REPS to spread compliance costs efficiently across all years. (In other words, no cost cap allowance is "left on the table" in any year if it is exceeded in another year) Therefore, we summed the annual cost caps for undesignated incremental energy from 2010-2025 (2010$s), and divided it by the sum of annual undesignated resource energy requirements (MWh), to obtain an average maximum incremental energy cost (equivalent to the REC cost) of about $35.00.

By adding the maximum REC cost to the assumed avoided cost of energy for the utilities, we obtained a maximum levelized cost of energy (LCOE) for undesignated REPS resources. Using the La Capra Associates financial model, we calculated that the LCOE for a utility-owned dedicated biomass plant[211] could only remain below the maximum if delivered biomass fuel could be available for $2.40/MMBtu or less. For a project that co-fires biomass with an existing coal plant, the fuel could cost as much as $6.40/MMBtu.

Assuming that stumpage price is about 36% of the delivered price of woody biomass[212], and that woody biomass has 50% moisture content and energy rate of 8,500Btu/dry lb, we calculate a maximum stumpage price of $7.34/green ton for dedicated new biomass plants and

211 Using capital cost, O&M cost and heat rate assumptions from Figure 16.

212 From R. Abt.

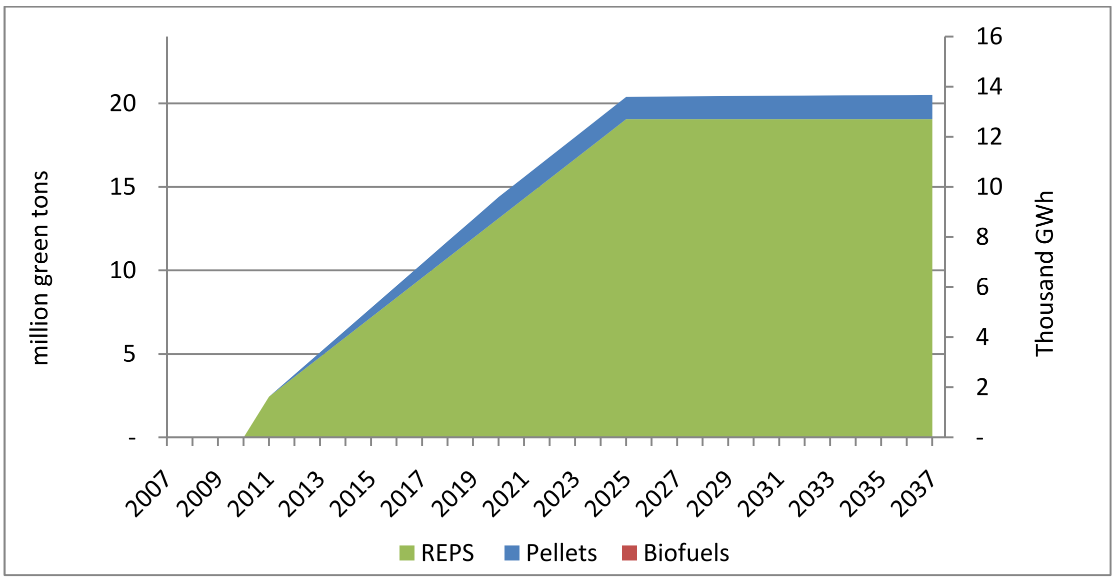
$19.58/green ton for biomass co-fire plants. These approximate fuel cost caps play a role in our evaluation of the scenarios runs in SRTS.

MODEL RUN OUTPUT ANALYSIS

5.3.28 *SCENARIO 1A (BASE CASE)*

Scenario 1a was run in SRTS using the assumptions described above, and with total energy demand for biomass comprised of maximum REPS demand and low "other" bioenergy demand (see Figure 87).

