
by

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# LIST OF ACRONYMS AND ABBREVIATIONS

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Full Form</th>
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<tbody>
<tr>
<td>Berkeley Lab</td>
<td>Lawrence Berkeley National Laboratory</td>
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<tr>
<td>CC</td>
<td>Combined Cycle</td>
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<tr>
<td>CT</td>
<td>Combustion Turbine</td>
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<tr>
<td>DSM</td>
<td>Demand-Side Management</td>
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<tr>
<td>Duke</td>
<td>Duke Energy Carolinas, LLC</td>
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<tr>
<td>EE</td>
<td>Energy Efficiency</td>
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<tr>
<td>EIA</td>
<td>U.S. Energy Information Administration</td>
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<tr>
<td>IOU</td>
<td>Investor-Owned Utility</td>
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<tr>
<td>IRP</td>
<td>Integrated Resource Plan</td>
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<tr>
<td>NC Power</td>
<td>Dominion North Carolina Power</td>
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<tr>
<td>NEMS</td>
<td>National Energy Modeling System</td>
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<tr>
<td>NPV</td>
<td>Net Present Value</td>
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<tr>
<td>O&amp;M</td>
<td>Operation and Maintenance</td>
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<tr>
<td>Progress</td>
<td>Progress Energy Carolinas, Inc.</td>
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<tr>
<td>PTC</td>
<td>Production Tax Credit</td>
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<tr>
<td>REPS</td>
<td>Renewable Energy and Energy Efficiency Portfolio Standard</td>
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<tr>
<td>RPS</td>
<td>Renewable Portfolio Standards</td>
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<tr>
<td>Solar PV</td>
<td>Solar Photovoltaic</td>
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ABSTRACT

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 sales from renewable resources. The RPS at state levels has become one of the most important policy incentives for stimulating clean energy expansion in electricity utilities in the United States. In 2007, North Carolina promulgated a Renewable Energy and Energy Efficiency Portfolio Standard (REPS), requiring the investor-owned utilities (IOUs) to meet up to 12.5% of their energy needs through renewable energy resources by 2021.

This Master's Project is designed to evaluate the cost and rate impacts of REPS on three IOUs in North Carolina from the perspective of retail market. Referring to the core modeling approaches and assumptions in the former technical report for North Carolina, this project establishes a cost impact model to compare the total annual cost of the Utilities' Portfolio and Alternative REPS Portfolio from 2011 to 2030. The project also analyzes the impacts of different sensitivities. The results suggest that the REPS policy exerts no cost impact on IOUs until 2017 and a 0.54 cents/kWh increase of retail electricity rate will be reached in 2030 under the REPS obligation. According to sensitivity analysis, the extended availability of Production Tax Credit (PTC), high fuel price of coal and natural gas, as well as high construction cost of nuclear plant will reduce the total incremental cost of the REPS policy over 20 years. It is noted that the design of the alternative REPS Portfolio in this project introduces major differences in model results compared to the former technical report. Levelized cost assumptions and forecasts of future fossil fuel prices would bring other uncertainties to this Master's Project.
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Introduction

As concerns on energy security and global warming increasingly grow, renewable energy and energy efficiency have become major foci of current energy policy in the United States. Among the various policy tools, the Renewable Portfolio Standards (RPS) at state level has emerged as one of the most popular and important policy drivers for reducing market barriers and stimulating clean energy expansion in the U.S. By 2007, mandatory RPS policies have been designed in 25 states and Washington D.C., and 4 additional states have non-binding goals, i.e. the voluntary standards (Figure 1). These state policies now collectively apply to approximately 50% of U.S. electricity load and exerting substantial influences on electricity markets, ratepayers, as well as local economies (Chen et al., 2009). This Master’s Project will analyze the cost and rate impacts of RPS on investor-owned utilities (IOUs) in North Carolina.

What are Renewable Portfolio Standards?
Renewables portfolio standards require a minimum amount of eligible renewable energy or capacity that is included in each retail electricity supplier’s portfolio of electricity resources (Chen et al., 2009). RPS policies are varied in different states and generally measured in either absolute

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units (kWh or MW) or a certain percentage share of retail sales. Figure 1 shows that the RPS requirement in each state ranged from 4% achieved by 2009 in Massachusetts to 40% reached by 2017 in Maine. Referring to Lawrence Berkeley National Laboratory’s (Berkeley Lab) 2008 report, a number of findings of RPS design and implementation at present were summarized and some relevant to this project are extracted as below:

- In 2007, 4 states established new RPS policies, 11 states significantly revised pre-existing RPS programs (mostly to strength them), and 3 states created non-binding renewables energy goals;
- RPS policy designs vary widely among states, and a “common” design has not yet emerged;
- Resources eligibility in state RPS programs has expanded beyond traditional renewables, now allowing energy efficiency to meet at least a portion of the RPS requirement;
- The retail electricity rate increases associated with existing state RPS policies generally equal 1% or less so far.

