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La Capra Associates

ANALYSIS OF A RENEWABLE PORTFOLIO STANDARD FOR THE STATE OF NORTH CAROLINA

Technical Report

PREPARED FOR

North Carolina Utilities Commission

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TABLE OF CONTENTS

NOTICE AND ACKNOWLEDGEMENTS i

EXECUTIVE SUMMARY ii

1. INTRODUCTION 2

1.1 WHAT IS AN RPS? 2
1.2 GENERAL RPS OBJECTIVES 4
1.3 APPLICABILITY TO NORTH CAROLINA 6

2. RPS SCENARIOS 9

3. RESOURCE SUPPLY ASSESSMENT 14

3.1 LANDFILL GAS 15
3.2 BIOMASS 16
Wood Residue *16*
Urban Wood Waste *18*
Corn Stover and Wheat Straw *19*
Additional Fuels Not Included *20*
Generating Technologies *20*
3.3 ANIMAL WASTE 25
Hog Waste and Anaerobic Digesters *26*
Poultry Litter *28*
3.4 WIND 29
Eastern Wind *32*
Western Wind *32*
Off-shore Wind *33*
3.5 HYDRO 33
3.6 SOLAR 35

4. RENEWABLE AND CONVENTIONAL SUPPLY COST DEVELOPMENT 38

4.1 RESOURCE COSTS AND OPERATIONAL CHARACTERISTICS 38
Installed Costs *38*
Operational Costs *39*
Tax Benefits *39*
4.2 FINANCING ASSUMPTIONS AND RESOURCE COST CALCULATION 41
Financing Non-Utility Renewables *41*
Levelized Costs *41*
Utility-Owned Generation *42*
4.3 FUEL PRICE ASSUMPTIONS 43

5. ENERGY EFFICIENCY 46

5.1 METHODOLOGY 48
5.2 RPS IMPLICATIONS 49

6. UTILITY RATE IMPACT 52

6.1 UTILITIES' AND RPS PORTFOLIOS 54
Utilities' Portfolio *54*
Alternative RPS Portfolios *56*
6.2 NORTH CAROLINA'S MARGINAL AVOIDED ENERGY COSTS 59
6.3 COMBINED RATE IMPACT FOR RPS SCENARIOS 60
6.4 SENSITIVITIES 63

US EPA ARCHIVE DOCUMENT

7. NON-ENERGY RELATED BENEFITS 66

7.1 STATE ECONOMIC IMPACT ANALYSIS 66
Economic Impact of Rate Increases 67
Job Creation and Multiplier Effect 69
Other Economic Benefits 76
7.2 ENVIRONMENTAL IMPACT 77
Air Quality 78
Greenhouse Gases 80
Water Usage 82
Land Usage and Fuel Extraction 82
Waste Disposal 83
7.3 OTHER BENEFITS 84

8. OTHER RPS CONSIDERATIONS 85

8.1 EXISTING OBSTACLES TO RENEWABLE ENERGY DEVELOPMENT IN NORTH CAROLINA 85
8.2 POTENTIAL RPS DESIGN CONSIDERATIONS 85
8.3 ADDITIONAL RPS-RELATED CONSIDERATIONS 89

9. CONCLUSIONS 94

GLOSSARY OF TERMS 97

BIBLIOGRAPHY 99

APPENDICES

APPENDIX A: JUNE 30, 2006 LETTER TO ENVIRONMENTAL REVIEW COMMISSION 103
APPENDIX B: LA CAPRA TEAM BACKGROUND 108
APPENDIX C: SOLAR CONTRIBUTION 110
APPENDIX D: COMMENTS TO TVA FROM NC ATTORNEY GENERAL ROY COOPER 111
APPENDIX E: ADDITIONAL RESOURCE DISCUSSIONS 114
APPENDIX F: RENEWABLE PORTFOLIO ASSUMPTIONS AND RESULTS 116
APPENDIX G: ENERGY EFFICIENCY MEASURES 121
APPENDIX H: ADDITIONAL ECONOMIC IMPACT DISCUSSION 125
APPENDIX I: NET METERING AND INTERCONNECTION RULES 128
APPENDIX J: EXCERPTS RELATED TO RPS PURPOSES FROM VARIOUS STATES 129

SUPPLEMENTAL ATTACHMENT: *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*

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Notice and Acknowledgements

This Report was prepared by La Capra Associates, Inc., GDS Associates, Inc., and Sustainable Energy Advantage, LLC (the "La Capra Team") pursuant to a Contract with the North Carolina Department of Commerce on behalf of the North Carolina Utilities Commission. In the course of performing this work, the La Capra Team engaged in an on-going dialog with the State's RPS Advisory Group, the members of which are listed in Appendix A to this Report.

The dialog between the La Capra Team and the RPS Advisory Group began in earnest with a meeting at the Commission's offices on July 26, 2006. Following that meeting, all significant inputs were discussed in a series of telephone calls with individual members of the Advisory Group, sub-groups of the Advisory Group and in teleconferences open to the entire Advisory Group. Further, as important project milestones were achieved, materials were provided to members of the Advisory Group for their information, review and comment. On October 23, 2006, the La Capra Team provided a draft report to the Advisory Group for further internal discussion and review. Input on the draft report was taken by the La Capra Team in subsequent telephone calls and in a meeting on November 1 at which all members of the Advisory Group were provided with the opportunity to express their opinions. After receiving input on the draft report, the La Capra Team revised the draft report and issued this Report.

The La Capra Team greatly appreciates the quality of inputs and collaboration from all members of the Advisory Group. In addition, the La Capra Team wishes to thank the Commission for its sage oversight of this constructive process.

The La Capra Team recognizes that it was engaged to provide its independent expert views of matters on 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 Advisory Group and the Commission. 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.

Additional thanks to experts who were consulted on this project including: Alex Hobbs and Beth Mast (North Carolina Solar Center); Christopher Hopkins (North Carolina State University); Larry E. Shirley and Bob Leker (State Energy Office); Ed Mussler (North Carolina Department of Environment and Natural Resources, Division of Waste Management); Maggie Inman (NC GreenPower); Dennis Scanlin, Jeff Tiller, and Dennis Grady (Appalachian State University); and Ollie Frazier (Duke Energy).

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Executive Summary

Overview

At its January 24, 2006 meeting, the Environmental Review Commission (ERC) of the North Carolina General Assembly requested that the North Carolina Utilities Commission (Commission) undertake a review of the potential costs and benefits of enacting a Renewable Portfolio Standard (RPS) in North Carolina (the State). The ERC directed the Commission to engage an experienced consultant to perform the study under the Commission's direction. Pursuant to a Request for Proposals (RFP) (as described in Appendix A), the Commission retained a team of consultants consisting of GDS Associates, Inc., Sustainable Energy Advantage, LLC, and La Capra Associates, Inc. (the La Capra Team).[1] This Report sets forth the results of the La Capra Team's review in response to the request of the ERC.

As this Report discusses in detail below, the **Key Findings** of our analysis are as follows:

- **North Carolina should have sufficient renewable resources within the State to meet a 5% RPS requirement for new renewable generation. A 5% RPS would increase average retail electricity rates by less than 1% and would be accompanied by net job creation and property tax benefits.**

- **The State would have difficulty meeting a more aggressive 10% RPS with only new renewable resources located within North Carolina. A 10% RPS focused solely on generation supply would only be achievable by the inclusion of larger hydroelectric generation and the development of wind in both the western part of the State and in off-shore locations. A 10% RPS met only with new renewable generation would increase average retail electricity rates by at most 3.6% in the tenth year.**

- **Inclusion of energy efficiency as an eligible RPS resource in addition to larger hydroelectric generation and wind in the western part of the State would enable the State to achieve a 10% RPS and could dramatically reduce the cost of an RPS. For example, if energy efficiency was permitted to comprise 25% of an expanded resources RPS portfolio, both a 5% RPS and a 10% RPS could reasonably be expected to produce total electric cost savings for consumers of about half a billion dollars over 20 years.[2]**

Introduction

A Renewable Portfolio Standard (RPS) is a policy tool that sets a requirement for retail sellers of electricity to provide a minimum portion of their electricity portfolio from renewable resources.[3]

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[1] A brief description of the La Capra Team is attached to this Report as Appendix B.

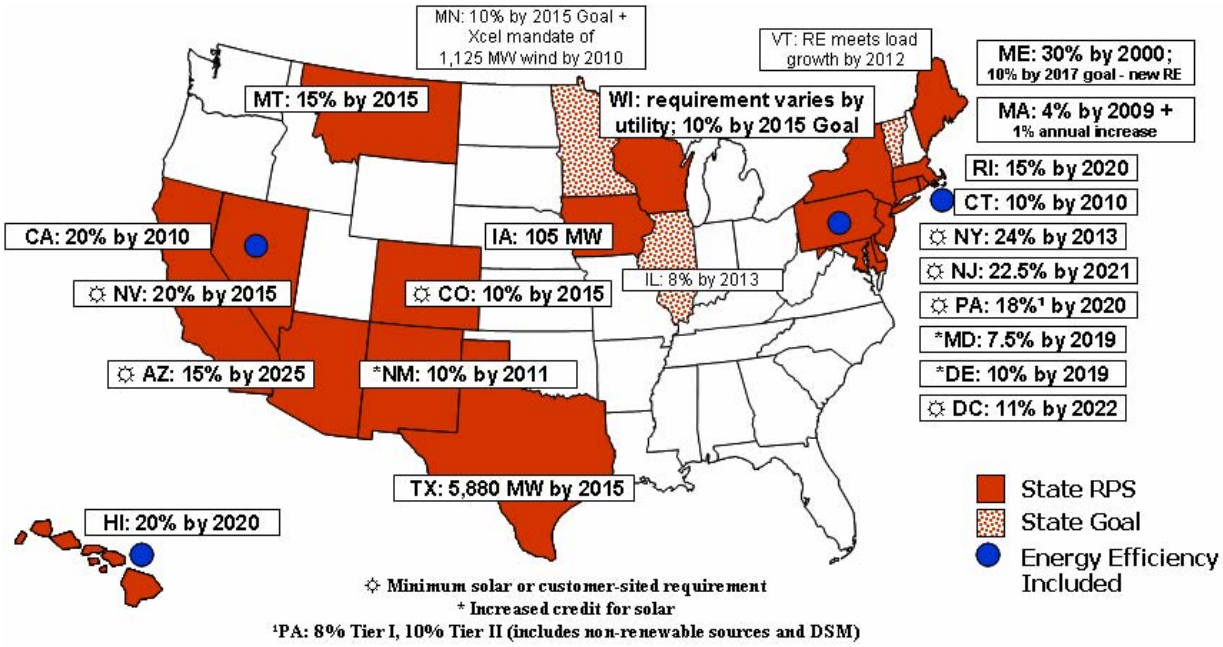
[2] This is calculated in Net Present Value (NPV) over 20 years using a discount rate of 10%.

[3] Renewable energy is often defined as electricity generated from renewable resources such as solar, wind, biomass, geothermal, and water. However, in an RPS context, the list of eligible resources will vary depending on the particular state's definition.

The RPS requirements are typically denoted as a percentage of electricity sold to retail customers and are achieved by phased-in increases in the target percentage over time. Some RPS requirements include existing renewable generation, and others focus primarily on new (additional) generation. The standards are applied to companies selling electricity to retail customers (often referred to as load serving entities (LSEs)), which may include investor-owned utilities (IOUs) and public utilities (municipals and cooperatives), as well as any competitive retail suppliers (if applicable).

While a Federal RPS has been considered by Congress, to date, all enacted RPSs have been adopted at the state or local levels. As a result, the resources that are eligible for each RPS vary from state to state, reflecting each state's access to economically available resources and other economic, environmental and political considerations established through various combinations of legislative, regulatory and stakeholder processes. Over twenty states and Washington, D.C. have now passed an RPS of some form (see Figure ES-1). Four of these states – Connecticut, Hawaii, Nevada, and Pennsylvania – have included energy efficiency[4] or demand-side management (DSM)[5] measures as qualifying resources, either to meet an RPS target in conjunction with other renewable energy or to meet a target created for a separate tier or class of resources as part of an RPS.

Figure ES-1: States with Renewable Portfolio Standards



Source: North Carolina Solar Center (updated November 2006)

[4] Energy efficiency is often defined as physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining the same or improved levels of energy services.

[5] Demand side management (DSM) encompasses both energy efficiency and other programs such as load management, load shifting, demand response, and other peak load reduction programs.

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The states that have adopted an RPS have cited a number of reasons for doing so, including:

- Providing local (in-state) economic development;
- Promoting the development of environmentally sustainable resources in a cost-effective manner;
- Reducing environmental impacts of electricity generation, including emissions of various local and regional pollutants and/or greenhouse gases;
- Diversifying the state's energy portfolio;
- Hedging against price volatility or increasing fuel costs; and
- Meeting incremental demand with small-sized renewables rather than relying on a single large facility.

In considering an RPS, the major areas of concern for state policymakers usually involve identifying the potential costs and benefits of an RPS and the renewable resources that can feasibly be developed to meet an RPS. Additionally, consideration must be given to unique issues related to a state's utility structure, as well as existing rules and policies related to utilities and electric generation. For example, in 2003 North Carolina implemented a voluntary green energy program, administered by NC GreenPower (NCGP).[6] The statewide program, designed to encourage the use of renewable energy, offers customers the opportunity to choose a supply option by paying a premium for grid-tied electricity generated by solar, wind, small hydroelectric (10 megawatts or less) and biomass resources.

The eligibility criteria established for NCGP resources are used in two of the RPS scenarios that were examined. For this analysis, the La Capra Team was also asked to estimate associated impacts if energy efficiency was included as a resource eligible to meet 25% of a total RPS requirement.

Key Questions Addressed

In this Report, the La Capra Team addresses four key questions to assist North Carolina policymakers in considering whether to implement an RPS:

- What amounts of new (additional) renewable resources and energy efficiency measures are feasible in North Carolina?
- If an RPS were implemented in North Carolina, what would be the impact on electricity rates?

[6] NC GreenPower is an independent, nonprofit organization created by state-government officials, electric utilities, nonprofit organizations, consumers, renewable-energy advocates and other stakeholders. It began operation in October 2003 as the first statewide green-power program in the United States. North Carolina's three investor-owned utilities -- Progress Energy, Duke Energy and Dominion North Carolina Power -- and many of the state's municipal utilities and electric cooperatives are participating in NC GreenPower. <http://www.ncgreenpower.org>

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- What other potential benefits and costs, aside from rate impacts, might result from an RPS?

- What other key issues must be considered relative to renewable energy development or an RPS in North Carolina?

What amounts of new (additional) renewable resources and energy efficiency measures are feasible in North Carolina?

- The State currently has more than 1,400 megawatts (MW) of utility-owned hydroelectric (hydro) capacity and more than 600 MW of nonutility-owned renewable generation capacity. **Combined, the approximate 2,000 MW of renewable generation capacity can meet about 4%-5% of the State's current energy needs.**

- Beyond the existing base of renewable generation, North Carolina has a diverse mix of untapped renewable energy resources that can be developed to meet an RPS. Though there may be upwards of 13,000 MW of renewable energy potential in the State, **we estimate that about 3,400 MW can be practically developed.** This estimate includes both eastern and western on-shore wind, but does not include any off-shore wind potential. In theory, the potential for off-shore wind can be much larger than that of on-shore wind, but it is difficult to provide a useful off-shore estimate given that no such projects have been permitted and installed in the U.S. thus far. Similarly, the solar photovoltaic (PV) potential in the State was also not estimated because it is not limited by technical or practical considerations but rather by current levels of installed costs.[7]

- **Biomass (wood and agricultural waste) would likely be the largest energy contributor to an RPS**. Biomass fuel can be co-fired in existing coal plants or can fuel new dedicated plants.[8] Additionally, North Carolina's farming sector (through poultry litter and hog waste) may be able to contribute close to 200 MW of generating capacity to the State.

[7] Solar thermal applications were not included in generation potential estimates, but have been included in some RPS.

[8] It is important here to point out the distinction between capacity and energy. Capacity is represented by megawatts (MW, which equal 1,000 kW) and reflects the maximum power output of a facility at any given time. Energy, measured in gigawatt-hours (GWh), megawatt-hours (MWh) or kilowatt-hours (kWh), represents the total amount of electricity that is generated or consumed over time (a 1 MW capacity facility can generate up to 1 MWh of energy per hour). Depending on the capacity factor of a particular generation technology (i.e. the fraction of energy produced over time relative to its maximum potential output), the energy output can vary greatly. Capacity factors for biomass facilities can range from 70% to 90%, while wind facilities often achieve capacity factors in the 30%-40% range. Therefore, even though the practical potential for wind in North Carolina may be greater in terms of MW, biomass facilities are likely to contribute a larger share of the energy.

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Table ES-1: New Renewable Resources Potential

Resources	Technical Potential (MW)	Practical Potential (MW)	Practical Energy Potential (GWh)*
Landfill Gas	240	150	1,000
Biomass (Wood and Ag. Crops Waste)	2,270	1,100	8,700
*Co-Firing***	*1,875*	*384*	*2,500*
Poultry Litter	175	105	800
Hog Waste	116	93	600
Wind (on-shore)***	9,600	1,500	3,900
Wind (off-shore)	N/A	N/A	N/A
Hydro****	508	425	1,700
Solar PV	N/A	N/A	N/A
Total In-State Potential	12,909	3,373	16,700

**Energy estimate rounded to nearest hundred GWh. **Co-firing is a subset of the Biomass assessment.*
**** Includes wind development in the western mountains.**** Includes hydroelectric generation larger than 10 MW.*

- **The energy efficiency potential in the State should be sufficient to meet 25% of RPS targets for scenarios that include energy efficiency.**[9] According to an analysis by GDS Associates,[10] energy demand in North Carolina could be reduced by 14% by 2017 with the implementation of additional cost-effective energy efficiency measures.[11]

If an RPS were implemented in North Carolina, what would be the impact on electricity rates?

Our analysis was structured to examine the resource potential and resulting costs (rate impacts) to meet a moderate RPS beginning in 2008 which ramps up at 0.5% per year to 5% in 2017 (the "5% RPS") and a more aggressive RPS which ramps up at 1% per year over the period 2008 to 2017 to reach 10% in 2017 (the "10% RPS").

The study utilized three different sets of eligible renewable resources and/or energy efficiency measures as shown below. These different "Resource Groups" reflect an array of resource options that could be included in an RPS.[12] Resource supply curves[13] were developed by year and by resource group for all the scenarios tested. The cost of renewables assumes that most of the renewable energy is procured through long-term power purchase agreements at a fixed price that would allow developers to earn a sufficient return on investment to attract capital.

[9] The 25% assumption used in the scenarios that include energy efficiency measures does not imply that the practical potential is limited to this modeled amount. This assumption was used for modeling RPS scenarios only.

[10] See accompanying report by GDS, "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."

[11] Cost-effective measures are defined as measures with a levelized cost per lifetime kWh saved of less than $0.05/kWh.

[12] In considering these resources, wind resources were separated into eastern and western parts of the State due to potential limitation on western wind pursuant to the Ridge Law discussed below.

[13] Supply curves rank potential supply options from lowest to highest cost and show their cumulative contribution.

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Table ES-2: Resource Groups for Scenarios

	I. NC GreenPower[14] Criteria	II. Expanded Renewables	III. Expanded Renewables Plus Energy Efficiency
Included Resources	▪ Landfill Gas to Energy ▪ Wood Residue[15] ▪ Wood Waste ▪ Animal Waste ▪ Agricultural Waste ▪ Small Hydro at Existing Impoundments [16] (<10 MW) ▪ Solar PV ▪ Wind (Limited to Eastern NC) ▪ Co-Firing with Wood Residue Only	All the Resources Under NC GreenPower Plus… ▪ New Hydro with or without Existing Impoundments (no size limitation) ▪ Incremental Hydro to Existing Capacity ▪ Wind (Entire State)	All the Expanded Resources Plus… ▪ Energy Efficiency

Using these combinations of RPS targets and allowable resources, annual incremental costs were calculated based on the difference in cost between a Utilities' Portfolio[17] of new conventional generation and Alternative RPS Portfolios[18] incorporating new renewables, energy efficiency and conventional generation. The direct impact of introducing a significant amount of renewable resources (and energy efficiency) into a utility's supply portfolio is twofold: (1) the displacement of some new capacity additions and (2) the displacement of some marginal energy generation from existing units. The incremental cost derived from these two impacts was then used to calculate rate impact by dividing the annual cost impact by total retail electricity sales in the State. These cost comparisons do not include all costs that may be incurred by either renewable generation, energy efficiency, or conventional generation, such as system operation costs or regional transmission upgrades that are highly site and resource specific.

The six RPS policy scenarios addressed in this Report produced a range of forecasted outcomes. As shown in the figures below, the six scenarios result in direct rate impacts ranging from a 0.0% to 0.7% change in 2008 and a (0.4%) to 3.6% change by 2017 as more renewable energy resources and/or energy efficiency are added to North Carolina's portfolio.[19]

[14] "NC GreenPower Program Plan," Advanced Energy, Nov. 2002. <http://www.ncgreenpower.org/elements/pdfs/NCGreenPowerProgramPlan.pdf>

[15] Wood residue is the portion of trees (branches, tops, etc.) left behind in forests as part of current forest harvesting activities.

[16] Small Hydro at Existing Impoundments refers to hydroelectric generation projects that are developed at sites with existing impoundments or diverting structures.

[17] The Utilities' Portfolio represents the sum of anticipated new projects needed to meet load growth and retirements according to Duke Energy and Progress Energy's 2006 Integrated Resource Planning (IRP) filings. (NCUC Docket No. E-100, Sub 109).

[18] The Alternative Portfolios achieve RPS targets, while meeting both incremental capacity and energy needs of the State, as forecasted in the utilities' IRPs.

[19] These percentages assume average retail rates of 7.5 and 8.5 cents per kWh in 2008 and 2017, respectively.

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Figure ES-2:

Annual Rate Impact of 5% RPS Scenarios

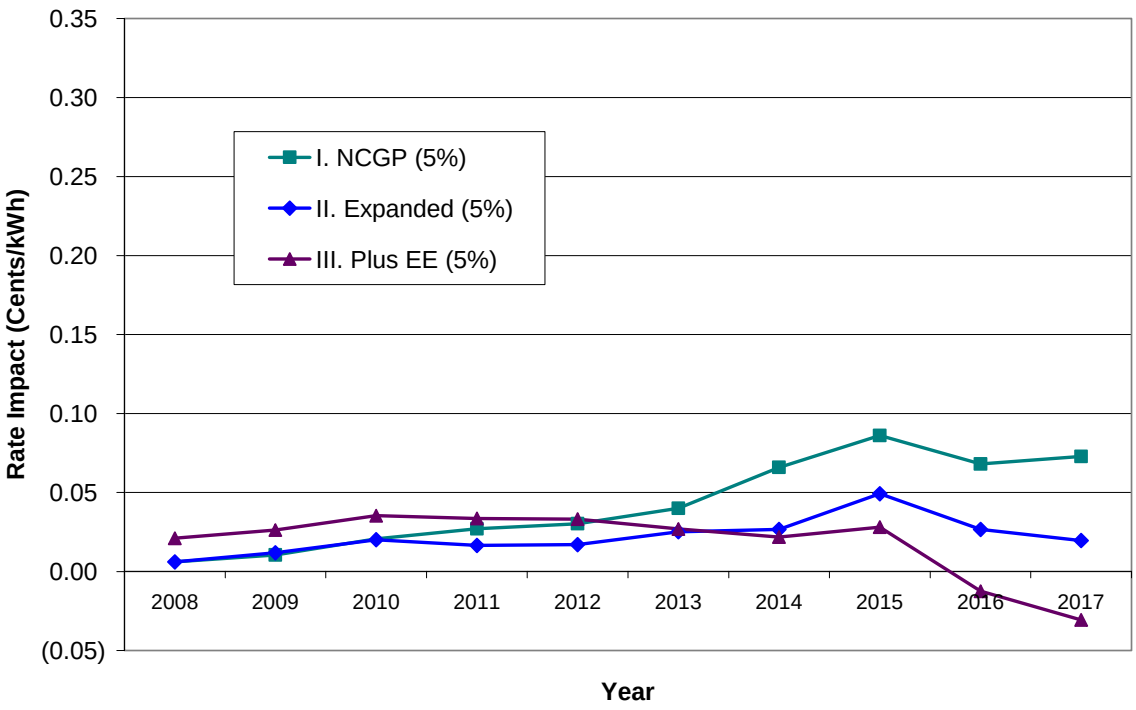
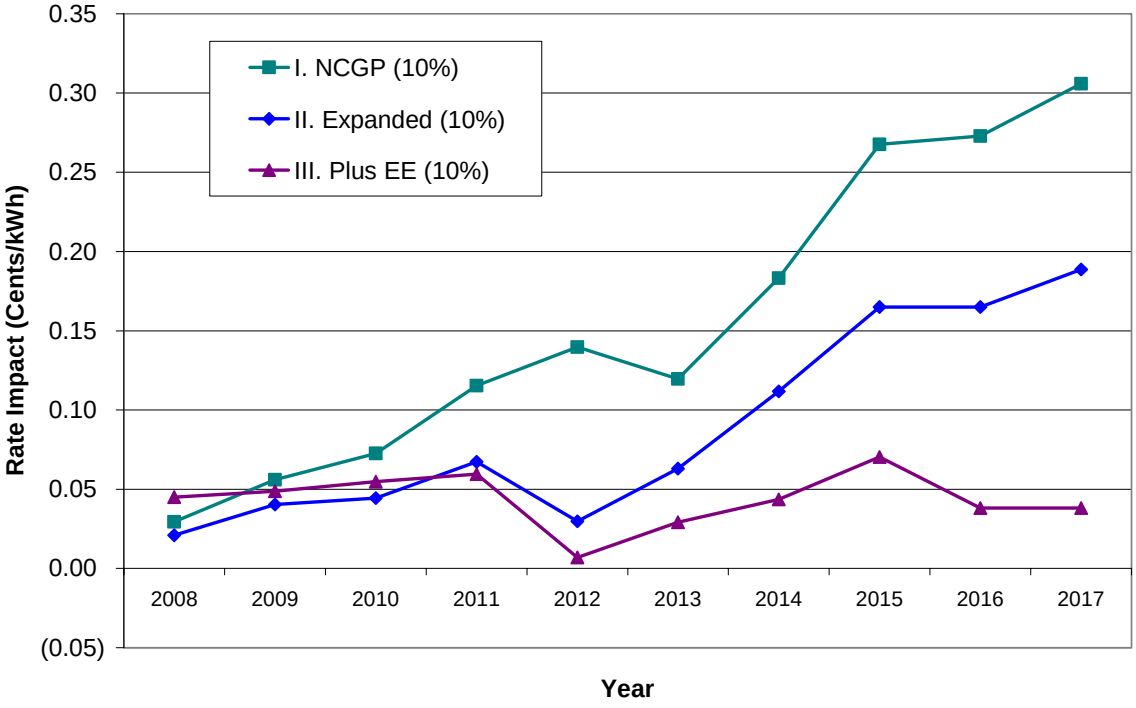


Figure ES-3:

Annual Rate Impact of 10% RPS Scenarios



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Further observations on the cost scenarios include:

- Overall, without including energy efficiency, the rate impact by the end of the 10-year time frame of the study is between 0.02 cents/kWh to 0.31 cents/kWh, depending on the RPS target and resources allowed. **Under these scenarios, the increase by the tenth year of an RPS for a typical residential customer, whose monthly consumption is 1,000 kWh, is estimated to be $0.20 to $3.10 per month, depending on the RPS target and eligible resources.**

- Without including energy efficiency in an RPS, the total statewide incremental cost relative to the Utilities' Portfolio in Net Present Value (NPV) to the State over 20 years ranges from $319 to $727 million for a 5% RPS and $1.6 to $2.7 billion for a 10% RPS.[20]

Table ES-3: Total Incremental Cost Over 20 Years in NPV

		20-year NPV ($million)[21]		
RPS Scenario	Resources	Utility Portfolio	Alternate Portfolio	Net Incremental Cost
5% by 2017	I. NCGP	$15,051	$16,036	**$727**
	II. Expanded		$15,653	**$319**
	III. Plus Energy Efficiency		$14,837	**($476)**
10% by 2017	I. NCGP		$18,492	**$2,691**
	II. Expanded		$17,272	**$1,584**
	III. Plus Energy Efficiency		$15,041	**($577)**

- If 25% of a 5% RPS target is met with energy efficiency, the rate impact would be higher (0.024 cents per kWh) initially and lower by the end of the study period (an overall rate decrease of 0.028 cents per kWh). The higher initial cost results from the passing of the full cost of an efficiency measure through to customers in the year of implementation.[22] Additionally, the rate impact takes into account potential adjustments to rates as a result of utilities' needing to recover fixed costs over less retail sales.[23] This effect is seen more readily in the 10% RPS case where greater energy reductions (2.5%) impact the fixed cost portion to a greater degree, and rate increases are 0.051 cents per kWh in 2008 declining to 0.044 cents per kWh in 2017.

- Allowing energy efficiency to supply up to 25% of an RPS results in saving about $476 to $577 million in NPV over 20 years relative to the Utilities' Portfolio. The net savings in both the 5% and 10% RPS scenarios are due to the low cost energy

[20] Net Present Value is the sum of the future stream of benefits and costs converted into equivalent values today. This is done by discounting future benefits and costs using an appropriate discount rate of 10%.

[21] See Appendix G for annual cost comparisons of Utilities' Portfolio vs. Alternative RPS Portfolios.

[22] The cost recovery mechanism for energy efficiency measures does not necessarily require full recovery in the first year of implementation of a measure. Some states choose to amortize the cost of energy efficiency measures over a longer period of time similar to generation capacity for cost recovery purposes.

[23] The average fixed cost component in rates for North Carolina utilities was estimated to be 5 cents per kWh.

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efficiency measures that were included and an overall reduction of energy consumption, despite an increase in near-term rates as described previously.

What other potential benefits and costs, aside from rate impacts, might result from an RPS?

Aside from examining rate impacts to the State, this Report also considered other costs and benefits related to an RPS. The primary areas of focus include:

- State economic development and associated impacts;
- Environmental impact; and
- Portfolio diversification benefits.

State Economic Development and Associated Impacts

We examined two primary economic benefits to North Carolina for implementing an RPS portfolio--net job creation and increased property tax revenues to communities. These are the most readily quantifiable economic development benefits to the State, though there will be other benefits such as landowner lease payments from wind projects and payments for biomass procured in-state. The study sums the jobs created from adding renewables in the State as a result of an RPS, while accounting for the loss of jobs due to potential rate increases and displacement of some conventional generation that would have otherwise been built as part of the Utilities' Portfolio.

The graph below shows the total net job impact in job-years for the scenarios tested over the first 20-years of operation for each facility.

- **Each of the three 5% RPS scenarios shows a forecasted net increase in jobs of at least 15% over the Utilities' Portfolio.**[24] These increases in jobs are primarily the result of sourcing biomass fuels locally, rather than importing conventional fuels for generation.[25]
- **In the 10% RPS scenarios (without energy efficiency) the job gains resulting from renewable generation development were largely negated by the impacts of increases in electricity costs.** At higher rate impact levels, the job losses from higher total cost of electricity across the State may exceed the jobs gained through renewables development.
- **Including energy efficiency in either a 5% or 10% RPS can result in net gains in jobs, especially in the scenario for a 10% RPS with 25% energy efficiency.** This is due to the lower overall cost of energy to the State as a whole as a result of lower energy usage, despite a slight increase in rates per kWh.

[24] For comparison purposes, please note that the Utilities' Portfolio is estimated to create about 146,000 job-years.

[25] This Report assumes that the transportation of conventional fuels within the State would not contribute to the local economy in terms of jobs, since the payments for delivery of conventional fuels are often made to entities outside of North Carolina.

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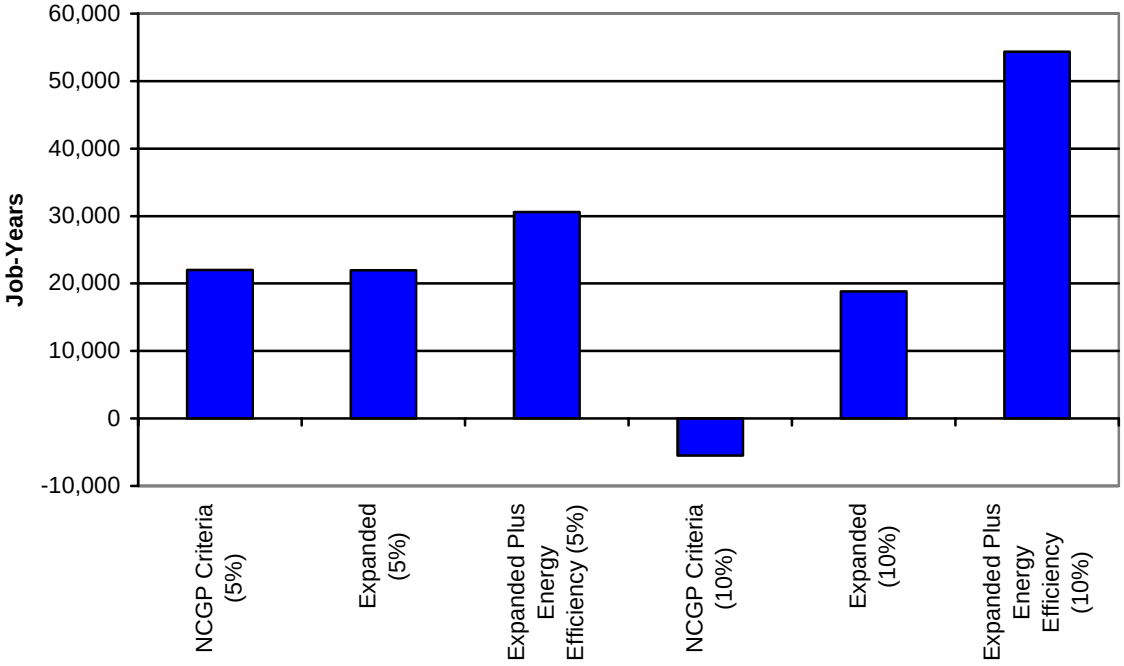
Figure ES-4:
Net Change in Job-Years for RPS Scenarios



- **Property tax revenues for North Carolina communities are likely to increase as a result of an RPS. This conclusion is true in all scenarios.** These scenarios represent a 6% to 54% increase in potential tax revenues for communities (as a whole) relative to the Utilities' Portfolio.[26] Property tax revenues are greater for renewables generally, because a larger share of total renewable energy project costs is related to capital expenditures than for conventional projects, so the value of a project used in calculating taxes is greater per MW. An added benefit is that renewables development may be more dispersed around the State relative to large generation installations, so more communities can benefit from receiving property tax revenues from renewable energy projects.

[26] This is an indicative comparison. Since individual communities have the option to negotiate tax rates with developers, the ultimate outcome may be different. Only the NPV of the first year of tax revenues derived from individual project installations over time is shown because depreciation and property tax assessments will vary after the first year of installment.

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Environmental Impact

The environmental impact from renewable energy generation was examined relative to conventional generation resources since renewable energy generation displaces the need for some conventional generation. The potential benefits or avoided environmental costs can fall into the following categories: air quality, greenhouse gas emissions, water quality, land usage, fuel extraction, and waste generation.

Many studies have attempted to quantify, in economic terms, these environmental benefits, or "externalities," but reviews of such studies found results that differed by several orders of magnitude.[27] For this discussion, the impact is presented in relative terms only.

In general, an RPS will produce the following environmental benefits:

- **Displacement of carbon dioxide from new coal and natural gas generation can be achieved because most renewable and energy efficiency measures are considered either non-emitting or carbon-neutral.**[28] Some resources such as landfill gas and anaerobic digesters may be able to receive additional credit for converting methane, a higher impact greenhouse gas, to carbon dioxide. The annual displacement of carbon dioxide, once a 5% or 10% RPS is achieved, could total 7.3 to 13.6 million tons per year. This does not take into account methane combustion benefits. If greenhouse gas regulations are ever enacted, this can help the State meet overall emission goals.

- **Potential displacement of pollutants related to air quality and health, such as nitrogen oxides, sulfur dioxide, particulate matter, and mercury, is expected.** However, non-emitting resources, such as wind, hydro, solar, and energy efficiency, will make a far larger contribution to such displacement than biomass-fired generation, which does have some related emissions similar to new coal plants. Likewise, nuclear generation also does not have associated air emissions.

- **Renewable generation facilities either do not produce waste or the waste products are more benign than from coal and nuclear fuels.** The ash byproducts from biomass firing can be used as fertilizer or soil amendments in most cases because there are minimal toxic chemicals in the ash. Likewise, treated waste material from anaerobic digesters can also be used as fertilizer. Coal plants today either landfill the toxic ash byproducts or the ash is used in cement production processes. While nuclear facilities do not contribute any emissions to the air, the largest unresolved issue associated with nuclear is the long-term management of radioactive waste.

- **Renewable energy resources do not have significant environmental impact from fuel extraction in contrast to the extraction impacts of coal, natural gas, and nuclear fuel.** Many of the renewable resource options presented either do not require

[27] "Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard," Rutgers University, 2004.

[28] Most energy generation from biomass resources is assumed to be carbon neutral because plants reabsorb the carbon dioxide that is emitted from biomass facilities over a relatively short-period of time.

fuels or utilize on-site waste products and, therefore, do not have related fuel extraction issues. Collecting wood residue from logging operations will have some environmental impact, but the incremental impact beyond that of a logging operation itself is minor if conducted in a sustainable manner. On the other hand, the extraction of conventional fuels (oil, coal, natural gas, and uranium) has substantial environmental impact on the land itself, which often leads to habitat destruction and contamination. Furthermore, the processing, transporting and storing of these fuels can also cause major environmental damage. Since North Carolina does not have fuel extraction activities, the impacts associated with fuel extraction occur outside of the State.

- **Including energy efficiency programs will have no adverse impact on the environment.** Since these programs reduce the need for electricity generation, energy efficiency measures have the greatest positive environmental benefit relative to any form of generation.

Portfolio Diversification Benefits

North Carolina electricity consumers rely on coal and nuclear power for more than 90% of their electricity.[29] The fuel costs of these sources have escalated in recent years, though not to the degree of natural gas and oil.[30] Further, issues such as a potential future "carbon tax" or similar regulation, as well as nuclear waste disposal costs, mean that a large part of the State's resource portfolio is subject to potentially substantial risk. Additionally, one benefit of renewable energy resources is that they are more flexible than conventional power plants both in terms of size and typical development and construction time frames, so less risk is placed on the success of a few, large-sized projects. It is clear that the addition of new renewable resources and development of energy efficiency programs would help to diversify the State's resource mix and, as such, could have beneficial effects over the long-term for customers.

What are some other key issues related to renewables development or an RPS in North Carolina?

In addition to identifying the available renewable resources and estimating the various economic and environmental impacts of various portfolio options, the La Capra Team was also engaged to discuss briefly some key issues that are associated with the development of renewable energy in North Carolina. The issues identified are:

- **Current wholesale avoided cost[31] levels are not sufficient to enable new renewable resources to be financed.** Current filed avoided costs are between 4 and

[29] Coal and nuclear plants are baseload generation sources that provide 90% of the State's electricity needs. "Annual Report of the North Carolina Utilities Commission Regarding Long Range Needs for Expansion of Electric Generating Facilities for Service in North Carolina," NCUC, July 2005. <http://www.ncuc.net/reports/lr2005.pdf>

[30] Natural gas and oil are fossil fuels used for electric generation to greater degrees in many other parts of the country.

[31] "Avoided cost" is defined in the Federal Public Utility Regulatory Policies Act of 1978 (PURPA) as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another

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6 cents per kWh (including capacity payments) for long-term contracts. In North Carolina, avoided costs are calculated based on marginal power costs, which reflect the weighted cost of generating electricity on the margin, and the capacity value associated with new combustion turbines.

- **The current IRP Process compares resources on a busbar cost basis without taking into account externality costs.** This approach filters out higher-cost resources such as renewable generation and energy efficiency measures. If externality costs are considered, then different resources might be selected.

- **Conflicting interpretations of the Mountain Ridge Protection Act of 1983, often referred to as the "Ridge Law," add substantial uncertainty to large-scale wind development in the western mountains.** The Ridge Law[32] states: "no . . . building, structure or unit shall protrude at its uppermost point above the crest of the ridge by more than 35 feet." Protected mountain ridges are all mountain ridges whose elevation exceeds 3,000 feet and whose elevation is 500 or more feet above an adjacent valley floor. Exemptions to the Ridge Law include: Water, radio, telephone or television towers or any equipment for the transmission of electricity or communications or both. Structures of a relatively slender nature and minor vertical projections of a parent building, including chimneys, flagpoles, flues, spires, steeples, belfries, cupolas, antennas, poles, wires, *or windmills are also exempt*. In written comments to the Tennessee Valley Authority, North Carolina Attorney General Roy Cooper stated, in 2002, that the Ridge Law would prohibit construction of a wind farm being proposed in the Tennessee mountains if the project were being proposed in North Carolina just east of the proposed Tennessee site. (See Appendix D.) However, to our knowledge, the Ridge Law's precise applicability to wind turbines has not been definitively resolved. Accordingly, there is uncertainty and confusion as to whether this law would bar wind development along North Carolina's windiest ridgelines.

- **Development of large-scale wind and other remote renewable resources may require major transmission/network upgrades to deliver the energy to customers.** If the scale of wind development that is reflected in the scenarios is installed (500-2,800 MW), transmission upgrades are likely necessary in some areas of the State. However, costs for such upgrades are site-specific and would have to be considered relative to transmission upgrades needed for new conventional generation. Other renewable generation is less likely to have as significant an impact on transmission as wind due to the more remote location of wind projects.

source." 16 U.S.C. § 824a-3. The avoided cost is designed to produce no rate impact to customers and reflects the marginal cost of generating electricity, but does not necessarily reflect the all-in cost of building baseload generation.

[32] N.C. Gen. Stat. § 113A-205, et seq.

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Conclusions

- North Carolina should have sufficient renewable resources within the State to support a 5% RPS, whether energy efficiency measures are included or not. A 5% RPS would have a relatively small impact on retail electricity rates assuming lower cost options are developed first through a competitive bid process. Adoption of a 5% requirement would double the current level of renewable energy generation in the State. At the same time, 1,100 additional jobs may be created, additional property tax revenues may be earned by local governments, and about 1,000 MW of new baseload generation[33] may be avoided. This translates to the potential avoidance of over 7 million tons of CO_2 per year if the displaced generation is coal-based. If instead, a nuclear plant is avoided, there would be no carbon benefits since nuclear plants also do not have associated carbon emissions.

- A more aggressive 10% RPS without including energy efficiency would require the development of 900 - 2,300 MW of off-shore wind since other practical on-land resources would already be developed. Presently, no off-shore wind projects have been installed in the U.S. due to numerous permitting obstacles. If off-shore wind projects do not become feasible during the forecast period, a 10% RPS would only be achievable by including energy efficiency programs, larger hydro generation, and development of wind in the western part of the State.

- Inclusion of energy efficiency for 25% of an RPS can dramatically reduce the cost. The RPS portfolios (5% and 10% RPS) with energy efficiency are each estimated to save about half a billion dollars in NPV over 20-years relative to the Utilities' Portfolio. Essentially, the reduction of load of 1.25% or 2.5% by the end of the RPS study period creates energy cost savings overall for the State. The inclusion of energy efficiency measures in an RPS could create 1,500 to 2,700 additional jobs relative to the Utilities' Portfolio. However, if the State does proceed with the development of an RPS, careful consideration should be given to whether an RPS or a separate policy vehicle is the appropriate policy tool to promote energy efficiency measures.

- Through a high-fuel cost sensitivity test for the 5% NCGP Criteria scenario, we found that an RPS can help mitigate some risks related to high fuel prices, but even high fuel costs would not offset all the added cost of the RPS scenario tested.

- The cost analyses in this Report assume that the Federal Production Tax Credit that partially offsets the delivered cost of energy from many types of renewable projects continues to be in effect throughout the study period. The incremental cost of an RPS may be 40% higher than modeled if the Federal Production Tax Credit is not renewed after five years. This tax credit has been in effect since the early 1990's and has been extended a number of times. The current law is set to expire again after 2007. So,

[33] About 1,000 MW of baseload generation can be displaced by renewable generation, but in the 5% scenarios, 500 MW of natural gas combined-cycle generation that operates as intermediate facilities would also be needed to make-up any potential shortfalls of capacity and energy. In a sensitivity excluding co-firing, no additional combined-cycle generation is needed since additional biomass facilities provide the state with its needed capacity.

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attention to the status of proposed extensions of the law will be important if North Carolina adopts an RPS.

- Additional nuclear plants are included in the future electricity portfolio in North Carolina as proposed by Duke Energy. The uncertainty concerning project costs for new nuclear plants will have a significant impact on an RPS assessment. Depending on their actual cost, the addition of nuclear plants can either make an RPS appear to be an attractive alternative for new generation or double the incremental cost of an RPS. From past experience with nuclear plants, there would appear to be uncertainty regarding present cost estimates for nuclear plant construction. Similarly, the cost of new coal plants used in this analysis may also have related uncertainties, as evidenced by recent increases to installation cost estimates in current utility coal plant proposals.

- Solar photovoltaic (PV) systems are not directly cost-competitive with most other resources, including other new renewable technologies. However, a number of states have decided to encourage the development of solar power by giving extra credit for solar power in RPS implementations. If the State is interested in promoting solar installations, crediting solar energy at a multiple of other renewable energy will not change the overall cost of an RPS, while providing some additional job benefits. Furthermore, solar PV may be able to provide other benefits, such as providing distributed generation,[34] summer peak shaving (see Appendix C), and emissions reductions. Another alternative to promote solar is to dedicate a portion of an RPS target to solar in the form of a set-aside as is being done in some states.

  We tested the sensitivity of adding 112 MW of solar installations over the ten-year study period. This would be equal to installations on 16,000 residential roofs (32 MW) and 3,200 commercial/industrial roofs (80 MW).[35] To implement such large-scale development, promoting solar PV manufacturing in the State would likely be needed. This would provide additional manufacturing jobs that were not included in the jobs analysis. Similar considerations may be provided to other technologies the State may wish to promote, such as solar thermal heating and cooling.

- There are many ways to design an RPS. The scenarios presented in this Report reflect a few key policy choices, but there are many additional RPS design and implementation issues that would need to be addressed before an RPS can be implemented. These issues include:

  - **Applicability:** In principle, the costs for development of renewables should be applied to as much of the State's retail electric load as possible for equitable cost sharing. However, several states have excluded municipal and cooperative electric utilities and/or certain levels of industrial load from RPS rules for a variety of reasons. Such exclusions, however, do create the inequity of having only some ratepayers pay for an RPS which provides benefits throughout the State.

[34] Distributed generation is the small-scale production of electricity at or near customers' homes and businesses. It has the potential to improve system reliability, reduce local distribution loading during peak moments, and/or avoid system upgrades in some cases.

[35] As a point of reference, 1,460 MW of new solar PV systems were installed worldwide during 2005.

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- **Balanced Supply and Demand:** The pace of an RPS start and ramp-up should be set so that sufficient resources can be reasonably developed, but in a cost-effective manner. The ramp-up should also take into account existing commitments to resource additions.

- **Stability of Targets:** The development of all electric energy resources is a long-term undertaking. For an RPS to effectively encourage the development of renewable energy facilities, the RPS requirements should provide a long-term commitment that enables projects to obtain cost-effective financing. One option is requiring long-term power purchase agreements while allowing utilities full recovery of prudently incurred costs in a timely manner.

- **Compliance and Alternative Compliance Payments:** Appropriate compliance requirements should be included to ensure that load serving entities comply. At the same time, the law should be flexible enough for LSEs to comply in a cost-effective manner, such as setting an effective cap on costs with the use of alternative compliance payments (ACP). Additionally, appropriate methods for calculating and attributing contributions from renewable generation and energy efficiency measures would need to be determined.

- **Compatibility with Other State Policies:** North Carolina has several policies in place or under development that may need to be reviewed in conjunction with an RPS, such as the Clean Smokestacks Act, EPA's Clean Air Interstate Rule, cap-and-trade programs, Carbon Policies, and the interaction of a mandatory RPS with voluntary purchases under the NC GreenPower program.