FIGURE 87: BIOMASS ENERGY DEMAND IN SCENARIO 1A (BASE CASE): MAX REPS DEMAND; LOW ALTERNATIVE BIOENERGY DEMAND

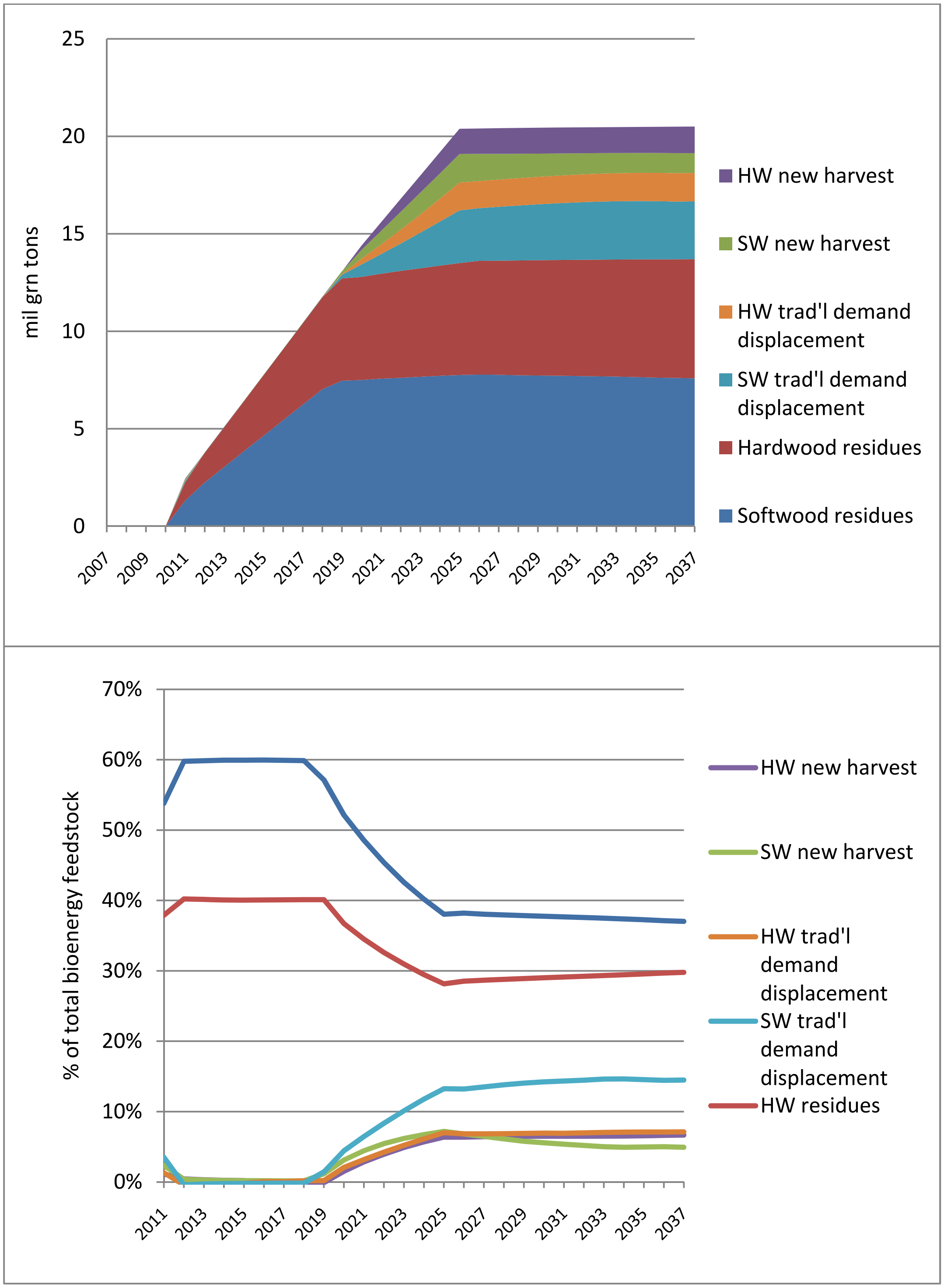


We examined model outputs to determine if the scenario represents a "feasible" outcome according to several possible metrics. The results are described below:

Feedstock Composition

REPS-driven biomass demand is met almost entirely with residuals from the beginning of the REPS demand period until 2019. In 2019, the demand for biomass exceeds residuals, and there begins to be dedicated biomass harvests. By 2025, 20% of biomass for energy comes from displacement of harvests that would have been for traditional wood demand; 14% comes from increases in total harvest activities; and 66% is met with residuals. These levels remain fairly steady for the remainder of the study period (see Figure 88).

FIGURE 88: FEEDSTOCK COMPOSITION (IN TOTAL GREEN TONS AND %) OF BIOMASS ENERGY DEMAND IN SCENARIO 1A



Pulpwood Harvest Impacts

By 2025, more than 4.1 million green tons of softwood and 2.7 million green tons of hardwood are harvested annually for biomass energy. That represents 34% and 27%, respectively, of the total softwood and hardwood pulpwood harvest in the baseline forecast.

In 2025, 22% of baseline softwood demand and 14% of baseline hardwood demand for pulpwood is displaced by biomass energy demand. In addition, pulpwood harvesting increases 13% for softwoods and 12% for hardwoods over baseline levels. About half of the softwood and 40% of the hardwood harvest change happens out of state, in Virginia and South Carolina border regions (see Figure 90).

FIGURE 89: PINE PULPWOOD HARVEST CHAGE DUE TO BIOENERGY DEMAND (SCENARIO 1A)

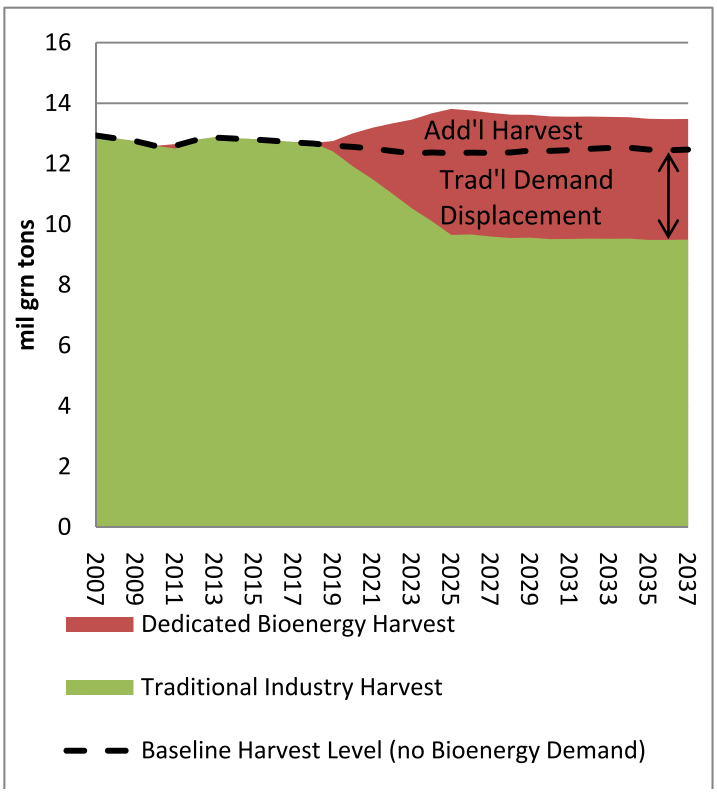
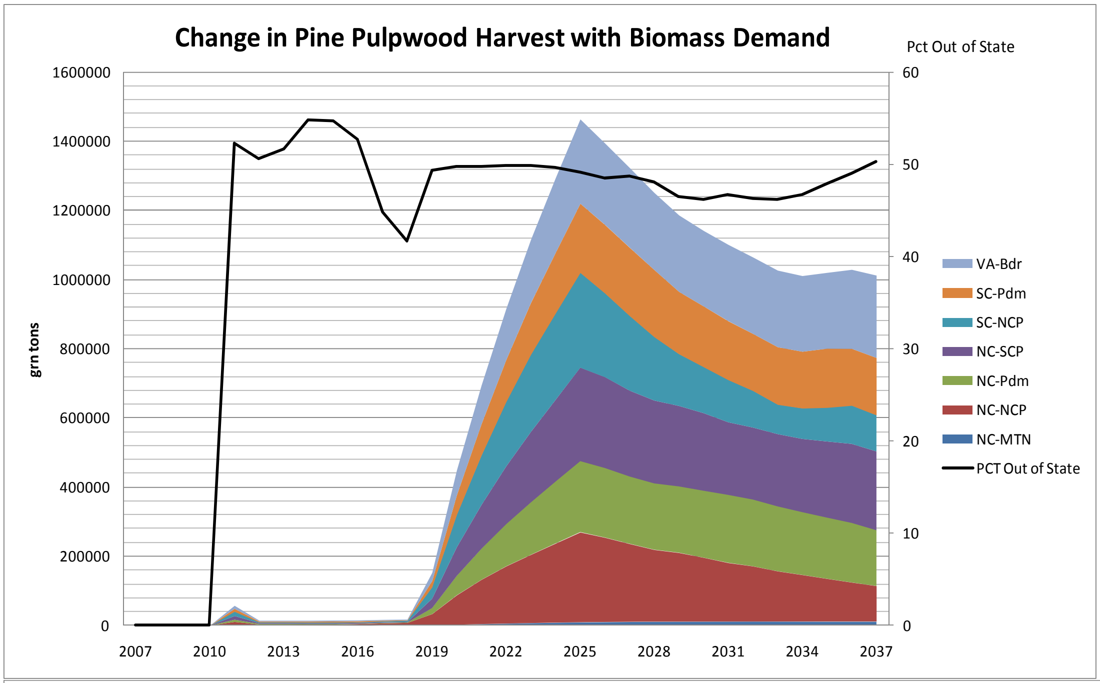
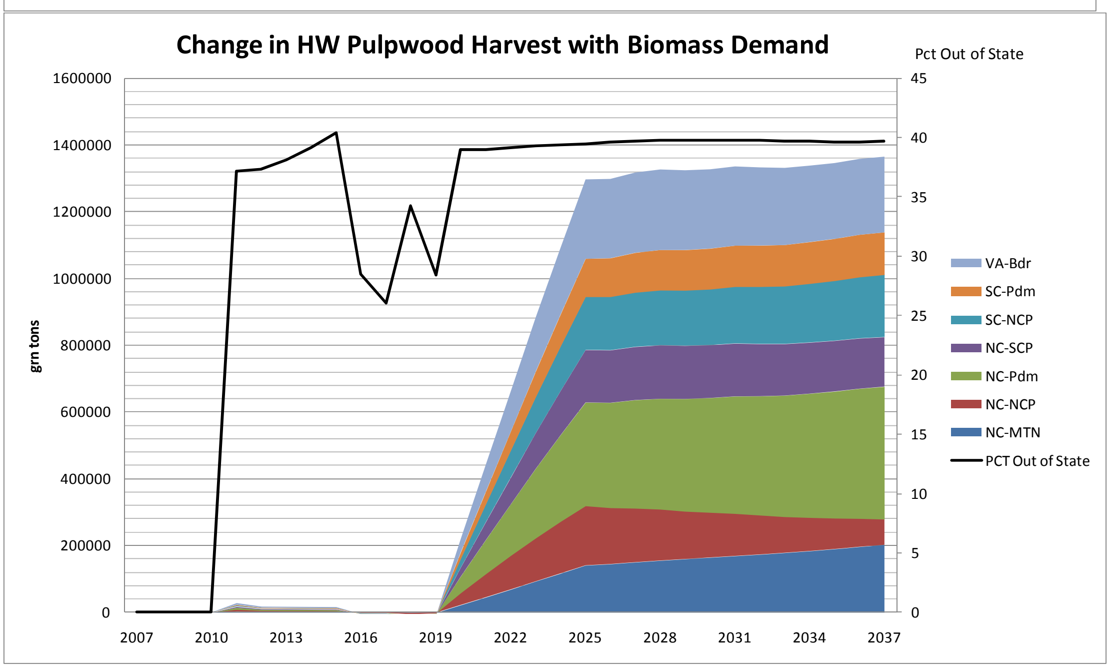