**Direct and Indirect Impacts of RPS Policies**

Two significant impacts of RPS policies are: the direct costs of RPS deployment and the projected impacts on renewable resource mix that are indirect. In the former case, the direct costs are defined to include the incremental costs due to RPS requirement and impact of renewable portfolio on retail electricity rates. These impacts are claimed to be direct because they influence consumer electricity bills. Among study cases sampled by Berkeley Lab’s 2008 report, the base-case increase in retail electricity rates proved to be modest, indicating that the median projected increase is 0.8% and these studies report the rate increase ranged from -5.2% (i.e. reducing retail rate by 0.4 cents/kWh) to 8.8% (i.e. increasing retail rate by 0.7 cents/kWh) in the first peak target year (Chen et al., 2009).

On the other hand, the RPS policies have substantial impacts on the mix of renewable technologies that would be used to meet state RPS requirements. Typically, it is assumed that both

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2 Berkeley Lab’s contributions to this report were funded by the Office of Energy Efficiency and Renewable Energy and by the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No.DE-AC02-05CH11231. It is the first report in a regular series that seeks to fill the need to keep up with the RPS design and projected impacts of these programs, by offering basic, factual information on RPS policies in the U.S.

3 The summarized rate impacts here were expressed in 2003 dollars, referring to Berkeley Lab’s 2009 report.
the costs and potential availability of resources should be taken into consideration, implying the least-cost and more-available resources in the certain state are selected primarily).

**RPS Policy in North Carolina**

On August 20, 2007, North Carolina signed Session Law 2007-397 (i.e. Senate Bill 3), becoming the first state in the Southeast to adopt a Renewable Energy and Energy Efficiency Portfolio Standard (REPS). Pursuant to the REPS policy in North Carolina, the electricity suppliers, including Electric Public Utilities -- Investor-owned Utilities (IOUs) and Electric Membership Corporations and Municipalities, are required to meet up to 10% of their 2017 NC retail sales through renewable energy resources or energy efficiency measures by 2018; the IOUs should go further and reach the 12.5% standard by 2021. REPS policy in North Carolina also included energy efficiency, indicating that IOUs subject to this policy could meet up to 25% of the requirements of REPS through savings due to implementation of energy efficiency measures, and up to 40% when beginning in calendar year 2021 and each year thereafter.

In addition to the general requirement concluded above, North Carolina also created specific standards and schedules of compliance with REPS through use of solar energy resources, swine waste resources and poultry waste resources. Table 1 shows the overall REPS requirement and subsections that shall be complied with by IOUs according to the following schedule:

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4 It is worth mentioning that some studies of RPS policy treat the renewable resource mix as an input to their cost estimate model while in other studies the mix is a model output (Chen et al., 2007). When taken as an input – as done in this Master’s Project – the renewable energy mix is estimated based on the cost and availability situation in the certain state being modeled. When treated as an output, renewable energy use is usually estimated by constructing an aggregate renewable resource supply curve, with the state RPS target level determining which resources are selected in a given year.

5 An investor-owned utility is a business organization, supplying a product or service regarded as a utility, often termed a public utility regardless of ownership, and managed as a private enterprise rather than a function of government or a utility cooperative. In North Carolina, three major IOUs are included in this category and they are also chosen as the study objective in this project.

6 "Renewable energy resource" under the REPS in North Carolina implies “a solar electric, solar thermal, wind, hydropower, geothermal, or ocean current or wave energy resource; a biomass resource, including agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane; waste heat derived from a renewable energy resource and used to produce electricity or useful, measureable thermal energy at a retail electric customer’s facility; or hydrogen derived from a renewable energy resource.” Renewable energy resource does not include peat, a fossil fuel, or nuclear energy resource (North Carolina General Statute, 62-133.8, 2007).

7 "Energy efficiency measure" under the REPS in North Carolina implies “… an equipment, physical, or program change implemented after January 1, 2007, that results in less energy used to perform the same function.” It includes, but is not limited to, energy produced from a combined heat and power system that uses nonrenewable energy resources, while does not include demand-side management (North Carolina General Statute, 62-133.8, 2007).
Table 1. REPS Schedule Promulgated in NC G.S. 62-133.8.