- Beyond these major issues, there are a host of other details to be considered if the State decides to adopt an RPS. While the full exposition of these is beyond the scope of this Report, the La Capra Team notes that these topics should include: the precise definition of and certification of resource eligibility, the treatment of existing resources, geographic eligibility (including constraints imposed by the U.S. Constitution's Commerce Clause on restrictions on out-of-state resources), the tracking of environmental attributes of various generating supply for RPS compliance purposes, and inclusion of sufficient flexibility mechanisms to minimize compliance costs while not destabilizing the market. None of these issues are insurmountable, even though they do require careful attention.

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1. Introduction

At its January 24, 2006 meeting, the Environmental Review Commission (ERC) of the North Carolina General Assembly requested that the North Carolina Utilities Commission (Commission) undertake a review of the potential costs and benefits of enacting a Renewable Portfolio Standard (RPS) in North Carolina. The ERC directed the Commission to engage an experienced consultant to perform the study under the Commission's direction. Pursuant to an RFP, the Commission retained a team of consultants consisting of GDS Associates, Inc., Sustainable Energy Advantage, LLC, and La Capra Associates, Inc. (the La Capra Team).

As noted in the Notices and Acknowledgments section above, this Report was prepared in parallel with a constructive dialog with the State's RPS Advisory Group, the members of which are listed in Appendix A. The dialog included two group meetings, a number of group conference calls and a series of individual telephone calls and e-mails. These discussions provided the La Capra Team with a substantial amount of valuable input.

In this Report, the La Capra Team addresses four key questions to assist North Carolina policy makers in considering whether to implement an RPS:

- What amounts of new (additional) renewable resources and energy efficiency measures are feasible in North Carolina?
- If an RPS were implemented in North Carolina, what would be the impact on electricity rates?
- What other potential benefits and costs, aside from rate impacts, might result from an RPS?
- What other key issues must be considered relative to renewable energy development or an RPS in North Carolina?

1.1 What Is an RPS?

A Renewable Portfolio Standard (RPS) is a policy tool that sets a requirement for retail sellers of electricity to provide a minimum portion of their electricity portfolio from renewable resources.[36] The RPS requirements are typically denoted as a percentage of electricity sold to retail customers and are achieved by phased-in increases in the target percentage over time. Some RPS requirements include existing renewable generation and others focus primarily on new (additional) generation. The standards are applied to companies selling electricity to retail customers (often referred to as load serving entities (LSEs)), which may include investor-owned utilities (IOUs) and public utilities (municipals and cooperatives), as well as any competitive retail suppliers (if applicable).

[36] Renewable energy is often defined as electricity generated from renewable resources such as solar, wind, biomass, geothermal and water. However, in an RPS context, the list of eligible resources can vary depending on particular state's definition.

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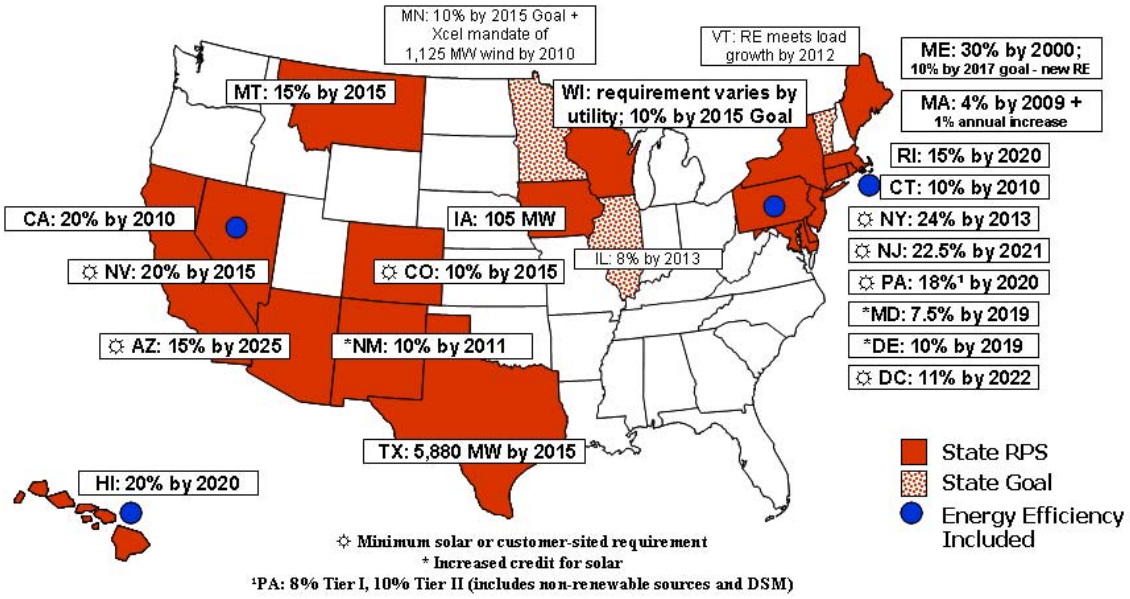
While a Federal RPS has been considered by Congress, to date, all enacted RPSs have been adopted at the state or local levels by state legislation or regulatory initiative. As a result, the resources that are eligible for each RPS vary from state to state, reflecting each state's economically available resources and other economic, environmental, and political considerations established through various combinations of legislative, regulatory, and stakeholder processes. Over twenty states have now passed an RPS or similar requirement of some form, with each state developing rules customized to its regulatory and market environment. Most RPS targets are state-mandated "requirements" that have specific consequences for non-compliance; a few are simply voluntary "goals." In addition to resources universally regarded as renewable, such as wind, geothermal, solar and biomass (sometimes with fuel or emissions limitations), some states have included certain types of hydroelectric facilities and alternatives such as energy efficiency, waste tires or waste-to-energy, fuel cells using non-renewable fuels, cogeneration, and coal-mine methane as potential resource options. Of the states with an RPS, four (Connecticut, Pennsylvania, Nevada, and Hawaii) have included energy efficiency[37] or demand-side management (DSM)[38] measures as qualifying resources, either to meet an RPS target in conjunction with other renewable energy or to meet a target created for a separate tier or class of resources as part of the RPS.

Figure 1: States with Renewable Portfolio Standards



Source: North Carolina Solar Center (updated November 2006)

The initial state RPS policies were adopted primarily in the context of state electricity restructuring plans to address concerns that there would no longer be mechanisms to support existing renewable facilities or to promote new renewable resources in the absence of centralized planning once wholesale and/or retail competitive markets were established. In many states

[37] Energy efficiency is often defined as physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining the same or improved levels of energy services.

[38] Demand side management (DSM) encompasses both energy efficiency and other programs such as load management, load shifting, demand response, and other peak load reduction programs.

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public benefits funds were also created either as alternatives or complements to RPS policies to help promote renewables and energy efficiency during the restructuring process. However, in recent years, regulated states, such as Wisconsin, Minnesota, Nevada, Hawaii, Arizona, and New Mexico, have also passed RPS policies. Some of these states had started the restructuring process and adopted an RPS, but subsequently decided against restructuring while retaining the RPS as a desirable state policy.

1.2 General RPS Objectives

The debate over whether to adopt an RPS usually focuses on resolving the tension between a group of key objectives and the expected or potential cost of achieving those objectives.

The states that have adopted an RPS have cited a number of reasons for doing so, including providing local (in-state) economic development, promoting the development of environmentally sustainable resources, reducing environmental impacts of electricity generation (including emissions of various local and regional pollutants and/or greenhouse gases), diversifying the state's energy portfolio, and mitigating fuel and electricity price fluctuations. These objectives may be of more or less importance to any particular state. These potential objectives are more fully articulated as follows:

- **In-state economic benefits and economic development:** Some states note that local renewable energy resources will help promote increased economic development relative to developing conventional resources. The primary reasons for this stem from increased construction, operations and maintenance staff needed for the same amount of energy generated and the use of locally-sourced fuels, such as biomass, landfill gas, and animal waste. Additional economic benefits can be gained if manufacturing facilities for renewable generation technologies are located in the state or if construction materials and/or services for these more capital-intensive generators are procured in-state.

- **Promote environmentally sustainable resources in a cost-effective manner:** States have adopted an RPS to encourage environmentally sustainable energy resources. Through increased development of certain renewable energy technologies, the costs and reliability of such technologies should improve. By setting targets, allowing competition to dictate which projects get built, and providing flexibility in meeting the targets, more cost-effective options, in theory, should be utilized first, resulting in lesser cost impacts to ratepayers. If a state is interested in promoting specific resources, especially those found within the state, design features encouraging a subset of eligible technologies can be incorporated into an RPS. Greater reliance on sustainable, indigenous resources is also cited as a way to improve energy security and to recognize that strict cost analysis does not necessarily include externality costs.

- **Reduce emissions affecting the state:** The ability of non-emitting renewable generation to displace either new or existing fossil-fueled generation will help reduce overall emissions in a state. The magnitude of this benefit would depend on the types

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of generation being displaced, whether existing or new, coal or nuclear. Additionally, some states have cited climate change concerns as a driving rationale for establishing an RPS, or have otherwise set policy to include non-emitting or carbon-neutral generation such as renewable energy as a mitigation option.

- **Diversify energy portfolio:** Establishing an RPS can also be a way of driving diversity in a state's energy generation portfolio, ensuring that resource plans consider indirect costs/benefits available from renewable energy technologies. Some states adopting RPSs have noted that evaluating resource options only on a projected busbar cost basis leaves the portfolio vulnerable to major shifts in fuel costs, environmental regulations, or geopolitical conditions. Furthermore, recent events have caused energy prices to be highly volatile, and renewable generation can provide a hedge against such volatility for a portion of the portfolio, as many renewable energy options do not require a fuel input or have fuel costs that are relatively low. In some cases, renewable generation, given current tax incentives and high fossil-fuel costs, is more cost-effective today than some conventional generation.

- **Meet incremental energy needs:** Some states have decided that new renewable generation and energy efficiency should be part of a state's resource mix to help meet future load growth. Renewable energy projects can range from 1 kW to over 300 MW and can be added in relatively small increments as load grows. This resource expansion can be attractive in comparison to relying on a single large facility that may be over-sized to meet near-term growth. Reliance on smaller projects may also provide distributed generation benefits[39] relative to large utility-scale baseload generation that can be 500 to 2,000 MW built at a single site.

Concerns related to implementing RPS policies often include:

- **Cost.** Many parties are concerned that requiring a certain amount of renewable energy would have too great an impact on electric rates, as renewable generation often costs more than conventional generation.

- **Resource availability.** The resource options in some states may be too limited. For example, wind and biomass are often the most significant contributors to meeting an RPS, but some states do not have sufficient amounts of economic wind and/or biomass resources available.

- **Integrated resource planning can be a good alternative to an RPS.** It can be argued that if a state already selects resources through an integrated resource planning (IRP) process, it is through that process that any preference for certain types of resources can be taken into account. For example, if a state wishes to encourage greater reliance on renewable resources, the preference can be explicitly factored into the criteria in assessing resource options. An estimated cost of externalities such as environmental costs and health-related costs can be factored into the IRP also.

[39] Distributed generation is the small-scale production of electricity at or near customers' homes and businesses. It has the potential to improve system reliability, reduce local distribution loading during peak moments, and/or avoid system upgrades in some cases.

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- **Hesitance to mandate specific resource options.** In some states that have not adopted an RPS, customers have the ability to voluntarily support renewable resources through "Green Power" programs. Instead of mandating customers' options, allowing the voluntary market to operate can be seen as the best way to gauge public support for renewable energy. In several states, the popularity and success of such voluntary programs was critical to gauging support for later establishing an RPS.

It is important to note that RPS design options are available to mitigate many of these concerns. This Report will provide North Carolina policy makers with information to assist in their decision about how to evaluate these competing concerns as they apply to the State.

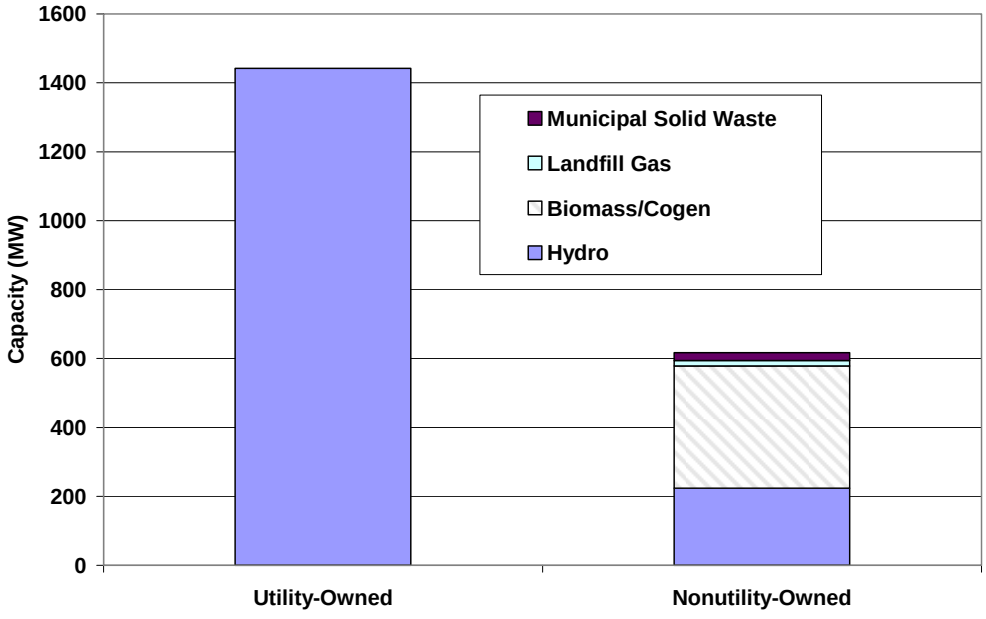
1.3 Applicability to North Carolina

While North Carolina remains a regulated state with vertically-integrated utilities, exposure to risks associated with changing environmental regulations and fuel supply market uncertainties makes this a good time to consider the important policy directions embodied in an RPS. The RPS objectives described above have to be weighed against the cost advantages of the State's potential expansion of its current portfolio of relatively low-cost coal and nuclear generation.

The State currently already has over 1,400 MW (excluding pumped storage capacity) of utility-owned hydroelectric capacity (hydro) and about 600 MW of nonutility-owned renewable generation capacity. Combined, the 2,000 MW of renewable generation capacity can meet about 4%-5% of the State's current energy needs.

Figure 2

Existing Renewable Generation Capacity in North Carolina



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In addition, North Carolina implemented a voluntary green energy program, administered by NC GreenPower (NCGP),[40] in 2003. The statewide program, designed to encourage the use of renewable energy, offers customers the opportunity to choose a supply option by paying a premium for grid-tied electricity generated by solar, wind, small hydro (10 megawatts or less), and biomass resources. Nationally, average participation rates among utility green-pricing programs have remained steady at just more than 1% of customers,[41] although the top performing utility green pricing programs have achieved rates ranging from 4% to 15%.[42] Being a fairly new program, NCGP has almost 8,000 subscribers totaling over 17,000 MWh per year.[43] The State's annual energy consumption is about 150,000,000 MWh, so the NCGP program thus far has been able to provide 0.011% of the State's energy needs through qualifying renewable resources.

Even with the NC GreenPower program, there remain a number of barriers for larger-scale renewable resource development in North Carolina:

- Existing average avoided cost[44] rates (4 to 6 cents per kWh) for wholesale energy including capacity paid to Qualifying Facilities under PURPA are insufficient for new renewables to be built in the State. Avoided costs are calculated based on marginal power costs, which reflect the weighted cost of generating electricity on the margin, and the capacity cost associated with new combustion turbines. However, the avoided cost calculation does not take into account the full cost of new baseload generation. Furthermore, many of the existing non-utility owned generators' long-term contracts are expiring, and those projects are facing lower avoided cost rates for the energy today, risking potential closure of the facilities. Others are considering wheeling the energy into PJM and selling the energy out-of-state where wholesale prices are higher and there is potential opportunity to participate in other states' RPS programs.

[40] NC GreenPower is an independent, nonprofit organization created by state-government officials, electric utilities, nonprofit organizations, consumers, renewable-energy advocates and other stakeholders. It began operation in October 2003 as the first statewide green-power program in the United States. North Carolina's three investor-owned utilities -- Progress Energy, Duke Energy and Dominion North Carolina Power -- and many of the state's municipal utilities and electric cooperatives are participating in the NC GreenPower program. <http://www.ncgreenpower.org>

[41] Though the average rate is 1% customer participation, the actual "green energy" purchased may be much lower since customers often have the option to purchase green credits for a portion of their consumption, not necessarily 100%.

[42] "Green Power Marketing in the United States: A Status Report (Eighth Edition)", NREL, 2006. <http://www.eere.energy.gov/greenpower/resources/pdfs/38994.pdf>

[43] "Summer 2006 Newsletter," NC Greenpower. <http://www.ncgreenpower.org/media/newsletters/2006/newsletter_summer2006.html?#update>

[44] "Avoided cost" is defined in the Federal Public Utility Regulatory Policies Act of 1978 (PURPA) as "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." 16 U.S.C. § 824a-3. The avoided cost is designed to produce no rate impact to customers and reflects the marginal cost of generating electricity, but does not necessarily reflect the all-in cost of building baseload generation.

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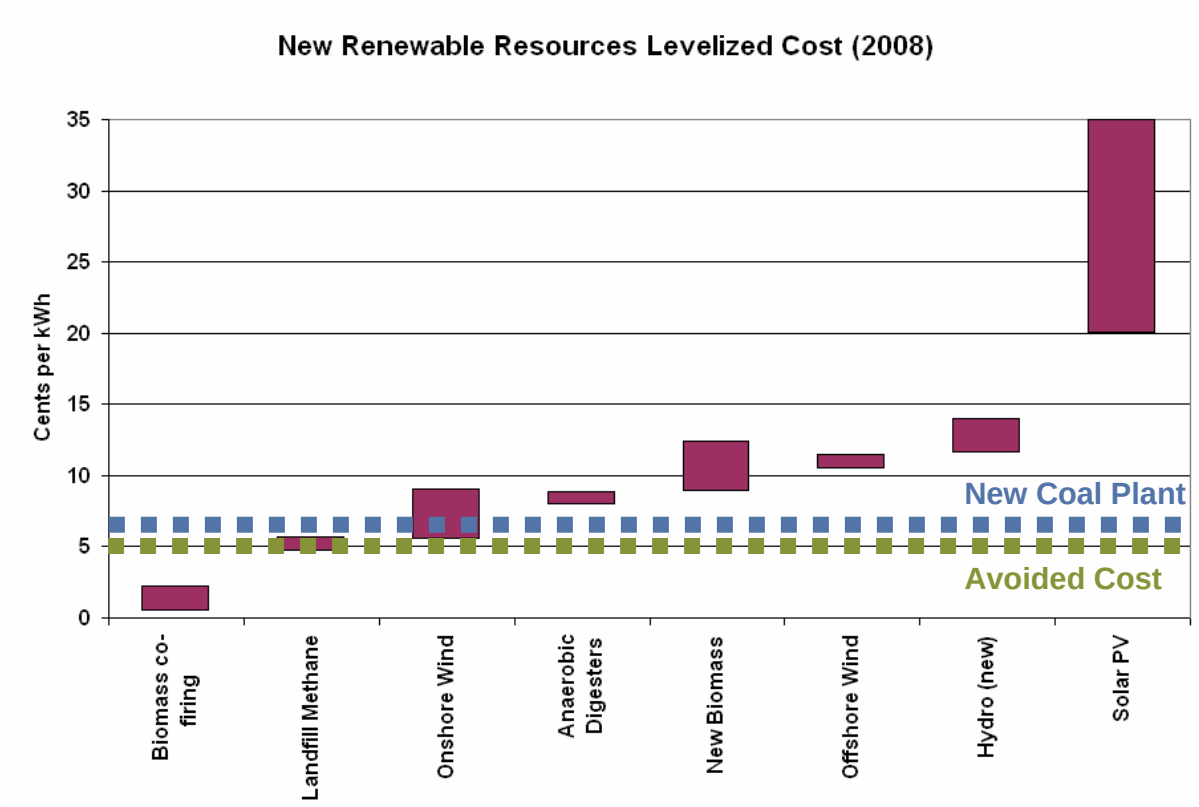
Figure 3



- Since North Carolina is primarily supplied by coal and nuclear energy (over 90%),[45] the State has limited exposure to more volatile oil and gas prices, though both coal and nuclear fuel prices have also increased significantly in the last few years. There is little incentive to explore alternative fuel options that may be more costly as the State currently benefits from having relatively low electricity rates, while, at the same time, is in direct competition with surrounding states that also have relatively low rates.

- The comparison of resources purely on a cost basis for IRP purposes filters out higher cost options such as renewable energy in the initial screens. The State's utilities' IRP process begins with a comparison of levelized busbar costs of a variety of generation technologies/fuels where renewables invariably are filtered out in the initial steps as having too high costs, since no other externality costs are taken into account.

- Wind, a potentially inexpensive option for the State, has an added barrier to development as a result of the Mountain Ridge Protection Act of 1983, otherwise know as the "Ridge Law," which limits development of tall structures along ridgelines. While the Ridge Law appears to exempt windmills, different interpretations of the law raise questions as to whether the exemption pertains to wind farms consisting of multiple, large-scale turbines. Until the Ridge Law is clarified, some of the most cost-effective renewable resources may be stymied.

[45] "Annual Report of the North Carolina Utilities Commission Regarding Long Range Needs for Expansion of Electric Generating Facilities for Service in North Carolina," NCUC, July 2005. <http://www.ncuc.net/reports/lr2005.pdf>

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2. RPS Scenarios

A number of steps were necessary to establish the framework of the analysis. The details of these steps are discussed in Sections 2 to 4. These steps were:

- Establish different policy scenarios to investigate that include different RPS targets and eligible resources.
- Estimate resource potential (renewable energy and energy efficiency) within the State and costs associated with each type of resource.
- Develop renewable resource supply curves assuming most would not be utility-owned facilities but would be contracted through long-term power purchase agreements (PPAs). The expectation is that lower cost resources will be developed first.
- Estimate North Carolina's future electric supply expansion needs based on the State's utilities' filed Integrated Resource Plans (IRPs). This is called the Utilities' Portfolio.
- From the supply curves, determine the mix of resources (renewable, energy efficiency, and conventional generation) that would fulfill each of the RPS scenarios, while meeting future capacity and energy growth.
- Compare the costs of the Alternative RPS Portfolios with that of the Utilities' Portfolio.
- Conduct similar comparisons for sensitivity tests.

The first step in the analysis was to develop RPS scenarios to test. Issues that were addressed in designing appropriate scenarios included:

- The treatment of existing resources;
- The time frame to be covered by the study;
- The RPS target or targets to model; and
- The types of resources that should be included.

Based on consultation with the Advisory Group, six sets of RPS scenarios were agreed upon that would offer different results for combinations of RPS targets and applicable resources.

Existing renewable resources would not be included in this study. While North Carolina already has about 2,000 MW of renewable generation capacity that can meet 4%-5% of the State's current energy needs, the RPS targets discussed in this Report reflect new generation over and above the existing base. Accordingly, this Report focuses on the development and costs of

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only new renewable resources that would be built after the future passage of an RPS, recognizing that there is a base of existing renewables in North Carolina.[46]

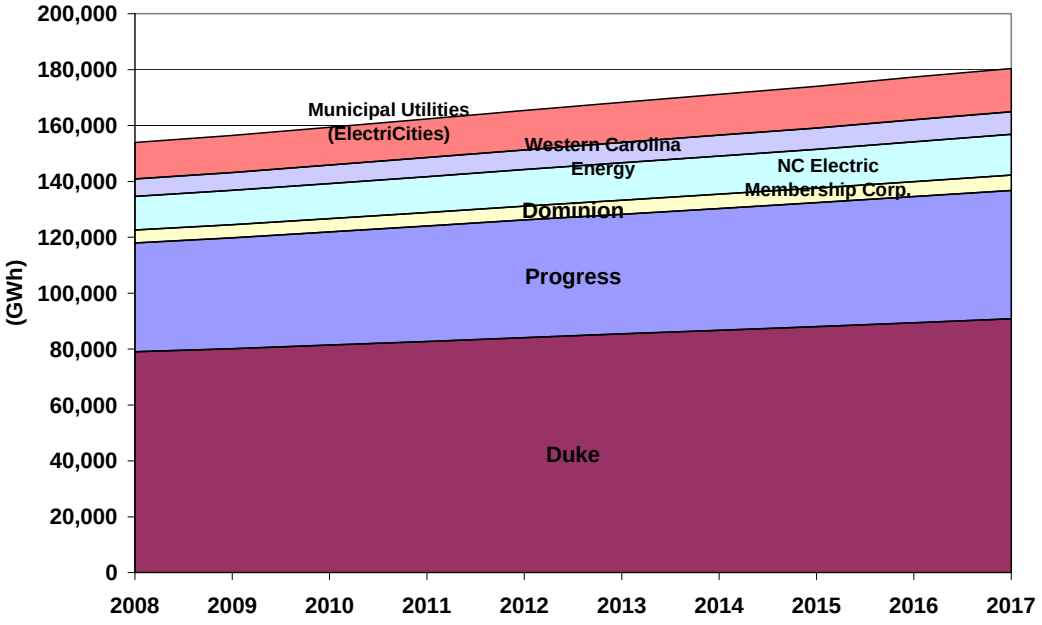
The analysis would cover a ten-year period 2008 to 2017. As agreed with the Advisory Group, the RPS ramp-up period would fall within this time frame even though the benefits and costs would extend past 2017. The use of this period allowed a good match with the current utility IRP study period.

We acknowledge that the 2008-2017 study period is not likely to provide sufficient time for the design and implementation of an RPS. However, the study period alignment with the 2006 IRP time horizon was deemed more important in estimating the potential cost of an RPS. If an RPS is actually implemented, the initial date will likely be later than 2008, but requirements in initial years are generally low so the analysis results should not be significantly different.

The RPS targets modeled would achieve 5% and 10% of the State energy usage with new renewable energy by 2017. Overall energy usage is forecasted to grow between 1.7% and 1.9% per year during the RPS time frame. The first graph below provides a breakdown of energy usage served by the State's utilities as reported in their Annual Energy Plans and Integrated Resource Plans. These numbers also assume that an RPS would apply to the whole of North Carolina electricity sales to retail customers, including those being served by IOUs, municipals and cooperatives, with the non-IOUs making up about 22% of the usage.

Figure 4

Forecasted North Carolina State Energy Usage



[46] It is not the intention of the study to comment on whether existing renewables should be included in an RPS. Existing renewables are permitted under the NC GreenPower (NCGP) program as long as the renewable resources qualify. These resources currently or previously received QF contracts and/or NCGP contracts for their output. The analysis here does not attempt to include the cost of existing resources, though if an RPS is implemented, consideration would need to be given to addressing the treatment of existing resources.

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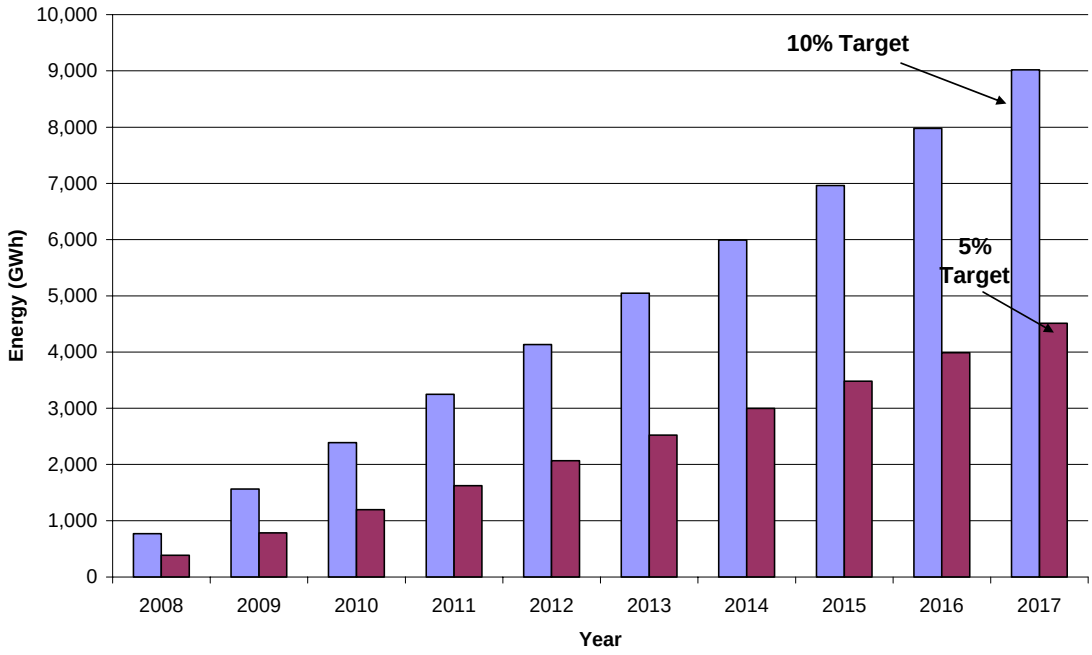
Two different RPS targets were used for developing new renewables estimates in the State: (1) an increase of 0.5% per year reaching 5% in 2017 and (2) an increase of 1.0% per year reaching 10% in 2017. These targets would offset part, but not all, of the State's incremental energy needs in the future.

As depicted in the graphs below, a 10% target would result in 18,000 GWh of new renewable energy by 2017, while a 5% target would result in 9,000 GWh by 2017. Assuming an average resource capacity factor of 75%, a 10% target translates to over 2,700 MW of new renewables capacity in the State. The actual outcome will differ from 2,700 MW depending on the types of resources that are incorporated into the portfolio.

Figure 5

Projected RPS Energy Requirements



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Three "Resource Group" scenarios were developed to encompass different limitations to eligibility and development. The Resource Groups are listed in the matrix below.

Table 1: Resource Groups for Scenarios

	I. NC GreenPower[47] Criteria	II. Expanded Renewables	III. Expanded Renewables Plus Energy Efficiency
Included Resources	▪ Landfill Gas to Energy ▪ Wood Residue[48] ▪ Wood Waste ▪ Animal Waste ▪ Agricultural Waste ▪ Small Hydro at Existing Impoundments [49] (<10 MW) ▪ Solar PV ▪ Wind (Limited to Eastern NC) ▪ Co-Firing with Wood Residue Only	All the Resources Under NC GreenPower Plus… ▪ New Hydro with or without Existing Impoundments (no size limitation) ▪ Incremental Hydro to Existing Capacity ▪ Wind (Entire State)	All the Expanded Resources Plus… ▪ Energy Efficiency

Resource Group I includes "NC GreenPower"[50] resources ONLY since the list has already been agreed to through a rigorous stakeholder process. Resources that qualify for either the Mass Market Product or the Large Customer Product[51] are included. An additional limitation to resources is wind on ridgelines. We understand that wind projects currently face a great deal of uncertainty in the western part of North Carolina due to the Ridge Law (this issue is described in detail in Section 3). Thus, in Resource Group I, there is a general assumption that no large-scale wind projects are developed in western North Carolina. Co-firing in coal plants are also limited to those that have implemented emissions controls per the Clean Smokestacks Act (see Section 3) and can burn wood residue only.[52]

In Resource Group II, an expanded set of resources is included: hydro greater than 10 MW, undeveloped hydro, incremental hydro at existing facilities, and wind located in western North Carolina. The expanded list of resources allows us to test the cost impact of including additional options outside of the NC GreenPower definition with current perceived development limitations that may be addressed if an RPS is implemented.

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[47] "NC GreenPower Program Plan," Advanced Energy, Nov. 2002. <http://www.ncgreenpower.org/elements/pdfs/NCGreenPowerProgramPlan.pdf>

[48] Wood residue is the portion of trees (branches, tops, etc.) left behind in forests as part of current forest harvesting activities.

[49] Small Hydro at Existing Impoundments refers to hydroelectric generation projects that are developed at sites with existing impoundments or diverting structures.

[50] "NC GreenPower Program Plan," Advanced Energy, November 22, 2002. <http://ncgreenpower.org/elements/pdfs/NCGreenPowerProgramPlan.pdf>

[51] The large customer product allows the inclusion of existing generators to "assist existing green power producers who have experienced significant reductions in their 'avoided cost' payments from the utilities." However, for modeling incremental, new resources, we are not including any existing resource base in our calculations, except for co-firing in existing coal plants.

[52] We understand that the utilities are in the process of testing other biomass fuels, but this assumption is made for modeling purposes only.

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Lastly, in Resource Group III, we also test a set of scenarios that assume energy efficiency plays a role in the RPS, helping to meet 25% of the requirement each year through energy efficiency programs that would reduce overall energy consumption throughout the year. Since an RPS typically addresses the energy needs of a state, programs such as load response, load shifting, and load management are not included, as these programs are primarily capacity reducing measures and do not necessarily contribute much energy reduction.

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3. Resource Supply Assessment

This Section of the report focuses on available resources in North Carolina and their potential for development. (In Section 4, we summarize the assumed installed cost, operating costs, and fuel-related costs for each resource.) In developing the supply assessment, we relied on several sources of information, including those developed by various State entities and universities as well as various U.S. agencies and research centers that have assessed renewable resource potential for North Carolina.

The focus was on the following categories of resources, as these are more applicable to the State and can be implemented at a fairly meaningful scale: (1) Landfill Gas; (2) Biomass (wood and vegetation); (3) Biomass (animal waste); (4) Wind; (5) Hydro; and (6) Solar PV. The technologies reviewed are those that are considered commercially available or utilize conventional technologies. There are many emerging technologies that can also meet an RPS, but the costs and performance of such technologies have not been fully tested, so are not included as part of the cost analysis.

In this section, we discuss briefly North Carolina's current renewables status, their characteristics, and the potential of each resource. We distinguish technical potential from practical potential; by this we mean that even though there may be an abundance of a certain resource (such as wind), after taking into account practical considerations, the potential may be somewhat limited. This estimate includes both eastern and western on-shore wind, but does not include any off-shore wind potential. In theory, the potential for off-shore wind can be much larger than that of on-shore wind, but it is difficult to provide a useful off-shore estimate given that no such projects have been permitted and installed in the U.S. thus far. Similarly, the solar photovoltaic (PV) potential in the State was also not estimated because it is not limited by technical or practical considerations but rather by current levels of installed costs. Below is a summary of the resources examined and the range of their technical and practical potential.

Table 2: New Renewable Resources Potential

Resources	Technical Potential (MW)	Practical Potential (MW)	Practical Energy Potential (GWh)
Landfill Gas	240	150	1000
Biomass (Wood and Ag. Crops Waste)	1,976-2,567	953-1,239	7500-8100
*Co-Firing**	*1,875*	*384*	*2500*
Poultry Litter	175	105	800
Hog Waste	116	93	600
Wind (on-shore) **	9,600	500-1,500	1300-3900
Wind (off-shore)	N/A	N/A	N/A
Hydro***	508	66-425	300-1700
Solar PV	N/A	N/A	N/A
Total In-State Potential	12,615-13,206	1,867-3,512	11,500-16,100

**Co-firing is a subset of the Biomass assessment.*
*** Depends on whether western wind is included or not.*
**** Depends on whether hydro larger than 10 MW is included.*

3.1 Landfill Gas

Under the NC GreenPower program, landfill methane projects qualify as a renewable resource. The methane production at waste landfill sites can be a valuable fuel for either direct thermal applications or for electricity generation. North Carolina is part of the EPA's Landfill Methane Outreach Program (LMOP) and is actively promoting the development of landfill gas-to-energy (LGTE) projects.

By way of background, seventeen LGTE projects are currently operating in North Carolina and several more are under consideration. Some of these projects are operating at closed sites while other sites continue to accept waste. North Carolina has six landfill gas projects that are generating electricity, totaling over 15 MW of capacity. Additionally, eleven other landfill projects currently consume the landfill gas directly for thermal applications.

The State has a number of closed landfill sites. All municipal solid waste landfills operating in North Carolina after January 1, 1998 were required to be lined and, thus, all unlined landfills were closed by 1998. With the closure of unlined landfills located in almost every county, North Carolina has a number of landfills with the potential to support LGTE projects. However, for our modeling purposes, the closure date (1998) and the start of the RPS (2008) is a decade apart, so we assume that these sites would be less likely to support long-term electricity generation as the methane production from closed sites normally drops significantly after the first five to ten years of closure and continues to decline over time. These closed sites may be able to provide some methane for other applications as the State actively seeks consumers for the gas output.

On the other hand, North Carolina has approximately 34 out of a total of 40 operating lined landfills that can be characterized as "large" facilities which could support LGTE projects now or in the future. Most of the permitted, lined landfills in North Carolina will be subject to the New Source Performance Standards (NSPS) requirements, where, due to their anticipated size and emissions production, emissions gathering and control equipment would be required at some time in the future. Several are in the process of installing the requisite controls now. This requirement means that a gas collection infrastructure will likely be put in-place at sites that reach the EPA threshold size under NSPS and provide readily available methane for electricity generation in the future.

To estimate the electric generation potential at landfill gas sites, the EPA uses a methodology that applies a conversion factor to "total waste-in-place" to derive a total electric generation potential at both closed and open sites in North Carolina of around 60-70 MW total.[53] We find this methodology may underestimate the generation potential of some sites, particularly those that are newer and designed with much larger capacities than the current levels of "waste-in-place."

Since we are providing estimates for the 2008-2017 timeframe, we opted to approximate the potential based on the current annual waste acceptance rate at existing sites as reported by the North Carolina Division of Waste Management and the projected life of the sites based on their

[53] "A Primer on Developing North Carolina's Landfill Gas Utilization Potential," EPA, 2001. <http://www.epa.gov/lmop/>

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design capacity. EPA's Landfill Gas Emissions Model (LandGEM 3.02)[54] was used to estimate average methane production. This method estimates a maximum of 200 MW of potential over time from existing open sites that do not have electricity generation in-place yet. Additionally, if EPA's estimate of potential at closed landfill sites and existing electricity generation sites are included, there may be another 40 MW of potential, totaling 240 MW. For our modeling purposes, we assume 30 sites are prime for development in the future with an average capacity of 5 MW per site, based on average methane production levels over the life of a project and an 80% capacity factor, recognizing that methane production peaks and then gradually declines over time. The practical potential would be 150 MW total. Furthermore, for the cost analysis, we assume that the first sites to be developed will be those that have installed gas collection systems to comply with NSPS standards and, thus, would not incur costs for developing a gas collection system. Additionally, fixed costs include a portion allocated for lease or off-take payments to landfill owners.

3.2 Biomass

Under the NC GreenPower program, qualifying wood resources are defined by the following statement:

> *The following guidelines have been developed for the types of wood waste that will be allowed for NCGP qualification: tree trimmings, mill residues (bark, sawdust and fines from primary processing facilities); segregated construction and demolition wood (excluding painted, treated, glued, pressurized wood or any wood contaminated with plastics or metals); clean wood waste from manufactured home plants, pallet recycling facilities, furniture manufacturers, finished building products and other similar industries; wood from land clearing that would otherwise end up in landfills; and wood bedding material removed from poultry brooder houses. Wood "chips" derived from processing whole trees within forested land will not be allowed as qualifying wood waste.*

According to this definition, wood residue and wood waste qualify, but wood chips from the harvesting of whole trees for the primary purpose of energy generation is not permitted. The State's total practical biomass potential (not including landfill gas, poultry litter or hog waste) can supply up to 950 MW of new greenfield capacity or up to 1,240 MW of co-firing capacity.[55]

Wood Residue

Several studies have estimated the State's wood residue potential. We relied primarily on the USDA Forest Service Forest Inventory and Analysis (FIA) Timber Product Output (TPO) reports

[54] The LandGEM model estimates a gas production profile going forward as a site continues to accept waste. In this case, the life of a landfill gas electric generation project is projected to be 20 years. In actuality, the output of landfills normally declines over time after a landfill has been closed. However, for modeling purposes, we chose to model the landfill gas output as an annual average over the life of the project. <http://www.epa.gov/ttn/catc/dir1/landgem-v302.xls>

[55] Co-firing capacity will be higher than greenfield capacity due to the lower capacity factor of coal plants compared to new greenfield projects. In other words, less fuel is consumed for each MW of co-firing capacity relative to a greenfield site.

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by county. The amounts of products delivered to mills are multiplied by ratios of utilization (developed by the FIA for each state, species group, and size category) to estimate the volume of logging residue left in the woods. This does not include the cull and sapling trees left in the woods and never delivered to a mill. Wood residues from logging operations are assumed to result from historical levels of annual wood harvesting for North Carolina's pulp and paper and timber industries. This methodology provides an estimate of the annual average rate of wood residue generation that can potentially supply energy facilities. This does not take into account potential changes in wood residue generation if the State's forest industries decrease or increase production or if there is a change in forest management practices in the future.

A study published by the North Carolina Solar Center (NCSC) in 2005[56] used an Oak Ridge National Laboratory (ORNL) database, updated with county-specific data, to estimate the potential of wood residue at various price points for each county. However, to our understanding,[57] the data do not make an assessment based on the rate of generation per year, but rather the available wood in-place, so the results from the NCSC study may tend to overestimate the State's sustainable woody biomass potential.

Using the county-by-county data from the TPO,[58] we developed two cost blocks based on the wood concentration in counties. We assumed that biomass facilities would locate in counties with higher wood concentration first and thus pay less to transport the fuel to the plant. The second cost block assumes the counties with less wood density would need to export their fuel across a longer distance as facilities would not locate there first and a larger transportation radius would be needed to source the required amount of biomass from less concentrated counties. The radii of transportation assumed were 25 miles for the first cost block and 50 miles for the second. The assumed cost blocks, or marginal costs, of $40 per dry ton and $50 per dry ton include payments to landowners, collecting, hauling, transporting, and unloading. These costs translate to about $2.35/mmbtu and $2.95/mmbtu, respectively, assuming a heat rate of 8,500 btu/dry lb. As a point of reference, today's biomass fuel delivered costs range between $1.50/mmbtu to $2.00/mmbtu since the price facility operators are willing to pay for delivered biomass are constrained by the current price of electricity paid to biomass generators.

Also, new generating facilities should be sited in locations where there is not much overlap of delivery radii or competition for supply to ensure costs are not driven up. This is a potential risk for the price of biomass fuels, as evidenced by PURPA-era biomass plants in some states.[59] *Without expanding the supply infrastructure, increasing use will increase prices; but the studies indicate sufficient biomass fuel availability in North Carolina if a robust harvesting and distribution infrastructure is put in place, which can enable sustainable usage of greater volumes without creating shortages.*

[56] "Use of Agricultural and Forest Waste as a Distributed Generation Power Resource in North Carolina," NC Solar Center. 2005. <http://www.ncsc.ncsu.edu/research/documents/technical_papers/Final_Report_5-22809.rev2.pdf >

[57] Based on discussions with Christopher Hopkins, PhD candidate, NCSU, Dept. of Forestry, in August/September of 2006.

[58] Data is reported in green tons; a 50% moisture content is assumed to derive dry tons calculation.

[59] Morris, G. "Biomass Energy Production in California 2002: Update of the California Biomass Database", NREL, 2002.

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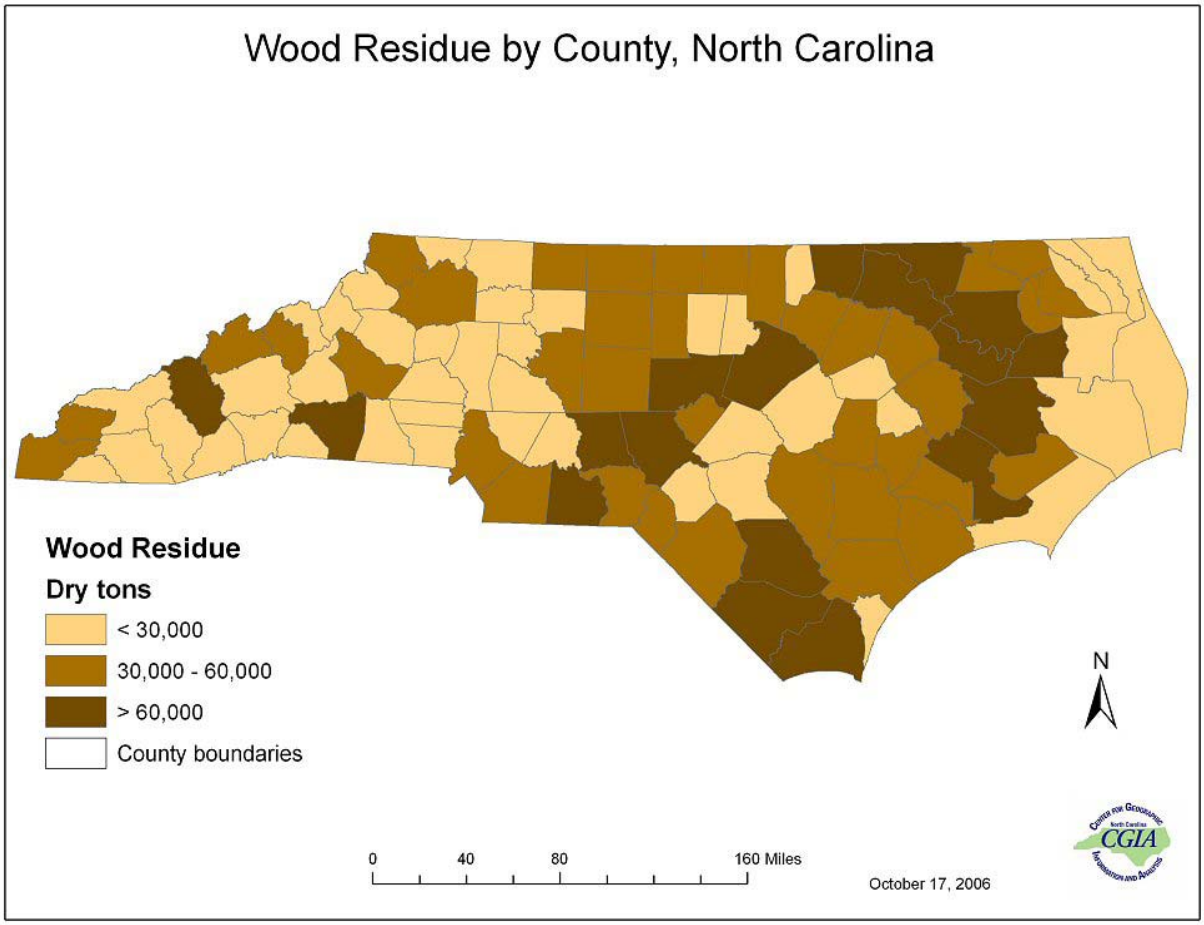
Figure 6



Urban Wood Waste

Urban wood waste, which qualifies for the NC GreenPower program, primarily refers to construction, demolition, and renovation waste (C&D waste), but excludes municipal solid waste (MSW) as this may be contaminated and cause added emissions. Much of this waste currently ends up in landfills. The NCSC study included an estimate of clean C&D waste (about 0.9 million tons per year) that is unused[60] presently. The reason that C&D waste is a cost-effective resource is that there is typically a tipping charge (about $25-$30 per ton) associated with the material, so the waste has minimal costs relative to wood residue, except for the cost of separation and transportation. In this assessment, it is assumed that C&D waste is essentially free at the pick-up point and the only cost incurred is delivery within a 50 mile radius ($14/dry ton).[61] It is also assumed that C&D waste can be consumed in fluidized bed, gasification systems, and in conventional stoker technology[62] fitted with emissions controls. A blending of up to 20% is assumed because there is limited availability and distribution of this resource, so it is unlikely to be the primary feedstock for a biomass plant.

[60] "Unused" implies that the C&D waste does not have a secondary application and/or is not recycled.

[61] This assumes 15% moisture content of C&D waste.

[62] The Craven County biomass plant, which is a stoker technology, can consume mixed fuels, including chicken litter, railroad ties, and wood residue, but the operator indicates that the fuels are relatively dry before being burned.

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Corn Stover and Wheat Straw

As part of the study by ORNL for the NCSC, an assessment of corn stover[63] and wheat straw[64] potential from agricultural operations was also included. There are a total of about 960,000 tons of economically available corn stover and 60,000 tons of wheat straw estimated in the State. These fuels combined can likely fuel about 150 MW of new biomass capacity. However, low concentration of supply by county, which increases cost of collecting, requires the resource to be mixed with other feedstock for power generation. In our analysis, we assume these resources can be a supplemental feedstock to new biomass facilities utilizing gasification, fluidized bed, or stoker technologies.