FIGURE 90: CHANGE IN PINE AND HARDWOOD PULPWOOD HARVESTS DUE TO BIOMASS DEMAND, BY REGION, IN SCENARIO 1A

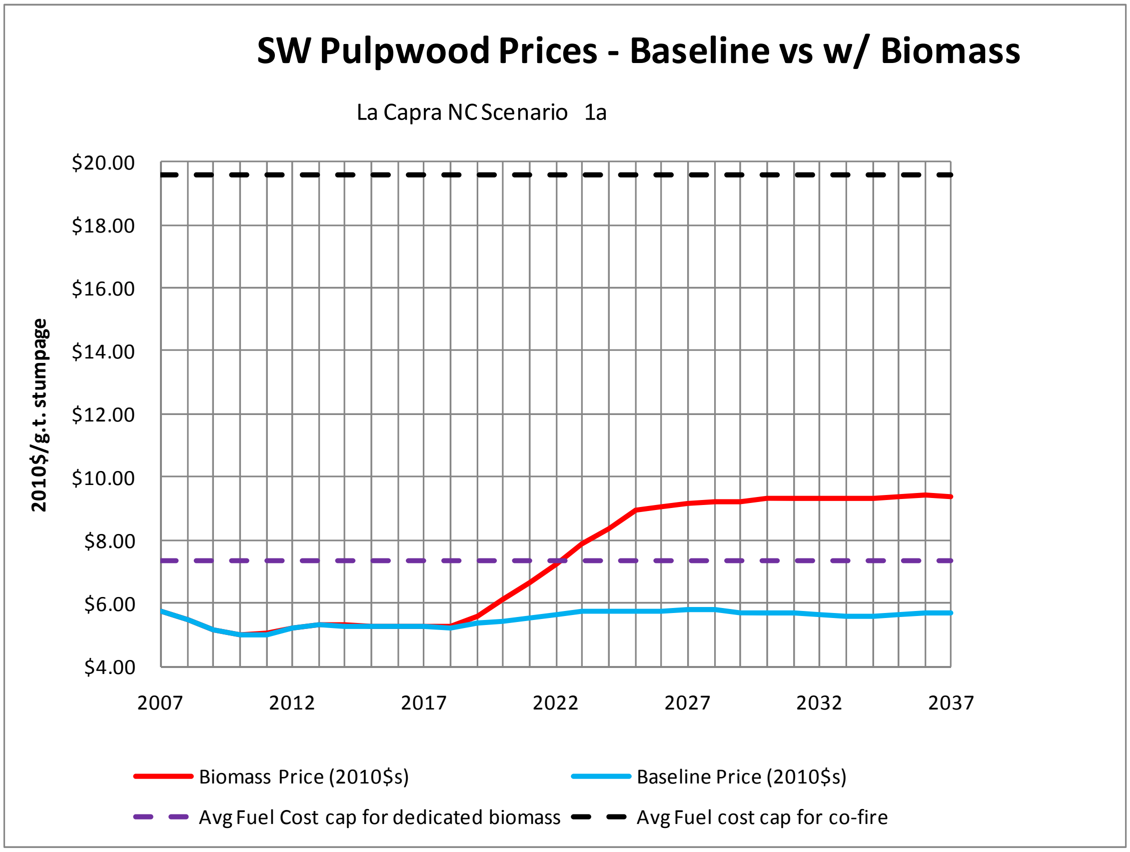




Pulpwood prices

As a result of the exhaustion of residues in 2019 and the entrance of biomass energy demand into the pulpwood market, the price of pulpwood spikes significantly. Between 2018 and 2025, the stumpage price for pine pulpwood increases from $5.25/Green Ton (GT) (2010$s, using 2006-2008 average of Forest2Market (F2M) quarterly price quotes for all North Carolina regions as 2007 price) to $8.96/GT – a 71% increase. After 2025, the price continues to climb, but at a much slower rate – reaching $9.38 (2010$s) by 2037. In the baseline case, pine pulpwood prices peak at $5.78 in 2027, and then fall to $5.68 by 2037.