<table>
<thead>
<tr>
<th>REPS Requirement</th>
<th>Calendar Year</th>
<th>For IOUs</th>
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<tr>
<td></td>
<td></td>
<td>2012</td>
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<td></td>
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<td>3% of 2011 retail sales</td>
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<td></td>
<td></td>
<td>2015</td>
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<td></td>
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<td>6% of 2014 retail sales</td>
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<td></td>
<td></td>
<td>2018</td>
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<tr>
<td></td>
<td></td>
<td>10% of 2017 retail sales</td>
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<tr>
<td></td>
<td></td>
<td>2021 and thereafter</td>
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<tr>
<td></td>
<td></td>
<td>12.5% of 2020 retail sales</td>
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</tbody>
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<table>
<thead>
<tr>
<th>Subsections of REPS Requirement</th>
<th>Calendar Year</th>
<th>Solar Energy</th>
<th>Swine Waste</th>
<th>Poultry Waste</th>
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<tbody>
<tr>
<td></td>
<td></td>
<td>2010</td>
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<td></td>
<td>0.02%</td>
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<td></td>
<td></td>
<td>2012</td>
<td>0.07%</td>
<td>0.07%</td>
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<td>170000 MWh</td>
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<td></td>
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<td>2013</td>
<td>-</td>
<td>700000 MWh</td>
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<td>2014</td>
<td>-</td>
<td>900000 MWh</td>
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<td>2015</td>
<td>0.14%</td>
<td>0.14%</td>
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<tr>
<td></td>
<td></td>
<td>2018 and thereafter</td>
<td>0.20%</td>
<td>0.20%</td>
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Significance

Although a growing number of studies have attempted to quantify the potential or practical impacts of RPS policies in various states, few similar investigations or analyses have been found in North Carolina, in particular after the REPS policy officially enacted since 2007. To model the cost/rate impacts of REPS policy for North Carolina proves to be significant regarding to the lack of the latest studies. In a sum, the significance of this Master’s Project could be summarized as below:

- **No up-to-date studies for North Carolina after the REPS policy was officially enacted**: So far the previous report performed in 2006 (La Capra’s Team, 2006) is the only authoritative research that analyzed the potential impacts of RPS in North Carolina before the policy promulgated in 2007. The RPS requirements assumed in this report were greatly different from those published by North Carolina government in 2007. Hence a current study adopting the latest data and the official policy standards is very meaningful at this point.

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8 Different from other requirements, this subsection of poultry waste requirement is assigned for all electric power suppliers in North Carolina, not restricted to IOUs. So in the following section of methodology, this part of requirement will be adjusted for IOUs according to their market share of retail electricity sales in NC.

• **No universal template of modeling methodologies developed:** While a Federal RPS has been considered by Congress, all enacted RPS policies have been adopted at the state or local levels, implying that the RPS policy designs are widely different among states without a “common” design emerging (Chen et al., 2009). It means that a universal template of modeling methodologies has not yet been developed. To figure out an appropriate modeling methodology and scenario analysis specifically for North Carolina is significant.

• **Potential improvements of REPS in North Carolina:** A well-designed RPS could provide incentives for electricity suppliers to meet their renewable purchase obligations in a least-cost fashion. Based on various scenario analyzes and sensitivity analysis, the results of this project might be able to propose a few potential improvements and adjustments to the current REPS policy for IOUs in North Carolina.

**Literature Review**

Since 1998, a growing number of studies have carried out cost impact analyses of RPS on distinct state or utility-level. Figure 2 below identifies the authors of 31 RPS studies covered in Chen’s comparative analysis in 2009, a large number of which reflect the recent surge in state RPS adoption and practice. Most of these studies estimate retail rate impacts, while some others report changes in electricity generation costs. In addition, a wide range of sensitivity scenarios were modeled and analyzed by the state RPS studies, including but not restricted Production Tax Credit (PTC) availability, renewable technology cost, fossil fuel price uncertainty, resource eligibility, load growth etc. The following findings are commonly detected in the state RPS studies: (1) scenario analyses reveal significant cost sensitivity to input parameters; (2) analysis assumptions tend to be more important than model selection. The limitation of budgets and timeframes that often applies to state RPS studies proved to become the more significant determinant of modeling approaches chosen. Under such condition, the assumptions proposed have played an extraordinarily important role in the studies that have to adopt less sophisticated models with lower expense; (3) understanding of the public benefits of RPS policies needs to be improved further. Although an

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increasing number of studies have modeled the macroeconomic effects of state RPS policies, the estimated impacts seemed to depend more on the study assumptions rather than on the amount of required expansion plan of renewable generation due to RPS practice. The first two issues will be also discussed in this project, analyzing relevant sensitivities as model inputs and comparing model assumptions to the previous study for North Carolina.