One point to note is that corn stover and wheat straw are located primarily in the eastern half of the State and will likely contribute to generation in this region only.

Table 3: Biomass Resource Potential Summary

	Cost Block 1[65] (dry tons)	Cost Block 2[66] (dry tons)	Additional Fuels (dry tons)	Heat Content (btu/dry lb)	Total Fuel (mmbtu)	MW Potential Co-Fire	MW Potential @13,000 btu/kWh
Softwood	854,782	1,039,523		8,500	32,203,200	408	314
Hardwood	793,108	1,267,955		8,500	35,038,076	444	342
Urban Clean Wood Waste	897,785	0		8,500	15,262,345	194	149
Corn Stover	600,239	363,255		7,400	14,259,711	181	139
Wheat Straw	5,644	54,769		7,800	942,443	12	9
					Total Potential	**1,239**	**953**
Pulpwood			4,779,566	8,500	81,252,627	1,031	793
MSW Wood Waste			836,779	8,500	14,225,243	180	139
Switchgrass			263,132	8,000	4,210,112	53	41
Hybrid Poplar			302,909	8,500	5,149,453	65	50
					Additional Potential (Not Included in Practical Potential)	**1,330**	**1,023**

[63] Corn stover refers to the unused portion of a corn plant, including the cob, stalk, and leaves, but excluding the grain.

[64] Wheat straw refers to the unused portion of a wheat plant, including the husk, stalk, and leaves, but excluding the grain.

[65] Cost Block 1 refers to potential at an assumed cost of $2.35/mmbtu (2006$) delivered.

[66] Cost Block 2 refers to additional potential at an assumed cost of $2.95/mmbtu (2006$) delivered.

Additional Fuels Not Included

The table above shows additional fuel options in North Carolina that are not included as part of the practical potential in the State for a variety of reasons. However, these fuels may serve as potential options for the State if the price or eligibility rules allow their use.

Pulpwood is a common input to the pulp and paper industry, and most of the pulpwood generated in the State is currently being consumed by the industry, some of which is used in cogeneration facilities in the State already. If there is direct competition with the pulp and paper industry for this material, it would likely drive the price up, which makes pulpwood a less competitive fuel option in the near term, unless there is a decline in the pulp and paper industry in the future.

Municipal solid wood waste is considered to be less clean than C&D waste because of potential toxic contaminants in the wood which may cause increased emissions output. It is often excluded from RPS eligible resources. Additionally, separation from other municipal solid waste material may increase costs.

Switchgrass and hybrid poplar are two energy crop options that may also serve as fuel inputs, but the costs for these fuels are higher due to the low density of distribution and higher harvesting costs.

Generating Technologies

Though the resources listed above adhere to the NCGP list of allowable resources, the current NCGP rules are silent with regards to the electricity conversion technologies allowed. For modeling purposes, we assume that co-firing, stoker, fluidized-bed, and gasification technologies all can consume the above biomass resources. *However, this analysis does not imply that the NCGP program would accept all the technologies described above for its green power products, as that is evaluated on a case-by-case basis.* Also, many existing biomass-fired generation facilities in North Carolina historically were built with the purpose of providing thermal/steam heating to a co-located industrial customer in a combined heat and power (CHP) arrangement. This type of structure helps reduce costs and improves fuel utilization efficiency. *However, this study does not include the CHP potential for the State because such an assessment would require site-by-site evaluation of potential load.*

From an environmental standpoint, combustion of biomass leads to many of the same kinds of emissions as the combustion of fossil fuels, including criteria air pollutants, greenhouse gases, and solid wastes (ash). Air emissions and water consumption are usually the principal sources of environmental concern related to biomass facilities. Greenhouse gases are less of an issue because biomass, if harvested in a "sustainable" manner, is assumed to be carbon-neutral. Like conventional generation, biomass power plants are also required to achieve stringent emissions control levels for the pollutants, which are usually controlled by using advanced combustion technologies, often including fluidized-bed combustors, staged-combustion, and flue-gas recirculation. Some of the newest biomass power facilities are required to use ammonia injection to further control NO_x emissions. Sulfur dioxide emissions generally are not a major concern with biomass combustion because biomass, especially woody forms of biomass, has very low sulfur content. Some facilities that have fluidized-bed combustors inject limestone to

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capture sulfur, but no biomass facilities are required to have flue-gas scrubbers to control SO_2 emissions.

Particulates are controlled using a variety of technologies. Virtually all biomass power plants use cyclones to remove most large particulates from the flue gas. Most biomass facilities are equipped with electrostatic precipitators for final particulate removal; some facilities use baghouses. Most modern biomass power plants are required to achieve zero visible emissions to meet environmental permit conditions. Their emissions of total and sub-micron particulates are also regulated and controlled to stringent levels, comparable to or better than the emissions levels achieved by conventional fossil fuel plants.

Co-Firing in Coal Plants

North Carolina has over 12,500 MW of in-state coal-fired generation capacity. The State's utilities have explored the possibility of co-firing biomass in their coal plants to varying degrees.

In general, co-firing can be achieved through either blending the biomass fuel with coal, or retrofitting existing boilers to allow them to burn a greater amount of biomass. Generally, blending should be achievable in all the coal plants in the State at a level of up to 3%-5% of the rated capacity. Some limited capital investment for blended feed systems may be required. On the other hand, if a coal plant chooses to retrofit, it should be able to co-fire to a level up to 10%-20%. However, a retrofit requires a more substantial capital investment, making modifications or additions to the fuel handling, storage, and feed systems, depending on the specifics of the existing coal facility and type of biomass to be used. Furthermore, facilities that will invest or have invested in selective (SCR) or non-selective catalytic reduction (NSCR) systems may not want to risk the effectiveness of the control equipment by co-firing. While the potential of alkali interference with the effectiveness of catalytic reduction systems designed to control for nitrogen oxides in coal plants has not been definitively confirmed,[67] it has been found that some biomass fuels do have higher alkali levels than coal.

For modeling purposes, the assumed technical potential can be up to 15% of all existing coal capacity, but the practical potential will be limited by the availability of economical resources within 50 miles of a coal plant and other emissions controls limitations. However, we also make the assumption that coal plants that intend to retrofit with emissions controls (scrubbers or NO_x control equipment) under the North Carolina Clean Smokestacks Act (see discussion in Section 7) are less likely to face environmental permitting issues and other potential objections related to life extension of plants when seeking to co-fire biomass.

The map below divides the biomass co-firing regions into five zones, with most of the coal plants in North Carolina located in Zones A and B. It is assumed that the 4,030 MW of coal plants in Zone A and 3,544 MW in Zone B, which have installed or plan to install SCR/SNCR control systems, are less likely to retrofit for co-firing due to the risk of interfering with the emissions control systems. In Zone A, therefore, only plants without SCR/SNCR are assumed to retrofit for 15% co-firing. Because there are so many coal plants in Zone B, not all coal plants in this zone can co-fire and still have access to economical fuel supply. In fact, there is only

[67] "The Potential for Biomass Cofiring in Maryland," Maryland Department of Natural Resources, March 2006.

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enough biomass to supply up to 5% of some of the coal plants' capacity in Zone B, which means only blending makes economic sense for these coal plants.

Using the Clean Smokestacks Act limitation, one coal plant in Zone D and one in E can also retrofit up to 15% of its capacity for co-firing, since there should be sufficient biomass resources in that zone to meet this requirement. However, coal plants in Zone C are not included in the assessment because they do not have to comply with the Clean Smokestacks Act.

It is important to note here that the exclusion of certain coal plants that do not have to comply with the Clean Smokestacks Act does not preclude the retrofit of these facilities to consume biomass if an RPS is, in fact, enacted. Appropriate environmental permitting standards would be required.

Finally, we also assume that co-firing biomass in coal plants will not contribute incremental energy or capacity to the State's energy needs. *This means existing coal plants do not expand their rated capacities nor would they increase energy production from historical levels, which may otherwise increase emissions output. With these assumptions, the primary benefit of co-firing is the displacement of coal fuel and the availability of emissions allowances for sale or use in other plants which will go to reduce the cost of this option.*

Figure 7

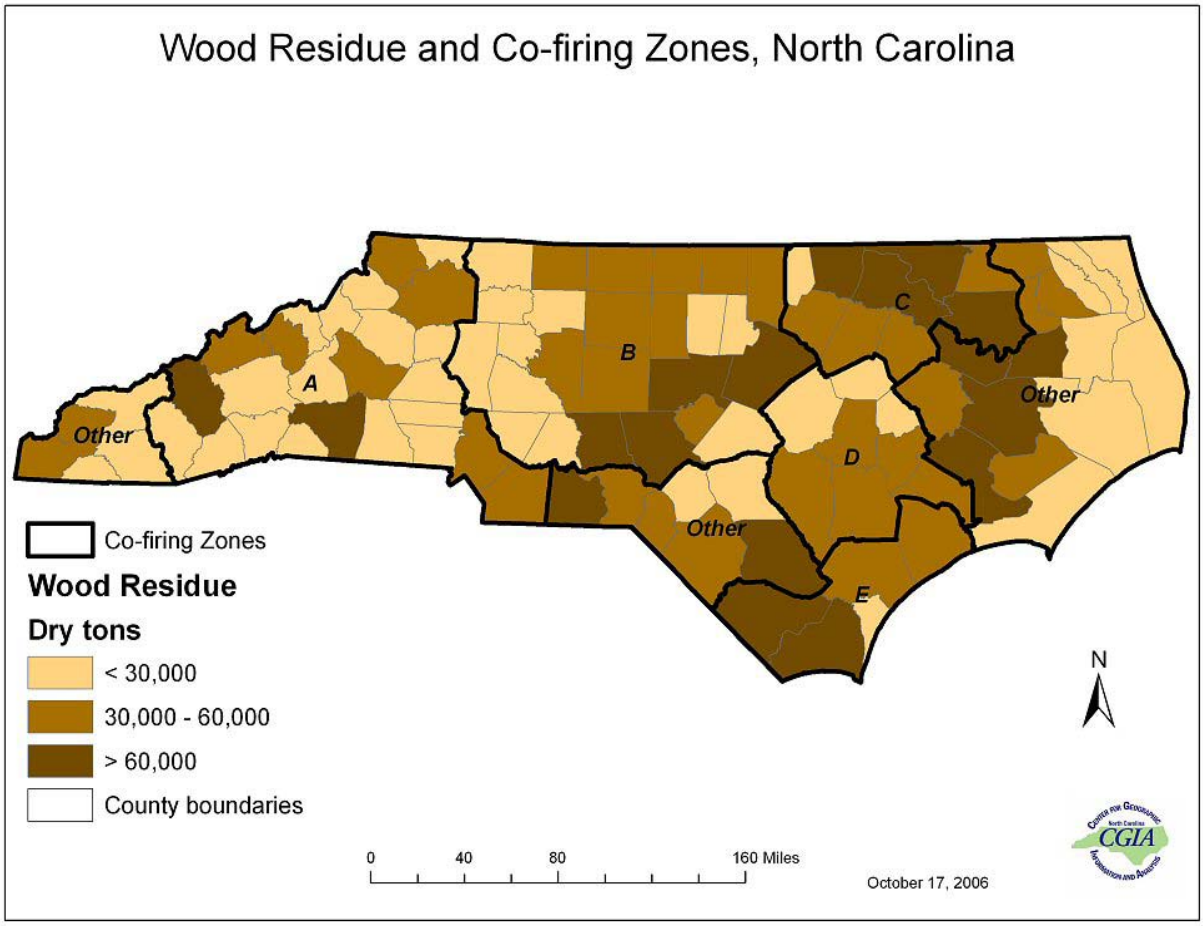

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Table 4: Co-Firing Potential

Coal Zone	MW of Coal[68]	MW of Coal without SCR/SNCR Installations	Co-Fire Blending Potential (5%)	Co-Fire Retrofit Potential (15%)	Available Biomass Fuel Block 1	Available Biomass Fuel Block 2	Max Potential
A	4,602	571	9	86	**32**	**107**	Retrofit 86 MW
B	6,443	2,899	145	435	**61**	**121**	Blending 182 MW
C	0	0	0	0	**91**	**39**	None
D	328	328	16	49	**0**	**57**	Retrofit 49 MW
E	447	447	22	67	**46**	**22**	Retrofit 67 MW

Stoker Boiler

Most existing biomass plants in the nation use stoker boiler technology. Craven County Biomass, a 50 MW biomass plant in North Carolina built in 1990, is an example of stoker technology. A stoker boiler uses a direct combustion process; direct combustion involves the oxidation of biomass with excess air, producing flue gases which produce steam in the heat exchange of the boilers. The term stoker refers to a relatively simple, proven boiler technology in which biomass material is combusted on or over a traveling stoker grate.

The **Craven County Wood Energy (CCWE)** is a 50 MW biomass plant that utilizes stoker technology located in New Bern, NC. The plant historically has used a diverse mix of fuels including: wood processing waste, such as chips from logging residuals, bark and sawdust from pulp and sawmills, railroad ties, poultry litter and wood waste from area landfills as fuel. The plant utilizes over 500,000 tons of waste products per year to generate approximately 400,000 MWh of power. The process annually generates 13,000 tons of fly ash and 2,000 tons of bottom ash. Previously, these landfilled ash by-products represented 13 percent of the total solid waste generated annually in Craven County. In 1993, the plant began delivering fly ash to area farmers as a soil amendment; the bottom ash is used as daily landfill cover by the local landfill.

Photo of Craven County Wood Energy

Some technical advances have been made with this technology in terms of improved efficiency. Generally, emissions rates are higher for stoker boilers than fluidized bed, though plants can be

[68] Only coal units that intend to retrofit with emissions equipment under North Carolina's Clean Smokestacks Act are included. Of these, 4,030 MW in Zone A and 3,544 MW in Zone C have installed or plan to install SCR/SNCR controls for NO_x.

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fitted with emissions control. It is assumed that new stoker boilers are fitted with the best available control technologies (BACT) to achieve lower emissions in the modeling of these plants.

Fluidized Bed

The next generation of biomass plants is expected to be primarily fluidized bed technology, which is common in coal plants. Fluidized bed technologies also use a direct combustion process. However, in the fluidized bed boiler, the biomass is injected into the bottom of a hot sand bed below the furnace. The biomass is then raised through the sand bed and combusted. This combustion process results in the heat rising to the furnace and subsequent production of steam.

The fluidized bed technology generally results in higher combustion efficiency than stoker plants, particularly for biomass fuel that has high moisture contents. It is suitable also for a wider variety of biomass fuels (including those with relatively low btu content) than stokers, as the fluidized bed allows for a more complete and uniform combustion process. Emissions rates are also generally lower than for those of stoker boilers without emissions controls.

Gasification

Gasification is a developing technology that converts solid fuels (biomass or coal) to gas for power generation. If cost and some technological issues are overcome, it promises to be a relatively attractive biomass technology. There are several demonstration projects in the country utilizing gasification technology.

Gasification is a two step process. First, biomass material is gasified to produce so called "producer gases." Then, the producer gas is used as an input to any gas-fired electric generators. There are several different types of gasifier technologies, which differ based on the direction of flow of the fuel and air streams, but the generation technology is conventional. Gasification can feed simple cycle, combined cycle, or steam turbines, though most utility-scale applications would likely utilize a combined cycle configuration.

Gasification offers several advantages to direct combustion technology. It allows a wider variety of fuels to be used, generally results in fewer emissions, and is expected to have higher efficiencies than direct combustion technologies. It also offers the potential to be used or blended with natural gas.

However, because of the need for additional gasifying equipment, the technology currently has higher capital costs than direct combustion technologies; with more widespread development, this has the potential to decline. In addition, biomass fuel with high moisture content may present some challenges for gasification, and some gasification technologies still need to resolve issues presented with gas clean-up and residual contaminants.

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3.3 Animal Waste

North Carolina is a leading U.S. producer of both hogs and poultry. According to 2004 national agriculture statistics,[69] North Carolina ranks second in hog and pig production (behind Iowa) with approximately 10 million animals. North Carolina swine production represents just over 16 percent of the total U.S. production. The State's poultry industry ranks second and fourth nationally, in turkey and broiler production, respectively. In 2004, North Carolina farms raised 39 million turkeys (approximately 15 percent of the total U.S. production) while chicken operations produced over 700 million broilers (approximately 9 percent of the total U.S. production).

Increasingly, theses industries are facing more stringent environmental regulations related to treatment and disposal of animal waste, more commonly referred to as "nutrient management." In particular, large animal operations are facing increasing federal, State, and local regulations as well as siting restrictions related to odor, nutrient management and surface and ground water contamination. For example, no new lagoons are allowed to be built in North Carolina for hog operations.

In 2000, North Carolina and one of the major hog producing companies, Smithfield Foods, entered into agreements to fund research and development of environmentally superior waste management technologies for use on North Carolina swine farms. Over $17 million was provided by Smithfield, the State and others to fund the effort. To date, the Smithfield project included eight different methods in its Phase 1 technology evaluation for nutrient management; two methods explicitly utilized anaerobic digesters to convert the waste to methane for electricity conversion. One of the anaerobic projects is located at Barham Farms.

The agreements define an environmentally superior technology as:

> *[A]ny technology, or combination of technologies that (1) is permittable by the appropriate governmental authority; (2) is determined to be technically, operationally and economically feasible for an identified category or categories of farms as described in the agreements; and (3) meets the following performance standards:*
>
> 1. *Eliminates the discharge of animal waste to surface waters and groundwater through direct discharge, seepage or runoff;*
> 2. *Substantially eliminates atmospheric emissions of ammonia;*
> 3. *Substantially eliminates the emission of odor that is detectable beyond the boundaries of the parcel or tract of land on which the swine farm is located;*
> 4. *Substantially eliminates the release of disease-transmitting vectors and airborne pathogens; and*
> 5. *Substantially eliminates nutrient and heavy metal contamination of soil and groundwater.*

[69] "How North Carolina Agriculture Compares with Other States – 2004 Production," NC Department of Agriculture and Consumer Services, May 2, 2005. <http://www.ncagr.com/stats/nc_rank/ncrallyr.htm>

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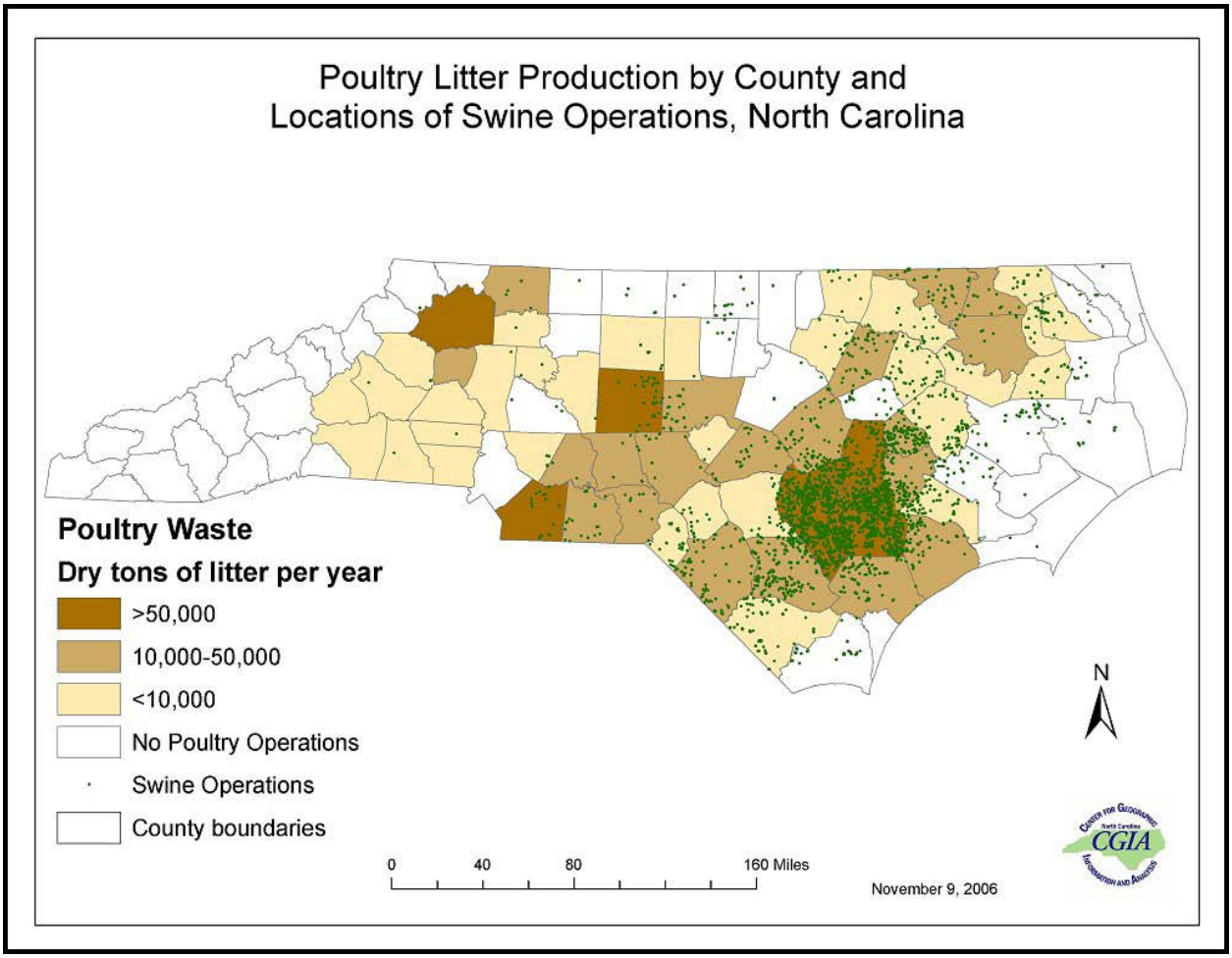
Poultry litter,[70] historically used as a substitute to fertilizer, presents a somewhat different issue. There has been increasing concern that over-fertilizing with poultry manure may result in both groundwater and surface water problems as excess nutrients wash off or are leeched into groundwater supplies.

Figure 8



Hog Waste and Anaerobic Digesters

Over the past two years, the number of digesters has more than doubled across the U.S. due to a diverse array of national, state, and local activities. The majority of commercially operating digester systems for treatment and disposal of hog waste fall into two categories: ambient temperature covered lagoons and mesophilic temperature covered lagoons.

In determining statewide potential, we considered only operations similar or greater in size and production capacity to the Barham facility (described below) in order to generate sufficient methane for electricity production. According to the 2004 North Carolina agriculture statistics,

[70] Poultry litter consists of a combination of poultry manure and bedding material.

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there are 620 hog operations in North Carolina with over 5,000 heads per site, totaling about 7.5 million. The average operation is estimated to consist of about 12,000 heads, which can produce methane in the range of about 10,000 mmbtu/year[71] to 18,000 mmbtu/year.[72]

Aerial view of Barham Farm

EPA's AgStar program conducted a study to assess the biogas opportunities for North Carolina with the assumption that farms with greater than 2,000 swine can provide methane for electricity generation. That program identified 1,179 total feasible operations with 9,358,000 heads of mature swine. The study estimated 11.5 billion cubic feet per year of methane production (1.3 mmbtu/head/year) and 766,000 MWh/year of electricity generation. This would be equivalent to about 116 MW of electric generation capacity at a 75% capacity factor.

The **Barham Farms** ambient anaerobic digester was one of the systems evaluated during the Smithfield project. The 4,000 head farrow-to-wean operation located near Zebulon, North Carolina originally combined an ambient temperature anaerobic digester with an engine generator to convert the methane produced into electricity. The ambient digester consists of an impermeable cover over an in-ground digester. Waste is moved from the houses in which pigs are kept to the in-ground digester. Methane gas that is produced during the digestive process is extracted and delivered to a generator, where electricity is produced for use on the farm. Heat from the generator is captured and used to produce hot water that is used by the farm in its production activities. Effluent from the digester flows into a second-stage lagoon that was the primary lagoon before the digester was built. Today, the nutrients in the effluent from the second-stage lagoon are used to fertilize plant and vegetable species in a greenhouse adjacent to the swine production facility, but electric generation has been discontinued.

Taking the median of the wide range of methane production potential, we assume an annual net methane production for a 12,000 head operation to be about 14,000 mmbtu per year, which can power a 150 kilowatt (kW) internal combustion engine generator at 75% capacity factor with a heat rate of 14,000 btu/kWh. For modeling purposes, we assume a typical generator capacity of 150 kW per location, which would provide a maximum potential (at operations greater than 5,000 heads) of about 93 MW of electric power generation statewide. The actual size of generators would have to be sized appropriately for the farm size, average animal size, and anticipated methane production. Furthermore, farmers are able to reduce their own retail electricity costs by

[71] Assuming 2,300 btu/head/day net methane. "Methane Fuel Gas from Livestock Wastes: A Summary," Professor James C. Barker, NCSU, March 14, 2001. <http://www.bae.ncsu.edu/programs/extension/publicat/wqwm/ebae071_80.html>

[72] From Smithfield project estimate of daily average methane production of 3.57 cubic feet/lb. of volatile solid, 1.1 lb. of VS/day/head, and 1,066 btu/cubic foot methane conversion.

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consuming the electricity generated on-site or participate in net-metering if the generators are sized below 100 kW. Owners of multiple farms may also consider aggregating sites that are in close proximity to one another to take advantage of scale economies, but transport costs would have to be taken into account.

The Smithfield project does note the benefits to hog operations for installing an anaerobic digester include more than electricity generation, such as having an effective method of treating and disposing of the waste from farming operations and having usable byproducts of heat and fertilizer. Unfortunately, the other economic benefits of such a system to farm operations are difficult to quantify at this time and, thus, not captured in our analysis. Also, the cost per unit of energy may be significantly reduced if the digester system produced more methane than estimated.

Poultry Litter

As discussed before, poultry litter is commonly used as a fertilizer substitute and soil amendment, but it poses somewhat of a different problem than hog waste. There is concern that over-fertilizing with poultry manure may result in both groundwater and surface water problems as excess nutrients wash off or are leeched into groundwater supplies. The State is exploring alternative outlets for the material in the form of a fuel input to energy generation,[73] similar to Fibrowatt plants being developed in other parts of the U.S. (described to the right).

Fibrowatt LLC, an affiliate of a United Kingdom company, Fibrowatt Ltd, is exploring the possibility of developing several generation projects in North Carolina that would consume chicken litter as its primary fuel input. The company is in the process of constructing the first U.S. poultry litter fueled power plant in Minnesota, which is expected to come on-line in 2006. When completed the 55 MW plant will sell all of its baseload electricity to Xcel and consume 700,000 tons of agricultural waste (primarily turkey litter) annually.

In estimating the potential in North Carolina, we used the State's 2004 total turkey production[74] and broiler production[75] and applied the average litter per thousand birds for each,[76] which results in an annual potential of over 1.4 million tons of poultry litter. We then applied a heat content of 6,200 btu/lb[77] to the annual litter production to estimate a potential capacity of around 175 MW if the litter is consumed in a plant dedicated to poultry litter such as the Fibrowatt facilities. This is equal to five facilities of 35 MW capacity.

One uncertainty related to this resource is that the biomass facilities may be competing directly with farmers for poultry litter, as it is an inexpensive alternative to purchasing industrial fertilizer during times when high fuel prices increase the cost of fertilizer, which has a potential

[73] Currently, Craven County Biomass is utilizing poultry litter for a small portion of its biomass fuel supply.

[74] "2004-2005 Agricultural Statistics, County Estimates", NC Department of Agriculture and Consumer Services, September 19, 2006. <http://www.ncagr.com/stats/cnty_est/ctytrkyr.htm>

[75] "2004-2005 Agricultural Statistics, County Estimates", NC Department of Agriculture and Consumer Services, September 2006. <http://www.ncagr.com/stats/cnty_est/ctybroyr.htm>

[76] Camberato, Jim, "Land Application of Poultry Manure," NRAES 1999. <http://hubcap.clemson.edu/~blpprt/pasture/lpptable.html>

[77] "Biomass Energy Data Book", Oak Ridge National Laboratory, 2006 <http://cta.ornl.gov/bedb/appendix_a/Approximate_Heat_Content_of_Selected_Fuels_for_Electric_Power_Generation.xls>

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nutrient value of $20-$35/ton.[78] *On the other hand, concern over excess nutrient run-off resulting from the use of poultry litter as a fertilizer may alter this demand completely in the future.*

Due to potential competition with farmers for use of the poultry litter as a fertilizer substitute, it is assumed that only three 35 MW facilities, or a total of 105 MW, can ultimately be built and receive cost-effective fuel supply.

Even though it is possible (and necessary) to mix poultry litter with other available agriculture biomass[79] (similar to the Minnesota project) such as crop residue and forest industry waste, for modeling purposes, we assume that poultry litter is consumed in dedicated facilities. We also understand that utilities are currently exploring the use of poultry litter as a co-firing input to existing plants, which is an option that we have not modeled.

3.4 Wind

Wind energy is a major component of most states' RPS portfolios, and, with cost reductions and performance improvements over the last 20 years, wind could be significant in any RPS adopted by North Carolina. The potential for this resource has been well-known for many years as North Carolina was one of the first states to erect a large-scale wind turbine in the U.S. with the construction of a 2 MW turbine in Boone in 1979. Additionally, Appalachian State University has conducted numerous studies on the potential and benefits of wind in North Carolina.

Boone Wind Turbine

The wind industry has grown rapidly in the last decade, and there are now more than 10,000 MW of wind turbines installed in the U.S. The development of widespread wind resource analysis has accompanied the industry's growth so that the current technical potential for wind energy is reasonably well-documented for each state. In assessing North Carolina's technical and practical

[78] Lichtenberg et al., "Economic Value of Poultry Litter Supplies in Alternative Uses," University of Maryland, October 2002.

[79] The remainder of the biomass used in the Fibrowatt Minnesota project will be secondary vegetative biomass, which could include materials such as alfalfa stems, oat hulls, distiller grains, corn stover, sugar beet residue, annual grasses, sunflower hulls, and other similar agricultural or biomass materials.

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wind energy potential, we referred to recent updated information from the National Renewable Energy Laboratory (NREL),[80] a wind resource study conducted by AWS TrueWind in 2004 (a leading firm in wind resource studies) for the State Energy Office, and studies conducted by universities for the State Energy Office.[81]

Buffalo Mountain, Tennessee: 15 Vestas 1.8 MW Wind Turbines.

As one would expect, the starting point for evaluating wind energy potential is to analyze the available wind resource. The referenced studies estimate average annual wind speeds at different heights above the ground across the State; we then used that information to estimate the economics of developing wind projects in North Carolina. The average annual wind speeds are often identified by wind speed "classes," with Class 1 being the lowest and Class 7 being the highest. Class 4 and better winds are present at preferred development sites, though improved low-speed wind turbines can produce acceptable economics at Class 3 sites. The higher the Class rating, the higher capacity factors can be gained from the same amount of installed wind capacity and the lower the unit cost of energy. Net capacity factor is calculated based on the total expected net energy generation per year divided by the total maximum generation for a turbine.

The State's best wind potential can be found along the east coast and in the western mountains. From the information sources noted above, we estimated that there is about 2,800 MW[82] of Class 4 and above on-shore wind energy potential in North Carolina. In addition, there is about 6,800 MW of Class 3 wind energy potential.

[80] NREL staff provided current information in telephone conversations and e-mail in August 2006.

[81] Reviewed multiple studies listed on ASU wind web site. <http://www.wind.appstate.edu/index.php>

[82] This estimate is based on 20 MW per square mile of windy land. While the number of MW available at any site will depend on the specific topography, our review of turbine spacing requirements and of many wind projects that are operating or are in development shows that approximately 10 MW of wind turbines can be installed per linear mile and that two rows can be installed in each square mile.

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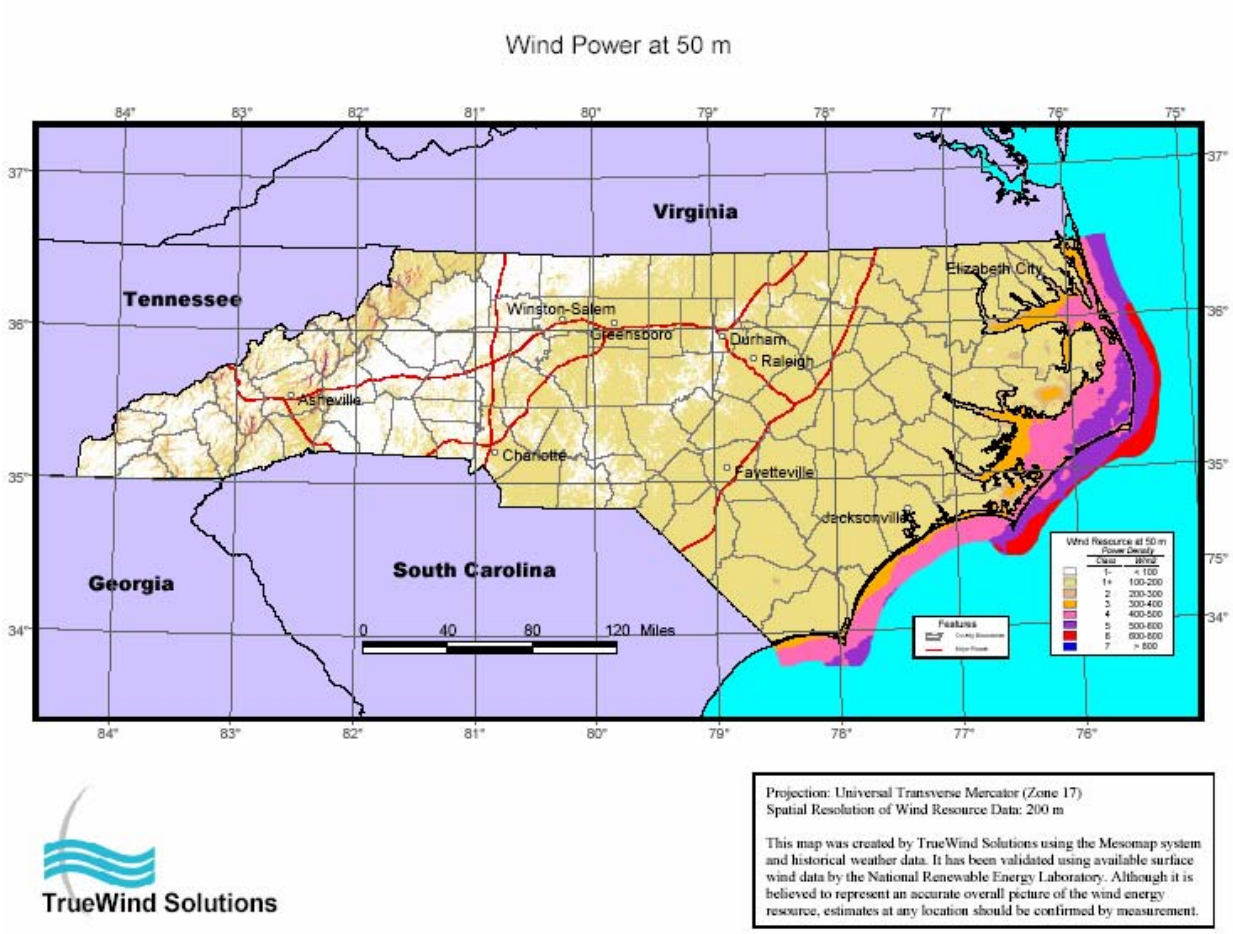
Figure 9



However, much of this potential may not be developable for a variety of reasons. As a result, the technical potential numbers cited in the preceding paragraph are reduced to reflect:

- Potentially sensitive environmental land. This would include wildlife, wilderness and recreation areas as well as other sites known or estimated to be under environmental restriction.
- Incompatible land uses such as wetlands, urban areas and certain forested areas.
- Other exclusions including steep slopes, a buffer around excluded land areas, and small pockets of land that would not be large enough to support economic wind development.

The cumulative result of the identified exclusions is about a 75% reduction in wind capacity potential. Using this information, the estimated total on-shore potential is 2,250 MW broken down as follows:

Class 3	1,550 MW
Class 4	380 MW
Class 5 +	320 MW

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In addition, other permitting and siting issues, such as the Ridge Law (discussed to the right), are likely to limit the practical amount of wind development. Accordingly, for modeling purposes, the above estimates were reduced further by one-third to produce 1,500 MW of practical on-shore wind energy potential, with one-third (500 MW) located in the east and 1,000 MW located in the west.

Because of the uncertain impact of the Ridge Law, we considered the practical on-shore potential wind resource in two main components: (1) eastern North Carolina, and (2) western North Carolina. In addition, inland sounds have the potential to support wind development, and we have, accordingly, considered those "off-shore" areas as discussed below.

The Mountain Ridge Protection Act of 1983 (Ridge Law) states: "no . . . building, structure or unit shall protrude at its uppermost point above the crest of the ridge by more than 35 feet." Protected mountain ridges are all mountain ridges whose elevation exceeds 3,000 feet and whose elevation is 500 or more feet above an adjacent valley floor. Exemptions to the Ridge Law include: water, radio, telephone or television towers or any equipment for the transmission of electricity or communications or both. Structures of a relatively slender nature and minor vertical projections of a parent building, including chimneys, flagpoles, flues, spires, steeples, belfries, cupolas, antennas, poles, wires, or ***windmills are also exempt.*** In written comments to the Tennessee Valley Authority, State Attorney General Roy Cooper stated, in 2002, that North Carolina's Mountain Ridge Protection Act of 1983 would prohibit construction of a wind farm being proposed in the Tennessee mountains if the project were located in North Carolina.

Eastern Wind

Developable on-shore sites in the East are primarily Class 3 wind resource sites. These sites can be found in a few areas along the coast and on the barrier islands. While this contains some Class 4 sites, given practical development limitations in viewsheds, we have assumed that a number of areas, including the barrier islands, will not be developable. Accordingly, we estimated practical use of 25 square miles in response to an RPS and the installation of approximately 500 MW of wind capacity. Depending on the exact configuration, such development may occasion the need for the construction of a major transmission line, since much of the better wind resource appears to be located in an area which would require at least a 115kV line to transfer the electricity out of the region. Based on the applicable wind maps, 100 MW of the eastern wind resource could be considered Class 4 with a 32% net capacity factor and 400 MW would be in Class 3 wind regimes with a 29% net capacity factor.

Western Wind

The wind resource analyses show that western North Carolina has significant technical wind energy potential, mostly along mountain ridges. However, the practical development of the resource depends on broad policy issues that are yet to be decided. Accordingly, wind projects in the western part of the State are included only as part of the Expanded Resources scenarios.

Using the wind resource information discussed above, the 1,000 MW to potential development was broken down by Class in the Expanded Resources scenarios as follows:

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Class	Potential	Net Capacity Factor
Class 3	650 MW	29%
Class 4	150 MW	32%
Class 5+	200 MW	35%

To install 1,000 MW of wind projects in western North Carolina, approximately 100 miles of ridgelines would be required. This would equal approximately 5% of the 1,850 miles of ridgeline above 3,000 feet in elevation.

Off-shore Wind

In scenarios that include resources from Resource Group I, there is an assumption of little to no development of wind in the western part of the State due to the Ridge Law. As a result, additional wind energy may have to be tapped along the coast in order to achieve a higher RPS target. Due to its higher installed cost, an off-shore project, to be considered potentially viable, must be located within a Class 4 wind regime, which can be found 1-2 miles off the North Carolina coastline and in the sounds. For 2,000 MW of off-shore turbines (3 MW each) to be installed in such areas, approximately 100 square miles of water surface would be required (though not fully occupied by turbines). By way of comparison, the sounds alone comprise approximately 1,700 square miles of surface area. We assume installation in the sounds as the more economic option for off-shore development because of shallower waters and easier access.

3.5 Hydro

North Carolina currently has over 1,650 MW of hydropower capacity, most being utility-scale conventional hydro. In order to qualify as a NCGP resource, new small hydro facilities must be less than 10 MW. According to NCGP,[83] it anticipates that most of the small hydro will involve the installation of new generating capacity on existing impoundments (dams). Any new hydro generating facility that involves a new impoundment will not automatically be included in the program but will require special approval. In assessing the potential for such facilities in North Carolina, we used studies published by the Idaho National Engineering and Environmental Lab (INEEL).

In the INEEL study, each potential hydropower site in a state was reviewed and grouped into three categories as follows: W – currently developed sites with generation but has additional capacity potential; W/O – developed sites with some type of impoundment or diversion structure but no power generation capability presently; and U – undeveloped sites with no structure or power generating capabilities. Furthermore, INEEL also developed the Hydropower Evaluation Software (HES) to compile environmental attributes surrounding potential projects and give the sites a project environmental sustainability factor (PESF) between 0.1 (lowest likelihood of development due to environmental factors) and 0.9 (highest likelihood).

The HES software identified 93 North Carolina sites, ranging from 1 kW to 76 MW, with hydropower potential that falls under the three categories listed above. The total undeveloped

[83] "NC GreenPower Program Plan," Advanced Energy, Nov. 2002. <http://www.ncgreenpower.org/elements/pdfs/NCGreenPowerProgramPlan.pdf>

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potential weighted by PESF is roughly 500 MW, with 77% of the sites in North Carolina being under 5 MW in size.

Table 5: INEEL HES Potential in North Carolina

	Number of Sites	HES-Modeled Potential (MW)
With Power	6	14.3
W/O Power	57	369.0
Undeveloped	30	124.5
North Carolina Total	93	507.8

In developing the practical potential of hydro sites, we chose to use sites with a PESF weighting of 0.50 or greater to estimate capacity potential. These sites were divided into two groups: a <10 MW class, which would qualify for NC GreenPower program, and a 10+ MW class which does not qualify at the present. We excluded hydro sites that have a potential of less than 1 MW because the development costs would be too great. This left 38 potential sites that have unutilized hydropower potential and have a reasonable likelihood of being developed, with a total potential capacity of about 410 MW.

To estimate annual production, another INEEL study provided monthly average hydro profiles for North Carolina rivers. That study shows an estimated annual capacity factor of 45%,[84] which was used in the study's model. The average NCGP criteria hydro project was assumed to be 2.5 MW and the average (10+ MW) larger hydro project was assumed to be 25 MW.

Table 6: Practical Hydro Potential Estimate (PESF*MW)

	NCGP(<10MW)	10+ MW
W/O Power	51	311
Undeveloped	15	30
North Carolina Total	66	344

According to INEEL, there is very little incremental hydro potential in North Carolina at existing hydropower facilities, except for one site, Rhodhiss. Rhodhiss can potentially increase its capacity by about 15 MW, but this facility is used primarily to meet peaking needs according to the facility owner, Duke Energy.[85]

[84] Hall, Douglas G., Richard T. Hunt, Kelly S. Reeves, and Greg R. Carroll, "Estimation of Economic Parameters of U.S. Hydropower Resources," Idaho National Engineering and Environmental Laboratory, June 2003.

[85] "Rhodhiss Hydro to Celebrate 75th Anniversary," Duke Energy News Release, February 18, 2000. <http://www.duke-energy.com/news/releases/2000/Feb/2000021801.html>

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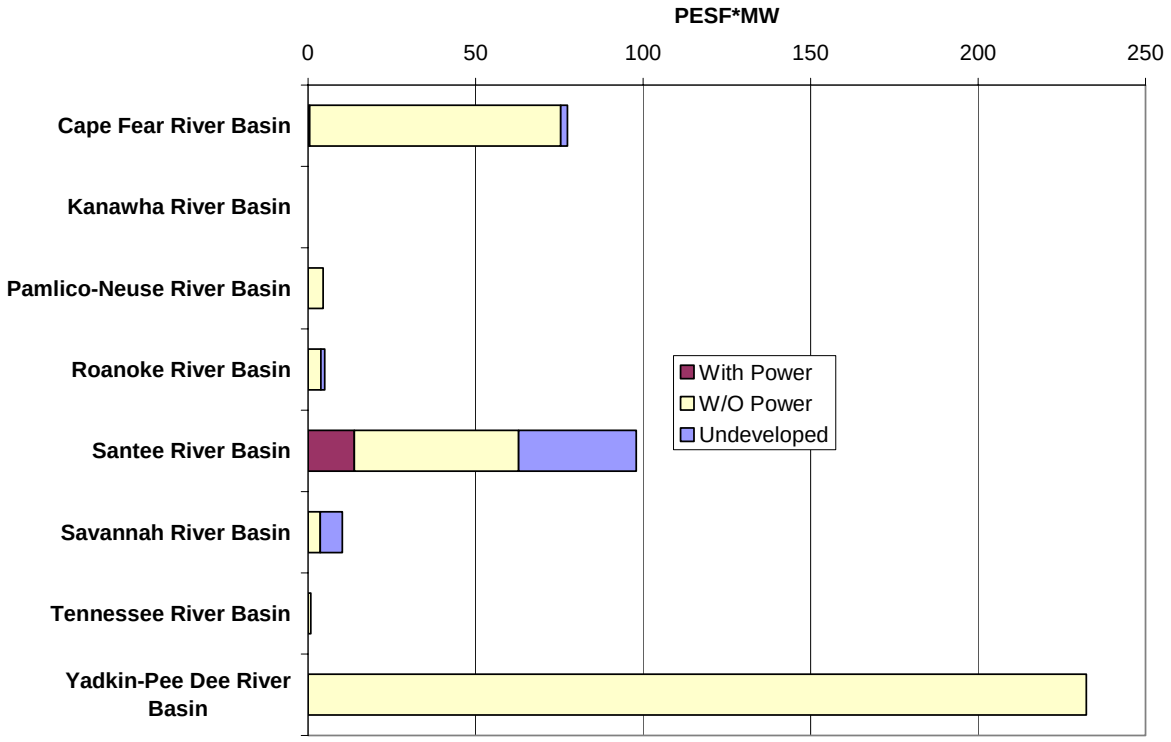
Figure 10

INEEL Additional Hydroelectric Potential by River Basin



3.6 Solar

Based on North Carolina's location, the State has good solar resources throughout. Energy from the sun can be used in several ways:

1. Generate electricity by means of using **photovoltaic (PV) systems** that convert sunlight directly to electricity;
2. **Direct thermal energy conversion** either for heating or cooling applications;[86]
3. **Electricity generation utilizing the sun's thermal energy**.[87]

For the purpose of assessing the electric contribution potential from solar, we focus this discussion on PV systems only because this is the technology with most commercial experience. In 2005, the worldwide installations of solar PV totaled 1,460 MW for that year.[88] The solar PV

[86] Solargenix, a solar thermal technology company based in North Carolina, is one of a few renewable technology companies in North Carolina.

[87] Southern California Edison signed a contract for 500-850 MW of solar generation with Stirling Energy Systems to construct a facility using "Stirling Solar Dishes." It is a technology that uses large reflective dishes to concentrate solar energy to be used in a Stirling heat engine to convert the heat into electricity. <http://www.stirlingenergy.com/breaking_news.htm>

[88] "2006 World PV Industry Report Highlights," Solarbuzz, March 15, 2006. <http://www.solarbuzz.com/Marketbuzz2006-intro.htm>

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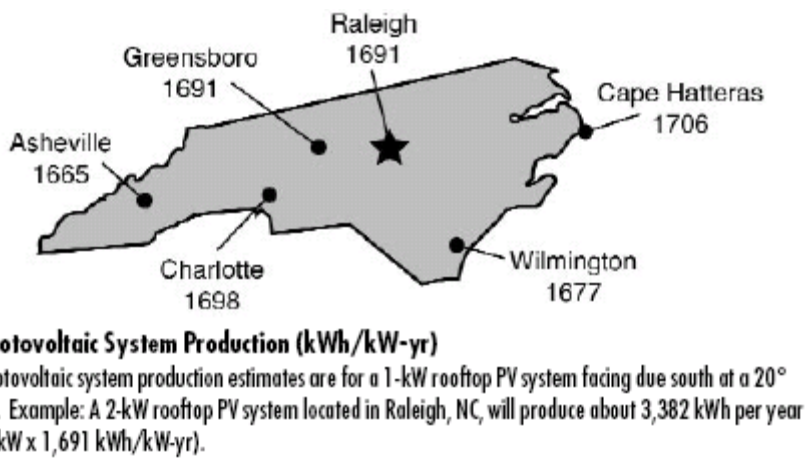
potential in the State was not estimated because it is not limited by technical or practical considerations but rather by current levels of installed costs.