FIGURE 91: SOFTWOOD PULPWOOD PRICES FOR SCENARIO 1A – COMPARED TO BASELINE WITHOUT BIOENERGY DEMAND

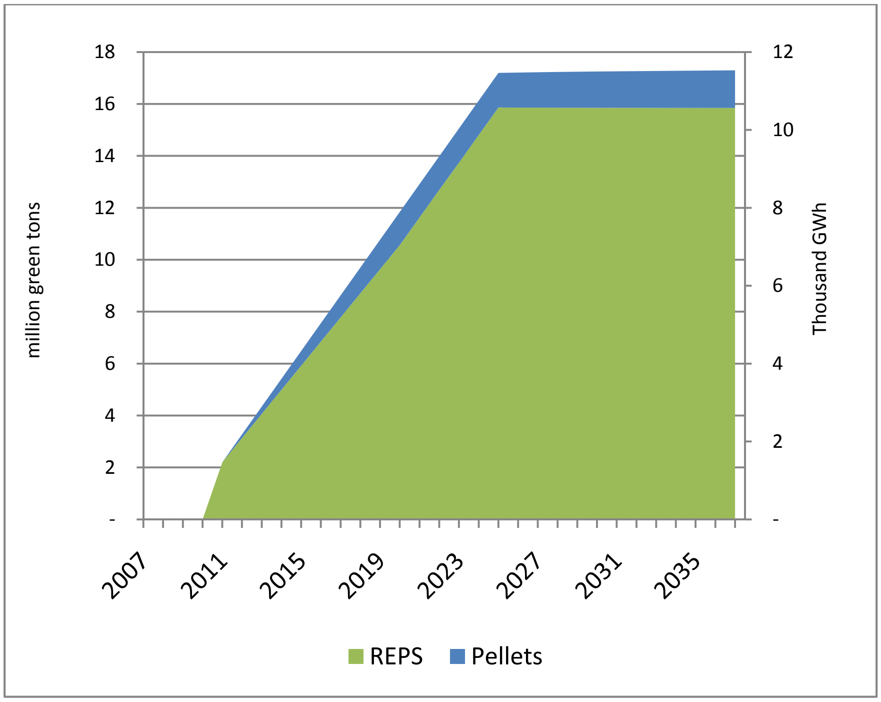


As a result of the troubling implications of the Scenario 1a model results according to many of the metrics discussed above, we determined that parameter inputs for bioenergy demand in this scenario were not practical given the other inputs and assumptions.

5.3.29 *SCENARIO 1B ANALYSIS*

We ran the model again with lower REPS demand for biomass energy holding all other inputs and assumptions equal. The new parameter inputs for bioenergy demand (with pellet demand the same as before) are shown in Figure 92. We reviewed the output from this model run against the same set of metrics as Scenario 1a.