![Figure 2. State RPS Cost-Impact Studies Published by 2008](image)

Referring to Chen’s comparative report, a diversity of modeling approaches are identified with four broad categories of cost-estimate models (Chen et al., 2009): (A) spreadsheet model of renewable generation and avoided utility cost; (B) spreadsheet model of renewable generation and generation dispatch model\(^{11}\) of utility avoided cost using non-RPS resources mix; (C) spreadsheet model of renewable generation and generation dispatch model of avoided cost using RPS resource mix; (D) integrated energy model\(^{12}\). Among all four categories of modeling approaches, Category A has been adopted most widely due to its advantages of simplicity, transparency, flexibility and relative low cost (Chen et al., 2007). Regarding to the limited resources available to this project, a spreadsheet model in Category A will be adopted to calculate the cost and rate impacts while using

\(^{11}\) The dispatch models are complex software programs that simulate the interaction of supply and demand in an electric system, e.g. GE MPAS, PROSYM.

\(^{12}\) The integrated energy model can endogenously determine fuel prices, capacity expansion and electricity prices. The two most commonly used integrated energy models are NEMS (National Energy Modeling System) developed by EIA, and IPM (Integrated Planning Model) developed by ICF Consulting.
resources mix as model inputs. It is worth noting that a more complex model would not be necessarily more effective than a simpler one. As one of most commonly used integrated models in many studies, NEMS is an extremely complex set of modules, estimating prices and outputs for all types of energy along with macroeconomic forecasts. Its outcomes depend on literally thousands of assumptions, some at the choice of users and others embedded with in hundreds of equations, so Michaels (2008) claimed that its extreme details makes it impossible for all but dedicated specialists to evaluate the sensitivity of forecasts to alternative assumptions or to simulate their reasonableness.

In addition to the state studies mentioned above, some literature used case studies to evaluate the RPS’s effectiveness or impacts; Gan et al. (2007) compared the RPS policy in the U.S. to other green electricity policies developed in Germany, the Netherlands, Sweden\textsuperscript{13}, and indicated the consistent observations with respect to the strengths and weaknesses of each policy instruments; in the study of Texas, RPS legislation effectively led to the deployment of 915 MW of wind energy in 2001, more than twice the Texas’s 2001 RPS benchmark (Langniss and Wiser, 2003). On the other side, some other literature used additional qualitative evaluation techniques to reveal that RPS policies have experienced a number of successes to date (Berry and Jaccard, 2001; Wiser et al., 2007). Furthermore, Kydes (2006) adopted the 2001 version of the National Energy Modeling System (NEMS) of EIA and the assumptions and results from the Annual Energy Outlook 2002 (AEO 2002), modeling the potential effect of a Federal 20% non-hydropower RPS on energy markets in the U.S. Its modeling results suggested that electricity prices should be expected to rise about 3% which proved to be a bit higher than the median level estimated among the state-level studies\textsuperscript{14}, but still in a range of acceptability. Palmer and Burtraw (2005) modeled the effects of the two leading policies designed to encourage the renewable energy contribution to total U.S. electricity supply: a tax credit policy known as Renewable Energy Production Credit (REPC) and a requirement policy, i.e. RPS. The Haiku electricity market model was adopted to simulate electricity trades in their paper. The modeled results suggested that the RPS is more cost-effective than the REPC as a policy tool of both increasing renewable use and reducing carbon emission, especially when setting the goals of 15% or less.

\textsuperscript{13} Specifically, Gan et al. (2007) concluded that most case-study countries support renewable energy by financial incentives, including feed-in tariffs, production tax credit (PTC), tax exemption, subsidy and renewable energy fund; the quota system in Sweden and the RPS of the U.S. are presently the only non-financial instruments applied.