Solar thermal systems were evaluated under energy efficiency as a potential measure. While solar thermal systems can potentially displace the consumption of electricity, their potential was not assessed as part of electricity generation options. This does not necessarily preclude the eligibility of solar thermal systems in an RPS.

Solar photovoltaics are made of semiconductor materials that produce voltage and current when exposed to sunlight. These semiconductor materials are made into PV cells. The electricity generated by PV cells is direct current (DC) like that produced by batteries. As more light falls on a cell, more electricity is generated. The solar potential of a particular site is highly dependent on its latitude position and angle to the sun. A PV system in North Carolina can get a yearly average sun exposure of 5.0 – 6.4 hours per day depending on whether the system is fixed or tracking the sun.[89] In the figure below, the average annual energy production (kilowatt-hours per kilowatt) of a PV panel that is fixed due south is illustrated for various locations around North Carolina, translating to an annual capacity factor of about 19%.

Figure 11

Photovoltaic System Production by Region in North Carolina



Source: North Carolina Solar Center[90]

NCSC reported the cost of a 2 kW solar photovoltaic system (residential size) to be $20,000-$24,000 installed, or $10-$12 per watt. The cost of a larger system, 5 kW, comes to $40,000 to $50,000 or $8-$10 per watt.[91] The cost quoted by installers today in North Carolina is about $10 per watt installed for residential (1-2 kW) systems.

[89] "Photovoltaics: Electricity from the Sun," North Carolina Solar Center, June 2002, p. 4.

[90] "North Carolina Consumer's guide to Buying a Solar Electric System," North Carolina Solar Center. <http://www.ncsc.ncsu.edu/information_resources/factsheets/cnsmrguide.pdf>

[91] Ibid.

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Tax incentives at both the state (35%) and federal level (30% or $2,000) are offered to help defray the cost of solar PV systems. Despite these tax incentives, the cost of a PV today is not yet directly competitive with many other renewable generation options on a dollars-per-energy generated basis. However, PV systems do provide multiple benefits that may not be otherwise accounted for. For example, PV systems can offset peaking load since the times during which PV systems generate the most electricity from the sun often coincide with the highest summer load periods on an electric system (see Appendix C). Additionally, based on the annual electric generation estimates above, a PV system in North Carolina can produce electricity about 19% of the year without any added fuel costs and help offset the cost of electricity for a home or business owner at retail rates[92] rather than wholesale rates. Solar PV may be able to provide other benefits, such as providing distributed generation[93] capability without creating additional emissions.

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[92] Net-metering rules may apply.

[93] Distributed generation is the small-scale production of electricity at or near customers' homes and businesses. It has the potential to improve system reliability, reduce local distribution loading during peak moments, and/or avoid system upgrades in some cases.

4. Renewable and Conventional Supply Cost Development

In order to estimate the rate impact of a possible RPS, the La Capra Team developed cost estimates for the various renewable and conventional energy resources. After developing these estimates, the potentially available MW of resources were summed in order from least to highest cost. This resulted in a supply cost curve of resources.

In developing the supply cost curves for resources within North Carolina, we first compiled the costs of installing and operating the applicable technologies. Both renewable and conventional supply costs were included. Next, we calculated levelized costs per unit of energy production ($/MWh). The levelized costs are used to compare technologies with different cost profiles over time. For renewable resources, levelized costs are based on technology-specific financial assumptions applicable for independent project developers. In computing costs for conventional technologies, we used costs that would result from utility financing structures and depreciation for ratemaking purposes. All the results are presented in nominal terms, meaning inflationary effects are taken into account. For this analysis, the average inflation rate is assumed to be 2.5% per year.

4.1 Resource Costs and Operational Characteristics

In compiling resource technology costs and operational characteristics, this Report used a combination of information, including confidential data from actual projects, striving for realistic, current assumptions.

Installed Costs

While the renewable technologies reviewed are all deemed commercially available, some of the renewable technologies are not yet mature and initial development costs may be greater than national studies estimate for long-term achievable costs. However, these technology costs may decline over time to their expected cost levels with greater penetration of the technology. The range shown below for installed costs reflects our estimates of cost reductions in real terms over the study period for developing technologies and no reduction in real terms for mature technologies. Installed costs as represented are the total estimated project costs in 2006$ for the assumed facility size that is being modeled.

In an effort to appropriately reflect costs, we have attempted to account for related interconnection, development, and other soft costs, such as financing and contingency costs typical of these resources. The costs and operational characteristics in the study are representative of projects, both renewable and conventional, being built today, but the actual cost of individual projects can vary greatly depending on site-specific issues.

In particular, upgrades to local distribution/transmission systems are always a major consideration with wind energy economics. The basic cost estimates for wind energy projects in this assessment include the cost of constructing a substation and approximately 10 miles of

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transmission line to reach the current grid. The analysis of other system upgrades that may be needed is site specific and beyond the scope of this Report.

Operational Costs

Operation and maintenance costs are also estimated for the different technologies. These costs are assumed to increase with inflation. Finally, resources such as biomass and poultry litter are fuel inputs and require a fuel conversion rate or heat rate (btu/kWh) in estimating the fuel cost component. Likewise, conventional resources all require fuel inputs, and assumed heat rates are shown.

Tax Benefits

There are multiple types of tax incentives and credits that owners of these various resources can receive. The most prominent tax incentive is the Federal Production Tax Credit (PTC)[94] that applies to many of the resources above.

Historically, the PTC has applied to wind and some forms of biomass projects. In the Energy Policy Act 2005 (EPACT 2005), resources such as hydro 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. Though the PTC currently applies only to facilities that are installed by the end of 2007, in the scenarios analyzed, we assumed that the PTC gets renewed at the levels specified in EPACT 2005 throughout the RPS study period. This assumption appears reasonable in light of past extensions and the recent expansion of the resources covered by the PTC.

North Carolina offers a state tax credit for 35% of the cost installing renewable energy systems; however, 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.[95] Additionally, the credit for any specific project is capped at $25,000 for residential customers and $2,500,000 for businesses. In the modeling, small projects such as solar PV and anaerobic digesters would benefit the most from the State's tax credit.

Solar PV installations receive additional tax benefits through a federal tax credit for solar systems placed in service between January 1, 2006 and December 31, 2007. The credit has a residential and a business classification, where the residential credit equals 30% of the PV project and is capped at $2,000 per system. The business credit has no cap and is for 30% of the project cost (after other credits are accounted for) until December 31, 2007 at which point the credit drops to 10%.[96] It is assumed that, as with the PTC, the 30% federal tax credit will continue for businesses after 2007.

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[94] In 2006, the PTC was $0.019 per kWh. Each year, the PTC increases with an inflation adjuster with the PTC rounded to the nearest $.001 per kWh.

[95] "Guidelines for Determining Tax Credit for Investing in Renewable Energy Property," North Carolina Solar Center. <http://www.dor.state.nc.us/practitioner/individual/directives/renewableenergyguidelines.html>

[96] "Frequently Asked Questions on the New Federal Solar Tax Credit," Solar Energy Industries Association. <http://www.seia.org/getpdf.php?iid=21>

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For nuclear facilities, which are included only in a sensitivity case, EPACT 2005 also includes a PTC for the first 6,000 MW of new Advanced Nuclear plants built in the U.S. As noted in a previous section, this analysis assumed a 50% probability that nuclear facilities developed in North Carolina would be able to take advantage of the PTC.

Table 7: Summary of Generation Technology Costs and Operational Characteristics

Resources (Technology)	Practical Resource Potential	Modeled Size	Installed Cost	Fixed O&M	Variable O&M	Heat Rate	PTC
(Costs in 2006$)	MW	MW	$/kW	$/kW-year	$/MWh	btu/kWh	
Renewable Technologies							
Eastern Wind Farm	500	30	$1,700-$1,417	$45	$2	-	100%
Eastern Wind Cluster		5	$2,000-$1,667	$55	$2	-	100%
Eastern Offshore Wind	2,000	50	$2,400-$2,000	$65	$2	-	100%
Western Wind Farm	1,000	30	$1,700-$1,417	$45	$2	-	100%
Western Wind Cluster		5	$2,000-$1,667	$55	$2	-	100%
Biomass (Co-Fire with Coal)	950-1,240	20-69	$75-$230	$12	$5	12,000	-
Biomass (Stoker Technology)		25	$2,700	$75	$10	13,000	50%
Biomass (Fluidized Bed Technology)		25	$3,000-$2,618	$75	$10	13,800	50%
Biomass (Gasification)		25	$3,700-$2,946	$100	$10	12,500	50%
Incremental Hydro	13	13	$1,100	-	$5($3)	-	50%
Hydro without Power*	350	2.5 (25)	$3,300($2,750)	$20($10)	$5($3)	-	50%
Undeveloped Hydro*	45	2.5 (30)	$4,400($3,850)	$20($10)	$5($3)	-	50%
Landfill Gas (ICE)	150	5	$1,450	$200	-	12,000	50%
Poultry Litter (Stoker)	175	35	$2,927	$75	$10	13,000	50%
Hog Waste (Anaerobic Digester)	90	150 kW	$4,000	$270	-	14,000	50%
Solar PV**		2 kW (25 kW)	$10,000 ($8,000)	$75	-	-	-
Conventional Technologies							
Pulverized Coal		750	$1,600	$30	$5	9,100	-
Gas Combined Cycle		250	$700	$12	$2	7,000	-
Gas Combustion Turbine		150	$500	$12	$8	10,200	-
Nuclear		1,100	$2,000-$4,000	$60	$3	10,000	50%[97]

**Values denoted in parentheses are for hydro projects greater than 10 MW that do not presently qualify as a NC GreenPower resource.*
***Values denoted in parentheses are for larger installations at commercial/industrial sites.*

[97] Under EPACT 2005, the first 6,000 MW of advanced nuclear plants built in the United States would qualify for a PTC but the PTC is capped at $125 million per year per 1,000 MW plant. Since there is a limit to the number of nuclear plants that can actually receive the PTC, we assume a 50% probability of utilization of the PTC in the cost assessment.

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4.2 Financing Assumptions and Resource Cost Calculation

Financing assumptions are critical to estimating the cost of renewable technologies, as many are capital intensive with little or no fuel costs. Renewable energy projects have utilized multiple financing structures involving combinations of bank loans, equity investments, tax credits, and/or municipal bonds. Depending on a project's owner and its tax status, the financing structure will also vary. A utility-owned project will be structured differently than one owned by an independent power producer (merchant developer). This difference is captured in the assumptions below.

Financing Nonutility Renewables

Renewable energy projects are assumed to have nonutility owners, with the exception of biomass co-firing projects which will consist of retrofits at utility-owned coal-fired plants. The output of the nonutility-owned projects is assumed to be sold to utilities under long-term power purchase agreements (PPA) for a fixed price that is equivalent to a levelized cost which allows the owner to earn a market return on investment. The costs for the PPAs will be passed through to ratepayers. For small customer-side generation, the full cost is also taken into account, even though the energy may be net-metered. Conventional resources are assumed (i) to be utility-owned, with capital costs included in rate base and earning the utility's allowed rate of return; (ii) to have operating costs reflected in utility expenses; and (iii) to have longer book depreciation lives for ratemaking purposes.

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 range between 8.0% and 8.5%. The cost of equity for renewable project investors may range between 13% and 15% depending on the perceived risks associated with the development and output of a project. For this analysis, anaerobic digesters (for hog waste) and solar projects are assumed to be 100% debt financed as they are relatively small projects that can be viewed as capital expenditures fully funded either through an agricultural loan or a home mortgage.

Levelized Costs

Next, we developed levelized costs for renewable technologies to assess the associated annual costs for a portfolio of conventional resources and a portfolio that includes renewable resources. The purpose of levelizing costs is to normalize the unit cost of renewable generation that may have different debt terms, economic life, and capital requirements. All levelized costs calculated for renewable resources are in nominal terms and are calculated over a 20-year period where inflation is also taken into account. The annual levelized cost for each type of resource modeled represents the cost for a resource installed in a particular year. This is meant to mimic a fixed price 20-year PPA that a merchant renewables developer would be expected to offer to the State's utilities in the applicable year.

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Table 8: Generator Financing Assumptions and Levelized Costs

Technology	Economic Life	Range of Levelized Costs (2008)	Debt	Equity	Cost of Debt	Cost of Equity	Debt Term	Depreciation Life*
	Years	cents/kWh	%	%	%	%	Years	Years
Non-Utility Ownership								
Other biomass	20	8.9 – 12.4	70%	30%	8.0%	14%	15	20
Landfill Methane	20	4.7	70%	30%	8.0%	14%	10	7
Onshore Wind	20	5.5 – 9.1	60%	40%	8.0%	14%	15	5
Offshore Wind	20	10.5	60%	40%	8.5%	15%	15	5
Anaerobic Digesters	20	7.9	100%	-	8.25%	-	10	7
Hydro (upgrades)	30	2.5 – 10.4	70%	30%	8.0%	13%	20	20
Hydro (new)	50	11.6 – 14.0	70%	30%	8.0%	13%	20	20
Solar PV (small)	25	35	100%	-	5.78%	-	20	0
Solar PV (large)	25	20	100%	-	8.5%	-	10	5
Utility Ownership								
Biomass co-firing	10	0.5 – 2.2[98]	50%	50%	8.0%	12.5%	5	10
Pulverized Coal	40	N/A	50%	50%	8.0%	12.5%	25	20 (40)
Gas Combined Cycle	20	N/A	50%	50%	8.0%	12.5%	15	20 (25)
Gas Combustion Turbine	20	N/A	50%	50%	8.0%	12.5%	15	20 (25)
Nuclear	40	N/A	50%	50%	10.0%	12.5%	25	15 (40)

** Depreciation life denoted in parentheses indicates the depreciation life used in rate recovery calculations for utility-owned generation.*

Utility-Owned Generation

In order to properly reflect a utility-owned generator, it is important first to model utility costs that resemble its cost recovery profile. Therefore, the cost stream is based on the first 20 years of operation for conventional resources using a utility cost-recovery structure (40 or 25 year depreciation) at the current allowed rate of return (12.5%) for the equity portion of the capital. This is best demonstrated in the graph below showing an example of the annual utility cost recovery that includes the capital cost recovery and the annual operating costs for a coal plant. These cost streams were calculated for each of the utility-owned conventional technologies above. Since this RPS analysis is not an attempt to replicate an integrated resource planning process, we simplified the methodology by assuming one cost stream for each of the conventional technologies described. The fuel prices assumed for conventional technologies are described in the next section.

[98] Though biomass co-firing will likely receive utility rate-making treatment for cost recovery, this number reflects the incremental cost compared to using coal in existing coal facilities.

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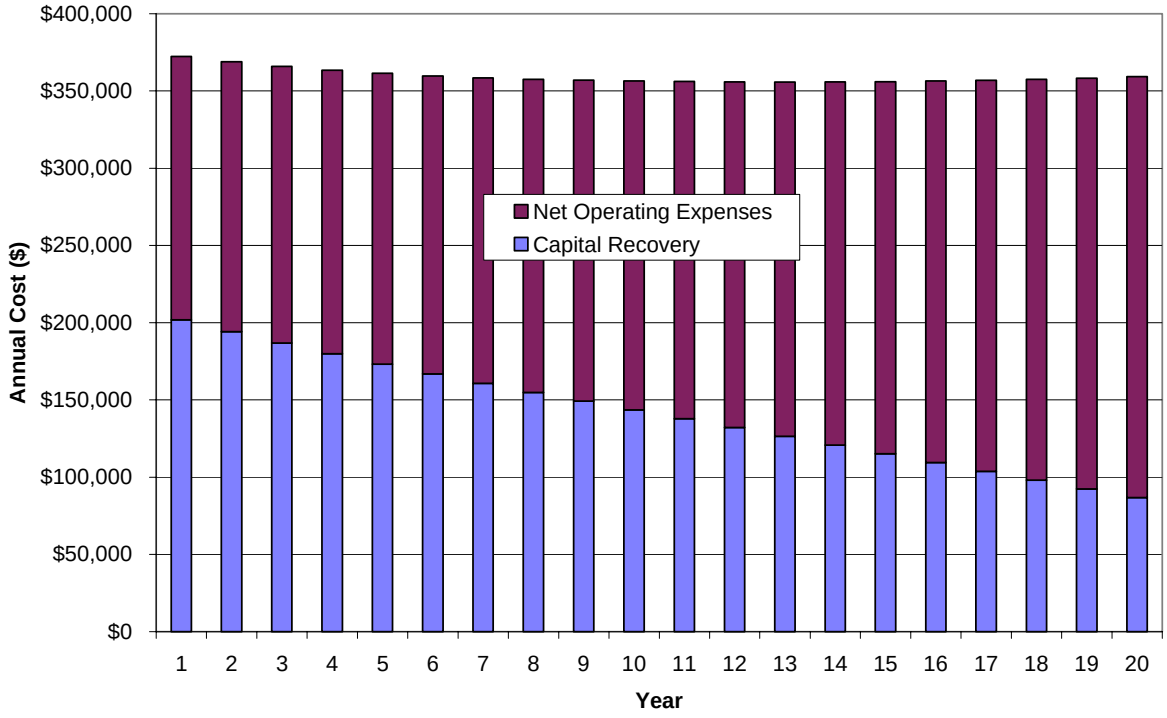
Figure 12

Example of Year-to-Year Recoverable Costs of a Utility-Owned Coal Plant



4.3 Fuel Price Assumptions

In assessing the costs of conventional resources, it was also important to develop a realistic set of assumptions related to future conventional fuel costs for North Carolina. Since 2003, the country has seen dramatic increases in prices for all the conventional electric generation fuels: oil (up 65%-90%), natural gas (up 45%), coal (up 30%), and even uranium (up over 100%). Below are two figures that reflect the trends of national average coal costs paid by electric generators historically and world uranium prices. Fuel prices for North Carolina are higher than reflected in the national averages.

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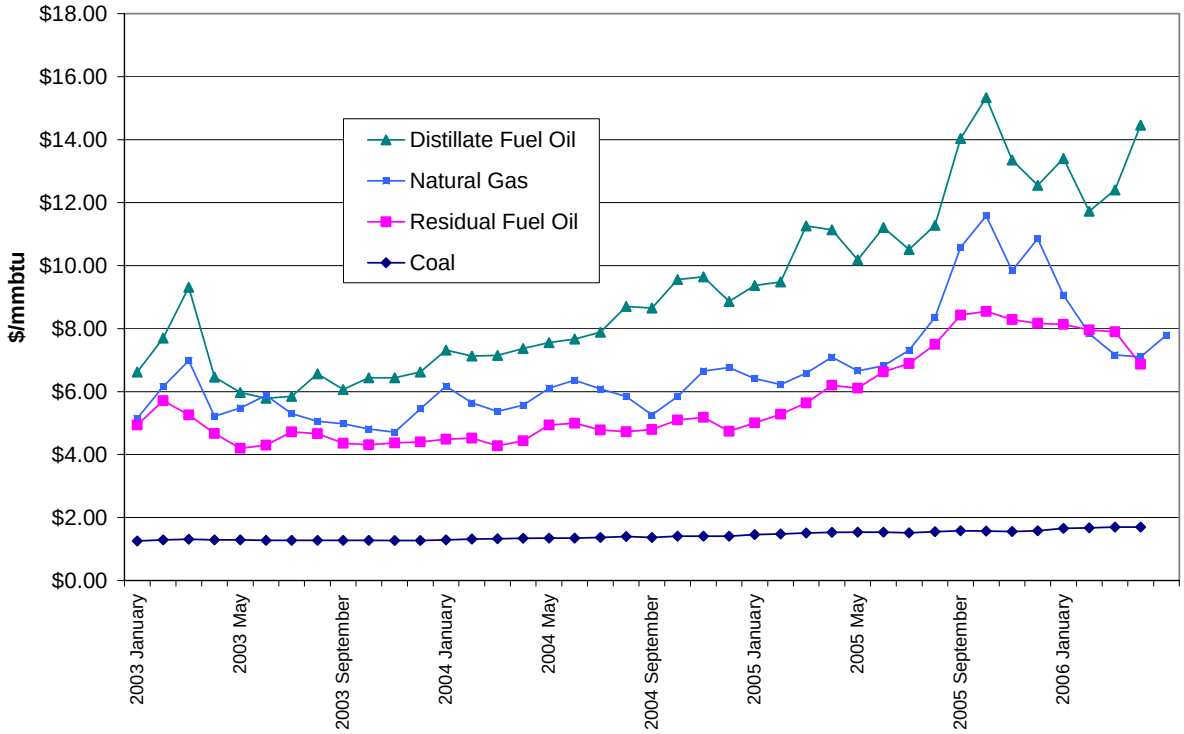
Figure 13

EIA Historical Fuel Receipts at Electric Generators



Source: EIA

Figure 14

Source: World Nuclear Association

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Similar increases have impacted North Carolina as well causing North Carolina utilities to file fuel adjustments to rates. Going forward, depending on the source of the forecast, future prices for these fuels can vary dramatically. A moderate assumption for future fuel prices in North Carolina to be used in this analysis is presented below. A high fuel case, similar to prices experienced over the past year, was also tested and is discussed in a sensitivity case in a later section. Fuel prices are assumed to increase with inflation (2.5% per year).

Table 9: Delivered Fuel Price Assumptions

	Base Fuel Prices (2006$/mmbtu)	High Fuel Prices (2006$/mmbtu)
Coal	$2.75	$3.25
Natural Gas (Firm)	$8.00	$10.00
Natural Gas (Spot)	$7.20	$9.20
Oil	$7.25	$9.25
Nuclear	$0.50	$1.00

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5. Energy Efficiency

As part of the scenario assessment, the Advisory Group was interested in understanding the implications of including energy efficiency (EE) as a possible option for meeting up to 25% of the requirements of an RPS. Energy efficiency opportunities typically are physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining the same or improved levels of energy services. Energy efficiency, for the purposes of this analysis, is a subset of Demand Side Management (DSM) programs that may encompass other programs such as load management, load shifting, demand response, and other peak load programs. In order to address this request in a timely manner, GDS, an expert in demand side management potential assessments, conducted a simplified analysis of the EE potential in North Carolina.

The GDS Report, entitled *"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,"* is not meant to be a detailed exploration of every possible demand-side management program that can be implemented in the State, but rather an overview of cost-effective potential for commercially available energy efficiency measures in the context of this RPS study. The focus, for the purposes of the RPS analysis, was to examine energy efficiency measures that could provide the greatest energy reductions in a cost-effective manner. Table 10 below lists the number of energy efficiency measures included in the GDS study by sector.

Table 10: Number of Energy Efficiency Measures by Sector

Sector	Number of Energy Efficiency Measures
Residential sector	34
Commercial sector	81
Industrial sector	12
All Sectors - Total	127

While there are limitations to the approach, which will be discussed later, the La Capra Team was able to use the GDS results to model scenarios in which 25% of the RPS requirements are met with EE. For additional information regarding this study, please refer to the attached full study text.

Before summarizing the key information from the GDS work, it is important to understand a few EE concepts, as follows:

- **Technical Potential** is defined in the GDS study as the complete and immediate penetration of all measures that were deemed technically feasible from an engineering perspective.

- **Achievable Potential** is defined as the penetration of an efficiency measure that can be achieved with a concerted, sustained campaign involving highly aggressive programs and market interventions. The State of North Carolina would need to undertake an extraordinary effort to achieve this level of savings.

- **Achievable Cost-Effective Potential** is defined as the potential for the realistic penetration of energy efficiency measures, derived from Achievable Potential estimates, that are cost effective according to a calculation of the levelized cost per lifetime kWh saved.[99] **Measures with a levelized cost per lifetime kWh saved of $.05 or less are considered to be cost-effective**. As demonstrated later in this report, North Carolina would need to continue to undertake an aggressive effort to achieve this level of electricity savings.

The process of narrowing down the energy efficiency potential in North Carolina began with an assessment of Technical Potential of 33% by 2017 and concluded with an Achievable Cost-Effective Potential of 14% by 2017.

Table 11: Total Potential Electricity Savings by 2017

Level of Potential Savings	Cumulative Annual Electricity Savings Potential in 2017 (GWh)	Percent of 2017 GWh Sales
Technical Potential	58,968	33%
Achievable Potential	36,234	20%
Achievable Cost-Effective Potential ($0.05/kWh or lower)	25,132	14%

The key conclusion that the La Capra Team draws from the GDS study is that the Achievable Cost-Effective Potential for energy efficiency in North Carolina should be able to meet 25% of either a 5% or 10% RPS. In reaching this conclusion, the La Capra Team notes:

- The GDS study estimates the **Achievable Cost-Effective Potential** for electric energy and related peak demand savings from energy-efficiency measures in North Carolina. The primary cost-effectiveness filter that GDS used for screening of energy efficiency measures is the levelized cost per lifetime kWh saved of each energy efficiency measure. Only measures costing **less than $.05 per lifetime kWh** saved were considered to be cost-effective.

  It is important to keep in mind that this screening criteria does not replicate any of the "Cost/Benefit Tests" that would normally be used in a regulatory DSM proceeding. The purpose here is to provide indicative potential and associated costs for programs that can be implemented in North Carolina as part of an RPS.

- Based on the cost-effectiveness screening described above, capturing the **Achievable Cost-Effective Potential** for energy efficiency in North Carolina can reduce electric energy use by **14 percent** by 2017.

[99] The levelized cost per lifetime kWh saved is a calculation based on the full incremental cost of a measure, amortized over its measure life by taking into account a discount rate. Incremental cost is the difference between the cost of an energy efficient measure versus the cost of a less-efficient counterpart. The levelized cost per year resembles equal payments of a mortgage over the measure life with an interest rate equivalent to the discount rate. The levelized cost screen does not include first year administrative costs, which is assumed to be $0.02 per first year kWh saved (2006$).

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The magnitude of the potential savings is consistent with results reported in recent studies for many other states.

- In estimating Achievable Cost-Effective Potential, GDS considered savings opportunities from **Market Driven Energy Efficiency program**[100] strategies.

- GDS selected a **target incentive level of 50 percent** of energy efficiency measure costs as the incentive necessary to achieve high rates of program participation required to achieve the savings potential. GDS noted that actual program experience has shown that very high levels of market penetration can be achieved with aggressive energy efficiency programs that combine education, training and other programmatic approaches along with incentive levels in the 50% range.

- There are additional program costs for administration, marketing, technical assistance and data tracking and reporting. In the GDS Study, **program administrative costs are assumed to be in addition to incentive costs and are assumed to be $0.02 per kWh of first year's savings of each measure.**

- The cost-effectiveness screening (using the levelized cost per lifetime kWh saved) is based upon a **nominal discount rate of 10%**.

5.1 Methodology

The analysis of energy efficiency potential was broken into three customer classes: residential, commercial and industrial. GDS used different approaches to estimate the impact of each customer class.

For the residential sector, GDS began by assessing the existing level of electric energy efficiency that has already been accomplished in North Carolina. This assessment included collecting data on the penetration of Energy Star appliances in the State for the period from 1998 through 2004. For each electric energy efficiency measure, this analysis assessed how much energy efficiency has already been accomplished as well as the remaining potential for energy efficiency savings for a particular electric end use.[101] For the residential sector, GDS addressed the new construction market as a separate market segment, with a program targeted specifically at the new construction market.[102] Additionally, GDS assumed an achievable long-term penetration rate of 80 percent by 2017 for the residential sector in North Carolina. This penetration rate is achieved over a ten-year period, not immediately.

For the commercial and industrial sector, GDS developed an estimate of the achievable cost-effective potential for North Carolina by calculating an average from eight other recent studies.

[100] Market driven measures occur only when existing equipment will be replaced with high efficiency equipment at the time a consumer is shopping for a new appliance or other energy using equipment, or if the consumer is in the process of building or remodeling.

[101] For example, if 100 percent of the homes in North Carolina currently have electric lighting, and 30 percent of light bulb sockets already have high efficiency compact fluorescent bulbs (CFLs), then the remaining potential for energy efficiency savings for this measure is 70 percent.

[102] In the residential new construction market segment, for example, detailed energy savings estimates for the ENERGY STAR Homes program were used as a basis for determining electricity savings for this market segment in North Carolina.

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The average achievable cost-effective potential savings in these other studies is 12.1% for the commercial sector and 10.8% for the industrial sector. Based on their experience in other states, GDS concludes that these estimates are reasonable proxies for opportunities in these sectors in North Carolina.

Another key element in this approach is the use of energy efficiency supply curves. The supply curve is typically built up across individual measures that are applied to specific base-case practices or technologies by market segment. Measures are sorted on a least-cost basis and total savings are calculated incrementally with respect to measures that precede them. An energy efficiency supply curve provides information on how much energy efficiency is available at a certain levelized cost per lifetime kWh saved. A list of measures that were examined is provided in Appendix G.

5.2 RPS Implications

There are several issues that are unique to energy efficiency measures and must be considered if EE is included in an RPS.

- Under current North Carolina ratemaking, the full cost associated with a measure, no matter the measure life, is eligible to be expensed in rates at the time the cost is incurred, unlike generation resources, where capital costs are often recovered over a longer period of time. This is how EE costs were modeled in the RPS analysis.

- Each energy efficiency measure has a unique useful life. As a result, some measures may be effective for a relatively short period of time, meaning the measures may not be persistent. To address this issue, additional funding is needed after the RPS study period to maintain efficiency levels achieved by 2017. The RPS modeling of EE scenarios includes additional funding after 2017 to replace expired measures.

- The measurement of energy efficiency savings for RPS compliance purposes can be difficult unless there are standardized savings designated for each type of EE measure. There is also the potential of some double-counting between what is included in utilities' forecasts versus achieved savings through an RPS. One way of dealing with this issue is to utilize appropriate tracking and accounting protocols and target specific programs that are not included in utilities' forecasts.

- The potential existence of free-riders and free-drivers[103] also poses a problem in attributing the correct amount of energy savings from EE measures that are part of an RPS versus what would have otherwise resulted without any incentives and may have already been accounted for in utilities' forecasts. For the RPS analysis, the impact of free-riders and free-drivers are expected to counterbalance each other based on a

[103] Free-riders are defined as participants in an energy efficiency program who would have undertaken the energy efficiency measure or improvement in the absence of a program or in the absence of a monetary incentive. Free-drivers are those who adopt an energy efficient product or service because of the intervention, but are difficult to identify either because they do not collect an incentive or they do not remember or are not aware of exposure to the intervention.

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study of a similar nature conducted for the New York State Energy Research and Development Authority (NYSERDA).

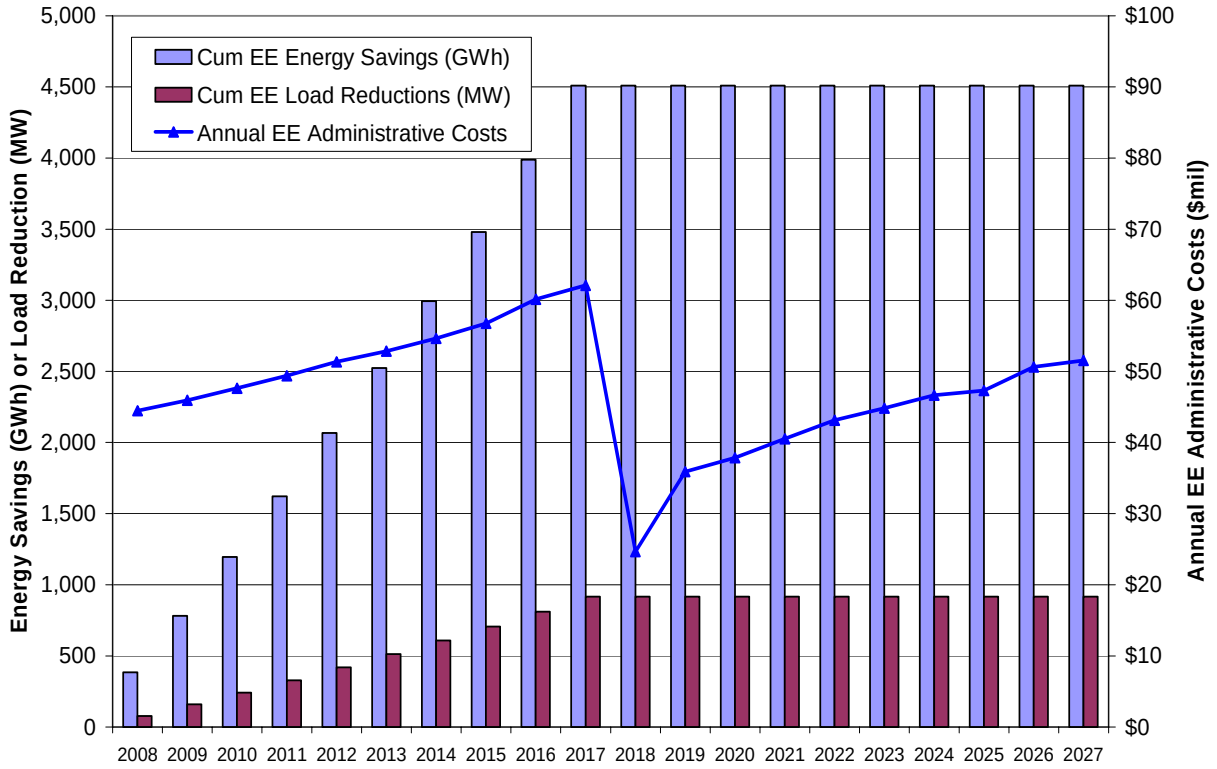
- If the State does proceed with the development of an RPS, careful consideration should be given to whether an RPS or a separate policy vehicle is the appropriate policy tool to promote energy efficiency measures.

Notwithstanding these observations, GDS's estimate that the cost-effective potential in the State is 14% by 2017 indicates that there should be sufficient EE potential to meet 25% of the statewide RPS targets discussed in this Report. Since the EE target equates, at most, to only 2.5% of total electric sales in the State by 2017, GDS concludes that there is ample cost-effective energy efficiency to meet the EE portion of an RPS.

Realizing the **Achievable Cost-Effective Potential** energy efficiency savings by the end of the RPS study period (in 2017) would require extensive programmatic support. Programmatic support includes financial incentives to customers, marketing, administration, planning, and program evaluation activities provided to ensure the delivery of energy efficiency products and services to consumers. The annual administrative costs shown below include all the costs described as part of programmatic support, including 50% of measure incremental costs (in the form of financial incentives paid to program participants).

Figure 15

Energy Efficiency Measures to Meet 25% of a 10% RPS Target



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GDS's study indicates that a ramp-up of programs and related costs to meet 25% of a 10% RPS may appear as in the graph above. Additional funding after the RPS period would be needed to sustain the same level of achieved savings.

As noted in the above graph, the energy efficiency measures can also be expected to reduce the amount of generation capacity that is needed. To calculate load (capacity) reductions, GDS assumed that the load factors associated with the energy efficiency savings would be 0.5 for the residential and commercial sectors and 0.8 for the industrial sector.[104] The capacity impact is represented by the red bars in the graph above.

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[104] GDS based these load factors on a review of energy efficiency load factor data from on-going programs operated by Wisconsin Focus on Energy, the New York Energy $mart Programs, Efficiency Vermont, and other energy efficiency organizations with active energy efficiency programs.

6. Utility Rate Impact

The direct impact of introducing a significant amount of renewable resources and/or energy efficiency measures into a utility's power portfolio is two-fold: (1) the displacement of some new capacity additions and (2) the displacement of some marginal energy generation from existing units. The cost of new baseload generation estimated in the utilities' IRPs exceeds the filed avoided costs. Therefore, relying solely on utilities' avoided cost filings would not be an appropriate comparison for assessing the incremental cost of a portfolio of new renewable supply options that can potentially displace some new baseload conventional generation. Using avoided cost alone may underestimate the value of new renewable generation and energy efficiency in meeting incremental generation supply needs.

In this analysis, we relied on the State's utilities' generic generation expansion plans as filed in their 2006 Annual Energy Plans or Integrated Resource Plans (IRP). These show the types and sizes of new resources needed over time in a portfolio of conventional fuel technologies. This combined portfolio is referred to as the "Utility Portfolio" in this Report. For each year in the RPS period (2008-2017), we compared the total annual cost of the Utility Portfolio and that of "Alternative RPS Portfolios" with renewables in the mix that would meet 5% and 10% RPS scenarios. The Alternative RPS Portfolios also have conventional technologies in the mix, as necessary, to ensure future capacity and energy needs are met.

A second step in assessing the incremental cost of an RPS is to account for any displacement of marginal generation. Since some renewable generation is not perceived to contribute to firm capacity needs, a portfolio with renewables in the mix that achieves the "capacity" targets of the proposed utilities' generation expansion plans may result in excess (or short) energy produced over (or below) the State's incremental energy needs. For this excess (or short) energy, we assume the avoided cost is equal to marginal energy costs, which would be used to reduce (or increase if short) the incremental cost of the Alternative RPS portfolios.

Incremental costs (the annual difference in costs between the Utility Portfolio and the Alternative RPS Portfolios) were calculated for each year within the study period (2008-2017) to derive the annual rate impact in terms of cents per kWh. Additionally, the total incremental costs were summed and translated to a 10-year net present value (NPV) and 20-year NPV, assuming a 10% discount rate. The latter reflects the long-term commitment of an RPS portfolio as contracts are likely to extend past the ten-year study period of the RPS.

It is important to keep in mind that this study is not meant to be an IRP analysis, but rather to provide indicative economic impacts related to an RPS. Many factors and assumptions can change the total cost calculated, but the impacts presented in the analysis provide good indications of relative costs and the potential magnitude of deviation.

The major conclusions derived from the scenarios are as follows:

- Achieving a 5% RPS without energy efficiency is very possible for North Carolina without exhausting the renewable resources in the State and is likely to have a minimal rate impact.

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- Overall, without energy efficiency, the rate impact by the end of the 10-year time frame of the study is between 0.02 cents/kWh to 0.31 cents/kWh, depending on the RPS target and resources allowed. For a typical residential customer whose monthly consumption is 1,000 kWh, the increase by the tenth year of an RPS is estimated to be $0.20 to $3.10 per month, depending on the RPS target.

- Achieving a 10% RPS without energy efficiency is problematic as numerous off-shore wind projects would need to be built under both the NCGP case (2,300 MW of off-shore needed) and the Expanded Resource case (900 MW of off-shore needed). Without off-shore wind, there are insufficient cost-effective and/or practical on-shore resource options to meet a 10% RPS.

- Depending on the types of renewable resources that are eligible (not including energy efficiency), the total incremental cost of a 5% RPS (in NPV) over 20 years is estimated to be $319 to $727 million, and a 10% RPS would cost $1.6 to $2.7 billion. The costs are not scaleable between a 5% and 10% RPS because higher cost resources must be developed to meet the higher RPS target. Greater access to wind on the western mountain ridges and larger hydro projects (>10 MW) lower the cost of an RPS because lower cost resources can be utilized. However, the development of these resources would need to be weighed against potential objections to their eligibility.

- If 25% of a 5% RPS target is met with energy efficiency, the rate impact would be higher (0.021 cents per kWh) initially, but this resource mix would result in a rate decrease of 0.031 cents per kWh by the end of the study period. The higher initial cost results from the full cost of an efficiency measure being passed through to customers in the year of implementation. Additionally, the rate impact takes into account potential adjustments to rates as a result of utilities' needing to recover fixed costs over less fewer retail energy sales. This effect is seen more readily in the 10% RPS case where greater energy reductions (2.5%) impact the fixed cost portion to a greater degree, and rate increases are 0.045 cents per kWh in 2008 declining to 0.038 cents per kWh in 2017.

- By adding energy efficiency to the list of eligible resources, a 10% RPS can be achieved while saving about $577 million in NPV over 20 years relative to the Utilities' Portfolio.

Sensitivity tests were conducted using the moderate Base Case of a 5% RPS with NCGP eligible resources. This produced a 20-year NPV of $727 million in incremental cost. Co-firing is included in the base case. The major conclusions from the sensitivity tests are as follows:

- The impact of not allowing co-firing is different depending on whether eligible resources are limited by NCGP definitions or expanded to include more wind and hydro. On one hand, if resources were limited by NCGP definitions and wind was barred from development in the western part of the State, co-firing appears to help reduce the overall cost of an RPS. On the other hand, if wind could be developed in abundance in the west, its ability to displace some new baseload coal, unlike co-firing

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(which has no incremental energy or capacity benefit as assumed) would result in minimal impact on rates overall.

- If the production tax credit (PTC) for many renewables is not renewed after the first five years of the RPS, this increases the total incremental cost (20-year NPV) of an RPS by over 40%.

- If solar (photovoltaic) installations receive a multiplier[105] of 3.5, resulting in about 112 MW of solar installations, there is no incremental cost relative to the base case. However, solar installations on this scale would need to coincide with major solar PV manufacturing within the State to optimize economic development and ensure adequate supply. Also, the PV multiplier displaces about 75 MW of new biomass development, which would have made a greater energy contribution to the State, since a multiplier would not have been applied to biomass development.

- If fuel prices (natural gas and coal) remain at recent levels as shown in the "High Fuel Price" case, the incremental cost of an RPS declines somewhat, but does not completely offset the cost of an RPS. Through the sensitivity tests, we found that an RPS can help mitigate some risks related to high fuel prices, but even in our high fuel cost scenario the RPS still carried an added cost.

- If nuclear plants are included in the Utility Portfolio, a 5% RPS can potentially displace an entire unit of nuclear capacity (about 1,100 MW).[106] The resulting incremental cost of an RPS will vary depending on what is assumed to be the cost of a new advanced nuclear facility that renewable resources are displacing. If the total installed cost of a new nuclear plant is $2,000 per kW (2006$), the resulting incremental cost of a 5% RPS is $1.323 billion. If the total installed cost doubles to $4,000 per kW (2006$), the result of a 5% RPS (without energy efficiency) is a $5 million NPV savings. As one can see, the incremental cost of an RPS could depend highly on the actual cost of a new nuclear facility, a cost that could be difficult to predict. Similarly, the cost of new coal plants used in this analysis may also have related uncertainties, as evidenced by recent increases to installation costs in coal plant proposals.

6.1 Utilities' and RPS Portfolios

Utilities' Portfolio

To determine the capacity impact on utilities' expansion plans, we first assembled a portfolio of supply expansions based on the utilities' 2006 Integrated Resource Plans (IRP) (see Table 12 below),[107] which, as noted above, is called the Utilities' Portfolio. Many of the smaller utilities

[105] A multiplier is a factor that provides added incentives to particular resources/technologies where one credit earned is multiplied by the factor.

[106] Like the 5% NCGP Scenario, 500 MW of gas combined-cycle would also be needed as part of the portfolio.

[107] Only Carolina Light and Power and Duke Energy filed expansion plans that described the types and quantities of resources needed.

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did not designate the types of resources they planned to procure or build and some indicated that incremental supply would be met through contracts with the large utilities in the State. As a result, we made the general assumption that these utilities would contract with the larger utilities for their future incremental capacity and energy needs. In other words, they would actually receive a share of the larger utilities' incremental portfolio additions and, thus, the smaller utilities' portfolios of incremental supply mix would resemble that of the IOUs.

Table 12 below represents the Utilities' Portfolio. It shows the capacity and energy needs under the utilities' 2006 IRPs only and does not include any existing utility resources or specifically identified projects. Also, while Duke Energy, in its 2006 IRP, had included nuclear additions of 617 MW in 2016 and another 1,117 MW in 2017, there is uncertainty regarding the feasibility of development of nuclear projects in North Carolina and their associated costs, making this difficult to properly model. Including nuclear plants in the Utilities' Portfolio was reserved for a sensitivity test. Instead, these nuclear units were replaced in the Utilities' Portfolio by baseload coal units with similar capacity and energy output. Based on the capacity needs, the total energy output of the incremental capacity was calculated assuming the following capacity factors: (1) Baseload = 90%; (2) Intermediate = 50%; and (3) Peaker = 5%. These capacity factors imply that new plants, with better efficiencies, are likely to be dispatched more often and may displace some operation of older plants. The total incremental capacity and energy is shown in Table 12 and Figure 16 below.

Table 12: Utilities' Combined Cumulative Portfolio Additions Starting 2008

Combined Cumulative Modeled Portfolio	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Baseload	0	0	0	800	1,600	2,355	2,355	2,355	3,720	4,837
Nuclear	0	0	0	0	0	0	0	0	0	0
Intermediate	0	0	0	0	0	0	0	0	0	0
Peaker	0	480	1,515	2,430	2,745	3,345	3,945	4110	4110	4,110
Energy	**0**	**210**	**664**	**7,391**	**13,856**	**20,032**	**20,295**	**20,367**	**31,129**	**39,939**

**Energy calculated based on assumed capacity factors.*

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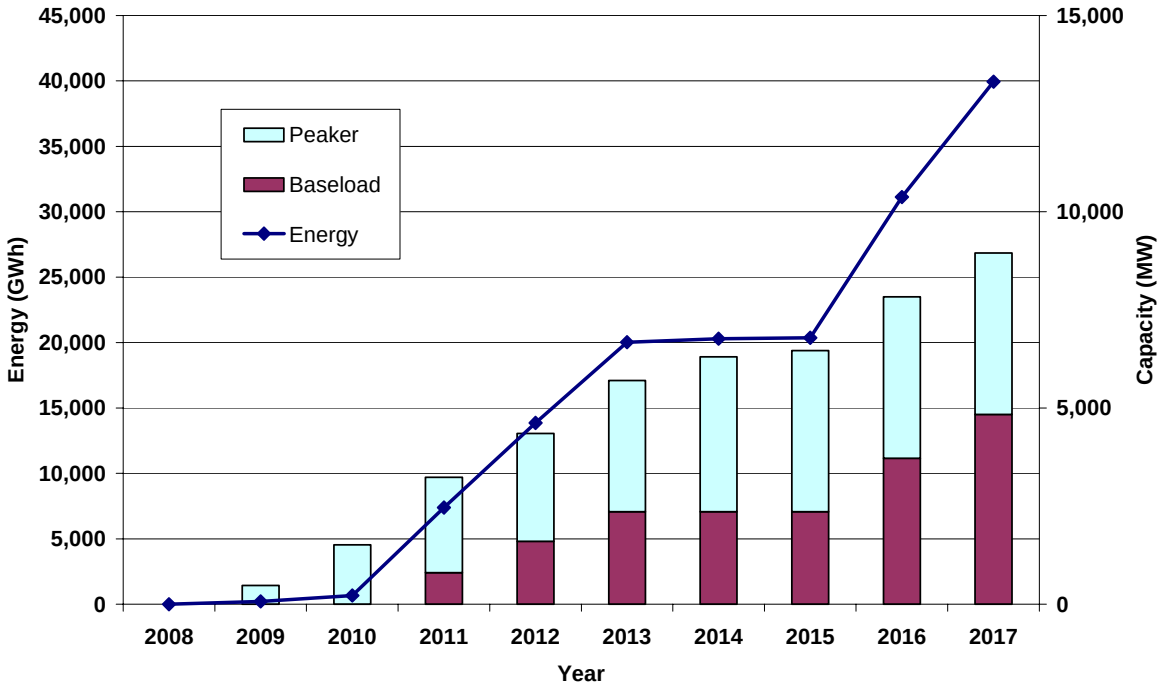
Figure 16

Combined Utilities' Capacity (and Energy) Expansion Plans Beyond 2006



Alternative RPS Portfolios

Next, for each RPS scenario, we developed an Alternative RPS Portfolio that achieved both the capacity and energy needs similar to the Utilities' Portfolio, but included the energy and capacity contributions of the renewable resources modeled. These Alternative RPS Portfolios included changes in conventional resource mixes to meet the capacity and energy targets of the Utilities' Portfolio. It was more important to achieve the capacity requirement as reflected in the Utilities' Portfolio for reliability purposes, while energy needs were often exceeded as many of the renewable resources are normally baseload or as-available generation (see Table 13 below).

It was also assumed that as-available (intermittent) resources, such as wind and hydro, would not contribute to the State's capacity for reliability purposes. However, these resources do provide energy contributions when generating. This is a rather conservative assumption since several studies have demonstrated that there is inherent capacity value to these resources, but there has not been an agreed metric in determining that value.

Additionally, co-firing does not necessarily add incremental capacity or energy to existing coal plants, so the co-firing capacity we modeled also does not contribute to incremental capacity and energy needs of the portfolios. This means that even though co-firing biomass can contribute to the RPS requirement, the energy generated does not necessarily displace the need for new generation, since the fuel is fired in existing facilities. This also implies that no net increase in emissions would result at the existing facilities. Essentially, co-firing with biomass offsets the procurement of coal at existing coal plants; this is reflected in the supply cost calculation already.