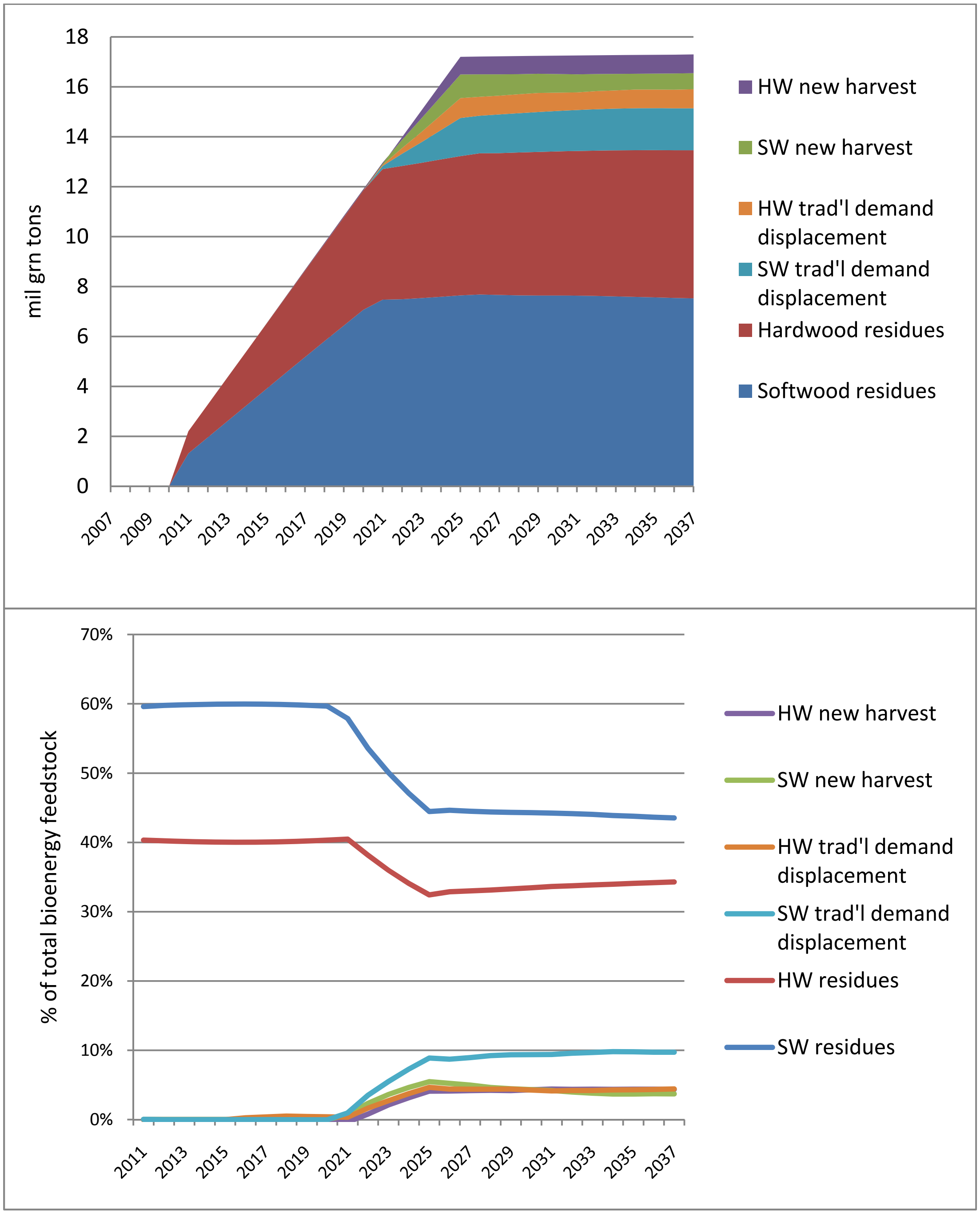
FIGURE 92: BIOMASS ENERGY DEMAND IN SCENARIO 1B



Feedstock composition

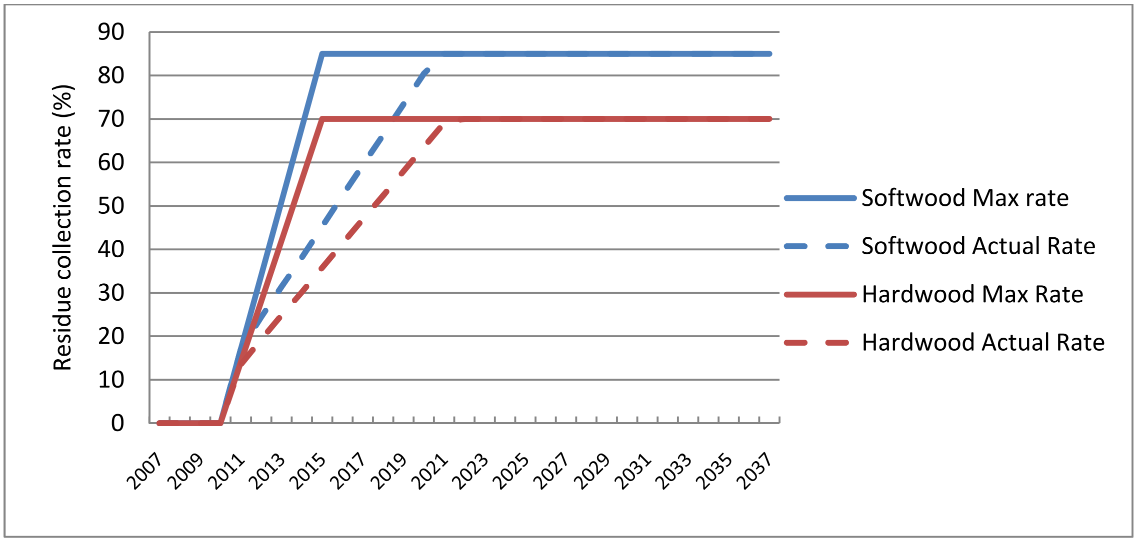
In this scenario, the feedstock composition of biomass energy demand is exclusively residuals through 2021, and heavily oriented toward residuals through 2037. The proportion of biomass demand met by residuals bottoms out at 76% in 2025, and then climbs back to 78% by 2031, where it remains for the duration of the study period (see Figure 93) In this scenario, only 14% of biomass of energy demand comes from displacement of traditional demand, and 8% comes through increased harvest activity. These are significantly lower impacts than were seen in the Scenario 1a results.

FIGURE 93: FEEDSTOCK COMPOSITION (IN MILLION GREEN TONS AND % OF TOTAL) FOR BIOENERGY DEMAND (SCENARIO 1B)



As a result of the lower demand, actual residue utilization rates remain well below our assumed maximum rates through 2021 (see Figure 94). The biomass demand in this scenario could still be met even if less aggressive assumptions about residue collections were used.

FIGURE 94: LOGGING RESIDUAL UTILIZATION RATES (SCENARIO 1B)



Pulpwood Harvest Impacts

Biomass dedicated harvest only reaches 19% of baseline total softwood harvest and 14% of hardwood harvest. For softwood, about 13% of baseline demand is displaced; 7% for hardwood. Softwood total harvest increases 6% over baseline and hardwood increases 7%.

FIGURE 95: PINE PULPWOOD HARVEST CHANGE DUE TO BIOENERGY DEMAND (SCENARIO 1B)