\textsuperscript{14} The median retail rate increase among the state-level RPS studies was summarized to be 0.8% in Chen’s comparative study (Chen et al., 2009).
Despite RPS policy's growing popularity in research publications, nevertheless, few studies attempted to empirically estimate the effectiveness of state RPS policies, nor explore the causal inference between RPS policies and renewable energy deployment (Carley, 2009). Menz and Vachon (2006) composed an empirical analysis on the effectiveness of state RPS policy incentives to wind power by estimating an ordinary least squares (OLS) regression model a sample of 39 states with the study period from 1998 to 2003. Building on Menz and Vachon's work in 2006, Carley (2009) presented another empirical analysis by directly testing the association between RPS policies and total renewable generation. They compiled individual variables from a variety of public sources between 1998 and 2006 to create a state-level database, with 50 states and 9 years. The idea of empirical analysis or program evaluation is impressive to test the RPS effects on renewable generation, but it should be noticed that the relative short-term application of RPS policies at state level would produce bias in the regression analysis. Omitted variable bias and low sample size would likely affect the statistical validity of regression analysis of RPS's effectiveness. Regarding to the fact that the RPS policy has been practiced in North Carolina for no longer than 4 years (starting in 2007), it is not practical or constructive to conduct empirical analysis or program evaluation for RPS policy in North Carolina so a perspective study is designed in this Master's Project accordingly.

The characteristics renewable energy that could mitigate the price risks of fossil fuels were also proposed in a number of studies, further providing a sound basis for RPS policies. Awerbuch (2003) detected the deleterious economic effects of fossil fuel volatility brought by energy prices, and these effects can be reduced only through energy diversification by incorporating renewable technologies such as wind, geothermal and solar PV, whose underlying costs are uncorrelated to fossil prices. Earlier in 2000, Awerbuch (2000) indicated the term “riskless” of renewable technologies as implying that their year-to-year generating costs are largely fixed and that any fluctuations are not correlated to movements in fossil fuel prices. Consequently, when added to the fossil mix, renewables might raise cost due to their relatively high investment, but they will also lower risk. In the article published by Lawrence Berkeley National Laboratory (Bolinger et al., 2004), renewable energy resources were also claimed to have nature of being immune to natural gas fuel price risk, in form of stable-price. Similar conclusions were also presented in the state RPS analyses mentioned previously, mainly in their sensitivity analysis; hence, this Master's Project will also conduct analysis to see if the RPS practice can help mitigate fuel price risks in North Carolina.

Last but not least, some analysts, opposite to many RPS studies, have noted that a few RPS policies were poorly designed and would do little to advance renewable energy markets (Wiser et
Possible reasons for these failures include: inadequate policy enforcement; policy duration uncertainty; overly aggressive RPS benchmarks; too many exemptions; or too much flexibility offered to utilities (Wiser et al., 2007, 2004). In the later part of this project, the potential shortcomings of RPS policy in North Carolina will be discussed referring to the evaluation criteria proposed in Wiser's article (Wiser et al., 2004).

**Objectives**

This Master’s Project is designed to conduct a cost (and rate)-impact analysis of REPS for IOUs in North Carolina, referring to the core modeling approaches and assumptions in 2006’s report (La Capra’s Team, 2006). It will model the cost/rate impacts of the latest REPS, as well as compare the modeling results with those in 2006’s report for North Carolina. The key problems that will be addressed are as follows:

- What are the cost/rate impacts of the REPS for IOUs in North Carolina?
- What is the renewable resource mix by the end of study period due to REPS implementation?
- What is the cost impact of different sensitivities under the REPS policy?
- How are the results modeled in this Master’s Project different from the previous reference study for North Carolina?

**Methodology**

Before describing the methodology adopted by this project, the research objects should be described: investor-owned utilities (IOUs) in North Carolina. Three IOUs operate under the regulation, owning their own generation facilities, and subject to the jurisdiction of the North Carolina Utilities Commission. They are Carolina Power & Light Company, running business as Progress Energy Carolinas, Inc. (Progress), Duke Energy Carolinas, LLC (Duke), and Virginia Electric and Power Company which runs business in North Carolina under the name of Dominion North

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15 This part of evaluation is not taken as emphasis in this Master’s Project, because, as mentioned formerly, this project is a perspective analysis aiming to estimate the cost impact of RPS practice in North Carolina. Without quantitative analysis, the possible shortcomings here will be discussed and explained by policy intuition.
Carolina Power (NC Power). In North Carolina, 43% of retail electricity sales are served by Duke, 29% by Progress and 3% by NC Power\(^\text{16}\). Regarding to the big share of IOUs in North Carolina and the REPS policy which has separate requirement for IOUs, this Master’s Project aims to take these IOUs as study objects.