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The alternative portfolios presented in this Report are meant to be indicative of potential portfolio outcomes only and do not entail the detailed processes and methodologies used in resource planning or dispatch modeling. The main objective is to produce representative cost differentials between two portfolios that would reflect the assumptions used in each RPS scenario and sensitivity tested.

Table 13: Comparison of Capacity Development in Scenario Portfolios Ending 2017

		5% by 2017			10% by 2017		
Capacity Additions (MW)	Utilities Portfolio	I. NCGP	II. Expanded	III. Expanded Plus	I. NCGP	II. Expanded	III. Expanded Plus
Baseload	4,838	3,750	3,750	3,750	3,000	3,000	3,000
Intermediate	0	500	500	500	0	0	0
Peaking	4,110	4,050	4,350	4,050	4,950	4,950	4,200
Renewables (Firm)		699	383	208	1,020	1,020	826
Renewables (Other)		866	1,689	1,389	3,201	3,104	2,034
Energy Efficiency				458			917
Change in Conventional Capacity Relative to Utilities' Portfolio							
Baseload		(-1,088)	(-1,088)	(-1,088)	(-1,838)	(-1,838)	(-1,838)
Intermediate		500	500	500	0	0	0
Peaking		(-60)	240	(-60)	840	840	90

From the scenario tests, a 5% RPS can potentially displace close to 1,100 MW of baseload generation, but 500 MW of additional combined-cycle generation would be needed to meet remaining capacity and energy needs. Combined-cycle units serve as intermediate units, meaning they operate when demand (load) exceeds the level that baseload units can provide, but would not run continuously. Natural gas combined-cycle generation has lower installed cost than a coal unit, but fuel costs are tied to a more volatile fuel market, so variable costs are typically higher than coal plants. In an IRP context, combined-cycle units may not be a least-cost resource.

Depending on whether the RPS eligible resources are NCGP-approved resources or part of the Expanded Resources Case, additional peaking generation may be needed when large amounts of wind are added to the system. For example, in the 5% NCGP Scenario, wind is limited to development along the eastern part of the State so a total of 500 MW is assumed to be built by the end of the study period. If wind development is allowed on ridge tops in the west as in the Expanded Resources Case, another 600 MW of wind may be developed to meet the 5% RPS. This additional wind development displaces more costly new biomass facilities that are built in the NCGP Case, but requires additional peaking generation to ensure sufficient capacity is available. Also, large hydro (>10 MW) projects are developed in the Expanded Resources Case.

For a 10% RPS target, over 1,800 MW of baseload generation can potentially be displaced, but about 840 MW of additional combustion turbines (peaking generation) would be needed to back-up a large amount (2,715 to 2,825 MW) of wind and hydro generation (see Figure 17 below).

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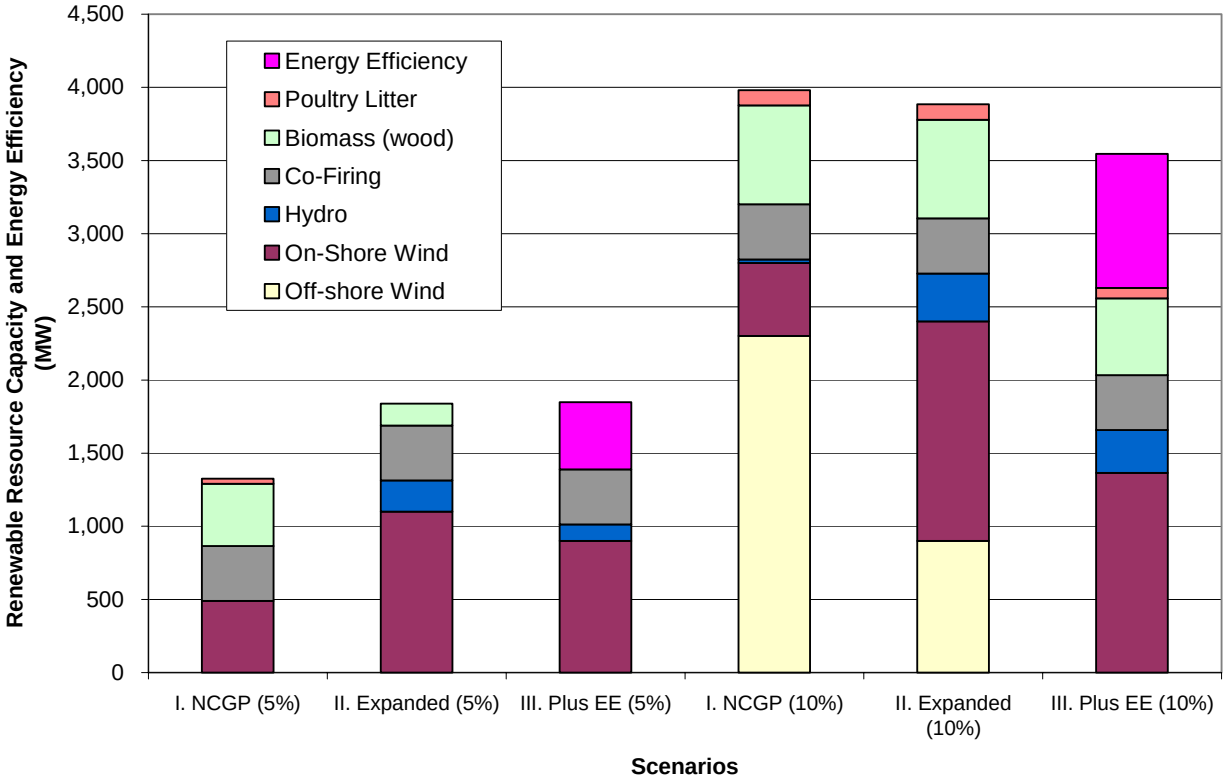
These resources are assumed to be non-firm and not contributing to capacity requirements in the State.

To meet a 10% RPS, all the practical land-based resources are utilized in both resource cases, so off-shore wind will be needed to fill in the remainder of the requirements. A 10% RPS target is likely impractical if 900 to 2,300 MW of off-shore wind would need to be developed. Given the current barriers to off-shore wind development, this magnitude of development is unlikely to occur in North Carolina. In other words, if the State opposed the development of off-shore wind projects, a 10% RPS is likely not achievable, unless energy efficiency is in the mix. Furthermore, development of wind on such a large scale would require transmission investments along transmission "trunks" to bring wind energy from remote regions to serve load. The cost of such transmission is not included in this study because it requires a thorough analysis of the utilities' existing transmission systems and the associated costs are highly site specific.

If energy efficiency is included in an RPS to meet 25% of the targets, off-shore wind projects would not need to be developed, as long as the Expanded Resource definition is applied. Additionally, on-shore resources would not need to be completely developed, putting less pressure on supply costs.

Figure 17

Resource Mix (after 10 years) for Scenarios Tested



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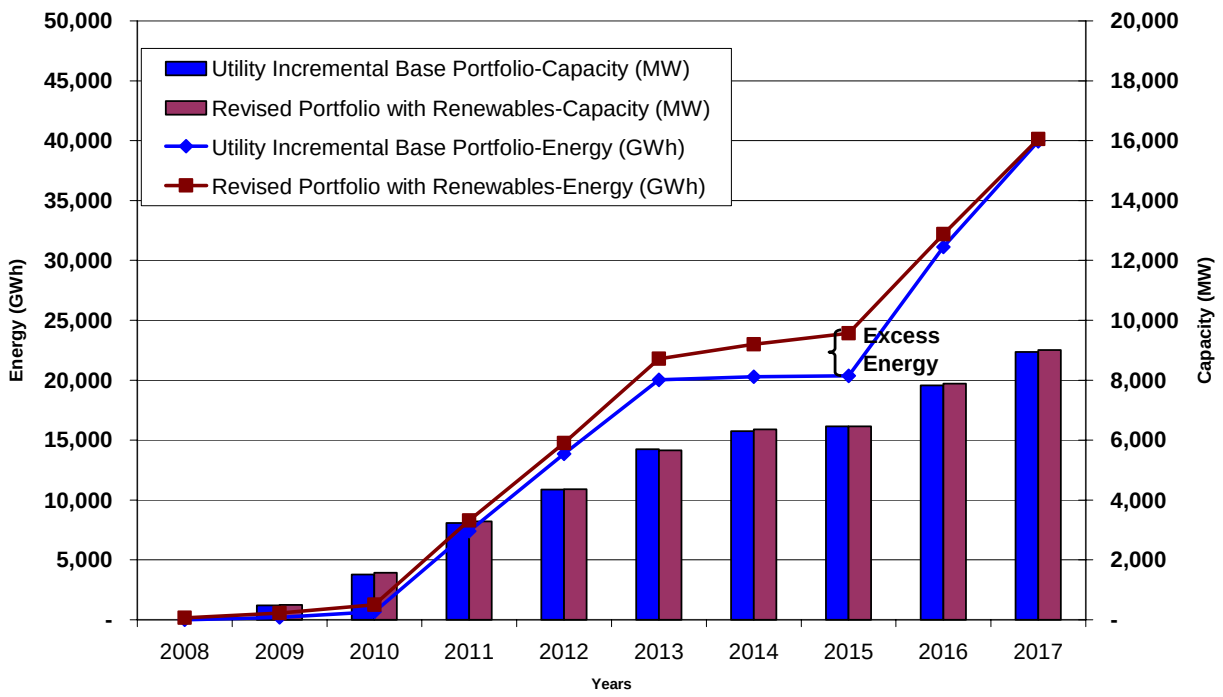
6.2 North Carolina's Marginal Avoided Energy Costs

As mentioned previously, even though some of the renewable generation for the RPS does not provide capacity value, energy may be produced in excess of the State's incremental energy needs (see example below in which excess energy offset some of the marginal generation in the conventional generation). Any of the excess energy that is generated as a result of the alternate portfolio is assumed to reduce generation from existing resources, similar to today's avoided cost calculation. For this excess (or short) energy, the avoided cost is assumed to equal marginal energy costs (without capacity value); this would be used to reduce the incremental cost of a renewables portfolio.

Figure 18

Example of Portfolio Comparison of Capacity and Energy Needs for North Carolina



The calculation of marginal cost resembles that of the utilities' filed avoided costs based on fuel prices assumed for conventional resources. In the graph below, both the Base and High Fuel prices are shown. The total avoided energy costs below do not include capacity value. They represent energy only.

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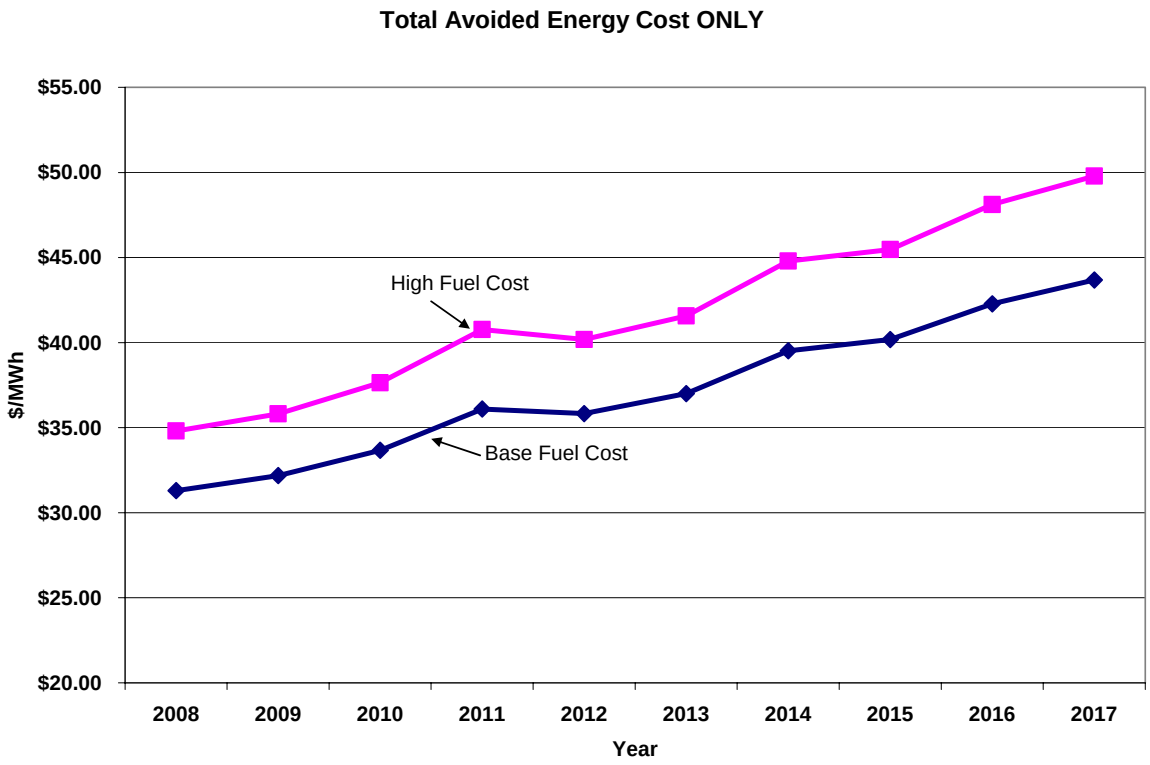
Figure 19



6.3 Combined Rate Impact for RPS Scenarios

The annual incremental rate impacts (cents/kWh) for the six scenarios are presented below; we derived these by dividing annual incremental costs by the expected total retail energy sales in the State for each year. RPS supply cost impacts increase over time as a result of both the increase in annual requirements and the higher cost resources being utilized in later years. However, the inclusion of energy efficiency programs produces slightly higher rate impacts in the beginning of an RPS and lower impacts thereafter. Based on each utility's current retail rates, the percentage impact would vary from utility to utility. Also, the long-term rate impact after 2017 would be similar to the levels shown in the final year of the RPS, assuming no additional renewable projects are built.

The actual year-by-year costs and rate impacts will depend on the types of resources that respond to the RPS each year, the level of competition among resource providers, and the degree of technology cost reductions over time.

It is important to point out here that the rate impact calculated in the scenarios with energy efficiency also takes into account two consequences that the reduction in total retail sales has on rates: (1) the denominator used to calculate incremental rate impact, the forecasted annual retail electric sales, is reduced, and (2) the fixed cost portion of retail rates would still need to be recovered despite a reduction in demand. The analysis assumes that the fixed cost portion of rates is approximately 5 cents per kWh. Therefore, while total portfolio costs and energy demand may be lower, there may still be rate increases per kWh.

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Figure 20

Annual Rate Impact of 5% RPS Scenarios

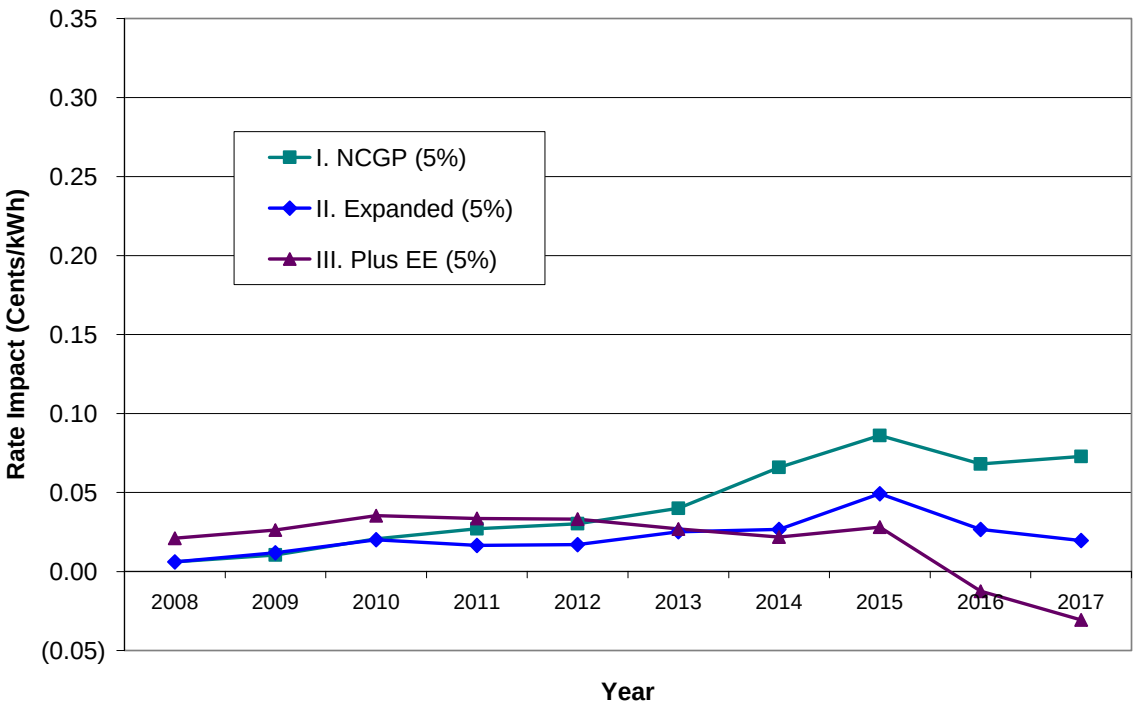
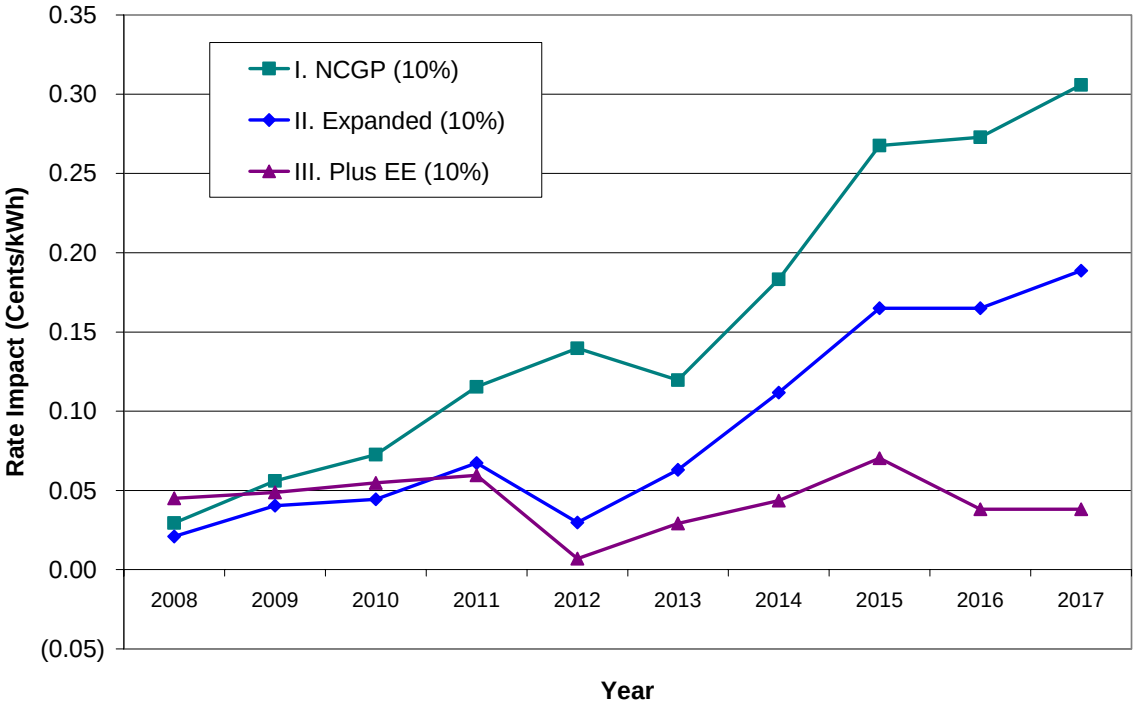


Figure 21

Annual Rate Impact of 10% RPS Scenarios



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We also present the total 10- and 20-year NPV impact for each of the scenarios, since much of renewable contract costs are incurred after the ten-year RPS ramp-up period. (Detailed annual costs can be found in Appendix F.) The assumed discount rate is 10%.

Table 14: Total Incremental Cost Over 10 Years in NPV

		10-year NPV ($million)		
RPS Scenario	**Resources**	**Utility Portfolio**	**Alternate Portfolio**	**Net Incremental Cost (with Marginal Energy)**
5% by 2017	I. NCGP	$7,028	$7,646	**$375**
	II. Expanded		$7,484	**$204**
	III. Plus Energy Efficiency		$7,024	**($95)**
10% by 2017	I. NCGP		$8,983	**$1,381**
	II. Expanded		$8,281	**$787**
	III. Plus Energy Efficiency		$6,973	**($177)**

Table 15: Total Incremental Cost Over 20 Years in NPV

		20-year NPV ($million)		
RPS Scenario	**Resources**	**Utility Portfolio**	**Alternate Portfolio**	**Net Incremental Cost (with Marginal Energy)**
5% by 2017	I. NCGP	$15,051	$16,036	**$727**
	II. Expanded		$15,653	**$319**
	III. Plus Energy Efficiency		$14,837	**($476)**
10% by 2017	I. NCGP		$18,492	**$2,691**
	II. Expanded		$17,286	**$1,597**
	III. Plus Energy Efficiency		$15,041	**($577)**

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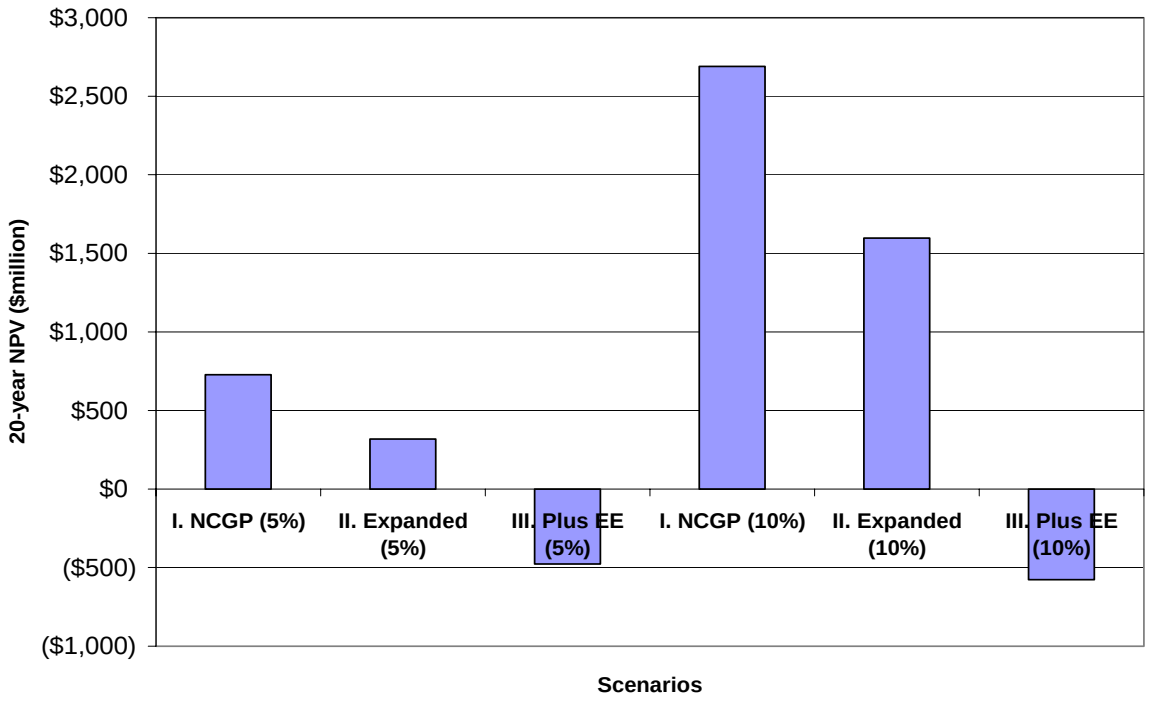
Figure 22

Total Cost for RPS Scenarios



6.4 Sensitivities

Along with the scenarios tested above, the Advisory Group was also interested in the impact of different sensitivities. We selected the 5% RPS with NCGP resources as the Base Case with which to test sensitivities. The graph below shows the change in 20-year NPV relative to the 20-year NPV of the Base Case (a $727 million increase) for each of the sensitivities. For example, if the PTC is not renewed after the first five years of the RPS, this increases the cost by $308 million over the Base Case (producing a total increase of $1.035 billion).

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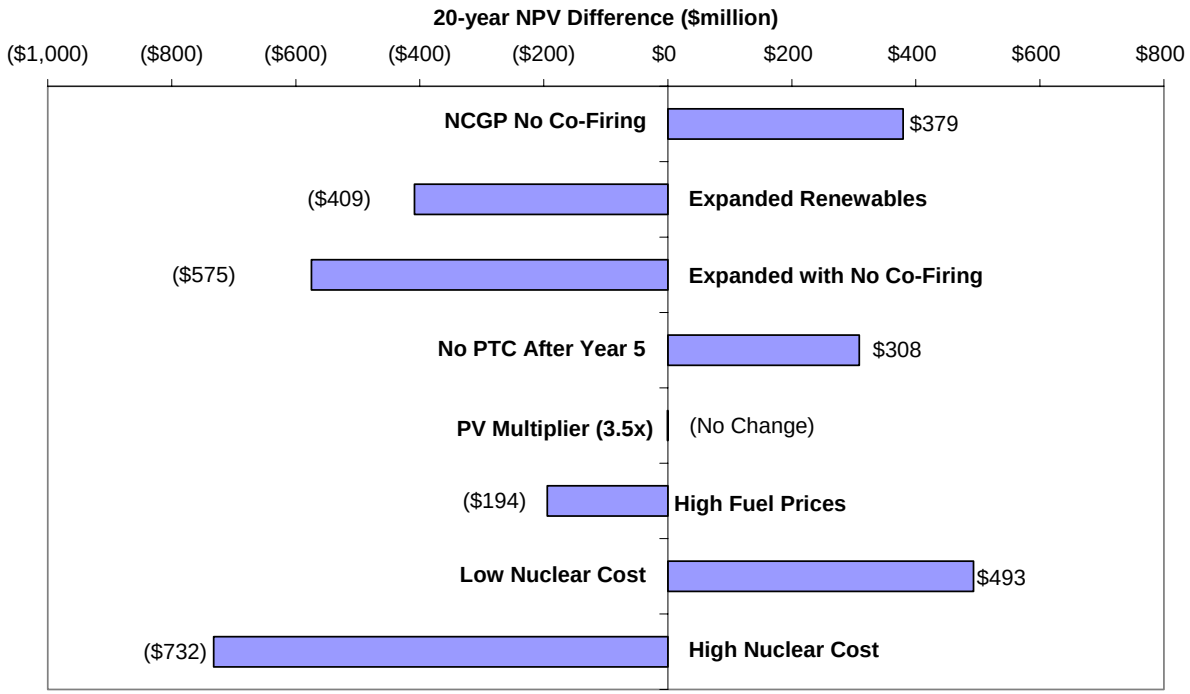
Figure 23

20-yr NPV Differential of Sensitivities and Reference Case
(5% NCGP 20-yr NPV $727 million)



The sensitivities tested include the following:

- **No Co-firing:** Since co-firing does not contribute to incremental capacity or energy needs, we tested the exclusion of co-firing from both the NCGP and Expanded Resource Cases.

- **PTC Expiration:** In the scenarios, the PTC was assumed to continue for new facilities throughout the 10-year RPS study period. However, the renewal of the PTC is uncertain, so we tested a case in which the PTC is not renewed after the first five years of the RPS.

- **PV Multiplier:** Solar photovoltaic technologies are not directly competitive with other renewable energy options for per unit of energy generated, but there are additional benefits of promoting PV installations that can justify the use of a multiplier for PV resources. A multiplier means that for each unit of energy purchased from a particular resource, its contribution to meeting an RPS is, in this case, 3.5 times that of other resources.

- **High Fuel:** There is great uncertainty around the future cost of fossil fuels. The Base Case assumed a moderate view of future fuel costs for North Carolina utilities with coal at $2.75/mmbtu (2006$) and natural gas at $8.00/mmbtu (2006$), both increasing with an assumed inflation of 2.5%. However, as the past few years have demonstrated, fuel costs have been on the rise at a rate greater than inflation. There is

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a risk that fuel costs may continue into the future at prices resembling recent highs of $3.25/mmbtu (coal) and $10.00/mmbtu (natural gas). This sensitivity reflects those higher prices and renewables' role as a hedge against some fuel price increases.

- **High and Low Cost Nuclear:** While Duke Energy, in its 2006 IRP, had included nuclear additions of 617 MW in 2016 and another 1,117 MW in 2017, the controversy regarding the feasibility of development of nuclear projects in North Carolina and associated nuclear costs are on-going and, thus, difficult to properly model. In this sensitivity, we compare the relative impact of an RPS, dependent on the assumed cost of a nuclear plant in 2006$, whether it is the average estimated cost for hypothetical nuclear projects ($2,000/kW) or potentially double that due to cost overruns ($4,000/kW). The displaced unit is a 1,117 MW unit in 2017, the last year of the RPS study period, but 750 MW of natural gas combined-cycle (intermediate generation) would be needed to make-up any energy and capacity shortfalls.

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7. Non-Energy Related Benefits

Aside from examining rate impacts to the State, this Report also considers other benefits related to an RPS. The primary areas of focus include:

- State economic development and impact.
- Environmental impact.
- Portfolio diversification benefits.

7.1 State Economic Impact Analysis

The economic impact of an RPS on a state's economy is two-fold. On one hand, as presented in the previous section, there are potential increases to electricity rates for end-users associated with having an RPS, which may have some negative economic impact in the form of reduced electric demand and some job reductions as a result of higher cost of living. On the other hand, jobs related to construction, installation, and operations of renewable energy generation may increase the amount of jobs available since several studies have concluded that the in-state job benefits resulting from renewables development are greater per MW than for conventional generation.

There are two primary sources of job creation in-state. Typically, the construction, operations and maintenance related to smaller projects are higher for each unit of energy generated relative to larger conventional resources. Secondly, for renewable projects that require fuel inputs, the fuel is locally sourced rather than imported from out-of-state. Therefore, the economic benefit remains primarily within the state.

For this analysis, we assessed the economic impact from increased electricity rates and the net positive impact through job creation and local fuel sourcing for North Carolina as a result of the development of renewable energy facilities and the implementation of energy efficiency programs. IMPLAN, an input-output economic model, was used to assess the economic impacts of renewable energy development in the State of North Carolina.[108] (For additional discussion of IMPLAN, see Appendix H.) Similar to the cost impact analysis, we examined the net change in economic and job impacts as a comparison between a Utilities' Portfolio and Alternate RPS Portfolios. Though results are shown for the six scenarios and some of the sensitivity analyses, the focus in this section is on two scenarios: (1) a 5% RPS with NCGP resources; and (2) a 10% RPS with Expanded Resources Plus Energy Efficiency.

[108] The USDA Forest Service in the mid-70s developed IMPLAN for community impact analysis. The current IMPLAN input-output database and model is maintained and sold by MIG, Inc. (Minnesota IMPLAN Group). Over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis. GDS Associates, a subcontractor to La Capra Associates for this study, is a registered and licensed user of the IMPLAN model.

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In general, the results indicate the following:

- The increase in rates due to an RPS has minimal impact on electricity demand, since the elasticity of demand was found to be negative 0.01 (for every 1 percent increase in electricity rates, there is a 0.01 percent decline in demand).

- For the 5% NCGP Scenario, job losses due to rate increases totaled about 16,000 job-years which is offset by an increase of renewables-related jobs of about 38,000 job-years. The total net increase is 22,000 job-years over 20 years and takes into account the displacement of some new coal and combustion-turbine generation. The net increase is primarily attributed to sourcing biomass fuel from within the State.

- For the 10% Expanded Resources Plus Energy Efficiency case, rate increases are balanced by decreases in total demand; thus, total energy expenditures do not necessarily increase. Therefore, we assumed that there are no job losses associated with rate increases. The net increase of RPS related jobs, including energy efficiency jobs, total 54,000 job-years over 20 years, or an annual average of about 2,700. Again, the net increase is primarily due to sourcing biomass fuel from within the State and installation/administration of energy efficiency measures.

- Solar PV and anaerobic digesters create the most jobs per MW because of the relatively small size of each installation and the larger portion of the installation cost attributable to labor.

- Biomass wood generation and co-firing create the next most jobs, primarily from sourcing biomass fuel from within North Carolina.

- Wind and hydro generation do not provide as many jobs per MW of capacity as other renewable resources because they do not require a fuel input and have much lower capacity factors than other baseload resources. However, if the capacity factor of the resources were taken into account, the job impact per equivalent MW would be about three times higher for wind and two times higher for hydro.

Economic Impact of Rate Increases

To assess the economic impact of increases in the price of electricity due to the implementation of a Renewable Portfolio Standard in North Carolina, we used the following analytical procedure:

- Using the cost impact analysis derived previously, we adjusted the base case forecast of the demand for electricity to reflect impacts due to electricity price elasticity.

- The long term electricity price elasticity for North Carolina used in this study was determined by the North Carolina Department of Commerce using the Regional Economic Models Inc (REMI) economic model. The long-term electricity price elasticity is estimated to be negative 0.01 (for a one percent increase in the price of electricity, overall consumption of electricity in North Carolina declines by 0.01 percent).

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- In the residential sector, higher electricity prices cause electric bills to be higher, and, thus, disposable household personal income to be lower. Based on the long term electricity price elasticity for North Carolina, the increase in expenditures for electricity, the decrease in electricity sales, and the decrease in disposable household personal income were calculated. The decreased personal income was then entered into the IMPLAN model to determine jobs lost due to less spending in the local economy.

- In the business sector, higher electricity prices may result in several behaviors from businesses. With the price elasticity being relatively low, businesses are not very sensitive to small changes in electricity prices, so a change in direct demand for electricity would be less likely. Instead, we assumed that businesses would pay the higher prices and have less money to spend on other goods and services. The additional cost of electricity was entered into the IMPLAN model to determine the number of indirect jobs lost through less spending on other products by businesses.

- Given that energy efficiency reduces overall cost of an RPS and the increase in rates as observed previously are offset by a decrease in total energy demand, it is assumed that there is no job reduction as a result of rate increases from the RPS scenarios with energy efficiency.

The estimated net increases in retail price of electricity due to the various RPS portfolios tested are displayed in Table 16. The job-years impacts assumed these price increases over a twenty-year horizon. The losses are estimated based on reduced personal disposable income for households and less income to spend on other goods and services for business and local government. IMPLAN's databases included personal consumption patterns that were used to estimate the job-years lost due to price increase.

Table 16: Job-Years Lost Through Price Impacts of RPS Over 20 Years

Portfolio	Long-Term Price Increase (2006 ¢/kWh)	Household Income Impacts	Business and Government Impacts	Total Job-Years* Lost
5% NCGP	**0.056¢**	**4,254**	**11,924**	**16,178**
5% Expanded	0.015¢	1,144	3,214	4,358
5% With EE	0.000¢	0	0	0
10% NCGP	0.237¢	17,866	50,080	67,946
10% Expanded	0.146¢	11,022	30,898	41,920
10% With EE	**0.000¢**	**0**	**0**	**0**
* 1 person working for twenty years equates to twenty job-years				

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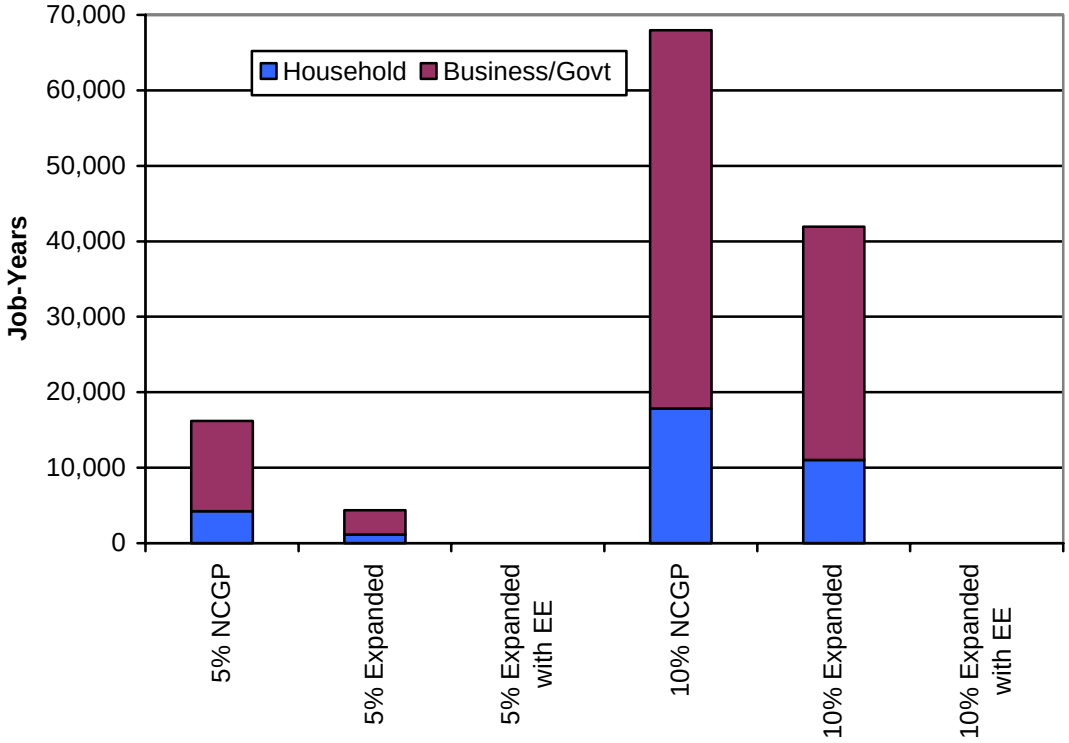
Figure 24
Job-Years Lost From Price Impacts



Job Creation and Multiplier Effect

The IMPLAN model was utilized to measure job impacts in two ways: 1) the average expected jobs per MW produced by construction and operation (O&M) of various resources; and 2) the net job impact of the RPS Alternative Portfolios versus the conventional Utilities' Portfolio. The first output provides comparative job impacts between resources. The latter demonstrates the effective net gain or loss of jobs due to implementation of the RPS in lieu of a conventional resource portfolio.

Development of the IMPLAN model inputs required two primary tasks: 1) development of total construction, operating and maintenance and fuel costs for each resource; and 2) determination of the amount of these costs that would be spent in North Carolina. Total construction costs are based on assumptions of installed cost per kW by resource, as presented previously. O&M and fuel costs are based on assumed capacity factors, heat rates, and fixed and variable costs per unit. All of these input assumptions were developed outside of the IMPLAN model. For this analysis, it has been assumed that only the labor portion of construction and O&M for each of the resources would impact the North Carolina economy, but material and supplies and other capital expenditures would be made outside of the State and would therefore not impact the local economy. *This is likely a conservative assumption, but it was not possible to properly estimate how non-labor costs would be distributed within or outside the State, given the construct of the IMPLAN model.*

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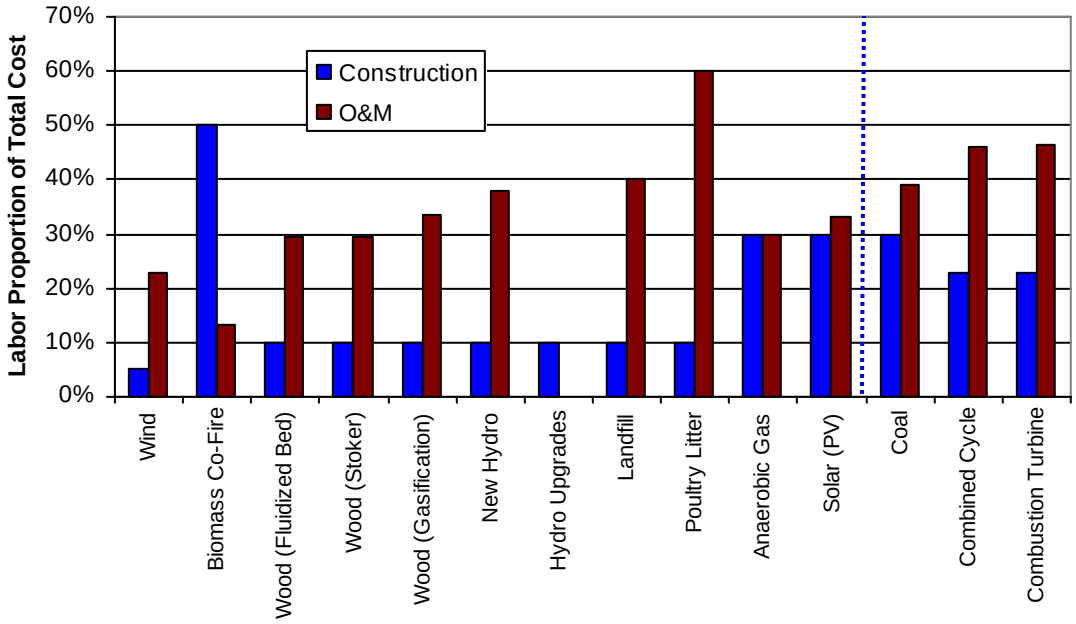
The assumed portion of capital and O&M costs that are directly related to labor are provided in the figure below.

Figure 25
Assumed Labor Portion of Costs by Resource Type



Since the IMPLAN database does not have customized sectors for renewable energy generation, general assumptions were made regarding construction and O&M jobs. However, harvesting and transporting woody fuels would impact the forestry sector as a whole.

- All construction labor spending associated with any of the generation technologies were assumed to impact the "Other Construction" sector.
- O&M labor spending for most generation technologies was assumed to impact the "Power Generation and Supply Sector," with the exception that anaerobic digester O&M at hog farms would likely impact the "Animal Production" sector instead.
- Fuel input costs for biomass co-firing and biomass wood resources would directly contribute to the North Carolina's economy as a result of a strong logging industry presence and the assumption that biomass resources would be sourced from within the State. Therefore, much of the biomass fuel expenditures were assumed to benefit the "Logging and Forestry Sector." Ten percent of the cost of biomass fuels, representing diesel fuel used in hauling and transporting the biomass, was assumed to be leakage.[109]
- Another fuel source, poultry litter, can also be sourced completely from in-state poultry farms, but the jobs created through transportation of the resource to potential

[109] Leakages are payments made for imported goods or to sectors which do not in turn re-spend the dollars within the state. Leaked dollars therefore can have no impact on the local economy.

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biomass plants would likely offset existing jobs related to waste management and field application of poultry litter (see Appendix E). Therefore, transportation of poultry litter fuel was assumed to have no net impact on the State economy and jobs.

- Fuel costs associated with conventional fossil fuel resources are assumed to have no impact on the State as coal and natural gas would need to be imported and there is no in-state extraction activity of these fuels. It was assumed that the transportation of conventional fuels within the State would not contribute to the local economy in terms of jobs, since the payments for delivery of conventional fuels are often paid to entities outside of North Carolina.

- Labor associated with the administration of an energy efficiency program was assigned to the "Power Generation and Supply Sector."

- 50% of the equipment costs related to an energy efficiency program was assumed to impact the "Wholesale Trade" sector. The remaining 50% of costs was assumed to impact the "Building Material and Garden Supply Stores" retail sector.

The IMPLAN model then estimated the jobs created within each sector in three ways. The direct jobs are those jobs created for the impacted industry. Indirect jobs are estimated using state-specific multipliers to estimate the impact on other sectors by the increase in direct jobs. Finally, induced jobs are those jobs generated by the fact that local households have more disposable income available for personal consumption due to increased economic activity.

The IMPLAN model provides job impacts for a single expenditure in a single year. The ratio of indirect and induced jobs to direct jobs varies by the industry impacted as shown below. Table 17 shows the relationship between direct and indirect plus induced jobs for the various sectors used in this impact analysis. The first three sectors (Other New Construction, Power Generation & Supply, and Animal Production) show impacts of labor-related costs only, so the indirect jobs effect tend to be lower. In other words, the direct industry's use of money to purchase goods and services are assumed not to have indirect impact on jobs. The Logging and Forestry Sector has greater impact on indirect and induced jobs because much of the fuel expenditures for biomass contribute directly to the Sector as a whole, not just for labor-related costs. The Wholesale Trade and Building Material and Garden Supply Store sectors include indirect and induced effects because energy efficiency equipment is being purchased from those sectors, therefore impacts are not exclusively related to labor.

Table 17: Relationship of Direct Jobs to Indirect and Induced Jobs by Industrial Sector

Sector	Direct Jobs	Indirect & Induced Jobs
Other New Construction	1	0.28
Power Generation & Supply	1	0.81
Animal Production Excl Cattle & Poultry	1	0.31
Logging & Forestry	1	1.10
Wholesale Trade	1	0.36
Building Material & Garden Supply Stores	1	0.71
Interpretation: For every direct labor job created in the Other New Construction sector, 0.28 additional jobs are created through indirect and induced means		

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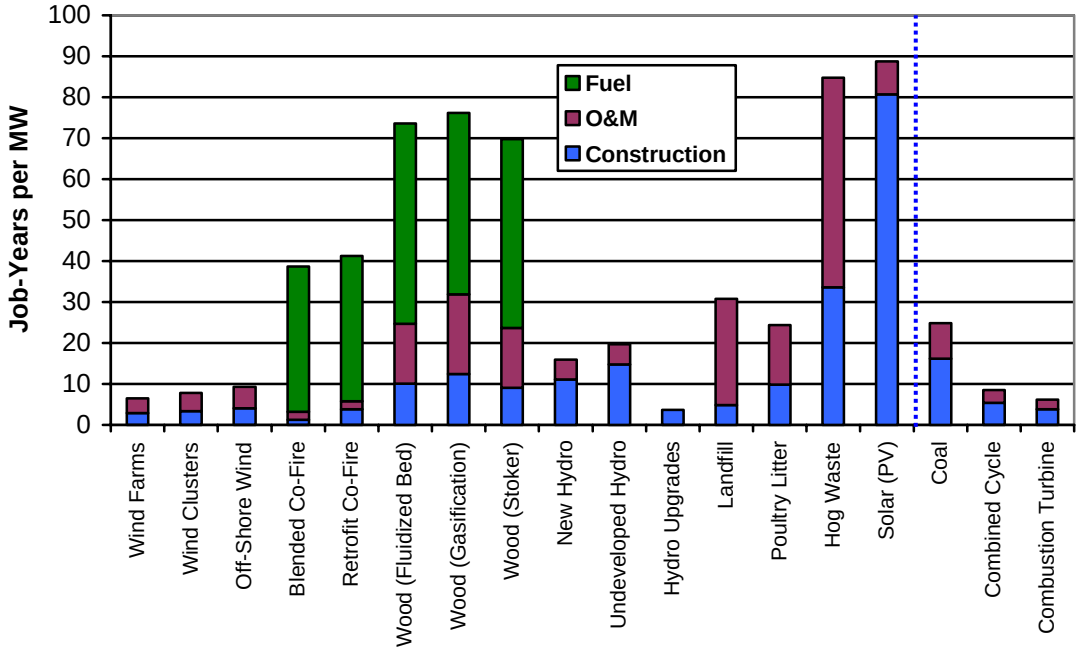
Since lead times on construction vary by generation technology, we converted the jobs from IMPLAN output into job-years to facilitate comparison. For example, one person working for one year represents one job-year and one person working for twenty years represents twenty job-years. For the construction estimates, the jobs provided by IMPLAN are in job-years, since total construction costs are input into the software. For ongoing O&M and fuel costs, we assumed twenty years of operations *after completion of construction* to measure job impacts over time. Therefore, single year jobs output by IMPLAN were multiplied by twenty to convert O&M and fuel related jobs to job-years. The results in job-years per MW by resource are provided in Figure 26, assuming a twenty-year operations horizon for O&M and fuel. The job-years impact from operations would be greater if the years of operation were extended, and less if the years were shortened.

Figure 26
Job-Years per MW by Resource Type



From these individual resource assessments, we can conclude the following:

- Solar PV and anaerobic digesters create the most jobs per MW because of the relatively small size of each installation and the larger portion of the installation cost is attributable to labor.
- Biomass wood generation and co-firing create the next most jobs, primarily from sourcing fuel from within the State.
- Wind and hydro generation do not provide as many jobs per MW as other renewable resources because they do not require a fuel input and have much lower capacity factor than other baseload resources. However, if the capacity factor of the resources

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were taken into account, the job impact per equivalent MW would be more significant for wind and hydro resources (see Appendix E for more detail).