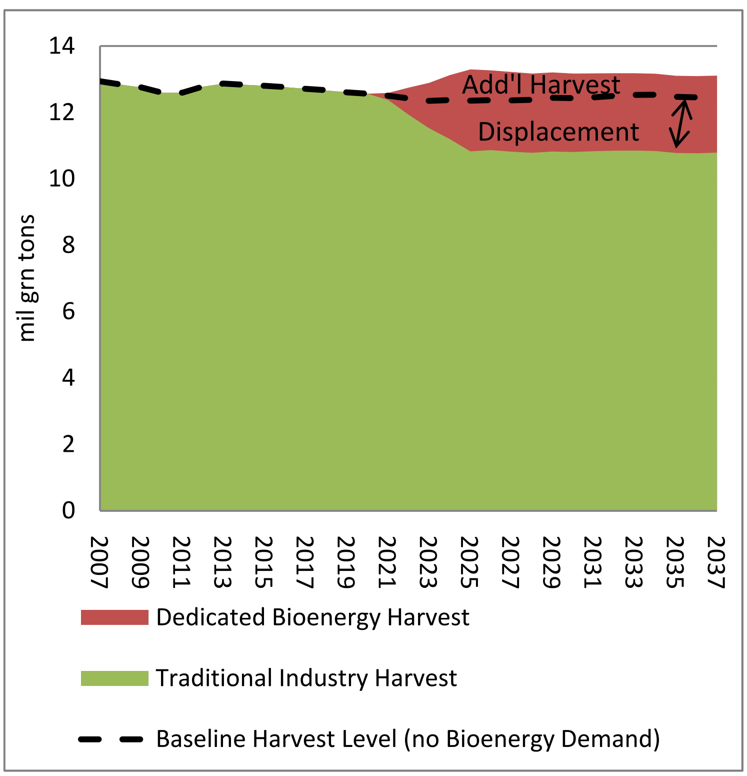


FIGURE 96: CHANGE IN SOFTWOOD PULPWOOD HARVEST DUE TO BIOMASS DEMAND IN SCENARIO 1B

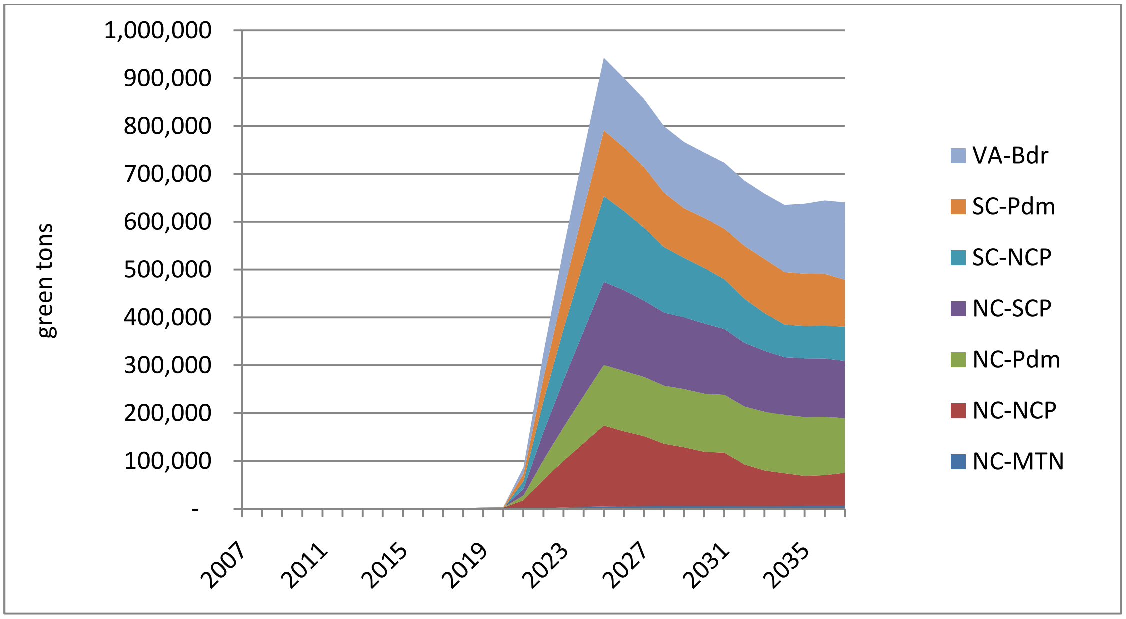
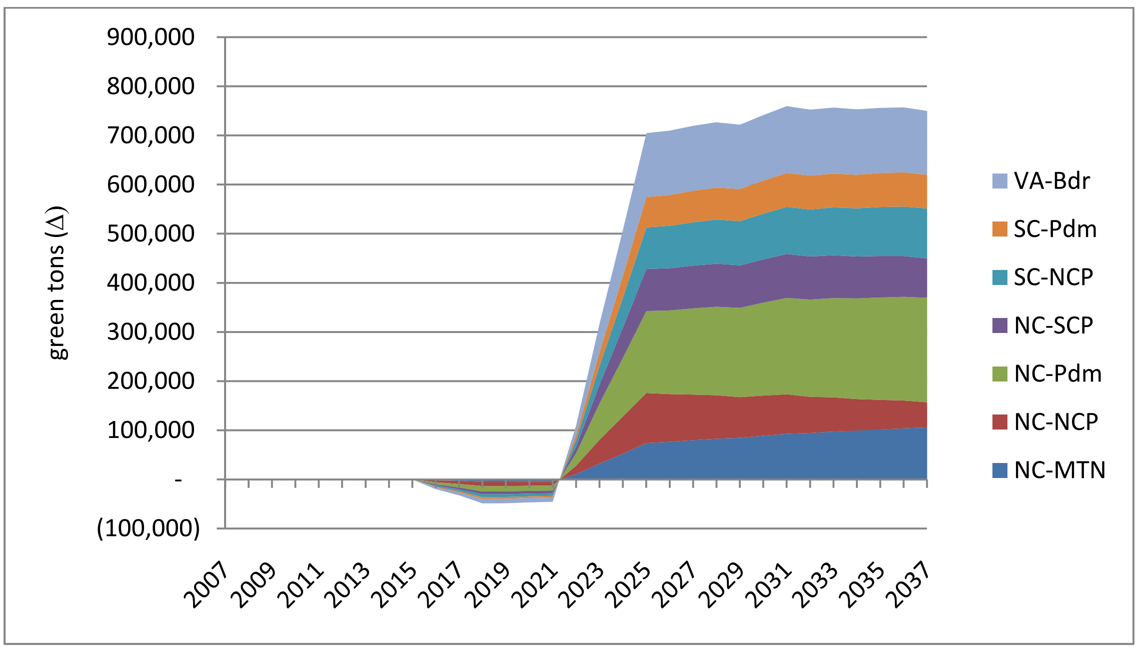


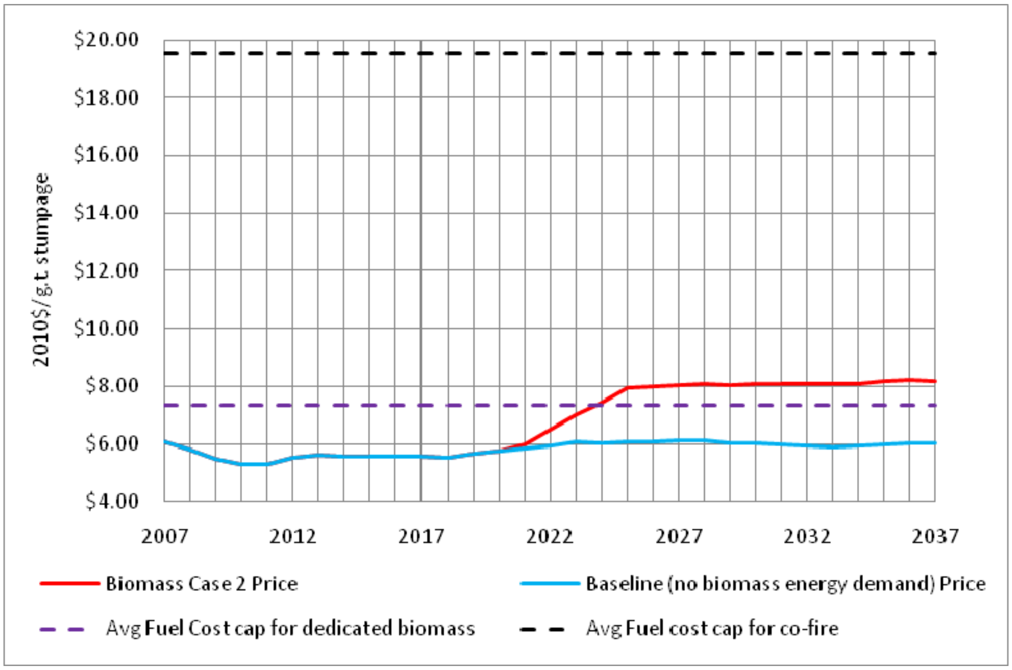
FIGURE 97: CHANGE IN HARDWOOD PULPWOOD HARVEST DUE TO BIOMASS DEMAND IN SCENARIO 1B



Pulpwood Price Impacts

The addition of biomass energy demand does not have any impact on pine pulpwood prices until 2021, when dedicated energy harvests are first needed. The use of roundwood for biomass energy demand causes a spike in prices between 2021 and 2025, but a much smaller spike than was seen in Scenario 1a. After 2025, the pine pulpwood price hovers near the calculated average fuel cost cap for dedicated biomass, but remains well below the fuel cost cap for co-fire plants. With a combination of dedicated biomass and co-fire generation, our analysis seems to indicate that this amount of biomass energy could be produced within the REPS cost cap.