**Scenario Design**

- **Base-Case Scenario**: The baseline REPS scenario is designed on the basis of REPS policy with the study period of 20 years, from calendar year 2011 to 2030\(^\text{17}\). The detailed schedule and requirements during the study period can be seen in Appendix I.
- **Energy-Efficiency (EE) Scenario**: According to REPS policy, IOUs are allowed to meet up to 25% of the requirements of REPS through savings due to implementation of energy efficiency measures\(^\text{18}\), and up to 40% beginning in calendar year 2021 and each year thereafter until 2030 (end of the study period).

**Utilities’ and Alternative REPS Portfolios**

This Master’s Project mainly referred to the method of impact determination used in La Capra’s 2006 Report, while changed some of the assumptions regarding to the practical situation of this project. The basic idea of cost impact determination is comparing the total annual cost of the Utilities’ Portfolio and that of Alternative REPS Portfolio with renewables in the resource mix which should meet the REPS requirement in each year from 2011 to 2030. Accordingly, the annual incremental rate impacts in the unit of cents per kilowatt hour will be calculated by dividing annual incremental costs by the projected retail sales in North Carolina from IOUs each year.

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17 The study period assumed in this project is referred to Duke’s 2010 Integrated Resources Plan which conducted forecast from year 2011 to 2030.

18 Currently, the IOUs use EE and DSM (Demand-Side Management) programs to help manage their customer’s demand in an efficient, cost-effective manner. In general, the EE programs are designed to reduce energy consumption through conservation programs while the DSM programs plan to reduce energy demand. But the REPS policy in North Carolina clearly states that the EE measure “does not include demand-side management”, therefore only EE programs are included in this project. Take Duke for instance, their EE programs are claimed to be non-dispatchable, conservation-oriented education or incentive programs. Energy and capacity savings are reached by changing customer behavior or through the installation of more energy-efficient equipment or structures, accordingly all effects of these programs are reflected in the customer load forecast (Duke Energy Carolinas, LLC., 2009).
1. **Utilities’ Portfolio**

To determine the capacity impact on utilities’ expansion plans, it is primarily relied on the IOUs’ generic generation expansion plans as filed in their 2010 Integrated Resource Plans (IRP). These IRPs forecasted types and sizes of new resources needed over a certain period in a portfolio of both conventional and renewable technologies. This combined portfolio is defined as the “Utility Portfolio” in this project. It is worth noticing that in compliance with REPS policy since 2007, each IRP has designed a certain portfolio of renewable energy generation. This makes a great difference from La Capra’s 2006 Report that didn’t report renewable generation in the Utilities’ Portfolio.

Table 2 below represents the Utilities’ Portfolio combined from three IOUs. It shows the capacity and energy needs under the IOUs’ 2010 IRPs only and does not include any existing utility resources. Referred to La Capra’s 2006 Report and statistic data from U.S. Energy Information Administration (EIA), the total energy output of the capacity additions was calculated with the capacity factors assumed as follows: (1) Baseload = 90%; (2) Peaking/Intermediate = 50%; (3) Renewables = 45%. The total incremental capacity and energy is shown in Table 2 and Figure 3 below.

**Table 2. IOUs’ Combined Cumulative Utilities’ Portfolio Additions from 2011 to 2030**

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<td>2743</td>
<td>4059</td>
<td>4256</td>
<td>4463</td>
<td>4986</td>
<td>5208</td>
<td>5431</td>
<td>5654</td>
<td>5877</td>
</tr>
<tr>
<td>Peaking/Intermediate</td>
<td>635</td>
<td>635</td>
<td>1555</td>
<td>2180</td>
<td>2180</td>
<td>2366</td>
<td>3121</td>
<td>3676</td>
<td>4618</td>
<td>4648</td>
<td>5289</td>
<td>5851</td>
<td>5892</td>
<td>6111</td>
<td>6331</td>
<td>6378</td>
<td>7675</td>
<td>7722</td>
<td>8419</td>
<td>8766</td>
</tr>
<tr>
<td>Renewables</td>
<td>43</td>
<td>174</td>
<td>211</td>
<td>331</td>
<td>462</td>
<td>473</td>
<td>482</td>
<td>1070</td>
<td>1220</td>
<td>1251</td>
<td>1327</td>
<td>1346</td>
<td>1371</td>
<td>1379</td>
<td>1480</td>
<td>1517</td>
<td>1538</td>
<td>1555</td>
<td>1576</td>
<td>1640</td>
</tr>
<tr>
<td>Energy (GWh)</td>
<td>3184</td>
<td>4152</td>
<td>8778</td>
<td>12443</td>
<td>13410</td>
<td>14612</td>
<td>18399</td>
<td>24114</td>
<td>29910</td>
<td>33338</td>
<td>48306</td>
<td>52564</td>
<td>63141</td>
<td>65782</td>
<td>68749</td>
<td>73223</td>
<td>80745</td>
<td>82773</td>
<td>87665</td>
<td>91195</td>
</tr>
</tbody>
</table>

19 Duke Energy Carolinas’ 2010 Integrated Resource Plan was filed on September 1, 2010; Progress Energy Carolinas, Inc.’s 2010 Integrated Resource Plan was filed on September 13, 2010; Integrated Resource Plan of Dominion North Carolina Power was filed on September 1, 2010.