- Coal generation actually creates more construction job-years per MW than most other generation technologies (except for solar PV and anaerobic digesters) primarily because the construction time frame for coal generation is 4-5 years compared to much shorter construction lead times for renewables. For example, wind projects take 6-9 months, landfill gas take 3-4 months, and even greenfield biomass projects are expected to take about 2-2.5 years.

To assess the overall impact of an RPS, the jobs generated by the RPS portfolio were compared to the jobs generated by the Utilities' Portfolio. The total job impacts were estimated for the mix of resources from the RPS Alternative Portfolios using the methodology described above for individual resources. Furthermore, due to the net increase in electricity prices from the RPS scenarios, some loss of jobs was included, as described in the previous section.

The figure below shows the net increase in job-years related to renewable generation for the 5% NCGP Portfolio, a net decrease in job-years related to displacement of coal and combustion turbines (plus addition of combined-cycle units), job-years lost due to rate impact, and finally the net change of the combined impacts. The 5% NCGP RPS produces a net gain for the North Carolina economy of about 22,000 job-years over a twenty-year operating time frame or, on average, about 1,100 jobs per year. The 5% NCGP portfolio job impact comparison is exhibited below.

Figure 27
Net Job Impact in Job-Years for 5% NCGP RPS Portfolio

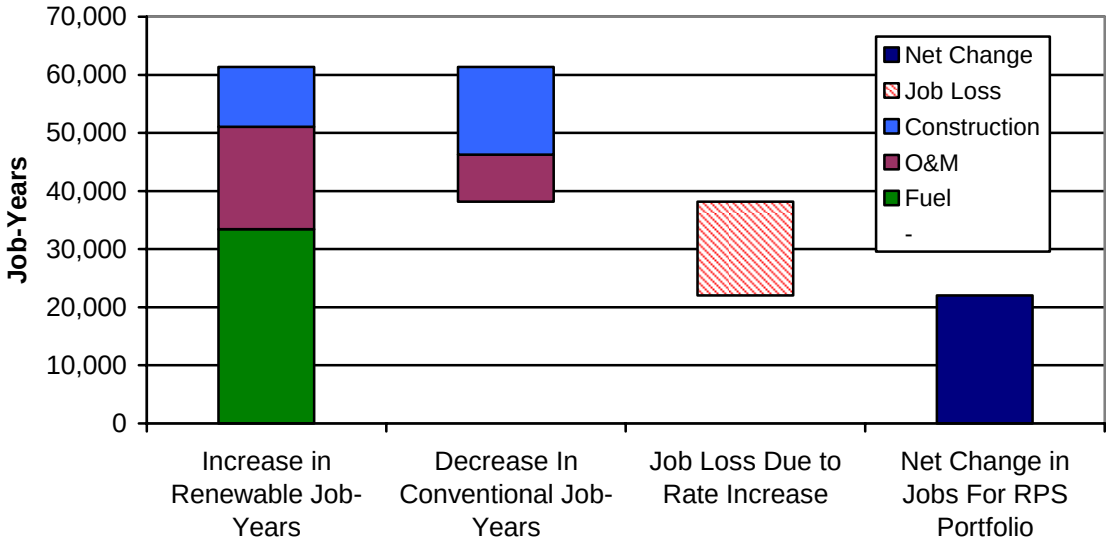

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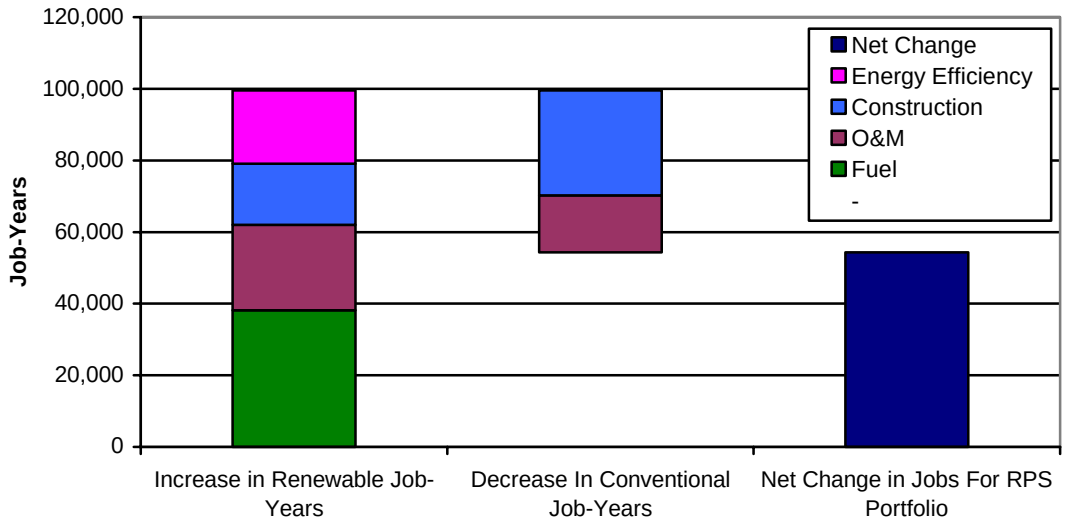
Figure 28
Net Job Impact in Job-Years for 10% Expanded with Energy Efficiency



Since the 10% Expanded Resources Plus Energy Efficiency Scenario (Figure 28) does not have negative job impacts from rates, the total net job impacts is over 54,000 job-years, or over 2,700 jobs annually.

Table 18 and Figure 29 summarize the comparative results for the RPS Alternative Portfolios examined (over a twenty-year horizon). Figure 30 shows results from some of the sensitivities tested.

Table 18: Net Job-Years Gained/(Lost) by RPS Portfolio Compared to Utilities' Portfolio

Portfolio	Renewable Job-Years Added (Including EE)	Conventional Job-Years Replaced	Loss of Jobs Through Rate Increases	Net Gain/(Loss) in Job-Years
5% NCGP	**61,362**	**23,176**	**16,178**	**22,008**
5% Expanded	47,636	21,314	4,358	21,964
5% With EE	53,761	23,176	0	30,585
10% NCGP	102,971	40,507	67,946	(5,482)
10% Expanded	101,264	40,507	41,920	18,837
10% With EE	**99,505**	**45,162**	**0**	**54,343**

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Figure 29
Net Job-Years Gained by Scenario

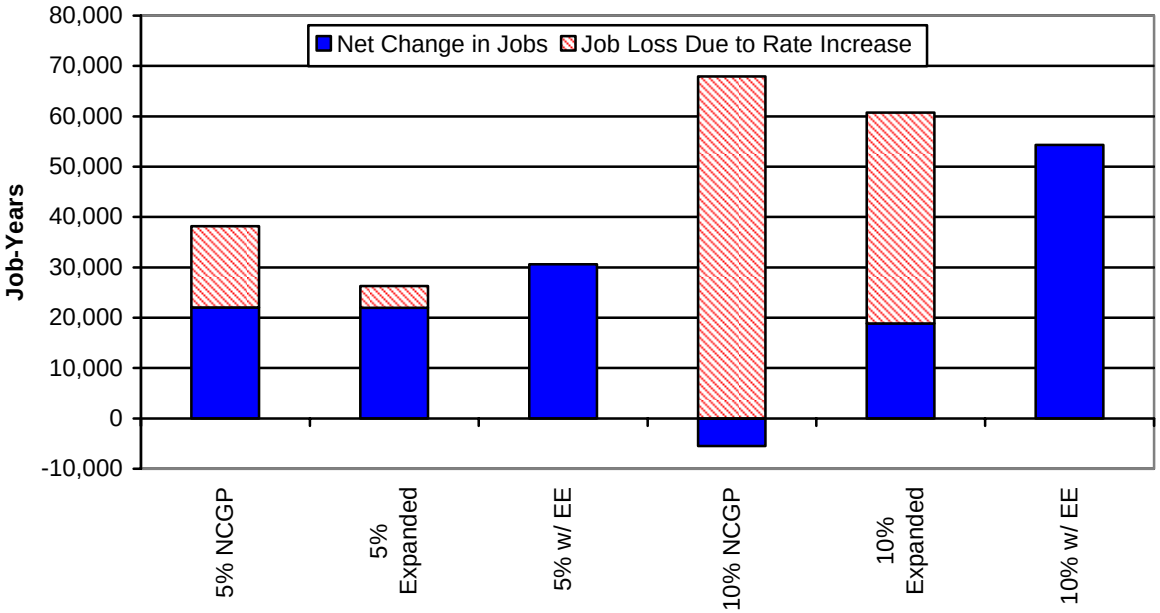
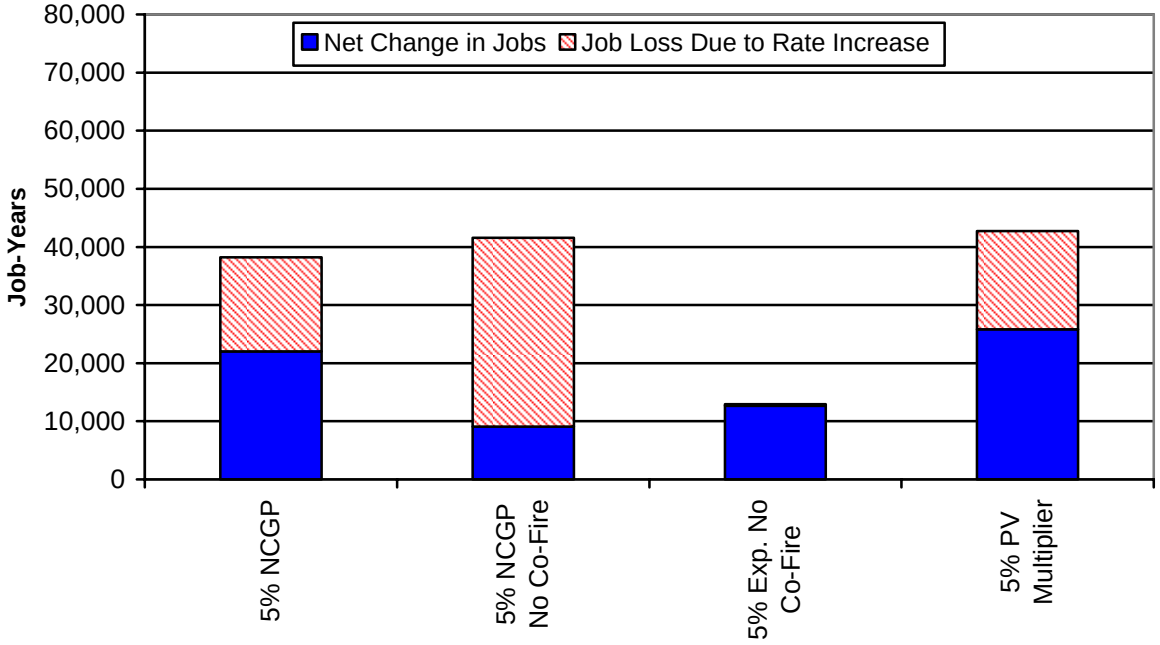


Figure 30
Net Job-Years Gained For Sensitivities



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Other Economic Benefits

Depending on the renewable resource, there are additional economic benefits that are not captured in the IMPLAN model. Local communities should receive increased property tax revenues, as many of the renewable generation resources discussed have higher capital costs per MW associated with capital equipment relative to conventional generation. Additionally, wind projects and landfill gas projects often provide lease payments to local landowners or landfill operators for the use of the sites.

Below is an illustrative comparison that shows property tax revenues for communities are likely to increase as a result of an RPS. The table below shows the potential property tax revenue increase in the first year of installation of both renewable and conventional generation, in Net Present Value. Tax revenues are greater for renewables generally because much of the project costs are related to capital expenditures, so the value of a project used in calculating taxes is greater per MW. Only the first year of tax revenues is shown because depreciation and property tax assessments will vary by county after the first year. These scenarios represent a 6% to 54% increase in potential tax revenues for communities relative to the Utility Portfolio. An added benefit is that renewables development may be more dispersed around the State relative to large generation installations, so more counties can benefit from receiving property tax revenues from renewable energy projects.

The inclusion of energy efficiency programs would, of course, decrease the amount of renewables installed, and thus the property tax revenue benefit is not as great, but still significant.

Table 19: NPV of Property Tax Revenues ($million) for First Year of Installations[110]

RPS Scenarios	Utilities' Portfolio	Alternative Portfolios	Additional First Year of Installation Property Tax Revenues	Percentage Gain Over Utilities' Portfolio
I. NCGP (5%)	$70.1	$78.0	$7.9	11%
II. Expanded (5%)		$82.6	$12.5	18%
III. Plus EE (5%)		$74.5	$4.3	6%
I. NCGP (10%)		$108.2	$38.0	54%
II. Expanded (10%)		$106.4	$36.3	52%
III. Plus EE (10%)		$84.7	$14.6	21%

Finally, the economic impact analysis assumes no in-state manufacturing of any of the renewable technologies within the State. Currently, North Carolina appears to have virtually no renewable technology manufacturers, though there are a few engineering/technology development companies that may benefit from an RPS. If North Carolina can promote itself as a renewables technology manufacturer, as well, the jobs impact can potentially be much greater.

[110] This assumes a tax rate of $1.03 per $100 property value. This is the 2006 arithmetic average of all county/municipal property tax rates in North Carolina. The actual property taxes range between $0.26 and $1.90 per $100 in assessed value. <http://www.dor.state.nc.us/publications/propertyrates.html>

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7.2 Environmental Impact

Environmental impact of renewable energy generation can be examined in relative terms to conventional generation resources since renewable energy generation displaces the need for some conventional generation. The potential benefits or avoided environmental costs can fall into the following categories: air quality, greenhouse gases, water quality, land usage, fuel extraction, and waste generation. Many studies have attempted to quantify, in economic terms, these environmental benefits or "externalities," but reviews of such studies found results that differed by several orders of magnitude.[111] In this discussion, the impact is presented in relative terms only. Below is a matrix contrasting the adverse environmental impacts of conventional technologies and renewables using indicators as follows: none, low, medium, and high. As shown, renewable energy resources have lower overall net environmental impacts than conventional generators and can often help reduce overall emissions for a state. *Including energy efficiency programs will have no adverse impact on the environment since these programs reduce the need for electricity generation, which would have the best environmental result relative to any form of generation.* The table below summarizes the comparison of environmental impact between conventional generation and renewables. Keep in mind that the utilities' portfolios presented in their 2006 IRPs propose additions of coal, gas combustion-turbines, and nuclear facilities.

Table 20: Comparison of Adverse Environmental Impacts

	Air Quality	Greenhouse Gases	Water Usage	Land Usage	Fuel Extraction	Waste Disposal
Conventional Resources						
Coal	Med to High	High	High	Med	High	Low to Med
Natural Gas (CCGT/CT)	Low to Med	Med	Low to Med	Low to Med	Med	Low
Nuclear	None	None	High	High	High	High
Renewable Resources						
Wind	None	None	None	Low to Med	None	None
Hydro	None	None	Med	Med to High	None	None
Solar	None	None	None	None to Med	None	None
Biomass (wood)	Med	None (neutral)	Low to Med	Low to Med	Low	Low (fertilizer)
Biomass (poultry litter)	Med	None (neutral)	Low to Med	Low to Med	Low	Low (fertilizer)
Landfill Gas	Med	None (net positive)	None	None	None	None
Anaerobic Digester	Med	None (net positive)	None	Low	None	None (positive net)
Energy Efficiency	None	None	None	None	None	None

[111] "Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard," Rutgers University, 2004.

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Air Quality

By introducing 5% to 10% RPS targets, the State may be able to avoid certain amounts of emissions that would have resulted from conventional fossil-fuel plants' generation. Reduction of such emission may help the State address issues related to regional haze, ozone, toxicity and health affects. The role of renewables in this regulatory environment is to both help a state meet the lower targets overall and to displace generation that would otherwise contribute to additional emissions.

Existing Regulations

Several federal and state regulatory standards require emissions reductions. To start, the EPA sets national air quality standards for the following criteria pollutants:[112] ozone, sulfur dioxide (SO_2), carbon monoxide (CO), nitrogen oxides (NO_x), particulate matter (PM), and lead. Recently issued CAIR[113] rules would significantly reduce sulfur dioxide and nitrogen oxide,[114] major contributors to ozone and regional haze caused by particulate matter (PM), which are major issues in non-attainment zones in North Carolina. Recently, the federal government also issued the Clean Air Mercury Rule[115] that would require a 70% reduction of mercury emission, considered a toxic gas, from electric plants.

In June 2002, the North Carolina General Assembly enacted the **Clean Smokestacks Act**, officially titled the Air Quality/Electric Utilities Bill (SB 1078), requiring significant emissions reductions from coal-fired power plants in the state. Under the act, power plants must reduce their NO_x emissions by 77 percent by 2009 and their SO_2 emissions by 73 percent by 2013. Under the legislation, power companies must reduce their NO_x emissions year-round, not just during the ozone season in the warmer months, as under federal requirements. Each utility must file an emissions reduction plan that involves the installation of emissions controls within the required time frame.

An important feature of the Clean Smokestacks Act is that North Carolina's two largest electric utilities, Duke Power Co. and Progress Energy Corp. (formerly known as Carolina Power & Light), must achieve these emissions cuts through actual reductions at their 14 power plants in the State – not by buying or trading emissions credits from utilities in other states, as allowed under federal regulations. The utilities also cannot sell credits for their emissions cuts, ensuring that utilities in neighboring states don't negate the gains achieved in North Carolina by purchasing the rights to increase or to avoid controlling their own emissions. An agreement between stakeholders to allow the passage of the Act resulted from negotiations that would freeze electric rates for five years while allowing utilities to accelerate the write off of their costs for installing new pollution controls – estimated at $2.3 billion.

[112] Criteria pollutants or common pollutants are pollutants for which EPA has set national air quality standards.

[113] On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR). CAIR will permanently cap emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) in the eastern United States. CAIR achieves large reductions of SO_2 and/or NO_x emissions across 28 eastern states (including North Carolina) and the District of Columbia. When fully implemented, CAIR will reduce SO_2 emissions in these states by over 70 percent and NO_x emissions by over 60 percent from 2003 levels.

[114] Sulfur dioxide (SO_2) and nitrogen oxides (NO_x) contribute to the formation of fine particles (PM), and NO_x contributes to the formation of ground-level ozone. Generators are required to have an adequate amount of allowances for these two types of emissions, which are both traded under cap-and-trade programs.

[115] A closely related action to CAIR is the EPA Clean Air Mercury Rule, the first ever federally-mandated requirements that coal-fired electric utilities reduce their emissions of mercury. Taken together, the recently issued Clean Air Interstate Rule and the new Clean Air Mercury Rule will reduce electric utility mercury emissions by nearly 70 percent from 1999 levels when fully implemented. The rule creates a market-based cap-and-trade program that will permanently cap utility mercury emissions in two phases: the first phase cap is 38 tons beginning in 2010, with a final cap set at 15 tons beginning in 2018.

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In general, new natural gas-fired plants and new coal plants would require control equipment to meet Lowest Available Emissions Rate (LAER) or Best Available Control Technology (BACT) levels. Under the Clean Smokestacks Act, existing coal plants will also need to retrofit with emissions controls and drastically reduce their current emissions. Of the conventional utility generation options, only nuclear does not produce any criteria air emissions or mercury.

Role of Renewables

Keeping in mind these national and state mandated reductions for certain types of emissions in the future, electricity generated from most renewable generators as part of an RPS will go to help the State meet the reductions or help reduce emissions further. In doing so, renewable energy may be able to displace some conventional generators' emissions, whether at existing or new plants, but will depend on whether the technology has associated emissions.

It is difficult to estimate the avoided emissions resulting from an RPS, since new renewable generation will primarily displace the emissions of new conventional generation that have not been built. New generation must undergo New Source Review where Lowest Available Emissions Rate (LAER) or Best Available Control Technology (BACT) levels are required. The resulting displacement may be less than historical levels or that of existing plants, as they are required to meet more stringent emission standards. Nonetheless, new generation typically must acquire (either through purchase or shut-down of another emitting source) emissions allowances for SO_2 and NO_x for all its anticipated emissions. Thus, in addition to avoided emissions, there is an avoided emissions cost to displacing new generation.

Renewable generation from wind, hydro, and solar produces no emissions at all. Smaller generators (internal combustion engines or gas turbines) burning landfill gas and anaerobic digesters do have emissions, primarily NO_x and carbon monoxide, since these smaller engines have different standards to follow.

Additionally, firing biomass, even assuming BACT, will produce emissions, primarily NO_x and particulate matter, at levels similar to new coal plants with applicable emissions controls. However, wood as a fuel input does not contain much sulfur, unlike coal and oil-fired generation, and thus has lower sulfur dioxide emissions. Additionally, co-firing of biomass wood in existing coal plants may help reduce total emissions for the existing facilities. Below is a comparison of emission rates collected from several sources of information. As one can see, BACT and LAER levels for new plants are much lower than historical averages for North Carolina.

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Table 21: Comparison of Emissions Rates

	NO_x	SO_2	CO_2
	lbs/MWh	*lbs/MWh*	*lbs/MWh*
EPA 2000 North Carolina Average	2.9	7.6	1293
EIA 2004 North Carolina Average	2.0	7.9	1267
Coal LAER[116]	0.6-0.9	0.9-2.2	N/A
Biomass BACT[117]	1.0	0.3	carbon neutral

Greenhouse Gases

Addressing greenhouse gases related to climate change, including carbon dioxide, is an emerging issue that has not yet been federally regulated. Despite the lack of federal mandates, several states[118] are planning to adopt, or have adopted, greenhouse gas or carbon dioxide reduction targets. Likewise, North Carolina has convened a task force, the Climate Action Plan Advisory Group (CAPAG), to make recommendations related to measures for reducing greenhouse gas emissions and sequestering or removing such gases from the atmosphere.[119] Renewable generation may help North Carolina meet its future Climate Change plans. Without sequestration,[120] conventional fossil-fuel generation cannot reduce carbon dioxide emissions, except through efficiency improvements to some extent. Of the conventional utility generation options, only nuclear does not produce any carbon dioxide.

In the future, there is a potential risk of increased costs associated with carbon dioxide emissions from fossil-based generation. The estimated costs for carbon range between $1/ton (under RGGI) to about $25/ton[121] (under the Kyoto Protocol). Currently, North Carolina utilities do not appear to include potential CO_2 emissions costs in the initial filtering of resources in their IRP process,[122] so there is no actual value associated with CO_2 for North Carolina currently.

Renewable generation can be a major contributor to greenhouse gas reduction or mitigation goals. As mentioned previously, wind, hydro, and solar do not produce any emissions. Every megawatt-hour generated from these resources can displace an equivalent amount from a carbon emitting generation resource. Biomass (wood) resources may also be considered carbon neutral since it is generally accepted that an equivalent amount of carbon dioxide is absorbed by plants

[116] LAER gathered from recent permits for coal plants in EPA's RACT/BACT/LAER Clearinghouse (RBLC) database. Permit levels were set in lbs/mmbtu which were then converted to lbs/MWh using 9,100 btu/kWh heat rate.

[117] "Draft BACT Guidelines for Biomass Projects," Massachusetts Department of Environmental Protection (Memorandum to RPS Stakeholders), June 23, 2006. <http://www.mass.gov/dep/air/laws/biombact.pdf>

[118] Seven northeastern and mid-Atlantic states (Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont).are collaborating on a Regional Greenhouse Gas Initiative (RGGI) to reduce greenhouse gases to 1990 levels through a cap-and-trade program for the region. Similarly, California has just adopted a cap-and-trade program for greenhouse gases also.

[119] CAPAG is run by Department of Environment and Natural Resources. There is a separate Global Climate Change Commission convened by the legislature that is also examining climate change issues.

[120] Carbon sequestration is the term describing processes that remove carbon from the atmosphere. A variety of means of artificially capturing and storing carbon, as well as of enhancing natural sequestration processes, are being explored.

[121] In early May, EU 2008 futures were around €20-€24/tonne (metric) or about $23-$28/ton (U.S.). "State and Trend of the Carbon Market 2006," World Bank.

[122] Duke Energy did run sensitivities that included carbon taxes in comparisons of portfolios comprised of conventional generation in its IRP.

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as is produced during combustion. There is, of course, some time lapse in the cycle between when the carbon dioxide is produced and when the full amount of emitted carbon dioxide is re-absorbed. Overall, existing U.S. and international carbon credit programs recognize that biomass resources are carbon-neutral, as long as the fuel is harvested in a "sustainable" manner as defined by each program.

Finally, as mentioned previously, landfill gas and anaerobic digesters actually provide positive net benefits in reducing greenhouse gases by burning methane produced from the decomposition of waste products. Since the fuel input is mainly methane from landfills, it has the added benefit of converting a potent greenhouse gas[123] to a lesser form of greenhouse gas – carbon dioxide. Current landfill regulations require collection and flaring of landfill gas for landfills of a certain size, but the heat energy generated may not be utilized. Likewise, anaerobic digesters have the same ability to isolate methane from animal waste and convert it to carbon dioxide when fired in a combustion engine or other energy conversion technologies.

In the table below, the minimum amount of carbon dioxide displacement from the scenarios presented previously is based on only the net change in new conventional resources. The carbon dioxide displacement per year could be over 7.2 million tons per year with a 5% RPS and 13.6 million tons per year with a 10% RPS. *This assumes all renewable generation is non-emitting or carbon-neutral, but does not take into account the additional benefits of converting methane from landfill gas and anaerobic digesters to carbon dioxide or biomass co-firing benefits. The example below also does not account for the additional displacement of marginal generation as was developed in the Rate Impact Analysis.*

Based on the range of potential future carbon costs, the carbon benefits may be $7-$180 million with a 5% RPS to $14-$340 million per year for a 10% RPS. These avoided costs reflect the portion of the utility portfolio displaced by renewable generation, if the U.S. becomes active Kyoto participants or carbon costs increase due to some regional/federal requirements.

Table 22: Estimate of Annual Carbon Dioxide Displacement Potential

Net Change in CO_2 for Conventional Generation (million tons/year)[124]	5% RPS	10% RPS
Net Change in Coal	(8.2)	(13.8)
Net Change in Combined Cycle	0.9	0.0
Net Change in Combustion Turbines	(0.0)	0.2
Net Change (Reduction)	**(7.3)**	**(13.6)**
Annual CO_2 Cost @$1/ton	($7,313,150)	($13,625,850)
Annual CO_2 Cost @$25/ton	($182,828,747)	($340,646,247)

[123] Every unit of methane has 23 times the Global Warming Potential (GWP) of the same unit of carbon dioxide, so the conversion of methane to carbon dioxide has significant impact.

[124] Using EIA carbon content equivalent: coal contains 25.98 million metric tons of carbon per quadrillion btu (23.6 tons per quad) and 14.47 million metric tons per quadrillion btu (13.1 tons per quad). Then, carbon tons were converted to carbon dioxide tons using a multiplier of 3.667.

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Water Usage

Many conventional plants today, with the exception of combustion turbines and some air-cooled combined-cycle units, require water for cooling purposes. When power plants remove water from a lake or river, fish and other aquatic life can be killed, affecting animals and people who depend on these aquatic resources. Additionally, once the water has been passed through boilers for generation, pollutants and heat build up in the water. When these pollutants and heat reach certain levels, the water is often discharged into lakes or rivers. While the levels permissible are regulated by permits, there is still a cumulative effect as a result of water use. Existing coal and nuclear plants have major water consumption needs for cooling purposes and have issues related to the discharge of the heated or contaminated water. There are designs for advanced coal and nuclear plants that employ closed-loop, air-cooled condenser systems that use one-fifth of the typical amount of water, but there are efficiency losses of 6%-9% and higher capital costs associated with these systems.

Among the renewable energy options, biomass firing would also require some form of cooling, but new plants being built today often opt for air-cooling systems. Water will still be required in the boilers for generating steam. Some new biomass facilities also try to co-locate with industrial buyers for the thermal/steam output of the plant in a combined heat and power arrangement. As for wind, solar, landfill gas, and anaerobic digesters, they do not require any water for cooling.

On the other hand, hydroelectric power plants have a different issue related to water. While hydro facilities do release water back into rivers after it passes through turbines, this water is not polluted by the process of creating electricity. Hydro facilities with pondage do have associated issues, because these hydropower facilities often require the use of dams, which can greatly affect the flow of rivers, altering ecosystems and affecting the wildlife and people who depend on those waters. Run-of-river systems and low-head hydro have less damaging effects as they allow water to pass through without controlling the flow or require a water retention area. Most of the future hydro development potential in North Carolina are located at existing impoundments (dams) so would have less of an environmental impact than building new dams.

Land Usage and Fuel Extraction

Land usage can be viewed in a few ways, either through direct impact, footprint, or general aesthetics. We also discuss land usage in terms of the fuel extraction impact and physical location of a facility. First of all, the extraction of conventional fuels (oil, coal, natural gas, and uranium) has substantial environmental impact on the land itself, which often leads to habitat destruction and contamination. Furthermore, the processing, transporting and storing of these fuels can also cause major environmental damage in the form of refinery pollution, pipeline and oil tanker leaks. Coal, if improperly stored on-site, can contaminate the surrounding land for decades. Uranium processing produces radioactive wastes that must be adequately stored and isolated to minimize the risk of radioactive release. Finally, the land on which conventional plants are built can occupy a considerable footprint, and high smokestacks and cooling towers contribute to negative aesthetics.

Many of the renewables resource options presented do not require fuels or they utilize on-site waste products and, therefore, do not have related fuel extraction issues. Collecting wood residue from logging operations will have some environmental impact, but the incremental impact beyond that of a logging operation itself is minor if conducted in a sustainable manner, such as leaving behind polewood[125] for future growth. Since biomass is sourced locally, as discussed previously, the transportation distances will be relatively short, consuming less fuel for transportation compared to conventional fuels.

Biomass generation plants do require a footprint similar in size on a per megawatt basis to that of conventional generation to hold the plant equipment and fuel storage. However, due to the smaller scale of biomass plants (25-50 MW) compared to conventional baseload generation (250-2,000 MW), the magnitude of the habitat and aesthetic impact is much less per site.

Wind projects can occupy a large area of land (20 MW per square mile), but landowners can utilize the land for multiple functions once the turbines are in place. Regarding aesthetics and habitat impact, wind has become a controversial topic in certain areas of the country where viewsheds are of concern for local residents. Community opposition has delayed many projects in these aesthetically sensitive areas, and the issue is no different in North Carolina. In general, several state and regional surveys have found that a majority of residents in a community often support wind projects, but the opposing minority voice can often delay or halt a project regardless. Another reason for opposition is concern with bird migration and bat habitat disruption. These issues must be addressed by developers on a site-by-site basis, but the protocol in the wind industry is that if avian and bat studies for a specific site demonstrate a potential issue for bird and bad species, the project would not likely proceed.

Waste Disposal

Lastly, waste disposal is also a major issue for coal and nuclear plants that most renewable generation do not face. Conventional plants using natural gas also do not face significant waste disposal issues.

The burning of coal creates solid waste, called ash, which is composed primarily of metal oxides and alkali. On average, the ash content of coal is 10 percent. Solid waste is also created at coal mines when coal is cleaned and at power plants when air pollutants are removed from the stack gas. Much of this waste is deposited in landfills and abandoned mines, although some amounts are now being recycled into useful products, such as cement and building materials.

Dealing with nuclear waste poses the biggest environmental issue for nuclear generation. Every 18 to 24 months, nuclear power plants must shut down to remove and replace the "spent" uranium fuel. This spent fuel has released most of its energy as a result of the fission process and has become radioactive waste. All of the nuclear power plants in the United States together produce about 2,000 metric tons per year of radioactive waste. Currently, the radioactive waste is stored at the nuclear plants at which it is generated, either in steel-lined, concrete vaults filled with water or in above-ground steel or steel-reinforced concrete containers with steel inner canisters. In addition to the fuel waste, much of the equipment in the nuclear power plants

[125] Polewood refers to the growing stock of merchantable trees.

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becomes contaminated with radiation and will become radioactive waste after the plant is closed. These wastes will remain radioactive for many thousands of years. The issues today for nuclear waste that still need to be resolved relate to long-term waste storage, radioactive waste transportation, potential of weapons-grade plutonium, national security and spent-fuel reprocessing.

Many of the renewable resources (solar, wind, hydro) presented do not generate waste, so waste disposal is not an issue. Anaerobic digesters convert animal waste to more usable forms of fertilizer that can be applied to agricultural land after the anaerobic process. Biomass firing does generate ash, but this byproduct is often resold as a soil amendment for agricultural applications. Unlike coal ash, which may contain toxic metals and other trace contaminants, biomass ash may be used as a soil amendment to help replenish nutrients removed by harvest.

7.3 Other Benefits

In addition to economic and environmental benefits of an RPS, diversifying a portfolio with renewable generation can help safeguard a portion of the State's energy needs from major fuel price fluctuations or increases. North Carolina has been somewhat insolated from much of this fuel price volatility, as over 90% of the State's electricity is supplied from coal or nuclear generation, for which fuel costs are typically locked in for several years at a time through long-term contracts. The fuel costs of these sources have escalated in recent years, though not to the degree of natural gas and oil. However, contract renewals in the future will rely heavily on the spot market prices at the time of renewal. Furthermore, as North Carolina is not a coal, oil, natural gas, or uranium producing state, all the fuels are imported from out-of-state.

Many of the renewable generation discussed have no fuel costs associated with the facilities, except for biomass which includes the cost of collection, processing and transportation of the fuel. For biomass, while a portion of the total cost is related to diesel prices for transportation, the overall cost of biomass fuels will not fluctuate as dramatically as national and global energy markets. Furthermore, as discussed in the economic development section, most of the cost of procuring the fuel stays within the State's economy.

Also, issues such as a potential future "carbon tax" or similar regulation, as well as nuclear waste disposal costs mean that a large part of the State's resource portfolio is subject to potentially substantial risk. Another benefit of renewable energy resources is that their size is more flexible than conventional power plants both in terms of magnitude and typical development and construction time frames, so less risk is placed on the success of a few, large-scale projects.

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8. Other RPS Considerations

In addition to identifying the available resources and estimating the economic and environmental impacts of various portfolio options, the La Capra Team was also engaged to discuss briefly some key issues associated with the development of renewable energy in North Carolina. These include existing obstacles to renewable energy development, as well as design and other issues that are likely to be important if the State decides to adopt an RPS. This section of the Report highlights these topics for future consideration as appropriate.

8.1 Existing Obstacles to Renewable Energy Development in North Carolina

In reviewing the current energy landscape, the La Capra Team noted a couple of important potential barriers to renewable energy development that will need to be considered if the State pursues an RPS.

- Current wholesale avoided cost levels are not sufficient to bring about new renewables. Current filed avoided costs are between 4 and 6 cents per kWh for long-term contracts. While the avoided cost filings apply to resources smaller than 5 MW and rates for larger units are negotiated between utilities and developers, the contract rates often reflect avoided cost rates. In the past, renewable projects were able to receive long-term PURPA contracts at rates above 6 cents per kWh, but current wholesale commodity electricity revenues appear insufficient to support the development of new renewables without supplemental revenue streams. If an RPS is implemented, the State will need to consider how best to procure and compensate renewable energy projects.

- Conflicting interpretations of the Mountain Ridge Protection Act of 1983, more commonly known as the "Ridge Law," add substantial uncertainty to large-scale wind development in the western mountains. To our knowledge, the precise meaning of the 1983 law, in light of recent developments in wind turbines, has not been definitively resolved. Accordingly, there is uncertainty and confusion as to whether this law would bar wind development along North Carolina ridgelines. In order for wind development to proceed in the mountains in response to an RPS, the State would need to clarify the law to alleviate this uncertainty.

8.2 Potential RPS Design Considerations

If North Carolina adopts an RPS, it will need to address a number of design issues. Below, we discuss issues that have arisen in other states during RPS design and implementation and identify some options for addressing them.

- **Applicability:** There are a couple of applicability dimensions to consider. A well-designed RPS would ideally apply equitably to all that benefit from increased

US EPA ARCHIVE DOCUMENT

renewable energy production. However, many states have chosen to deviate from requiring all load-serving entities or all load to comply with an RPS.

- Many states exempt public utilities, such as municipals and cooperatives, from a mandatory RPS, though most RPS legislation does suggest these entities should opt-in or attempt to comply on a voluntary basis. This may depend on the state or utility commission's jurisdictional authority over these entities.

- Additionally, in some states, certain customer classes (e.g. Large Industrial/Commercial) have also been exempt from an RPS requirement citing undue burden from a business perspective.

Both variations will tend to reduce the overall RPS target, since the percentage targets are calculated from applicable load. Exemptions of certain load will also unevenly distribute RPS costs to the customers that are covered by the RPS. The policies associated with both impacts should be considered as part of any RPS adoption process.

- **Balanced Supply and Demand:** An effective RPS will seek to establish requirements that can reasonably be met. This means that an RPS's requirements should be of sufficient size and structure, coupled with appropriate resource eligibility rules to ensure that the policy will (1) lead to new renewable energy development without (2) being so restrictive that compliance is not feasible or not cost-effective.

  - In the scenarios modeled, three resource options were examined: (1) NCGP-defined resources; (2) expanded resources; and (3) expanded resources with energy efficiency. The definition of eligible resources and the RPS target should take into account cost impacts as well as the types of resources being encouraged, the need to encourage sufficient competition to produce cost-effective renewable energy proposals, and infrastructure limitations.

  - In this analysis, the focus was on the development of new resources. However, consideration would need to be given to the existing renewables base in the State, since these resources may not be sufficiently compensated at current avoided cost levels or are currently operating under the NCGP program. NCGP allows projects constructed after January 1, 1997 to qualify for its mass-market product. In addition, for the large volume product, existing facilities can also qualify. Since an RPS is usually intended to develop renewables incremental to a base of existing resources, the treatment of existing resources in an RPS will be important. Two common solutions have been proposed to address this: (1) increase the overall RPS target by starting at a level close to the existing renewables base and escalating from that point; or (2) develop a second tier requirement with separate standards that would include existing renewables.

- **Stability of Targets:** An RPS needs to have sufficient duration and clarity to allow long-term contracting and financing to occur.

US EPA ARCHIVE DOCUMENT

- For example, if there is uncertainty for developers concerning the long-term RPS requirements, financing a project may be more difficult.
- Likewise, if there is a risk that eligibility rules may change during the course of an RPS, thus altering the available renewables in the market, the development and financing community will be hampered in producing projects.
- Requiring long-term power contracts for these resources will help provide necessary support for projects.
- Along with long-term contracts, the utilities should be allowed full and timely cost recovery for prudently incurred costs.

- **Resource Eligibility:** As noted above, the clear definition of eligible resources is a very important implementation design issue. Eligibility parameters may include: eligible fuel inputs or resources, on-line date, compliance with emissions standards, and resource location.
  - While this report included energy efficiency measures as a potential resource option, only four states so far have included energy efficiency as an option to meet their RPS. If included, energy efficiency measures are sometimes assigned to a separate tier/class from renewable generation. Often, other programs are developed alongside an RPS to promote energy efficiency programs because the administration, tracking, and monitoring of these programs are quite different than with electric generators and the energy efficiency measures may be cost-competitive without the need for an RPS. On the other hand, the State may favor allowing both renewables and energy efficiency measures to qualify and compete in an RPS in order to administer an RPS program in the most cost-effective manner.
  - An explicit exclusion of out-of-state resources may raise questions under the Commerce Clause of the U.S. Constitution. Some states have addressed this issue by specifying that the renewable energy must be physically delivered to the state or by requiring electrical interconnection to serve load directly in the state or region. Others have assigned higher multipliers to in-state versus out-of-state resources so that there is more of an economic incentive to locate within the state.

- **Special Treatment:** Depending on the State's policy objectives, certain resources may receive preferential or special treatment in the design process. Policy instruments that have been employed include: multiple resource tier requirements, multipliers, set-asides, or use of System Benefits Funds (SBF). These concepts are most applicable if North Carolina has interest in promoting certain renewable resources, such as solar or anaerobic digesters, that may not be directly cost-competitive with other renewable resources, but provide ancillary benefits.

US EPA ARCHIVE DOCUMENT

- Multiple tiers allow the categorization of certain resources, so their respective value or benefits are grouped with like resources. Targets are defined separately for each tier.

- Multipliers, as described previously, allow utilities to receive additional credit for certain resources to be applied to the utilities' RPS requirements.

- Set-asides refer to a requirement to procure a specific resource to ensure that resource is in the portfolio mix, irrespective of whether there are more cost-effective options.

- Lastly, though North Carolina does not currently have a System Benefits Fund, this option could be considered as a way to help develop emerging technologies or resources that are not directly cost-competitive.

- **Compliance and Alternative Compliance Payments:** An effective RPS must be mandatory and impose some form of alternative compliance payments on load-serving entities that fail to comply. Adequate flexibility mechanisms for compliance can help keep customer costs down. One mechanism often used for tracking compliance is renewable energy credits or certificates (RECs).

  - RECs are defined generally as all renewable, environmental and generation attributes associated with a renewable generator, excluding the energy itself. RECs allow for easier tracking and the potential transfer of credits between parties.[126] A REC market may not be necessary, but creation of certificates can facilitate tracking each utility's compliance, any transfer of credits between utilities, potential sales of excess renewable energy to PJM, and the use of credits in the NCGP program to avoid double-counting.

  - Another policy that facilitates flexible compliance is the ability for utilities/LSEs to "bank" credits. This means if the total output of contracted renewable resources in one year exceeds that year's requirement, the excess can be used to apply to requirements for the following year. Likewise, if the utility (or LSE) is short one year, it may be able to "borrow" from the following year's (or years') generation.

  - Compliance alternatives also need to be clearly described, so utilities/LSEs have a strong incentive to comply with the requirements. This may come in the form of Alternative Compliance Payments (ACP), which are paid by the utility/LSE for the portion of the RPS requirement it is short. The ACP can also be set to cap the premium to be paid for renewable resources, thereby controlling the cost of an RPS. Some states require a review of the situation by the utilities commission if the utility/LSE is not in compliance.

[126] PJM uses a centralized Generation Attribute Tracking System (GATS) to account for all RECs generated in and around PJM. Renewable projects within North Carolina are contemplating wheeling energy into PJM to sell RECs to meet the RPS of other states within PJM.

US EPA ARCHIVE DOCUMENT

- **Compatibility with Other State Policies:** When implementing an RPS, other existing and future state programs and policies would also need to be taken into consideration.

  - Some parties have voiced concern that an RPS may displace the need for a voluntary green program. In review of various RPS states across the country, this concern has not proven to be justified. Most RPS states continue to have voluntary green power programs despite the implementation of an RPS, and in some, the voluntary market thrives even in the presence of an RPS. It is critical, however, that voluntary green power purchases not be applied towards meeting the RPS targets, for doing so would undermine the core motivation for voluntary commitments beyond what would happen in the absence of that commitment.

  - If the objective of an RPS is to help reduce certain emissions, coordination between the RPS and emissions policies may be needed. For example, if a cap-and-trade program is established to meet certain emissions targets (e.g. CAIR, mercury, greenhouse gases), and renewable energy projects receive offsets or allowances, the sale of those allowances may increase emissions by allowing another generator to emit, so there may not be a net benefit. Also, if a REC tracking system is implemented, claims of emissions reductions by certain resources should not be counted if allowances are resold. There are other ways to address this, but coordination is critical.

8.3 Additional RPS-Related Considerations

- **Customer-side Generation:** Under current Commission rules, customer-side or on-site renewable generation that chooses to net-meter cannot sell renewable credits from non-metered energy from their projects to NCGP (see Appendix I). This is applicable to generation below 100 kW. This issue may need to be reconsidered if an RPS is in effect and renewable credits can be procured in a cost-effective manner from net-metered resources for the entire amount of energy generated. Likewise, if there is a policy to promote smaller-scale resources, a plan to compensate these resources would be needed.

- **Interconnection:** Current standard interconnection rules for small generators apply to resources below 100 kW and require single-phase, inverter-based systems (see Appendix I). There is uncertainty for projects greater than 100 kW interconnecting at a distribution-level voltage because the State's current standard rules are not applicable to these resources. Additionally, three-phase interconnections are not encompassed by the standard rules. Expanding standard rules to include projects greater than 100 kW and address three-phase systems would help small projects in an RPS context.

- **Transmission Upgrades**: In order to accommodate wind and other remotely located renewable energy resources, transmission expansion needs for these resources should

US EPA ARCHIVE DOCUMENT

be considered. Indeed, the scenarios modeled in this study include between 500 and 2,800 MW of wind project development in North Carolina. To be able to incorporate this magnitude of wind into the State's power system will likely require transmission system upgrades. The current transmission system in North Carolina is limited in its ability to bring large amounts of energy from remote areas of the State where wind resources are located to load centers, and there is real concern that 500 to 2,800 MW of wind can cause reliability problems for the system. This is an issue faced by many states that are developing wind on a large scale for purposes of an RPS or otherwise. The potential cost of large transmission line expansions were not included in the cost analysis because these costs are highly site-specific and require a separate transmission upgrade study. It is also important to keep in mind that with large conventional projects such as coal and nuclear plants, major transmission expansion plans might also be necessary to move electricity from the generator to the load centers.

- There are a number of studies being conducted by multiple states in determining region-wide transmission system needs if large amounts of wind are developed. One major issue is how to allocate the transmission expansion cost. Should the costs be borne by the first project in a transmission queue, allocated among a group of projects that need the system expansion, or charged to load?

- On June 15, 2006, the California Public Utilities Commission decided to allow utilities in that state to charge ratepayers under retail rates for upfront transmission costs of building major transmission facilities in areas to support expected development of renewable energy, especially wind projects.[127] The decision is a departure from FERC policy in which developers pay the costs to connect their projects to the grid and recover these costs over time from customers.

- California has also required an assessment of transmission upgrade costs to be included in the evaluation of renewable energy projects for the state's RPS. One of the state's utilities, Pacific Gas & Electric (PG&E) designated proxy costs to specific expansion areas.[128].Depending on the location, for 500 MW of expansions, the cost can vary between $27 and $244 million ($54/kW to $480/kW). These costs are highly site-specific, depending on the lines or substations needed for expansion.

- A review of more than 200 system integration studies related to wind shows that the variability of wind can be addressed without becoming an insurmountable obstacle for wind development and the solutions are relatively inexpensive per kWh.[129] As for system reliability, studies have found that

[127] "Transmission and Wind Energy: Capturing the Prevailing Winds for the Benefit of Customers," National Grid, September 2006. <http://www.nationalgridus.com/non_html/c3-3_NG_wind_policy.pdf>

[128] "2006 Transmission Ranking Cost Report of Pacific Gas and Electric Company in Compliance with Assigned Commission and Administrative Law Judge's Ruling in OIR 04-04-026," November 9, 2005.

[129] "The Costs and Impacts of Intermittency," The UK Energy Research Centre (UKERC) review of international transmission studies, April 5, 2006. <http://www.ukerc.ac.uk/content/view/258/852>

US EPA ARCHIVE DOCUMENT

incorporating up to 10% of wind into a state's generation mix does not adversely impact the transmission system, given certain actions taken by the wind project and system operators.[130] Studies of other regions and states have shown for each MWh of wind energy generated, the increased integration cost can be $0 to $8.87/MWh for 4% to 20% wind penetration. [131] Current peak load in North Carolina is about 25,000 MW, so 1,500 MW of wind in North Carolina would equate to about a 6% penetration of wind for the State. Substantial hydro and pumped storage capabilities can also help manage wind in the system.