FIGURE 98: PROJECTED PINE PULPWOOD PRICES WITH AND WITHOUT BIOENERGY DEMAND



CONCLUSION

Our analysis of the output from the SRTS modeling indicates that under the assumptions described in this paper, the REPS-driven biomass demand in Scenario 1b could be feasibly met with forest resources in the region. In 2021, this amounts to 7,600 GWh of biomass electricity fueled with forest biomass. This estimate should be treated as an aggressive estimate based on assumptions that are generally optimistic. If any of the conditions assumed in our modeling turn out to be less favorable to REPS biomass energy potential (i.e. lower achievable logging residue collections, lower traditional wood demand, higher alternative bioenergy demand in the region, etc.), it is likely our potential estimate will not be reached.

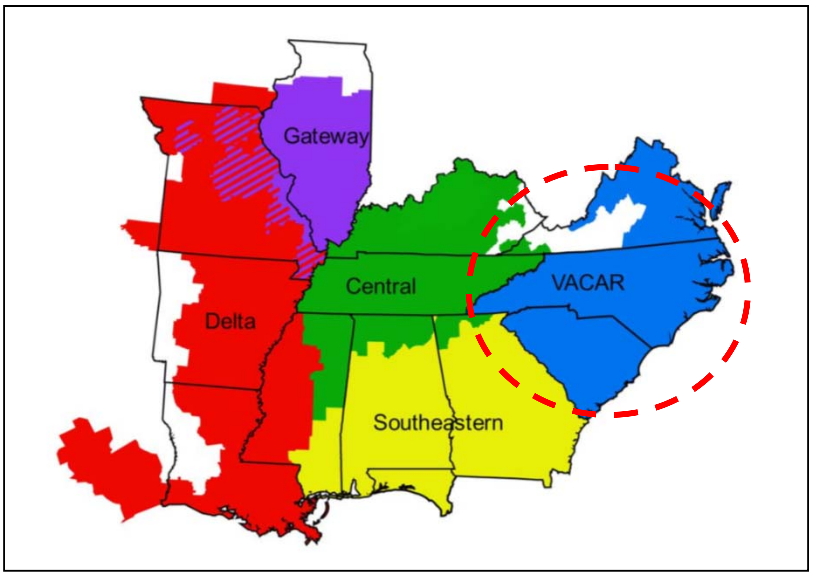
However, we believe that all of the assumptions made in the modeling are highly plausible, and that this represents the best estimate possible of a “ceiling” on biomass potential from forest resources.

APPENDIX D – AURORA MODELING METHODOLOGY

5.3.30 *MODEL OVERVIEW*

As operated for this analysis, the AURORA software utilizes zonal dispatch to simulate the electric system. In the case of North Carolina the model topology features one zone ("VP") for Dominion's portion of PJM, which includes the northeast corner of North Carolina and a portion of Virginia, and another zone ("VACAR South") for the remainder of the Carolinas. These two zones together represent the VACAR region seen in Figure 99 below. Most of our analysis focused on the VACAR South zone.[213]

FIGURE 99: SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL (SERC) SUBREGIONS[214]



With this model topology, all the resources in the Carolinas are dispatched to fulfill the combined load of the two states. In reality, Duke and Progress operate as independent systems—each covering portions of the two states - dispatching their own resources to meet the individual system loads.

[213] In each run of the AURORA dispatch software, the entire Eastern Interconnect is modeled. Since this analysis is focused only on VACAR, the interchange between this subregion and surrounding markets was heavily restricted to yield a more faithful representation of reality. The effect of this restriction is that the model required nearly all load in the region be fulfilled by generating resources in the region, rather than lower cost resources in surrounding markets.

[214] Source: Southeastern Electric Reliability Council (red circle added for clarification). http://www.serc1.org

While the model topology performs a centralized dispatch and does not distinguish separate operating systems, through an extensive benchmarking process La Capra Associates built a model that faithfully represents a typical dispatch in the VACAR region. [215]

Dispatch Methodology

The AURORA dispatch simulation software builds an hourly economic dispatch for each zone. Units are dispatched according to their variable costs, which include the cost of fuel, variable O&M, and any relevant emission costs. AURORA dispatches enough units to fulfill the hourly load subject to certain constraints, such as unit ramp time or minimum up time.

This primary dispatch methodology can be changed in certain circumstances. For example, in many of our scenarios we assumed that biomass facilities would run to their maximum capacity factor, even if their variable costs were higher than other units, to assure renewable energy production sufficient to comply with REPS requirements.

In the case of intermittent renewable resources such as wind and solar, generation (MWh) is modeled on an hourly basis using performance shapes that represent observed hour-by-hour conditions in North Carolina. Therefore, the model accounts for the total amount and timing of generation from these resources. With a marginal dispatch cost of essentially zero, the model assumes that when these resources are available, they are always dispatched first. Reserve generation required for intermittent resources is reflected in the model dispatch and associated production costs.

Model Inputs

There are a variety of system variables used by the model. The following list includes the key input components:

- Hourly load by zone: Seasonal and hourly load shapes are applied to annual load forecast values.
- Individual generating unit characteristics: Plants are either modeled as a whole or by individual unit with variables representing various characteristics, including:
    - Capacity
    - Fuel
    - Heat rate
    - Operating characteristics (minimum loads, ramp rates, etc.)

215 The proposed Duke/Progress merger identifies plans to have an integrated dispatch system. Duke Energy Corporation and Progress Energy, Inc. (2011). NCUC Docket E-2, Sub 998 and E-7, Sub 986. *Application of Duke Energy Corporation and Progress Energy, Inc. to Engage in a Business Combination Transaction and Address Regulatory Conditions and Codes of Conduct*

- Maintenance and forced outage rates
- Emission rates
- Variable O&M cost

- Transmission constraints between zones for import/export limits

Model Output

The output of each model run provides key data used for scenario comparison, provided on hourly, monthly, or annual basis. Model output metrics include:

- Generation (MWh) by unit
- Emissions by unit (SO_2, NO_x and CO_2)
- Variable costs (fuel, O&M, emissions)
- Zonal imports/exports

5.3.31 *MODEL IMPLEMENTATION METHODOLOGY*

Before modeling the various scenarios, La Capra Associates reviewed the default data and operation of the AURORA software in the North Carolina region. Based on access to proprietary and confidential information from North Carolina electric power suppliers, public information in utility IRPs, and independent market research, several modifications were made to the model input data to establish an accurate baseline that faithfully modeled the current system.[216] These changes are outlined below.

Load Forecast

La Capra Associates developed an estimate of zonal load based on forecasts provided by the IOUs as well as EMCs and municipal utilities. This composite forecast was compared to the default data contained in the model. Finding only minimal differences between the estimates (<1%), the default data was used.

Resource review

La Capra Associates compared all resources included in the model's database to information from utilities and other resources in order to verify accuracy. The primary information sources used was the detailed data included in the utilities' 2010 IRPs. In addition, utilities provided information in response to La Capra Associates' requests. Where the default data differed from

[216] While confidential and proprietary information was used in the modeling and validation process, no confidential information is disclosed in any form in this report.

utility data, the information received from utilities was used. Changes made to the default data were primarily to unit capacities, scheduled uprates/derates, heat rates, and emission rates.