20 Regarding to the fact that Duke holds the biggest market share among the three IOUs in North Carolina and the latest news indicates that Duke and Progress have announced to merge (http://www.duke-energy.com/progress-energy-merger/). The combined company will become the nation’s largest utility, with the name of Duke Energy. Hence, this Master’s Project will take Duke’s IRP as the dominant data source and reference to conduct all relevant analysis.


22 This study period is assigned according to the cumulative future resource additions published on Duke’s 2010 IRP.
2. **Alternative REPS Portfolio**

An Alternative REPS Portfolio, next, should be developed in order to achieve both the capacity and energy needs similar to the Utilities’ Portfolio, while strictly following the REPS schedule in North Carolina during the study period. This portfolio is designed to include changes in conventional resource mixes to meet the capacity and energy targets of the Utilities’ Portfolio, i.e. to meet a required planning reserve margin filed on IOUs’ 2010 IRPs. It is worth noting that it was more important to achieve the capacity requirement as reflected in the Utilities’ Portfolio for reliability purpose (reserve margin), while it would result in, accordingly, excess or short energy produced over or below the IOUs’ targets of incremental energy needs (La Capra’s team, 2006).

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An electric system’s reliability is its ability to continuously supply all of the demands of its consumers with a minimum interruption of service, as well as to withstand sudden disturbances (Annual Report of the North Carolina Utilities Commission, November 30, 2010). As one of the most widely used measure, the reserve margin is calculated as the ratio of reserve capacity to actual needed capacity, i.e. peak load. In recent years, the NC Commission has approved IRPs containing research margins lower than 20%. Consequently, the forecasted annual reserve margins filed by the three IOUs have fulfilled the requirement and are adopted in this project as reference.
To create the “Alternative REPS Portfolio”\(^\text{24}\) in this Master’s Project, four major steps are followed and a complete set of Alternative REPS Portfolio for both base-case and energy-efficiency scenarios would be shown in the Appendix II:

- **Step 1:** to decide annual REPS policy requirement. Both the overall requirement of renewable generation and subsections of solar, swine waste and poultry waste should be achieved. Annual REPS requirement from 2011 to 2030 can be found in the Appendix I. For the scenario including Energy-Efficiency (EE) implementation, this part can be met up to 25% by energy efficiency measures and since calendar year 2021, up to 40% of REPS requirement can be deducted by EE.

- **Step 2:** to calculate renewable energy mix of IOUs forecasted in their 2010 IRPs. The pie charts (Figure 4) below show the changes in IOUs’ energy mix between 2011 and 2030. The relative share of renewables (including hydro generation) increases while the relative share of coal decreases. Despite of an increase share of renewable generation, the total renewable generation only accounts for around 5%, far lower than the required REPS percentage.

\[\text{Figure 4. IOUs Energy Generation Mix in 2011 and 2030}\]

- **Step 3:** to compare the annual REPS requirement and IOUs’ forecasted yearly renewable generation from 2011 to 2030. Basically, the differential energy generation in a portfolio of

\(^{24}\) In La Capra’s 2006 Report, they claimed that the alternative portfolio in the Report was “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”. Likewise, the main objective of this Masters’ Project is to produce potential cost differentials between the two portfolios that might reflect the assumptions used in each scenario and sensitivity modeled later.
various renewable technologies is defined to be the category of renewable resource additions in the Alternative REPS Portfolio. It is worth noting a fact that in the 2010 IRPs, all three IOUs have added a certain amount of renewable resources into their forecasted expansion plans due to the REPS implementation in North Carolina since 2007, consequently there exist possibilities that during the study period the IOUs’ renewable generation already achieves or even exceeds the REPS requirement defined in Step 1; or the filed expansion plans of renewable generation could already cover the differential between REPS requirement and existing generation. Under such circumstances, the Alternative Portfolio will be kept unchanged from the Utilities’ Portfolio in the same year, implying no cost impacts of REPS policy.