The UK Energy Research Centre (UKERC) reviewed over 200 international studies and found that:

- *The output of fossil fuel plants will need to be adjusted more often to cope with fluctuations in wind output, but any losses this causes are small compared to overall savings in emissions.*
- *100% 'back up' for individual renewable sources is unnecessary; extra capacity will be needed to keep supplies secure, but will be modest and a small part of the total cost of renewables. It is possible to work out what is needed and plan accordingly.*
- *None of the 200+ studies UKERC reviewed suggested that the introduction of significant levels of intermittent renewable energy would lead to reduced reliability.*
- *The cost of intermittency at current levels is much smaller, but will rise if use of renewables expands.*
- *Wide geographical dispersion and a diversity of renewable sources will keep costs down.*

- **Co-firing:** Co-firing is the least-cost option for utilizing biomass fuels. However, the treatment of co-firing in an RPS does pose some concern. To start, the La Capra Team assumed that co-firing merely displaces a portion of coal fuel that is consumed in existing plants and does not increase the generation level of the plant. However, it is possible that lowered emissions (e.g. NO_x, SO_2, mercury) as a result co-firing with biomass free-up emissions allowances so that the plant or another plant can generate more. Depending on the type of retrofits needed for co-firing, New Source Review (NSR) under the Clean Air Act may be triggered which would require plants to implement Best Available Control Technologies. For our study, much of the co-firing capability is assumed to be blending of biomass (5%) with coal, and this is less likely to trigger NSR. However, this assessment does not imply that a coal plant cannot choose to increase the co-firing capability (up to 20% is technically feasible) at a single plant beyond what is assumed in the modeling. Also, co-firing at plants that do not have to comply with the State's Clean Smokestacks Act can be implemented. In fact, this may be a preferable option for utilities since these plants are less likely to install catalytic controls that can potentially be contaminated by

[130] "The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations." NYSERDA, May 2004. <http://www.nyserda.org/publications/wind_integration_report.pdf >

[131] "Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States" presented at the 2006 European Wind Energy Conference (EWEC). <http://www.uwig.org/ewec06gridpaper.pdf)>

US EPA ARCHIVE DOCUMENT

alkali in biomass. Finally, there are several small coal plants and retired plants that may be repowered to fire 100% biomass fuel. Their potential was not included in the analysis. Careful consideration must be given to whether total emissions and generation output will be altered as a result of any or all of these uses of existing plants, and proper eligibility rules are needed based on that analysis.

- **In-state Manufacturing:** Today, North Carolina has few manufacturers of renewable technologies. The economic benefits discussed previously are derived primarily from labor associated with construction/installation and operation/maintenance, while equipment and materials are supplied from out-of-state. Considerably more economic development can occur if manufacturers have incentives to locate in North Carolina. For example, Pennsylvania recently announced Gamesa, a major wind turbine manufacturer, will locate a large manufacturing facility to the state that will supply not only Pennsylvania's wind turbine needs but also that of other states. This adds both local manufacturing jobs and provides potentially lower-cost equipment for the state's RPS.

- **Public Acceptance**: Wind projects proposed in certain areas have produced vocal opposition. To assess the public attitude toward wind development in western North Carolina, a phone survey of western North Carolina residents was conducted in 2002 by Appalachian State University.[132] Three general issues guided the survey: (1) attitudes about energy issues in general; (2) attitudes about specific turbine placement options; and (3) perceptions of barriers in developing a wind industry in the region. The study concluded that:

  - *Western North Carolinians are favorably disposed toward the development of a wind energy industry in the Appalachian Mountains. They want more of their future electricity derived from renewable sources and less from fossil fuels. They are ambivalent toward nuclear energy.*

  - *By over 2 to 1, western North Carolinians do not believe that ridge top turbines should be prohibited. They are less favorably disposed to placing turbines in national forests and clustering them together. However, if a ridge top already has existing cell towers, 3 out of 4 would not mind adding a wind turbine to the clutter. An even higher ratio believes a person should be allowed to erect a turbine on his/her own property for residential use.*

  - *Support for ridge top placement is not systematically affected by experience with seeing a modern turbine in operation, awareness of energy issues, income, or education.*

  - *Most western North Carolinians do not foresee or cannot articulate a problem with developing a wind industry in the State. For those that do, the overwhelming problem noted is aesthetics. The concern raised is that the visual pollution of ridge top turbines would hurt the tourist trade and could*

[132] Grady, Dennis O., "Public Attitudes Toward Wind Energy in Western North Carolina: A Systematic Survey," Appalachian State University, December 9, 2002. <http://www.energy.appstate.edu/docs/wnc_pubsurvey.pdf>

US EPA ARCHIVE DOCUMENT

decrease property values. To a much lesser extent, people who do foresee problems identify the consistency of the wind, environmental hazards, and political/legal issues as potential barriers.

- **System Benefits Fund:** In conjunction with an RPS, the State may want to develop a System Benefits Fund to support emerging renewable technologies or centrally administered renewable energy and energy efficiency development programs. According to the North Carolina Energy Outlook 2003:[133]

  A public benefits fund attempts to address a number of problems that surround the generation, transportation and sale of electricity both at the federal and state levels. A public benefits fund pulls together resources through which states can, in a targeted but flexible fashion, attack pockets of energy waste, seize opportunities to develop renewable energy, improve electric services for low-income customers, and develop mechanisms for providing electricity cleanly and cheaply.

[133] Global Insight, May 2003. <http://www.energync.net/resources/docs/pubs/energyoutlook.pdf>

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9. Conclusions

The consideration of an RPS involves addressing many important analytical, policy, and implementation questions. The La Capra Team appreciates the opportunity to assist North Carolina in its thoughtful deliberations and hopes that this Report is helpful to all concerned. Below are conclusions from this Report.

- North Carolina should have sufficient renewable resources within the State to support a 5% RPS, whether energy efficiency measures are included or not. A 5% RPS would have a relatively small impact on retail electricity rates assuming lower cost options are developed first through a competitive bid process. Adoption of a 5% requirement would double the current level of renewable energy generation in the State. At the same time, 1,100 additional jobs may be created, additional property tax revenues may be earned by local governments, and about 1,000 MW of new baseload generation[134] may be avoided. This translates to the potential avoidance of over 7 million tons of CO_2 per year if the displaced generation is coal-based. If instead, a nuclear plant is avoided, there would be no carbon benefits since nuclear plants also do not have associated carbon emissions.

- A more aggressive 10% RPS without including energy efficiency would require the development of 900 - 2,300 MW of off-shore wind since other practical on-land resources would already be developed. Presently, no off-shore wind projects have been installed in the U.S. due to numerous permitting obstacles. If off-shore wind projects do not become feasible during the forecast period, a 10% RPS would only be achievable by including energy efficiency programs, larger hydro generation, and development of wind in the western part of the State.

- Inclusion of energy efficiency for 25% of an RPS can dramatically reduce the cost. The RPS portfolios (5% and 10% RPS) with energy efficiency are each estimated to save about half a billion dollars in NPV over 20-years relative to the Utilities' Portfolio. Essentially, the reduction of load of 1.25% or 2.5% by the end of the RPS study period creates energy cost savings overall for the State. The inclusion of energy efficiency measures in an RPS could create 1,500 to 2,700 additional jobs relative to the Utilities' Portfolio. However, if the State does proceed with the development of an RPS, careful consideration should be given to whether an RPS or a separate policy vehicle is the appropriate policy tool to promote energy efficiency measures.

- Through a high-fuel cost sensitivity test for the 5% NCGP Criteria scenario, we found that an RPS can help mitigate some risks related to high fuel prices, but even high fuel costs would not offset all the added cost of the RPS scenario tested.

[134] About 1,000 MW of baseload generation can be displaced by renewable generation, but in the 5% scenarios, 500 MW of natural gas combined-cycle generation that operates as intermediate facilities would also be needed to make-up any potential shortfalls of capacity and energy. In a sensitivity excluding co-firing, no additional combined-cycle generation is needed since additional biomass facilities provide the state with its needed capacity.

US EPA ARCHIVE DOCUMENT

- The cost analyses in this Report assume that the Federal Production Tax Credit that partially offsets the delivered cost of energy from many types of renewable projects continues to be in effect throughout the study period. The incremental cost of an RPS may be 40% higher than modeled if the Federal Production Tax Credit is not renewed after five years. This tax credit has been in effect since the early 1990's and has been extended a number of times. The current law is set to expire again after 2007. So, attention to the status of proposed extensions of the law will be important if North Carolina adopts an RPS.

- Additional nuclear plants are included in the future electricity portfolio in North Carolina as proposed by Duke Energy. The uncertainty concerning project costs for new nuclear plants will have a significant impact on an RPS assessment. Depending on their actual cost, the addition of nuclear plants can either make an RPS appear to be an attractive alternative for new generation or double the incremental cost of an RPS. From past experience with nuclear plants, there would appear to be uncertainty regarding present cost estimates for nuclear plant construction. Similarly, the cost of new coal plants used in this analysis may also have related uncertainties, as evidenced by recent increases to installation cost estimates in current utility coal plant proposals.

- Solar photovoltaic (PV) systems are not directly cost-competitive with most other resources, including other new renewable technologies. However, a number of states have decided to encourage the development of solar power by giving extra credit for solar power in RPS implementations. If the State is interested in promoting solar installations, crediting solar energy at a multiple of other renewable energy will not change the overall cost of an RPS, while providing some additional job benefits. Furthermore, solar PV may be able to provide other benefits, such as providing distributed generation,[135] summer peak shaving (see Appendix C), and emissions reductions. Another alternative to promote solar is to dedicate a portion of an RPS target to solar in the form of a set-aside as is being done in some states.

  We tested the sensitivity of adding 112 MW of solar installations over the ten-year study period. This would be equal to installations on 16,000 residential roofs (32 MW) and 3,200 commercial/industrial roofs (80 MW).[136] To implement such large-scale development, promoting solar PV manufacturing in the State would likely be needed. This would provide additional manufacturing jobs that were not included in the jobs analysis. Similar considerations may be provided to other technologies the State may wish to promote, such as solar thermal heating and cooling.

- There are many ways to design an RPS. The scenarios presented in this Report reflect a few key policy choices, but there are many additional RPS design and implementation issues that would need to be addressed before an RPS can be implemented. These issues include:

[135] Distributed generation is the small-scale production of electricity at or near customers' homes and businesses. It has the potential to improve system reliability, reduce local distribution loading during peak moments, and/or avoid system upgrades in some cases.

[136] As a point of reference, 1,460 MW of new solar PV systems were installed worldwide during 2005.

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- **Applicability:** In principle, the costs for development of renewables should be applied to as much of the State's retail electric load as possible for equitable cost sharing. However, several states have excluded municipal and cooperative electric utilities and/or certain levels of industrial load from RPS rules for a variety of reasons. Such exclusions, however, do create the inequity of having only some ratepayers pay for an RPS which provides benefits throughout the State.

- **Balanced Supply and Demand:** The pace of an RPS start and ramp-up should be set so that sufficient resources can be reasonably developed, but in a cost-effective manner. The ramp-up should also take into account existing commitments to resource additions.

- **Stability of Targets:** The development of all electric energy resources is a long-term undertaking. For an RPS to effectively encourage the development of renewable energy facilities, the RPS requirements should provide a long-term commitment that enables projects to obtain cost-effective financing. One option is requiring long-term power purchase agreements while allowing utilities full recovery of prudently incurred costs in a timely manner.

- **Compliance and Alternative Compliance Payments:** Appropriate compliance requirements should be included to ensure that load serving entities comply. At the same time, the law should be flexible enough for LSEs to comply in a cost-effective manner, such as setting an effective cap on costs with the use of alternative compliance payments (ACP). Additionally, appropriate methods for calculating and attributing contributions from renewable generation and energy efficiency measures would need to be determined.

- **Compatibility with Other State Policies:** North Carolina has several policies in place or under development that may need to be reviewed in conjunction with an RPS, such as the Clean Smokestacks Act, EPA's Clean Air Interstate Rule, cap-and-trade programs, Carbon Policies, and the interaction of a mandatory RPS with voluntary purchases under the NC GreenPower program.

- Beyond these major issues, there are a host of other details to be considered if the State decides to adopt an RPS. While the full exposition of these is beyond the scope of this Report, the La Capra Team notes that these topics should include: the precise definition of and certification of resource eligibility, the treatment of existing resources, geographic eligibility (including constraints imposed by the U.S. Constitution's Commerce Clause on restrictions on out-of-state resources), the tracking of environmental attributes of various generating supply for RPS compliance purposes, and inclusion of sufficient flexibility mechanisms to minimize compliance costs while not destabilizing the market. None of these issues are insurmountable, even though they do require careful attention.

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Glossary of Terms

- **Alternative RPS Portfolios:** Alternative resource options to achieve RPS targets, while meeting both incremental capacity and energy needs of the State.

- **British Thermal Unit (btu):** A measure of heat (energy) required to raise 1 pound of water by 1 degree Fahrenheit; 1,000,000 btu is expressed as mmbtu.

- **Capacity Factor:** Net capacity factor for a power plant is calculated based on the total annual energy generation expected to be delivered to the electric grid or end-user divided by the total maximum potential generation for the plant.

- **Energy Efficiency (EE):** Physical, long-lasting changes to buildings and equipment that result in decreased energy use while maintaining the same or improved levels of energy services. Energy efficiency, for the purposes of this analysis, is a subset of Demand Side Management (DSM) programs that may encompass other programs such as load management, load shifting, demand response, and other peak load programs.

- **Gigawatt-hours (GWh):** A measure of energy representing 1,000 MWh.

- **Heat Rate:** Fuel conversion rate reflecting the energy input needed for one unit of electric energy output, often represented as btu per kWh.

- **Heat Content:** The thermal energy content of fuels, often represented as btu per lb.

- **Installed Cost:** The total cost of a facility including all equipment, installation/construction, related interconnection to the electric grid, development, interest during construction, and contingency costs typical of the project type.

- **Integrated Resource Planning (IRP):** The long-term comparison of resource options that considers important selection criteria including cost, reliability, the environment, and other policy goals.

- **Kilowatt-hours (kWh):** A measure of energy representing 1,000 watt-hours.

- **Levelized Cost:** A single cost (often stated as a rate per kWh or MWh) that would produce the same economic outcome as a series of varying costs over the economic life of an investment.

- **Load Serving Entity (LSE):** Entities that provide electric service to end-users.

- **Megawatt-hours (MWh):** A measure of energy representing 1,000 kilowatt-hours.

- **Megawatts (MW):** A measure of power output or generation capacity representing 1,000 kilowatts or 1,000,000 watts.

US EPA ARCHIVE DOCUMENT

- **NC GreenPower (NCGP):** North Carolina's voluntary green power program.

- **Net Present Value (NPV):** NPV is the sum of the future stream of benefits and costs converted into equivalent values today. This is done by discounting future benefits and costs using an appropriate discount rate.

- **Production Tax Credit (PTC):** A federal tax credit available to certain electric energy production facilities based on the facilities' kWh production.

- **Renewable Portfolio Standard (RPS):** A policy tool that establishes a requirement to have a certain portion of an electricity portfolio be supplied from renewable or alternative resources. The RPS is typically denoted as a percentage of electricity sold to retail customers and is often achieved by phased-in increases over time.

- **Supply Curve:** The ranking of potential supply options based on cost from lowest to highest showing their expected cumulative MWh contribution.

- **Utilities' Portfolio:** The Utilities' Portfolio represents the sum of anticipated new projects needed to meet load growth and retirements according to the State's utilities' 2006 IRP filings.

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Appendices

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Appendix A: June 30, 2006 Letter to Environmental Review Commission

State of North Carolina

Utilities Commission

4325 Mail Service Center
Raleigh, NC 27699-4325

COMMISSIONERS
JO ANNE SANFORD, Chair
ROBERT V. OWENS, JR.
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COMMISSIONERS
LORINZO L. JOYNER
JAMES Y. KERR, II
HOWARD N. LEE
WILLIAM T. CULPEPPER, III

June 30, 2006

Sen. Charlie Albertson, Co-Chair
Sen. Daniel G. Clodfelter, Co-Chair
Rep. Pryor A. Gibson III, Co-Chair
Environmental Review Commission
545 Legislative Office Building
300 North Salisbury Street
Raleigh, North Carolina 27603

Dear Messrs. Albertson, Clodfelter, and Gibson:

On January 24, 2006, the Environmental Review Commission (ERC) of the North Carolina General Assembly adopted a motion requesting the North Carolina Utilities Commission (Commission) to undertake a study of the potential costs and benefits of enacting a renewable energy portfolio standard (RPS) in this State. The process proposed to and adopted by the ERC requires the Commission to issue a request for proposals (RFP) and to ultimately contract with an experienced consultant to perform the study under the direction and guidance of the Commission.

On February 23, 2006, we received a letter from George Givens, ERC Counsel, memorializing the above request. In his letter, Mr. Givens requested that the Commission provide the ERC with a status report on the study no later than July 1, 2006, and a final report on the study no later than December 1, 2006. We are pleased to provide the ERC with this status report of our progress to date, and we remain committed to provide our final report by December 1, 2006, as requested.

From the beginning, the Commission has recognized the importance of working with interested stakeholders and soliciting their input. Prior to the January 2006 ERC meeting, the Commission met with utility and environmental representatives to discuss options for performing a cost/benefit study. After the ERC meeting, the Commission formed an advisory group representing various stakeholder interests, including ratepayers, utilities, and environmental groups, to assist it in preparing its report for the legislature. The following nine persons have agreed to serve on the RPS Advisory Group:

430 North Salisbury Street • Raleigh, North Carolina 27603
Telephone No: (919) 733-4249
Facsimile No: (919) 733-7300

US EPA ARCHIVE DOCUMENT

Messrs. Albertson, Clodfelter, and Gibson
Page 2
June 30, 2006

Mitch Williams, Progress Energy
David Beam, North Carolina Electric Membership Corporation
Ivan Urlaub, North Carolina Sustainable Energy Association
Kris Coracini, Environmental Defense
Sue Gouchoe, North Carolina Solar Center
Preston Howard, Manufacturers and Chemical Industry Council of NC
Dr. Ed Erickson, Professor of Economics, North Carolina State University
James McLawhorn, Public Staff-NCUC
Len Green, North Carolina Attorney General's Office

Because this project involves the expenditure of State funds, it was necessary to solicit competitive bids from consultants willing to perform the cost/benefit study. The Commission's initial task, therefore, was to prepare a memorandum for the Department of Commerce (Commerce) to seek approval from the Department of Administration, Division of Purchasing and Contracts (Administration), to issue a request for proposals (RFP) to engage an experienced consultant to perform the required study. This memorandum was prepared and sent to Commerce on March 10, 2006. Approval to issue an RFP was received on April 6, 2006.

While awaiting approval to issue an RFP, the Commission, with the assistance of the RPS Advisory Group, drafted an RFP. After reviewing efforts undertaken in other states, Commission Staff prepared a draft RFP and circulated it to the RPS Advisory Group for comment. A final draft RFP was sent to Commerce on April 21, 2006. Additional changes were made, and the final RFP was sent to Administration on April 27, 2006.

After approval by Administration, the RFP was posted on May 12, 2006, with bids due on June 5, 2006. A copy of the final RFP is enclosed. Notice of the issuance of the RFP was posted on the Commission's web site. In addition, based upon input from the RPS Advisory Group and inquiries from press reports, nineteen individuals representing sixteen consulting firms were specifically notified by email and invited to bid. The Commission ultimately received five bids in response to the RFP.

To most efficiently complete the evaluation process, the following balanced, representative subset of the RPS Advisory Group was selected to assist the Commission with evaluating the bids submitted in response to the RFP: James McLawhorn, Ivan Urlaub, Mitch Williams, and Dr. Ed Erickson. All members of the RPS Advisory Group, however, will participate and lend their expertise in the remaining phases of this project, both in providing input to define the parameters of the study as well as in reviewing the work performed.

The evaluators met on May 26, 2006, before the bids were due, to determine the criteria against which the bids would be evaluated. The group decided that technical merits

US EPA ARCHIVE DOCUMENT

Messrs. Albertson, Clodfelter, and Gibson
Page 3
June 30, 2006

of the bids would be primarily evaluated against the non-cost criteria stated in Section 4.I of the RFP – "completeness, content, experience with similar projects, the ability of the offeror and its staff, proposed plan of action to carry out the requirements set forth herein" – and the bidder's references. The group further decided that bids would be evaluated by the group as a whole, rather than individually by each evaluator.

On June 6, 2006, copies of the bidders' proposals were distributed to evaluators, who then met on June 9, 2006, to evaluate the proposals. Based upon the results of the evaluation, a memorandum was sent to Commerce on June 15, 2006, requesting that the costs proposals be opened for those bidders who successfully passed the technical review. The required two days' notice was sent to those bidders on June 20, 2006, and the cost proposals were opened on June 23, 2006. Based upon a review of the cost proposals, a memorandum was sent to Commerce on June 23, 2006, recommending a bidder with which the contract should be awarded. The recommendation is currently being reviewed by Administration and a contract should be awarded shortly.

The Commission will meet with the consultant and the RPS Advisory Group within two weeks after the contract is awarded to discuss and determine the specifics of the study to be performed, including the analytical methods and models to be used, sources of data to be used as input for the study, assumptions to be made and used in the study, scenarios to be analyzed in the study, and sensitivity analyses to be performed as part of the study. Knowledgeable input from the consultant based upon prior similar research will be vital in determining the specific scope and details of the study and in maximizing the usefulness of the study to the legislature in its deliberations. The Commission expects the consultant, in gathering data for the study, to confer, to the greatest extent possible, with the State Energy Office, the North Carolina Solar Center, NC GreenPower, utilities, and others who have previously investigated or attempted to inventory the potential for renewable energy production in North Carolina. However, the consultant shall endeavor to independently verify the reasonableness of all data and assumptions used in the study.

The consultant shall deliver to the Commission an initial draft report, incorporating the results of the cost/benefit analysis, within twelve weeks after the contract has been awarded. The draft report will be circulated to members of the RPS Advisory Group for comment and critique. The consultant shall meet in Raleigh with the Commission and members of the RPS Advisory Group to discuss comments received and to determine final revisions necessary to the report, and shall deliver to the Commission a final report within three weeks thereafter. Lastly, the consultant shall assist the Commission in presenting the

US EPA ARCHIVE DOCUMENT

Messrs. Albertson, Clodfelter, and Gibson
Page 4
June 30, 2006

results of the study to the ERC and shall remain available to meet with the Commission and others to present and discuss the results of the study.

Please feel free to contact me if you have any questions. With warmest personal regards, I am

Very truly yours,

James Y. Kerr, II

JYK/LSW

Enclosure

cc: Environmental Review Commission Members
RPS Advisory Group Members
George F. Givens
Steven J. Rose
Robert P. Gruber
Commissioners

US EPA ARCHIVE DOCUMENT

Appendix B: La Capra Team Background

The La Capra Associates Team responsible for this Report consists of La Capra Associates, Inc, GDS Associates, Inc., and Sustainable Energy Advantage, LLC (SEA). Each firm has a significant energy practice and has assisted numerous clients in renewable energy and/or energy efficiency policy issues and project review and development across the country. In addition, each company draws on decades of experience with conventional energy issues from understanding the intricacies of electric power systems to ratemaking and resource planning. The La Capra Associates Team has a broad base of experience that covers most of the states across the U.S. in both regulated and deregulated electric environments.

Corporate Background

La Capra Associates, Inc. is an employee owned, Boston-based consulting firm specializing in the electricity industry. Since its founding in 1980, La Capra Associates has earned a reputation for practical and objective advice and for timely, accurate, and innovative analyses. Over the years, La Capra Associates has provided strategic planning advice to policy makers and senior managers along with expert, technical analysis to support policy, investment, and operational decisions. La Capra Associates provides consulting services regarding energy planning and risk management, power market analysis, ratemaking, and regulatory policy in the electric industry. La Capra Associates has a thorough understanding of electric power systems and the costs and risks related to production of electricity from both renewable and non-renewable generation.

GDS Associates, Inc. is a multi-service engineering and management consulting firm, headquartered in Marietta, Georgia, with offices in Auburn, Alabama; Austin, Texas; Manchester, New Hampshire; and Madison, Wisconsin. GDS has served its energy industry clients since its inception in 1986. GDS has conducted numerous technical potential and economic analysis studies on energy efficiency and renewable energy measures for various state entities as well as electric and gas utility clients. GDS is also well-versed in conducting economic modeling of costs and benefits of public policy decisions related to the electric and natural gas industries. More specifically, GDS has worked for North Carolina clients since 1987, and GDS consultants are very familiar with the electric industry structure and operations in North Carolina.

Sustainable Energy Advantage, LLC has provided interdisciplinary support to private, public and non-profit organizations involved in developing competitive electricity market ventures and market infrastructure for environmentally preferable electricity supply since 1998. SEA provides strategic, policy, marketing, product development and pricing, negotiation, and analytical support to developing wholesale and retail renewable electricity businesses. SEA has also been instrumental in assessing, developing, and implementing public policies regarding renewable energy including various state Renewable Portfolio Standards and subsidy and incentive programs.

Relevant Renewable Energy Experience

The La Capra Associates Team has broad experience concerning renewable energy markets and state renewable portfolio standards ("RPS"). Below we summarize the types of renewables-related projects we have been involved with in the past that serve as the foundation of our experience.

1) **Renewables Supply and Cost Analysis.** La Capra Associates, SEA, and GDS have all conducted extensive studies on the potential renewable supply and economic analyses in various

US EPA ARCHIVE DOCUMENT

states through work with state regulators, developers, and wholesale and retail buyers. La Capra Associates and SEA also provided all the renewables resource assumptions used in the Regional Greenhouse Gas Initiative (RGGI) that included the northeast and some mid-Atlantic states. This information was used as part of a modeling effort to determine RGGI policy costs. SEA and La Capra Associates have built an extensive database of resource costs and a methodology to assess resource potential in these states. GDS has also prepared technical potential and economic analyses of renewable energy options for several clients in the Southeast U.S.

2) **Rate Impacts of Renewables.** La Capra Associates and GDS have active regulatory practices and have participated in many rate-making cases involving both investor-owned and publicly-owned utilities. This work has included Integrated Resource Planning assessments that include renewables, determining how to set renewables/green rate riders or system benefit charges, and providing advice on how to determine rate recovery for such resources. Recently, SEA and La Capra Associates conducted studies that estimate the overall rate impact of RPS scenarios to consumers in Connecticut and New York. La Capra Associates has also been involved with ratemaking cases related to renewables procurement in regulated states. GDS has prepared studies on the rate impacts of solar energy systems for utility and governmental clients in the Southeast.

3) **RPS Design and Cost/Benefit Analysis.** La Capra Associates, GDS and SEA have been closely involved in the development of RPS legislation and policies in multiple states in the past five years. We have provided advice on RPS policy goals, structures, and potential impacts to policy makers, regulators, and market participants in Massachusetts, New York, Connecticut, Rhode Island, Delaware, Vermont, Wisconsin, Hawaii, New Hampshire, Maine, Texas, Georgia and California. As part of this work, we have provided cost/benefit analyses that capture many of the externalities of incorporating renewables and demand-side resources into a power mix.

4) **RPS Implementation.** The La Capra Associates Team also has first-hand experience in various states in translating RPS policies to specific rules and regulations and addressing the full range of RPS implementation issues. La Capra Associates, GDS and SEA have helped states in the implementation phase on several fronts, including: defining eligibility rules, guidance on procurement methods, and contracting for renewable energy and renewable energy certificates.

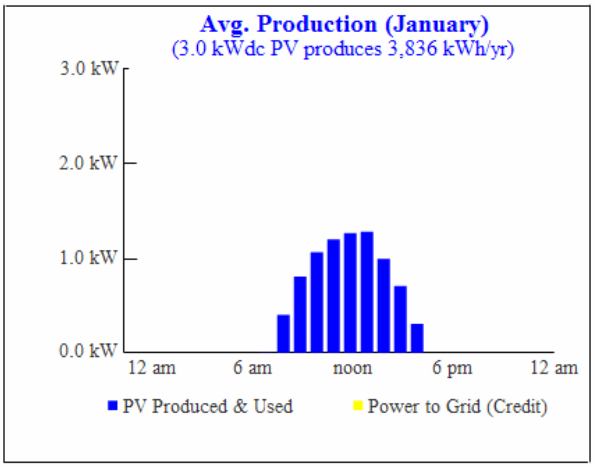
5) **Market/Portfolio Impacts of Renewables.** La Capra Associates also has a strong power supply analysis team and has performed detailed studies regarding the impact of renewables on regional power markets and power supply portfolios with respect to generation dispatch, cost and emissions/environmental impact. GDS has worked for the North Carolina Electric Membership Cooperative on power supply planning for many years and has knowledge of the North Carolina grid's design and operational characteristics.

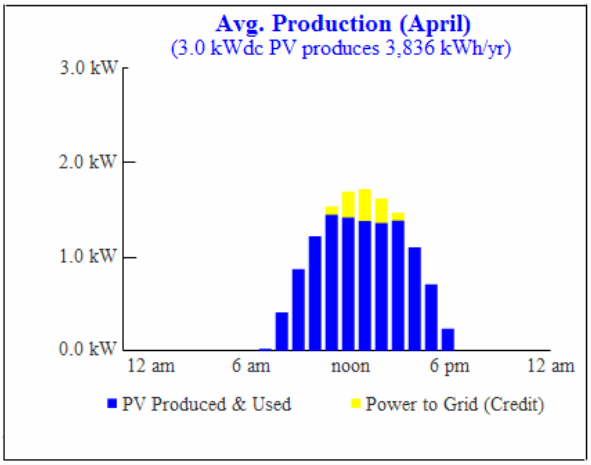
6) **Renewable Project Assessment.** All members of the La Capra Associates Team have provided financial feasibility assessments to a wide range of entities considering developing and purchasing the output of renewable energy resources. Our understanding of the financial and practical requirements faced by developers and potential wholesale and retail purchasers allows us to provide solid, practical policy advice that effectively and objectively assesses potential renewable energy resource development.

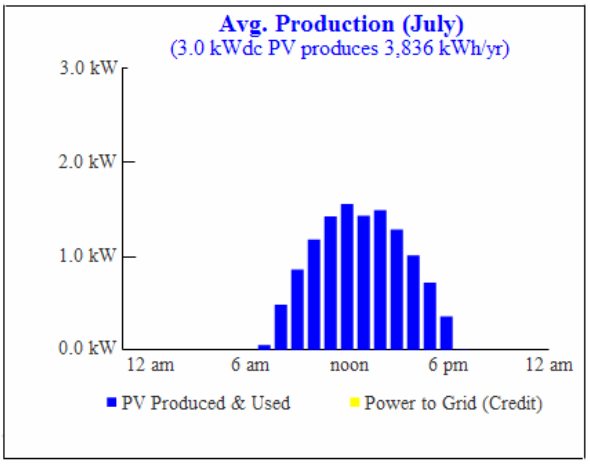
US EPA ARCHIVE DOCUMENT

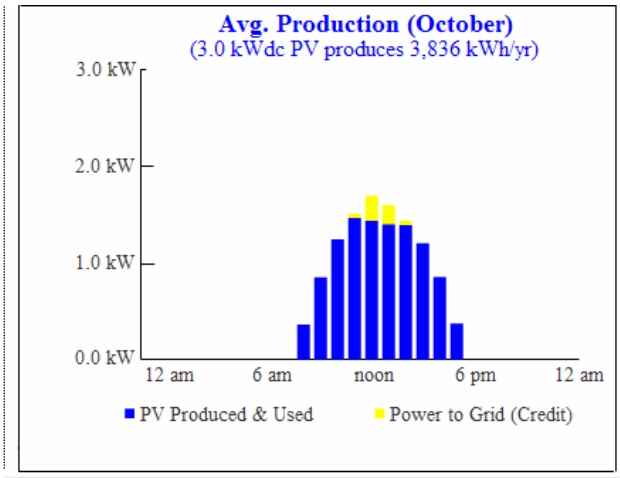
Appendix C: Solar Contribution

The following graphs illustrate solar photovoltaic energy production from a 3 kW DC system in winter, spring, summer, and fall for Raleigh, North Carolina. Local solar insolation data is used along with average residential load profiles. The graphs were generated using the North Carolina version of the *Clean Power Estimator*, a nationally-recognized PV economics evaluation tool, available at http://www.clean-power.com/nc/.









Source: North Carolina Solar Center

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Appendix D: Comments to TVA from North Carolina Attorney General Roy Cooper

State of North Carolina
Roy Cooper
Attorney General

February 4, 2002

Ms. Anita Rose
Tennessee Valley Authority
P.O. Box 1649
Norris, TN 37828

Transmission by U.S. Mail, facsimile to (865) 632-1493
and e-mail: akrose@tva.gov

Re: Environmental Assessment for the 20-MW Windfarm and Associated Energy Storage System Facility

Dear Ms. Rose:

I am making these comments on behalf of the State of North Carolina in my capacity as North Carolina's Attorney General. The State of North Carolina is pleased that TVA is considering wind-generated electricity alternatives. Like TVA, we are very interested in protecting the quality of our air and believe it is important to explore alternative ways to provide and conserve energy while pursuing that goal. It is, of course, also important when evaluating various alternatives in pursuit of this goal to balance them wisely with other important public values and concerns. It is mainly for this purpose that I write.

Unfortunately, the Environmental Assessment ("EA") has misinterpreted North Carolina's public policy with regard to mountain ridge top protection as set forth in "North Carolina Mountain Ridge Protection Act of 1983" N.C. Gen. Stat. §§ 113A-205 et seq. This public policy should be given due consideration and weight, because the Stone Mountain site is almost on the Tennessee-North Carolina border, and the EA itself concludes that "construction and operation of the [Stone Mountain] windfarm facilities would permanently alter the visual landscape character resulting in a significant [adverse] visual impact [in Watauga County, North Carolina,]" and "would create substantial visual discord and adverse contrast while reducing scenic attractiveness and tranquillity." (EA 4-30, 4-31).

The North Carolina Mountain Ridge Protection Act of 1983 N.C. Gen. Stat. §§ 113A-205 et seq. (1999)), prohibits the construction of buildings or structures over 40 feet tall on protected mountain ridges in North Carolina. According to the EA, "The North Carolina Act specifically excludes structures of a slender nature from being considered "tall buildings or structures"

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US EPA ARCHIVE DOCUMENT

Ms. Anita Rose
February 5, 2002
Page 2

regulated under the act."(EA 3-43) Apart from noting, correctly, that the windfarm will not actually be in North Carolina, this brief discussion is the EA's entire analysis of the North Carolina policy. It implies clearly, but incorrectly, that the North Carolina Mountain Ridge Protection Act would permit construction of the proposed windfarm in North Carolina. This is not the case.

The North Carolina Act must be interpreted in light of its purposes. These include the legislative finding that "Tall or major buildings and structures located on ridges are a hazard to air navigation and persons on the ground and detract from the natural beauty of the mountains." N.C. Gen. Stat. § 113A-207. In light of these findings, a windfarm such as that proposed here, with 13 to16 300-foot high towers (including the rotors) with flashing stroboscopic lights, spaced on average 900 feet apart for two miles along the top of a 4400 foot high mountain ridge, cannot properly be construed to fall within the exception for "Structures of a relatively slender nature and minor vertical projections of a parent building, including chimneys, flagpoles, flues, spires, steeples, belfries, cupolas, antennas, poles, wires, or windmills." N.C. Gen. Stat. § 113A-206 (3)(b). The Legislature in 1983 had in mind, the traditional, solitary farm windmill which has long been in use in rural communities, not windfarm turbines of the size, type or certainly number proposed here, especially when "*all the turbines would probably be seen together from most viewing locations.*" (EA 4-31)

The North Carolina Mountain Ridge Protection Act also has an exception for "any equipment for the transmission of electricity or communications or both," much like the Johnson County Act. N.C. Gen. Stat. § 113A-206 (3)(a) However, this exception would not apply to the proposed windfarm. The proposed windfarm would clearly be a "generating" facility. Traditionally, electricity generation and electricity transmission are viewed as distinct and separate concepts and functions. Indeed, separate certificates from our Utilities Commission are required for construction of electric transmitting lines and electric generating facilities. N.C. Gen. Stat. § 62-110; N.C. Gen. Stat. § 62-110.1. We believe that no interpretation of N.C. Gen. Stat. § 113A-206 (3)(a) is required. The windfarm would not be included within the exception by the plain meaning of the word "transmission." However, even if one were to conclude that there was some ambiguity requiring interpretation, we see no basis in this statute to read "transmission" more broadly. It is easy to see why the legislature would wish to make an exception for transmission lines which typically run up one side of a ridge, over the top at one point and down the other side. Such lines do relatively little to interfere with the beauty and integrity of a ridge line or create a potential safety hazard. The windfarm proposed here is a far cry from such a minimal intrusion.

The EA may well be correct that The Mountain Ridge Protection Act of Johnson County appears to be modeled after the North Carolina Mountain Ridge Protection Act and that the definition of protected mountain ridges used in the North Carolina statute is essentially the same as in the Johnson County Act. We do not purport to be experts in Tennessee law. However, for the reasons just mentioned, we question the validity of the EA's conclusion, apparently without analysis, that the exemption for equipment used for the "transmission of electricity" in the Mountain Ridge Protection Act of Johnson County exempts its application to the proposed windfarm "generating"

US EPA ARCHIVE DOCUMENT

Ms. Anita Rose
February 5, 2002
Page 3

equipment. We would be surprised if Tennessee law, like North Carolina's and that of most states, generally does not distinguish between electric *generating* facilities and electric *transmission* facilities.

We hope that you will give these comments due consideration and weight when considering the Stone Mountain alternative.[1] Thank you for the opportunity to make these comments on behalf of the State of North Carolina.

Very truly yours,

Roy Cooper

RAC/sm

cc: The Honorable Michael F. Easley, Governor
State of North Carolina
The Honorable William Ross, Secretary
Department of Environment & Natural Resources

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Appendix E: Additional Resource Discussions

Anaerobic Digesters

Current installations can cost anywhere between $50 to $200[137] per head depending on the farm size, animal weight, included components, and the type of operation. There are huge economies of scale with larger farms, as the electric generation system cost does not differ much between a 4320 head or 8800 head farm. The cost differential stems from the cost of a larger anaerobic digester and nitrification system needed for operations and the handling of more waste. For this analysis, the cost for a 12,000 head farm is assumed to be $600,000,[138] or $4000/kW for a 150 kW system, which is in-line with other sources of information. Anaerobic digesters also qualify for the North Carolina Renewable Energy Tax Credit of 35% of project cost that can be taken over 5 years.

Assessing the operation and maintenance costs is also difficult, because it is difficult to attribute which portion of costs should be allocated to electricity generation or normal farm operations. The O&M costs can range between $90/kW-year to $450/kW-year[139] depending on what costs are included. For our purposes, we assume the total costs are split evenly between electricity generation and normal farm operations.

The Barham Farm project uses the waste heat and effluent to feed a greenhouse, whose cost is not included in the cost estimates above. There is some cost benefit of utilizing the effluent in place of standard fertilizer applications, which is roughly 0.35 cents/kWh[140] in savings for a 12,000 head farm.

Poultry Litter

The estimate for total North Carolina state potential for firing poultry litter is derived as follows: [heat content of poultry litter (6200 btu/lb) * 1.415 million tons/year * (2000 lbs/ton)] / [(13,000 btu/kWh) * 8760 hours * 90% capacity factor] = 172 MW.

In estimating the cost of poultry litter as a fuel input, a 50-mile delivery radius ($0.25/ton-mile) is assumed for transportation costs as the poultry facilities are well scattered around the State. Additionally, $4/ton for cleanout and $13.50/ton is assumed for payment to poultry farmers for the value of the poultry litter. Since there is an inherent nutrient value of $20-$35/ton applied for poultry litter, biomass plants would need to compete with the fuel's alternative purpose. Thus, if

[137] According to cost modeling for the Smithfield project that was based on the Barham farm anaerobic digester system, installation costs for a 4000 head farrow-to-wean operation may cost about $425,000 ($106/head). However, for a 4320 head feeder-to-finish operation, the cost is about $365,000 ($85/head) and an 8800 head feeder-to-finish operation cost is about $500,000 ($57/head).

[138] In extrapolating to a 12,000 head farm, the cost is estimated to be about $600,000 ($50/head).

[139] The Smithfield project estimates O&M to total about $55,000 for an 8800 head operation--about 50% is attributed to the nitrification/denitrification systems and about 30% is attributed to digester maintenance. Only the remaining 20% is related to electricity generation.

[140] The Smithfield analysis also included a potential cost savings a year of $2380-$3090 per year for an 8800 head facility if the effluent is applied to row crops instead of standard fertilizer applications.

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poultry litter is used as a fertilizer, with cost of application and cleanout totaling $8-$25/ton, the net value to the poultry farmer can be anywhere between $4-$23/ton.[141] In this assessment, $13.50/ton is used as payment to farmers for the poultry litter and the total delivered fuel cost is $30/ton or $2.40/mmbtu. However, the ash from biomass firing (about 5% of input material) can also be used as fertilizer, with more concentrated nutrients, with a value that has been estimated at $30-$50/ton. In the analysis, we assume a value of $40/ton for the ash output, which offsets the cost of energy by about $2/MWh.

Wind

The cost of wind projects today is about 30%-40% higher than two years ago. There are several reasons for this increase. To start, there has been a dramatic increase in demand in the U.S. over the past few years, partially as a result of the increase in RPS requirements, coupled with an expiring production tax credit (PTC). This put pressure on the supply of turbines, resulting in increased turbine prices. Additionally, the costs for raw materials and turbine components have also increased due to unfavorable exchange rates and supply shortages. Prices in the near term are likely to remain at these levels, but with expansion of manufacturing capabilities and additional technology improvements, the expectation is that prices will decline over the long term.

[141] Lichtenberg et al, "Economic Value of Poultry Litter Supplies in Alternative Uses," October 2002, University of Maryland.

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Appendix F: Renewable Portfolio Assumptions and Results

Fuel Cost Assumptions

	Fuel Cost (2006$)	Units	High Case (2006$)	Units
Biomass Fuel Costs Block 1	$40.00	$/dry ton		
Biomass Fuel Costs Block 2	$50.00	$/dry ton		
Chicken Litter (50 mile radius)	$30.00	$/dry ton		
C&D Avoided Cost	$14.00	$/dry ton		
Coal Price	$2.75	$/mmbtu	$3.00	$/mmbtu
Natural Gas Price	$8.00	$/mmbtu	$10.00	$/mmbtu
Natural Gas Price for Combustion Turbines	$7.20	$/mmbtu	$9.20	$/mmbtu
Oil Price	$7.25	$/mmbtu	$9.25	$/mmbtu
Nuclear Fuel Price	$0.50	$/mmbtu	$0.50	$/mmbtu

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Model Cost Assumptions

Resource Type	Resource Block	Capacity Factor (2006 Assumption)	Modeled Project Size (MW)	Levelized Cost per MWH 2008	Levelized Cost per MWH 2017	NOMINAL INSTALLED COSTS Total Installed Cost (nominal$/kW of rated max output) 2008	NOMINAL INSTALLED COSTS Total Installed Cost (nominal$/kW of rated max output) 2017	INSTALLED COSTS IN 2006$ Total Installed Cost (2006$/kW of rated max output) 2008	INSTALLED COSTS IN 2006$ Total Installed Cost (2006$/kW of rated max output) 2017	Technology Decline Rate (% in Real$)
Wind Farms (10-50 MW)	Class III (Eastern)	29.0%	30	$72.29	$74.14	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class IV (Eastern)	32.0%	30	$62.99	$64.04	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Clusters (2-10 MW)	Class III (Eastern)	29.0%	5	$90.79	$94.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Clusters (2-10 MW)	Class IV (Eastern)	32.0%	5	$79.75	$82.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Farms (10-50 MW)	Class III (Western)	29.0%	30	$72.29	$74.14	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class IV (Western)	32.0%	30	$62.99	$64.04	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Farms (10-50 MW)	Class V (Western)	35.0%	30	$55.29	$55.67	$1,786	$1,860	$1,700	$1,417	2.0%
Wind Clusters (2-10 MW)	Class IV (Western)	32.0%	5	$79.75	$82.39	$2,101	$2,188	$2,000	$1,667	2.0%
Wind Clusters (2-10 MW)	Class V (Western)	35.0%	5	$70.61	$72.45	$2,101	$2,188	$2,000	$1,667	2.0%
Off-shore wind Class 4	Wind (Offshore)	32%	50	$105.19	$107.71	$2,522	$2,625	$2,400	$2,001	2.0%
Off-shore Wind Class 5	Wind (Offshore)	35%	50	$93.87	$95.59	$2,522	$2,625	$2,400	$2,001	2.0%
Biomass blended co-firing	Zone A Cost Block 1	75%	20	$5.14	$6.41	$79	$98	$75	$75	0.0%
Biomass blended co-firing	Zone B Cost Block 1	75%	20	$4.73	$5.90	$79	$98	$75	$75	0.0%
Biomass retrofit co-firing	Zone C	75%	0	$9.32	$11.64	$242	$302	$230	$230	0.0%
Biomass retrofit co-firing	Zone D	75%	49	$17.90	$22.35	$242	$302	$230	$230	0.0%
Biomass blended co-firing	Zone A Cost Block 2	75%	20	$17.90	$22.35	$242	$302	$230	$230	0.0%
Biomass blended co-firing	Zone B Cost Block 2	75%	20	$13.31	$16.61	$79	$98	$75	$75	0.0%
Biomass retrofit co-firing	Zone E Cost Block 2	75%	67	$17.90	$22.35	$242	$302	$230	$230	0.0%
New Biomass (gasification)	Wood Block 1 plus C&D	90%	25	$110.58	$120.78	$3,887	$3,866	$3,700	$2,946	2.5%
New Biomass (fluidized bed)	Wood Block 1 plus C&D	90%	25	$96.91	$112.25	$3,152	$3,436	$3,000	$2,618	1.5%
New Biomass (stoker)	Wood Block 1 plus C&D	90%	25	$89.52	$111.78	$2,837	$3,543	$2,700	$2,700	0.0%
New Biomass (gasification)	Wood Block 2	90%	25	$124.17	$137.74	$3,887	$3,866	$3,700	$2,946	2.5%
New Biomass (fluidized bed)	Wood Block 2	90%	25	$111.91	$130.98	$3,152	$3,436	$3,000	$2,618	1.5%
New Biomass (stoker)	Wood Block 2	90%	25	$103.65	$129.42	$2,837	$3,543	$2,700	$2,700	0.0%
New Hydro Cost Block 1	Hydro (new <10 MW ROR)	45%	2.5	$103.74	$129.55	$3,467	$4,330	$3,300	$3,300	0.0%
New Hydro Cost Block 2	Hydro (new >10 MW ROR)	45%	25	$80.59	$100.65	$2,889	$3,608	$2,750	$2,750	0.0%
Undeveloped Hydro Block 1	Hydro (new <10 MW ROR)	45%	2.5	$139.03	$173.62	$4,623	$5,773	$4,400	$4,400	0.0%
Undeveloped Hydro Block 1	Hydro (new >10 MW ROR)	45%	30	$115.88	$144.71	$4,045	$5,052	$3,850	$3,850	0.0%
Hydro Upgrades Cost Block 1	Hydro (new <10 MW)	45%	0	$44.68	$55.79	$1,734	$2,165	$1,650	$1,650	0.0%
Hydro Upgrades Cost Block 2	Hydro (new >10 MW)	45%	13	$24.61	$30.74	$1,156	$1,443	$1,100	$1,100	0.0%
Landfill Gas w/ collection	Landfill Gas	80%	5.0	$46.99	$58.67	$1,523	$1,903	$1,450	$1,450	0.0%
Fibrowatt Tech	Chicken Litter/Ag Waste	90%	35	$98.89	$123.48	$3,075	$3,841	$2,927	$2,927	0.0%
Anaerobic Gas (Hog Waste)	Anaerobic Gas (Hog Waste)	75%	0.150	$78.93	$91.66	$4,203	$4,376	$4,000	$3,335	2.0%
Solar PV	Residential	19%	0.002	$349.87	$390.05	$10,506	$11,452	$10,000	$8,728	1.5%
Solar PV	Commercial	19%	0.025	$202.79	$229.73	$8,405	$9,162	$8,000	$6,983	1.5%
Conventional Resources				**First Year Cost (not levelized)**						
Pulverized Coal (Supersub)		90%	750	$66.16	$82.62	$1,681	$2,099	$1,600	$1,600	
Combined Cycle		50%	250	$74.80	$93.41	$735	$918	$700	$700	
Combustion Turbine (Frame)		5%	150	$326.01	$407.14	$525	$656	$500	$500	
Nuclear		90%	1100	$52.48-$100.03	$65.54-$124.93	$2,101-$4,203	$2,625-$5,248	$2000-$4000	$2000-$4000	

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Model Cost Assumptions (cont'd)