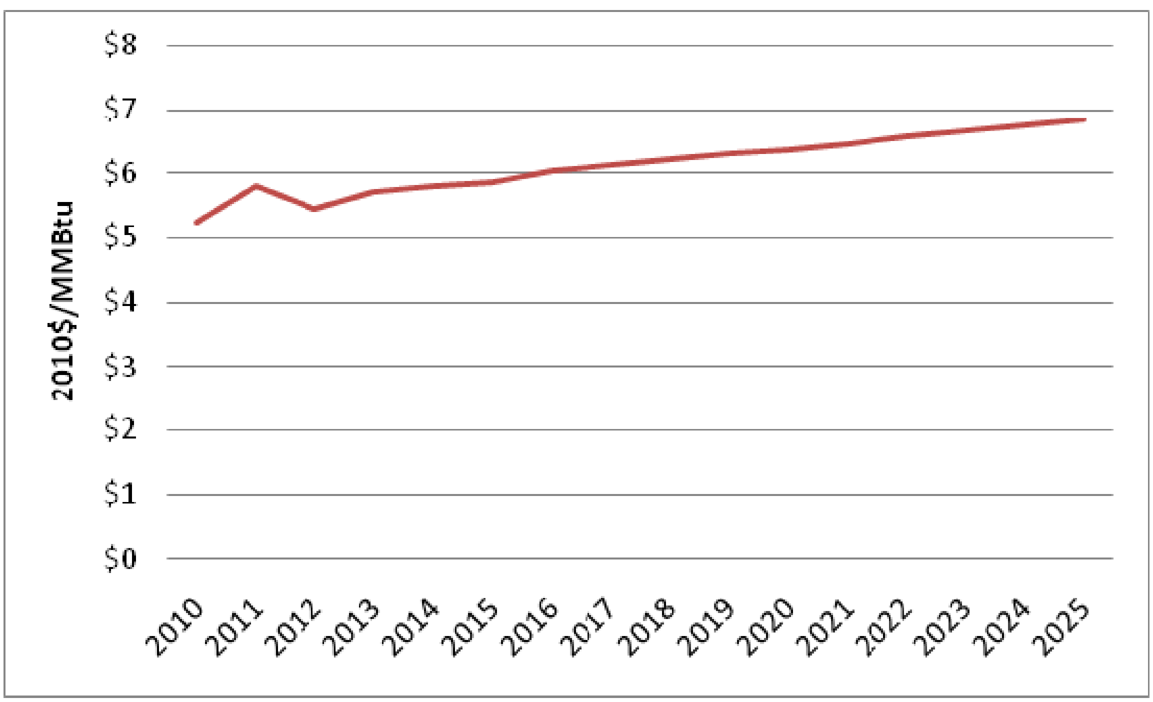
In addition to unit characteristics, La Capra Associates also modified the resources in the model to reflect projected unit retirement dates included in 2010 IRP filings. Although these dates are technically tentative, for this analysis it was assumed that all units identified to retire would be retired according to the stated timeline.

Finally, La Capra Associates added resources to the default database according to the utilities' IRPs. Like retirements, the addition of these units is not certain, but represents the best available forecast of future units. The addition of these units – particularly the planned nuclear plants – was a variable examined in the scenario development.

Fuel Prices

A key factor determining variable cost of generation, and therefore unit dispatch, is fuel price. For this analysis, La Capra Associates solicited price forecasts used by utilities in the IRP process and compared these values to forecasts developed by La Capra Associates as well as public domain sources, such as EIA estimates. The final fuel prices used were a composite of these resources and are the product of the analysis by La Capra Associates. The price forecast for natural gas is a key assumption impacting the model dispatch and our assumptions are displayed in Figure 100 below. These values represent the La Capra Associates estimate of Henry Hub prices with a regional price adjuster specific to the VACAR region. These prices are consistent with the delivered prices used by utilities in their IRP analyses.

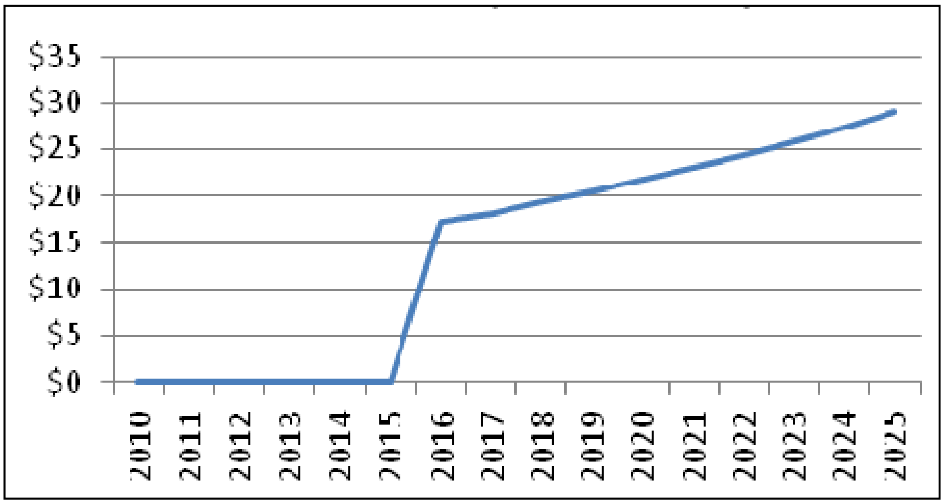
FIGURE 100: FORECAST OF DELIVERED NATURAL GAS PRICES, 2010-2025



Emission Prices

As with fuel price, emission prices influence the variable cost of generation. For NO_x and SO_2, La Capra Associates requested state-specific estimates from utilities and developed the final model inputs. Carbon dioxide prices are dependent on the development of federal or state legislation and the political environment related to carbon legislation is highly uncertain at this time. For this analysis, La Capra Associates used its own CO_2 forecast shown in Figure 101 below. This forecast assumes that there is no cost associated with CO_2 emissions due to federal or state regulations until 2016.

FIGURE 101: CARBON PRICE (2010$/TON), 2010-2025



Benchmarking

After making the changes outlined in the preceding sections, La Capra Associates benchmarked the model output using data received by utilities. Specifically, unit-specific metrics from the model runs were compared to utility-forecasted values for capacity factor and air emissions. Based on this benchmarking review, La Capra Associates then revised certain inputs (such as zonal import-export limits, dispatch costs of certain unit types, etc.) to refine the model until favorable benchmarking results were achieved and model results were consistent with utility forecasts.

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