		Operating Cost Assumptions (2006$)						LEVELIZED OPERATING COSTS BEFORE PTC	
Resource Type	Resource Block	Fixed O&M (2006$/kw yr)	Variable O&M Costs (2006$/MWh)	Fuel Heat Rate (btu/kWh)	Fuel Costs 2006$/mmBtu)	PTC Eligible? (%)	Byproducts ($/MWh)	Total Levelized Operating Costs, $/MWh, 2008 projects	Total Levelized Operating Costs, $/MWh, 2017 projects
Wind Farms (10-50 MW)	Class III (Eastern)	$45	$2	-	0.00	1.00		$23.96	$29.91
Wind Farms (10-50 MW)	Class IV (Eastern)	$45	$2	-	0.00	1.00		$21.94	$27.39
Wind Clusters (2-10 MW)	Class III (Eastern)	$55	$2	-	0.00	1.00		$28.75	$35.89
Wind Clusters (2-10 MW)	Class IV (Eastern)	$55	$2	-	0.00	1.00		$26.28	$32.81
Wind Farms (10-50 MW)	Class III (Western)	$45	$2	-	0.00	1.00		$23.96	$29.91
Wind Farms (10-50 MW)	Class IV (Western)	$45	$2	-	0.00	1.00		$21.94	$27.39
Wind Farms (10-50 MW)	Class V (Western)	$45	$2	-	0.00	1.00		$20.27	$25.31
Wind Clusters (2-10 MW)	Class IV (Western)	$55	$2	-	0.00	1.00		$26.28	$32.81
Wind Clusters (2-10 MW)	Class V (Western)	$55	$2	-	0.00	1.00		$24.23	$30.26
Off-shore wind Class 4	Wind (Offshore)	$65	$2	-	0.00	1.00		$30.61	$36.15
Off-shore Wind Class 5	Wind (Offshore)	$65	$2	-	0.00	1.00		$28.20	$33.31
Biomass blended co-firing	Zone A Cost Block 1	$12	$5	12,000	(0.37)	0.00		$2.91	$3.64
Biomass blended co-firing	Zone B Cost Block 1	$12	$5	12,000	(0.40)	0.00		$2.51	$3.13
Biomass retrofit co-firing	Zone C	$12	$5	12,000	(0.40)	0.00		$2.51	$3.13
Biomass retrofit co-firing	Zone D	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass blended co-firing	Zone A Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass blended co-firing	Zone B Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
Biomass retrofit co-firing	Zone E Cost Block 2	$12	$5	12,000	0.19	0.00		$11.09	$13.84
New Biomass (gasification)	Wood Block 1 plus C&D	$100	$10	12,500	2.05	1.00	1.47	$56.88	$71.02
New Biomass (fluidized bed)	Wood Block 1 plus C&D	$75	$10	13,800	2.05	1.00	1.62	$56.08	$70.01
New Biomass (stoker)	Wood Block 1 plus C&D	$75	$10	13,000	2.05	1.00	1.53	$54.20	$67.67
New Biomass (gasification)	Wood Block 2	$100	$10	12,500	2.94	1.00	1.47	$70.47	$87.98
New Biomass (fluidized bed)	Wood Block 2	$75	$10	13,800	2.94	1.00	1.62	$71.08	$88.73
New Biomass (stoker)	Wood Block 2	$75	$10	13,000	2.94	1.00	1.53	$68.33	$85.31
New Hydro Cost Block 1	Hydro (new <10 MW ROR)	$20	$5			1.00		$12.24	$15.29
New Hydro Cost Block 2	Hydro (new >10 MW ROR)	$10	$3			1.00		$6.73	$8.40
Undeveloped Hydro Block 1	Hydro (new <10 MW ROR)	$20	$5			1.00		$12.24	$15.29
Undeveloped Hydro Block 1	Hydro (new >10 MW ROR)	$10	$3			1.00		$6.73	$8.40
Hydro Upgrades Cost Block 1	Hydro (new <10 MW)	$0	$5			1.00		$6.08	$7.59
Hydro Upgrades Cost Block 2	Hydro (new >10 MW)	$0	$3			1.00		$3.65	$4.55
Landfill Gas w/ collection	Landfill Gas	$200				1.00		$34.69	$43.31
Fibrowatt Tech	Chicken Litter/Ag Waste	$75	$10	13,000	2.42	1.00	2.10	$59.40	$74.15
Anaerobic Gas (Hog Waste)	Anaerobic Gas (Hog Waste)	$270	$0	14,000	0.00	0.00	3.46	$45.74	$57.11
Solar PV	Residential	$75				0.00	0.00	$54.77	$68.38
Solar PV	Commercial	$75				0.00	0.00	$54.77	$68.38
Conventional Resources									
Pulverized Coal (Supersub)		$30	$5	9,100	2.75	0.00			
Combined Cycle		$12	$2	7,000	8.00	0.00			
Combustion Turbine (Frame)		$12	$8	10,200	7.20	0.00			
Nuclear		$60	$3	10,000	0.50	0.50			

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Scenarios Annual Costs

($million)	10-year NPV	20-year NPV	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utilities' Portfolio Cost	$7,028	$15,051	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,773	$3,478	$3,450	$3,427	$3,407	$3,389	$3,374	$3,361	$3,351	$3,341	$3,333	$3,327
Scenarios																						
I. NCGP Criteria (5%)																						
Alternative Portfolio Cost	$7,646	$16,036	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$2,934	$3,614	$3,592	$3,573	$3,557	$3,543	$3,531	$3,521	$3,512	$3,505	$3,499	$3,494
Avoided Marginal Energy	($243)	($257)	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	($40)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)
Delta Between Portfolios	$375	$727	$9	$16	$33	$44	$50	$67	$113	$150	$121	$131	$136	$141	$145	$148	$151	$153	$155	$157	$159	$160
II. Expanded Renewables (5%)																						
Alternative Portfolio Cost	$7,484	$15,653	$15	$103	$278	$868	$1,371	$1,943	$2,062	$2,154	$2,862	$3,525	$3,502	$3,482	$3,465	$3,450	$3,438	$3,427	$3,418	$3,410	$3,403	$3,397
Avoided Marginal Energy	($251)	($283)	($5)	($14)	($22)	($30)	($31)	($65)	($101)	($145)	($41)	($12)	($12)	($12)	($13)	($13)	($13)	($14)	($14)	($14)	($15)	($15)
Delta Between Portfolios	$204	$319	$9	$19	$32	$27	$28	$42	$46	$86	$47	$35	$39	$43	$46	$48	$50	$52	$53	$54	$55	$55
III. Expanded Renewables Plus EE (5%)																						
Alternative Portfolio Cost	$7,024	$14,632	$7	$81	$248	$831	$1,322	$1,854	$1,954	$1,999	$2,659	$3,285	$3,263	$3,244	$3,227	$3,213	$3,201	$3,191	$3,183	$3,175	$3,169	$3,164
EE Administration Costs	$157	$205	$22	$23	$24	$25	$26	$26	$27	$28	$30	$31	$12	$18	$19	$20	$22	$22	$23	$24	$25	$26
Avoided Marginal Energy	($248)	($262)	($6)	($12)	($22)	($31)	($34)	($63)	($104)	($143)	($37)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)	($7)
Delta Between Portfolios	($95)	($476)	$23	$21	$26	$14	$3	($18)	($38)	($39)	($122)	($167)	($181)	($171)	($166)	($161)	($157)	($154)	($151)	($149)	($146)	($144)
I. NCGP Criteria (10%)																						
Alternative Portfolio Cost	$8,983	$18,492	$72	$220	$431	$1,139	$1,711	$2,070	$2,335	$2,584	$3,350	$4,096	$4,073	$4,052	$4,034	$4,018	$4,004	$3,991	$3,980	$3,970	$3,961	$3,952
Avoided Marginal Energy	($574)	($751)	($27)	($62)	($92)	($141)	($169)	($33)	($106)	($195)	($93)	($66)	($68)	($70)	($71)	($73)	($75)	($77)	($79)	($81)	($83)	($85)
Delta Between Portfolios	$1,381	$2,691	$45	$88	$116	$187	$231	$201	$314	$466	$484	$552	$554	$556	$557	$556	$555	$553	$551	$548	$545	$541
II. Expanded Renewables (10%)																						
Alternative Portfolio Cost	$8,281	$17,286	$63	$198	$393	$1,062	$1,338	$1,977	$2,215	$2,401	$3,159	$3,882	$3,859	$3,839	$3,821	$3,805	$3,791	$3,778	$3,767	$3,757	$3,748	$3,739
Avoided Marginal Energy	($466)	($638)	($31)	($64)	($98)	($142)	$22	($35)	($109)	($190)	($93)	($64)	($66)	($67)	($69)	($71)	($73)	($74)	($76)	($78)	($80)	($82)
Delta Between Portfolios	$787	$1,597	$32	$63	$71	$109	$49	$106	$191	$287	$292	$340	$343	$345	$345	$345	$344	$343	$340	$337	$334	$331
III. Expanded Renewables Plus EE (10%)																						
Alternative Portfolio Cost	$6,973	$14,632	$32	$120	$302	$919	$1,140	$1,738	$1,889	$1,993	$2,663	$3,306	$3,285	$3,267	$3,251	$3,237	$3,224	$3,213	$3,203	$3,194	$3,186	$3,179
EE Administration Costs	$314	$409	$44	$46	$48	$49	$51	$53	$55	$57	$60	$62	$25	$36	$38	$41	$43	$45	$47	$47	$51	$52
Avoided Marginal Energy	($436)	($567)	($26)	($59)	($98)	($142)	$29	($33)	($105)	($180)	($83)	($49)	($50)	($51)	($53)	($54)	($55)	($57)	($58)	($60)	($61)	($63)
Delta Between Portfolios	($177)	($577)	$50	$37	$27	$15	($92)	($78)	($76)	($54)	($133)	($158)	($191)	($176)	($171)	($166)	($163)	($161)	($159)	($159)	($158)	($158)

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Sensitivities Annual Costs

($million)	10-year NPV	20-year NPV	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Sensitivities Test Against Reference Case (NCGP Critieria 5%)																						
NCGP (no co-fire)																						
Alternative Portfolio Cost	$7,875	$16,477	$64	$177	$378	$1,004	$1,544	$1,802	$1,951	$2,070	$3,128	$3,712	$3,689	$3,668	$3,650	$3,634	$3,620	$3,608	$3,598	$3,589	$3,581	$3,574
Avoided Marginal Energy	($268)	($319)	($26)	($48)	($77)	($99)	($115)	$59	$30	($14)	($101)	($19)	($20)	($20)	($21)	($21)	($22)	($22)	($23)	($23)	($24)	($24)
Delta Between Portfolios	$579	$1,106	$38	$59	$77	$94	$118	$25	$66	$132	$253	$216	$219	$221	$223	$224	$225	$225	$225	$224	$224	$223
5 Yr PTC																						
Alternative Portfolio Cost	$7,755	$16,344	$15	$98	$277	$886	$1,395	$1,980	$2,159	$2,264	$3,003	$3,699	$3,677	$3,658	$3,642	$3,628	$3,616	$3,605	$3,597	$3,589	$3,583	$3,578
Avoided Marginal Energy	($243)	($257)	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	($40)	($5)	($5)	($6)	($6)	($6)	($6)	($6)	($6)	($6)	($7)	($7)
Delta Between Portfolios	$484	$1,036	$9	$16	$33	$44	$50	$82	$143	$199	$189	$216	$221	$225	$229	$233	$235	$238	$240	$242	$243	$244
PV Multiplier																						
Alternative Portfolio Cost	$7,589	$15,948	$15	$98	$281	$873	$1,384	$1,958	$2,110	$2,205	$2,885	$3,601	$3,579	$3,560	$3,544	$3,530	$3,518	$3,508	$3,499	$3,492	$3,486	$3,480
Avoided Marginal Energy	($203)	($170)	($5)	($11)	($21)	($25)	($27)	($57)	($88)	($130)	($18)	$14	$14	$14	$15	$15	$15	$16	$16	$17	$17	$0
Delta Between Portfolios	$358	$726	$9	$16	$36	$37	$45	$66	$107	$151	$94	$137	$143	$148	$152	$156	$159	$162	$165	$167	$169	$154
High Fuel																						
Utilities Portfolio Cost	$7,562	$16,322	$0	$75	$239	$868	$1,407	$1,972	$2,061	$2,075	$2,991	$3,753	$3,733	$3,717	$3,704	$3,694	$3,686	$3,681	$3,679	$3,678	$3,678	$3,680
Alternative Portfolio Cost	$8,103	$17,145	$12	$97	$286	$933	$1,476	$2,085	$2,258	$2,348	$3,123	$3,858	$3,842	$3,830	$3,820	$3,813	$3,808	$3,805	$3,803	$3,804	$3,805	$3,808
Avoided Marginal Energy	($274)	($290)	($6)	($12)	($23)	($35)	($37)	($70)	($114)	($160)	($46)	($6)	($6)	($6)	($6)	($7)	($7)	($7)	($7)	($7)	($7)	($8)
Delta Between Portfolios	$267	$533	$6	$11	$24	$30	$32	$44	$83	$113	$86	$98	$103	$107	$110	$113	$115	$116	$118	$119	$120	$120
Low Nuclear Cost																						
Utilities Portfolio Cost	$6,904	$14,202	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,693	$3,246	$3,204	$3,159	$3,119	$3,082	$3,049	$3,019	$2,990	$2,962	$2,985	$3,052
Alternative Portfolio Cost	$7,529	$15,649	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$2,742	$3,522	$3,493	$3,468	$3,446	$3,427	$3,409	$3,394	$3,380	$3,367	$3,404	$3,393
Avoided Marginal Energy	($222)	($227)	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	$7	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	$0
Delta Between Portfolios	$403	$1,220	$9	$16	$33	$44	$50	$67	$113	$150	$56	$274	$287	$307	$325	$342	$358	$373	$387	$402	$416	$342
High Nuclear Cost																						
Utilities Portfolio Cost	$7,331	$16,174	$0	$70	$224	$811	$1,312	$1,836	$1,915	$1,924	$2,974	$4,043	$3,972	$3,892	$3,818	$3,751	$3,689	$3,631	$3,575	$3,521	$3,516	$3,556
Alternative Portfolio Cost	$7,754	$16,396	$15	$98	$277	$886	$1,395	$1,965	$2,128	$2,215	$3,023	$3,794	$3,753	$3,716	$3,683	$3,653	$3,626	$3,601	$3,578	$3,555	$3,583	$3,563
Avoided Marginal Energy	($222)	($227)	($5)	($11)	($20)	($31)	($33)	($63)	($101)	($142)	$7	($2)	($2)	($2)	($2)	($2)	($2)	($3)	($3)	($3)	($3)	$0
Delta Between Portfolios	$200	($5)	$9	$16	$33	$44	$50	$67	$113	$150	$56	($251)	($222)	($178)	($137)	($100)	($65)	($32)	($0)	$32	$64	$7

Appendix G: Energy Efficiency Measures

Excerpt from "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.

Table 5-4: Total Annual Achievable Cost-Effective Potential kWh Savings for Electric Energy Efficiency In North Carolina By 2017
Residential Sector - Market Driven and Retrofit Savings

1	2	5	6	7	8
Measure #	Measure Description	Levelized Cost Per kWh SF	Levelized Cost Per kWh MF	Total Cumulative Annual kWh Savings by 2017 (Levelized Cost $0.10 per kWh)	Total Cumulative Annual kWh Savings by 2017 (Levelized Cost $0.05 per kWh)
1	Refrigerator Turn-in	0.075	0.075	162,732,169	0
2	Freezer Turn-in	0.078	0.078	29,921,244	0
3	Room AC Turn-in without Replacement	0.818	0.818	0	0
4	Room AC Turn-in with ES Replacement	2.338	2.338	0	0
5	Energy Star Single Room Air Conditioner	0.036	0.036	20,698,606	20,698,606
6	Energy Star Compliant Top Freezer Refrigerator	0.053	0.053	81,446,188	0
7	Energy Star Compliant Bottom Mount Freezer Refrigerator	0.049	0.049	15,539,075	15,539,075
8	Energy Star Compliant Side-by-Side Refrigerator	0.045	0.045	45,813,481	45,813,481
9	Energy Star Compliant Upright Freezer (Manual Defrost)	0.092	0.092	20,932,558	0
10	Energy Star Compliant Chest Freezer	0.098	0.098	18,626,619	0
11	Energy Star Built-In Dishwasher (Electric)	0.113	0.113	0	0
12	Energy Star Clothes Washers with Electric Water Heater	0.162	0.162	0	0
13	Energy Star Clothes Washers with Non-Electric Water Heater	1.593	1.593	0	0
14	Energy Star Dehumidifier (40 pt)	0.000	0.000	21,301,956	21,301,956
15	Standby-Power	0.023	0.023	424,192,135	424,192,135
16	Pool Pump & Motor	0.065	0.065	93,827,113	0
17	Energy Star Compliant Programmable Thermostat	0.008	0.008	1,122,063,781	1,122,063,781
18	High Efficiency Central AC	0.098	0.098	746,606,300	0
19	CFL's: Homes with partial CFL installation	0.003	0.003	613,275,147	613,275,147
20	CFL's: Homes without CFL installation	0.003	0.003	812,263,289	812,263,289
21	Water Heater Blanket	0.008	0.008	406,337,894	406,337,894
22	Low Flow Shower Head	0.008	0.008	552,619,535	552,619,535
23	Pipe Wrap	0.064	0.064	53,636,602	0
24	Low Flow Faucet Aerator	0.018	0.018	92,645,039	92,645,039
25	Solar Water Heating	0.085	0.085	0	0
26	Efficient Water Heating	0.035	0.035	0	0
27	Efficient Furnace Fan Motor (Fuel Oil)	0.021	0.021	100,476,279	100,476,279
28	Efficient Furnace Fan Motor (Natural Gas)	0.021	0.021	200,952,558	200,952,558
29	Efficient Furnace Fan Motor (Propane)	0.021	0.021	108,849,303	108,849,303
30	Energy Star Windows	0.033	0.033	4,305,096,788	4,305,096,788
31	Insulation and Weatherization	0.024	0.024	2,765,815,391	2,765,815,391
32	Residential New Construction (Electric)	0.116	N/A	0	0
33	Residential New Construction (Non-Electric)	0.163	N/A	0	0
34	Low Income Insulation & Weatherization	0.049	N/A	398,327,232	398,327,232

Maximum Achievable Cost Effective kWh Savings		13,213,996,282	12,006,267,489
Forecast 2017 North Carolina Residential kWh Sales		71,078,000,000	71,078,000,000
Savings as a percent of forecasted residential sales in 2017		18.6%	16.9%

Note: The levelized costs were obtained from Appendix A, column 17. The kWh savings shown above are from table 5-3, and kWh savings in the last column in the above table are counted only for those measures that have a levelized cost less than $0.10/kwh saved.

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Appendix G: Energy Efficiency Measures (cont'd)

Table 6-3: Commercial Measures – Levelized Cost per kWh Saved

Measure	Levelized cost $ per kWh saved
Space Heating	
High Efficiency Heat Pump	$0.0050
Ground Source Heat Pump - Heating	$0.3420
Water Heating End Use	
Heat Pump Water Heater	$0.0390
Booster Water Heater	$0.2477
Point of Use Water Heater	$0.0504
Solar Water Heating System	$0.0242
Solar Pool Heating	$0.0802
Envelope	
Double Pane Low Emissivity Windows	$0.0077
Space Cooling - Chillers	
Centrifugal Chiller, 0.51 kW/ton, 300 tons	$0.0513
Centrifugal Chiller, 0.51 kW/ton, 500 tons	$0.0513
Centrifugal Chiller, Optimal Design, 0.4 kW/ton, 500 tons	$0.0513
Space Cooling - Packaged AC	
DX Packaged system EER = 10.9, 10 tons	$0.0266
DX Packaged System, CEE Tier 2, <20 Tons	$0.0179
DX Packaged System, CEE Tier 2, >20 Tons	$0.0265
Packaged AC - 3 tons, Tier 2	$0.0488
Packaged AC - 7.5 tons, Tier 2	$0.0425
Packaged AC - 15 tons, Tier 2	$0.0405
Ground Source Heat Pump - Cooling	$0.2589
Space Cooling - Maintenance	
Chiller Tune Up/Diagnostics - 300 ton	$0.0339
Chiller Tune Up/Diagnostics - 500 ton	$0.0335
DX Tune Up/ Advanced Diagnostics	$0.1013
HVAC Controls	
Retrocommissioning	$0.0145
Programmable Thermostats	$0.0038
EMS install	$0.0951
EMS Optimization	$0.2968
Ventilation	
Dual Enthalpy Economizer - from Fixed Damper	$0.0483
Dual Enthalpy Economizer - from Dry Bulb	$0.0329

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Measure	Levelized cost $ per kWh saved
Heat Recovery	$0.2215
Fan Motor, 40hp, 1800rpm, 94.1%	$0.0178
Fan Motor, 15hp, 1800rpm, 92.4%	$0.0064
Fan Motor, 5hp, 1800rpm, 89.5%	$0.0127
Variable Speed Drive Control, 15 HP	$0.0339
Variable Speed Drive Control, 5 HP	$0.0565
Variable Speed Drive Control, 40 HP	$0.0231
Motors	
Efficient Motors	$0.0153
Variable Frequency Drives (VFD)	$0.0979
Lighting End Use	
Super T8 Fixture - from 34W T12	$0.0494
Super T8 Fixture - from standard T8	$0.0427
T5 Fluorescent High-Bay Fixtures	$0.0315
T5 Troffer/Wrap	$0.0570
T5 Industrial Strip	$0.0626
T5 Indirect	$0.0570
CFL Fixture	$0.0234
Exterior HID	$0.0716
LED Exit Sign	$0.0461
Lighting Controls	$0.0308
LED Traffic / Pedestrian Signals	$0.0644
Electronic HID Fixture Upgrade	$0.0341
Halogen Infra-Red Bulb	$0.0996
Integrated Ballast MH 25W	$0.0643
Induction Fluorescent 23W	$0.0257
CFL Screw-in	$0.0023
Metal Halide Track	$0.0548
Lighting Controls	
Bi-Level Switching	$0.0783
Occupancy Sensors	$0.0296
Daylight Dimming	$0.0834
Daylight Dimming - New Construction	$0.1169
5% More Efficient Design	$0.0522
10% More Efficient Design	$0.0522
15% More Efficient Design - New Construction	$0.0174
30% More Efficient Design - New Construction	$0.0174
Refrigeration End Use	
Vending Miser for Soft Drink Vending Machines	$0.0159
Refrigerated Case Covers	$0.0098

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Measure	Levelized cost $ per kWh saved
Refrigeration Economizer	$0.5605
Commercial Reach-In Refrigerators	$0.0217
Commercial Reach-In Freezer	$0.0248
Commercial Ice-makers	$0.0260
Evaporator Fan Motor Controls	$0.0531
Permanent Split Capacitor Motor	$0.0562
Zero-Energy Doors	$0.1627
Door Heater Controls	$0.0116
Discus and Scroll Compressors	$0.0610
Floating Head Pressure Control	$0.0597
Anti-sweat (humidistat) controls (refrigerator)	$5.0209
Anti-sweat (humidistat) controls (freezer)	$2.5439
High Efficiency Ice Maker	$0.0179
Compressed Air End Use	
Compressed Air – Non-Controls	$0.0205
Compressed Air – Controls	$0.0990
Monitor Power Management	
EZ Save Monitor Power Management Software	$0.5883
Water/Wastewater Treatment	
Improved equipment and controls	$0.0593
Transformer End Use	
Energy Star Transformers	$0.0187

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Appendix H: Additional Economic Impact Discussion

The Economic Impact Model

The IMPLAN input-output economic model was used to assess the economic impacts of renewable energy development in the State of North Carolina.[1] This model is also used by the North Carolina Department of Commerce for economic impact analyses for the North Carolina legislature. The IMPLAN model is well documented and is used by many federal, state and local government agencies to assess economic impacts of economic policy and job development issues. A detailed description of the IMPLAN model is available in a report from the Minnesota IMPLAN Group (MIG) titled "The IMPLAN Input-Output System."[2]

IMPLAN was developed as a cost-effective means to develop regional input-output models. Input-output analysis uses mathematical models to examine the effects of a change in one or several economic activities on an entire economy. Such an impact analysis examines relationships between businesses and between businesses and final consumers.

There are two components to the IMPLAN system, the software and databases. The databases provide all information to create regional or state-specific IMPLAN models.[3] The software performs the calculations and provides an interface for the user to make final demand changes. We utilized the IMPLAN database developed by MIG for the state of North Carolina and its Input-Output analysis procedures to complete the economic impact assessment.

Modeling Assumptions

The economic impact analysis of an RPS for North Carolina is based on the following key assumptions:

- The economic input-output data and relationships for North Carolina provided by the Minnesota IMPLAN Group for use with the IMPLAN model are assumed to be applicable for the twenty-year analysis period for this study.
- The economic model constructed using IMPLAN for North Carolina is an input-output model and includes all of the standard input-output model assumptions:
  - *Constant returns to scale* – the production function for a given industry is linear, i.e., if additional output is required in an industry, all the inputs required to produce that output increase proportionately
  - *No supply constraints* – an industry has unlimited access to raw materials and its output is limited only by demand for its products

[1] The USDA Forest Service in the mid-70s developed IMPLAN for community impact analysis. The current IMPLAN input-output database and model is maintained and sold by MIG, Inc. (Minnesota IMPLAN Group). Over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis. GDS Associates, a subcontractor to La Capra Associates for this study, is a registered and licensed user of the IMPLAN model.

[2] "The IMPLAN Input-Output System." Scott A. Lindall and Douglas C. Olson. <http://www.implan.com/library/documents/implan_io_system_description.pdf>

[3] The IMPLAN database, created by the Minnesota IMPLAN Group (MIG), Inc., consists of two major parts: 1) a national-level technology matrix, and 2) estimates of sectorial activity for final demand, final payments, industry output and employment for each county in the U.S. along with state and national totals. New databases are developed annually by MIG, Inc.

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- *Fixed commodity input structure* – changes in the economy will affect the industry's output but not the mix of commodities and services it requires to make its products
- *Homogenous sector output* – an industry will not increase the output of one product without proportionately increasing the output of all its other products
- *Industry technology assumption* – the assumption that an industry uses the same technology to produce all of its products

- Long-term electricity price changes are based on the difference in cost between a Utility Portfolio and Alternative RPS portfolios that contain both renewable and conventional generation.
- Rate impact is based on the present value (in 2006$) of the long-term impact (estimate of rate impact in 2017) of the RPS scenarios presented in previous section. *This is a conservative assumption given that the first nine years of an RPS do not necessarily experience the higher rate impact of the tenth year.*
- Purchase of energy efficiency equipment would be equally split between wholesale and retail suppliers.

Job-Years Lost Through Price Impacts of RPS Over 20 Years

Portfolio	Long-Term Price Increase (2006 ¢/kWh)	Household Income Impacts	Business and Government Impacts	Total Job-Years* Lost
5% NCGP	**0.056¢**	**4,254**	**11,924**	**16,178**
5% Expanded	0.015¢	1,144	3,214	4,358
5% With EE	0.000¢	0	0	0
10% NCGP	0.237¢	17,866	50,080	67,946
10% Expanded	0.146¢	11,022	30,898	41,920
10% With EE	**0.000¢**	**0**	**0**	**0**
5% NCGP No Co-Fire	0.113¢	8,548	23,960	32,508
5% Expanded No Co-Fire	0.001¢	82	236	318
5% PV Multiplier	0.059¢	4,444	12,468	16,912

* 1 person working for twenty years equates to twenty job-years

The impacts for wind and hydro projects are relatively low due to their lack of a need for fuel and to their low capacity factors. If results are compared in terms of equivalent MW (MWe) where capacity factors are taken into account, wind project impacts can potentially triple and hydro impacts double. A significant impact is also created for Solar and Combustion Turbines. The figure below shows total job impacts (Construction, O&M, and Fuel) for each resource on a per MW and per MWe basis.

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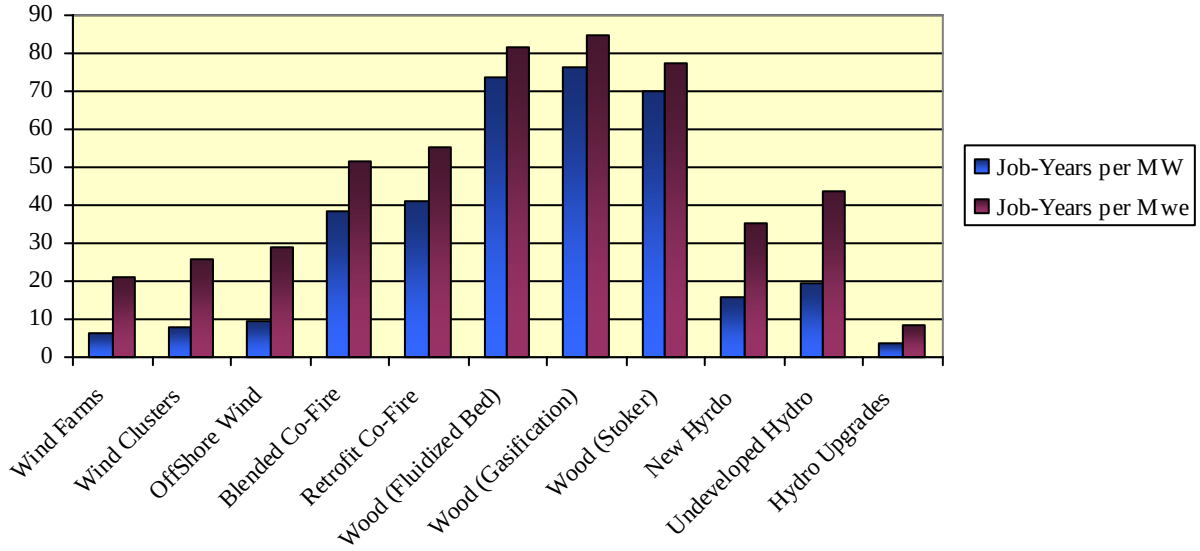
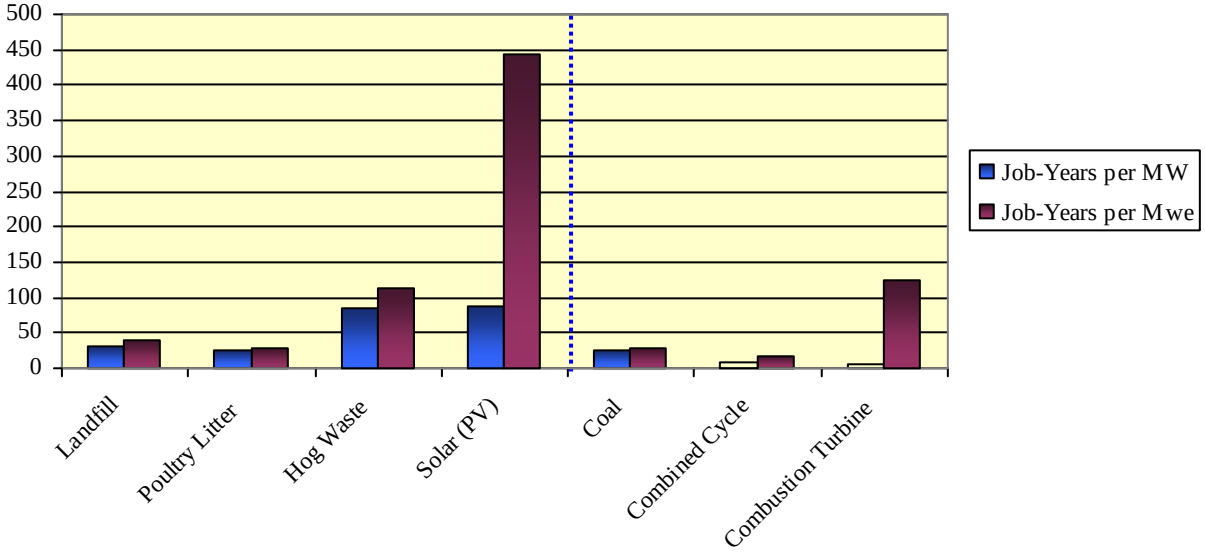
Job Impacts by MW and MWe





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Appendix I: Net Metering and Interconnection Rules

Net-Metering

<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NC05R&state=NC&CurrentPageID=1&RE=1&EE=1>

Excerpt from North Carolina Solar Center's description of Net Metering in North Carolina :

> *Utilities may not charge customer-generators any standby, capacity or metering fees, or other fees and charges in addition to those approved for all customers under the applicable time-of-use demand-rate schedule. North Carolina is the only state that requires customers to switch to a time-of-use tariff in order to take advantage of net metering. In its July 2006 order, the NCUC clarified that on-peak generation may be used to offset off-peak consumption (but not vice versa). Previously, the utilities' net-metering tariffs and riders only allowed excess on-peak production to be used to reduce on-peak consumption and excess off-peak production to be used to offset off-peak production. Net excess generation (NEG) is credited to the customer's next bill at the utility's retail rate, and then granted to the utility (annually) at the beginning of each summer season. Any renewable-energy credits (RECs) associated with NEG are granted to the utility when the NEG balance is zeroed out. This provision is designed to limit the size of individual facilities to match on-site power needs, according to the NCUC. Significantly, customer-generators who choose to net meter are not permitted to sell electricity under the NC GreenPower Program.*

Interconnection

<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NC04R&state=NC&CurrentPageID=1&RE=1&EE=1>

Excerpt from North Carolina Solar Center's description of Interconnection Rules in North Carolina:

> *The North Carolina Utilities Commission (NCUC) adopted simplified interconnection standards for small distributed generation (DG) in 2005. The standards apply to renewable-energy systems and other forms of DG up to 20 kilowatts (kW) in capacity for residential systems, and up to 100 kW in capacity for non-residential systems. There is a $100 application fee for residential systems and a $250 application fee for nonresidential systems. Utilities may not require residential customers to carry liability insurance beyond the amount required by a standard homeowner's policy ($100,000 minimum coverage), but nonresidential generators are required to carry "comprehensive general liability insurance" ($300,000 minimum coverage). Significantly, generators are responsible only for upgrade and improvement costs associated directly with a system's interconnection. Utilities are prohibited from imposing indirect fees and charges. North Carolina's interconnection standards include provision for mutual indemnification. A redundant external disconnect switch is required, and the capacity of all interconnected generation is limited to a maximum of 2% of rated circuit capacity. Applications for interconnected systems that exceed this saturation limit may be reviewed on a case-by-case basis.*

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Appendix J: Excerpts Related to RPS Purposes from Various States

California
<http://www.dsireusa.org/documents/Incentives/CA25R.pdf>

Senate Bill No. 1078

(a) In order to attain a target of 20 percent renewable energy for the State of California and for the purposes of increasing the diversity, reliability, public health and environmental benefits of the energy mix, it is the intent of the Legislature that the California Public Utilities Commission and the State Energy Resources Conservation and
Development Commission implement the California Renewables Portfolio Standard Program described in this article.
(b) Increasing California's reliance on renewable energy resources may promote stable electricity prices, protect public health, improve environmental quality, stimulate sustainable economic development, create new employment opportunities, and reduce reliance on imported fuels.
(c) The development of renewable energy resources may ameliorate air quality problems throughout the state and improve public health by reducing the burning of fossil fuels and the associated environmental impacts.

New Mexico
<http://www.dsireusa.org/documents/Incentives/NM05R2.htm>

New Mexico Administrative Code

17.9.572.6 OBJECTIVE
The purpose of this rule is to implement the Renewable Energy Act, NMSA 1978 Section 62-16-1 et seq, and to bring significant economic development and environmental benefits to New Mexico.

17.9.572.10 RENEWABLE PORTFOLIO STANDARD

A. Each public utility must develop a reasonable cost renewable energy portfolio. In developing its renewable energy portfolio, a public utility shall take into consideration the potential for environmental and economic benefits to New Mexico. The portfolio shall be diversified as to type of renewable resource, taking into consideration the overall reliability, availability, dispatch flexibility and cost of the various renewable resources made available by providers and generators. Renewable energy resources that are in a public utility's electric energy supply portfolio on July 1, 2004 shall be counted in determining compliance with this rule. However, renewable energy sold to customers through a premium-priced renewable energy tariff shall not be counted in determining compliance with this rule. Other factors being equal, preference shall be given to renewable energy generated in New Mexico.

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Texas
<http://www.dsireusa.org/documents/Incentives/TX03R.pdf>

Chapter 25, Substantive Rules Applicable to Electric Service Providers

§25.173. Goal for Renewable Energy.
(a) **Purpose.** The purpose of this section is to ensure that an additional 2,000 megawatts (MW) of generating capacity from renewable energy technologies is installed in Texas by 2009 pursuant to the Public Utility Regulatory Act (PURA) §39.904, to establish a renewable energy credits trading program that would ensure that the new renewable energy capacity is built in the most efficient and economical manner, to encourage the development, construction, and operation of new renewable energy resources at those sites in this state that have the greatest economic potential for capture and development of this state's environmentally beneficial resources, to protect and enhance the quality of the environment in Texas through increased use of renewable resources, to respond to customers' expressed preferences for renewable resources by ensuring that all customers have access to providers of energy generated by renewable energy resources pursuant to PURA §39.101(b)(3), and to ensure that the cumulative installed renewable capacity in Texas will be at least 2,880 MW by January 1, 2009.

Illinois
<http://www.dsireusa.org/documents/Incentives/IL04R.pdf>

Illinois Commerce Commission: Docket : 05-0437
Response to Governor's Sustainable Energy Plan for the State of Illinois

By the Commission:
WHEREAS, the inflation-adjusted prices of fossil fuels have risen steadily in the last five years; and
WHEREAS, the prices of fossil fuels have a significant effect on the future price of electricity; and
WHEREAS, the price of fossil fuels are decided in national and international markets that are beyond the control of state jurisdiction; and
WHEREAS, on February 11, 2005, the Governor of the State of Illinois sent to the Illinois Commerce Commission a proposal for a Sustainable Energy Plan for Illinois; and
WHEREAS, the Governor's proposed Sustainable Energy Plan included a Renewable Portfolio Standard and an Energy Efficiency Portfolio Standard; and
WHEREAS, the Governor's proposed Sustainable Energy Plan included a recommendation that the Illinois Commerce Commission establish an Illinois Sustainable Energy Advisory Council, with members appointed by the Chairman; and
WHEREAS, the Illinois Commerce Commission commenced the Sustainable Energy Initiative, issuing a "Request for Public Comment Concerning the Implementation of Governor Blagojevich's Proposal for a Sustainable Energy Plan for Illinois" on March 2, 2005; and
WHEREAS, the Illinois Commerce Commission organized workshops to discuss potential issues and invited Illinois utilities to present proposed implementation plans consistent with the Governor's proposed Sustainable Energy Plan; and

WHEREAS, during the course of the workshops, the Illinois Commerce Commission learned that the use of renewable energy sources will lead to rural economic development and improve environmental quality; and
WHEREAS, the Staff of the Energy Division of the Illinois Commerce Commission produced a Staff report dated July 7, 2005 addressing the various issues surrounding the implementation of renewable energy, demand response and energy efficiency programs; and
WHEREAS, the Illinois Commerce Commission adopted a resolution accepting Staff's report on July 13, 2005.
IT IS THEREFORE RESOLVED by the Illinois Commerce Commission that the Commission hereby adopts the Governor's proposed Sustainable Energy Plan with modifications based on information gathered through the Sustainable Energy Initiative and Staff's Report.
IT IS FURTHER RESOLVED that the Renewable Portfolio Standard should be set as follows: 2% of the bundled retail load should be obtained from renewable energy resources as defined below in 2007, 3% in 2008, 4% in 2009, 5% in 2010, 6% in 2011, 7% in 2012 and 8% in 2013.
IT IS FURTHER RESOLVED that sources of renewable energy shall include wind, solar thermal energy, photovoltaic cells and panels, dedicated crops grown for energy production and organic waste biomass, methane recovered from landfills, hydropower that does not involved the construction of new dams or significant expansion of existing dams, and other such alternative sources of environmentally preferable energy.
IT IS FURTHER RESOLVED that the Illinois Commerce Commission recognizes the benefits to Illinois by implementing the Sustainable Energy Plan, including using renewable energy and energy efficiency as a hedge against rising fossil fuel costs, and demand response as a mechanism to maintain system reliability and lower prices for all customers. Additionally, the Sustainable Energy Plan will create economic benefits in rural areas, create jobs and reduce air pollutants.

Pennsylvania
<http://www.puc.state.pa.us/PcDocs/621947.doc>

Pennsylvania Utilities Commission: Docket No. L-00060180
Implementation of the Alternative Energy Portfolio Standards Act of 2004

Background
Governor Edward Rendell signed the Act into law on November 30, 2004. The Act, which became effective February 28, 2005, establishes an alternative energy portfolio standard for Pennsylvania. The Act includes two key mandates: one, greater reliance on alternative energy sources in serving Pennsylvania's retail electric customers; two, the opportunity for customer-generators to interconnect and net meter small alternative energy systems.

Delaware
<http://www.dsireusa.org/documents/Incentives/DE06R.doc>

Senate Bill No. 74

Section 1. Amend Chapter 1, Title 26 of the Delaware Code, by inserting therein, between subchapters III and IV thereof, the following new subchapter:
"Subchapter III-A. Renewable Energy Portfolio Standards.

US EPA ARCHIVE DOCUMENT

§ 351. Short title; declaration of policy.

(a) This subchapter shall be known and may be cited as the Renewable Energy Portfolio Standards Act.

(b) The General Assembly finds and declares that the benefits of electricity from renewable energy resources accrue to the public at large, and that electric suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the state. These benefits include improved regional and local air quality, improved public health, increased electric supply diversity, increased protection against price volatility and supply disruption, improved transmission and distribution performance, and new economic development opportunities.

(c) It is therefore the purpose and intent of the General Assembly in enacting the Renewable Energy Portfolio Standards Act to establish a market for electricity from these resources in Delaware, and to lower the cost to consumers of electricity from these resources.

Maryland
<http://www.dsireusa.org/documents/Incentives/MD05R.htm>

Code of Maryland Public Utility Companies

§ 7-702. Intent and findings

(a) Intent. -- It is the intent of the General Assembly to:

(1) recognize the economic, environmental, fuel diversity, and security benefits of renewable energy resources;

(2) establish a market for electricity from these resources in Maryland; and

(3) lower the cost to consumers of electricity produced from these resources.

(b) Findings. -- The General Assembly finds that:

(1) the benefits of electricity from renewable energy resources, including long-term decreased emissions, a healthier environment, increased energy security, and decreased reliance on and vulnerability from imported energy sources, accrue to the public at large; and

(2) electricity suppliers and consumers share an obligation to develop a minimum level of these resources in the electricity supply portfolio of the State.

Maine
<http://www.dsireusa.org/documents/Incentives/ME01R.htm>

Maine Revised Statutes
TITLE 35-A. PUBLIC UTILITIES
PART 3. ELECTRIC POWER

US EPA ARCHIVE DOCUMENT

§ 3210. Renewable resources

1. POLICY. In order to ensure an adequate and reliable supply of electricity for Maine residents and to encourage the use of renewable, efficient and indigenous resources, it is the policy of this State to encourage the generation of electricity from renewable and efficient sources and to diversify electricity production on which residents of this State rely in a manner consistent with this section.

New York
<http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Web/85D8CCC6A42DB86F85256F1900533518/$File/301.03e0188.RPS.pdf?OpenElement>

New York Public Service Commission: CASE 03-E-0188

BY THE COMMISSION:
I. INTRODUCTION
This proceeding was instituted on February 19, 2003, to explore the development of a renewable portfolio standard (RPS), which is a program to increase the proportion of renewable energy that is consumed by retail customers in New York State.

The development of additional renewable energy resources is a long-standing energy policy objective of the State. The 2002 State Energy Plan (June 2002) warned of the possible consequences of New York's fossil fuel dependency, noting that the State's primary sources of energy are imported, to a large degree, from abroad, have significant long-term environmental effects, and ultimately face depletion. Since the institution of this proceeding, over 150 parties, Department of Public Service (DPS) Staff, other governmental agencies, and thousands of members of the public have participated to address the issues identified in the Instituting Order and to craft an RPS program for New York State. Based upon the voluminous record before us, we endorse a policy of encouraging the increased use of renewable resources and institute a program, including the adoption of a renewable portfolio standard (RPS), consistent with such a policy.

An RPS is a recognized means of increasing the proportion of non-fossil fuel electricity purchases in a given jurisdiction. Many states have commenced RPS program initiatives and comparable RPS programs are in place in the United Kingdom, Denmark, Germany, the Netherlands, and Japan. It is worth noting that the specifics of individual RPS programs vary from one jurisdiction to the next in terms of targets to be achieved, eligibility of resources, implementation mechanisms, and time frames for achieving goals based on the individual circumstances of those jurisdictions.

We believe the policy we are adopting herein addresses the energy, economic, and environmental objectives of New York State by creating the potential to build new industries in the State based on clean, environmentally responsible energy technologies that meet the needs of New York energy consumers as well as the growing global market for these kinds of technologies.

US EPA ARCHIVE DOCUMENT

RPS programs generally require that renewable resources deemed eligible for participation are awarded a certain level of financial incentives to support their development. Currently, renewable resources are generally more expensive than non-renewable resources, such as fossil fuels. Therefore, without access to financial incentives to cover all or some of these above-market costs, renewable resources struggle to compete with resources using fossil fuels. However, as noted in the Final Generic Environmental Impact Statement (GEIS) related to this proceeding and issued by this Commission in August, 2004, renewable resources provide ancillary benefits such as increased fuel diversity and energy security, the potential for economic development as a result of growing industries that typically tap into indigenous resources and invest in local and regional economies, and reduced environmental impacts. Accordingly, they warrant a certain level of support to facilitate their growth. The program we are adopting will provide sufficient financial incentives for the development of renewable resources so that they may more readily compete with facilities that use natural gas, coal, and oil to generate electricity. Ultimately, this effort may result in reducing costs associated with renewable resources as technologies continue to advance.

In adopting this program, we affirm that system reliability is of paramount importance and concern. Thus, while we are proceeding with the RPS, we also acknowledge that the implementation phase should be sufficiently flexible to accommodate a process for review and analysis of the potential impacts of renewable generation on the electric grid, as well as the ability to reflect modifications, if any, that are necessary to protect the reliability of the electric system.

Currently, about 19.3 percent of the electricity retailed in New York State is derived from renewable resources, the vast majority coming from large-scale hydroelectric facilities in Western New York, upstate New York, and Canada. We seek to increase the proportion of electricity attributable to renewable resources to at least 25 percent of electric energy used in New York State by the end of 2013. We intend to accomplish this by implementing an RPS that will utilize revenues derived from delivery charges on electric utility customers. These revenues will be administered by the New York State Energy Research and Development Authority (NYSERDA). On a regular basis, NYSERDA will award financial incentives that are the minimum necessary to stimulate development of generating facilities that meet the eligibility requirements described herein.

We believe an important objective of the RPS program is to stimulate and complement voluntary/competitive renewable energy sales and purchases (or "green markets") so that these competitive markets, not government mandates, sustain renewable activity after the RPS program ends. "Green power" is an industry term for electricity that is derived solely from renewable resources. Green marketing is the practice employed by energy service companies (ESCOs) or other marketers that promote the environmental and economic benefits of renewable resources to customers in the hopes that customers will, voluntarily, pay added costs associated with green power based on the value they place on these added benefits. The design and goals of this program demonstrate our support for fostering these competitive retail markets for green power to deliver greater choice and value to customers.

The policy and program adopted herein are designed to achieve the goal of at least 25 percent of the electricity used in New York State being provided by renewable resources.

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Specifically, the RPS delineated herein will mandate the collection of revenues, to be administered by NYSERDA, for the purpose of providing incentives to increase the percentage of electricity used by retail customers in the state that is derived from renewable resources from the current level of 19.3 percent to 24 percent. Hereafter, we will refer to this as the "mandatory" component of this renewable policy. We anticipate that at least an additional one percent of renewable energy sales will result from voluntary green market programs for a total goal of at least 25 percent. Hereafter, we will refer to this additional voluntary effort as the "voluntary" component of this renewable policy.

The additional new renewable electricity generation fostered by both of these components is expected to result in the displacement of some existing fossil fuel-based generation supply. Changes in generation resources due to implementation of these initiatives are expected to create greater diversity in the State's electric energy supply portfolio, and reduce the exposure to wholesale oil and natural gas price spikes and supply interruptions, thereby increasing the security of the State's electric energy supply.

We, therefore, adopt a policy of encouraging the retail use of renewables through implementation of a retail renewable portfolio standard pursuant to our authority to preserve environmental values and conserve natural resources (Public Service Law (PSL) §5(2));2 and a policy of encouraging and supporting green marketing efforts.

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