- **Step 4:** to complete the Alternative Portfolio. As many of the renewable resources are normally baseload generation, the renewable generation additions calculated in the former step will primarily aim to displace baseload supply from conventional fuel technologies; meanwhile, additional peaking/intermediate generation would be needed to compensate remaining capacity and energy needs (La Capra’s 2006 Report). Table 2 indicates comparison of capacity development in scenario portfolios ending 2030. From the scenarios design, the REPS implementation in IOUs will potentially displace around 1100 MW of baseload generation, but almost 2000 MW of additional peaking/intermediate generation would be needed to fulfill the reserve margin demands. The further assumptions and expressions about types and sizes of technologies adopted in each set of portfolio will be discussed later.

### Table 3. Comparison of Capacity Development in Scenario Portfolios Ending 2030

<table>
<thead>
<tr>
<th>Capacity Additions (MW)</th>
<th>Utilities’ Portfolio by 2030</th>
<th>REPS Scenarios (17%) by 2030</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>I. Base-Case</td>
</tr>
<tr>
<td></td>
<td></td>
<td>II. Energy-Efficiency</td>
</tr>
<tr>
<td>Baseload</td>
<td>5877</td>
<td>4773</td>
</tr>
<tr>
<td></td>
<td></td>
<td>5518</td>
</tr>
<tr>
<td>Peaking/Intermediate</td>
<td>8766</td>
<td>10754</td>
</tr>
<tr>
<td></td>
<td></td>
<td>8855</td>
</tr>
</tbody>
</table>

25 The energy generation will be converted by using the capacity factors of each type of technology. All capacity factors adopted in this project will be listed in the following section.

26 Based on the REPS policy in North Carolina, the energy-efficiency measures can be adopted by IOUs to meet a portion of REPS requirement. It implies, in this project, when added EE, IOUs’ renewable contributions to their total generation are supposed to be larger compared to the Base-Case Scenario. Therefore, fewer renewable capacity expansions were designed under the EE Scenario (see Table 3), and more baseload, accordingly, were required to fulfill the expansion needs than those under the Base-Case Scenario.
Avoided Energy Cost

In La Capra’s 2006 Report, it was claimed that some renewable generation would not be perceived to contribute to firm capacity needs (La Capra’s Team, 2006), the Alternative REPS Portfolio with renewables in the mix that achieves the capacity targets primarily may result in excess or short energy produced over or below the energy generation from expansion plan reflected in Utilities’ Portfolio (Figure 5). Any of the excess (or short) energy generated as a result of the alternative portfolio is assumed to reduce (or increase) generation from existing resources, and this part would be taken as similar to avoided cost calculation. In this Master’s Project, the avoided energy cost for the excess (or short) energy is assumed to equal marginal costs of peaking/intermediate load generation, regarding that, as mentioned previously, the remaining capacity and energy needs after baseload generation replacement by renewables are met by peaking/intermediate load technologies.

<table>
<thead>
<tr>
<th>Renewables</th>
<th>1640</th>
<th>3848</th>
<th>1972</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Change in Capacity Relative to Utilities’ Portfolio</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Baseload</td>
<td>(-1104)</td>
<td>(-359)</td>
<td></td>
</tr>
<tr>
<td>Peaking/Intermediate</td>
<td>1988</td>
<td>89</td>
<td></td>
</tr>
<tr>
<td>Renewables</td>
<td>2208</td>
<td>332</td>
<td></td>
</tr>
</tbody>
</table>

Figure 5. Portfolio Comparison of Capacity and Energy Expansions from 2011 to 2030
Impact Models and Cost Assumptions

Annual cost impact of REPS policy in this project is defined as the incremental costs, i.e. the annual difference in costs between the Utilities’ Portfolio and the Alternative REPS Portfolio, for each year with the study period (2011 ~ 2030). The annual total costs of expansion plans for both two portfolios are calculated by multiplying the energy generation from each technology (GWh) by levelized cost of each new generation resources ($/MWh). In addition, the total incremental costs will be summed and transformed to a 20-year net present value (NPV), assuming a 10% discount rate. This 20-year NPV value would reflect the long-term commitment of the REPS policy of IOUs in North Carolina. Furthermore, the rate impact will be derived by dividing the annual cost impact by retail sales forecast (GWh) from IOUs, in unit of cents per kilowatt hour (cents/kWh).

1. Modeled Variables

Table 4 summaries the generation costs and operational characteristics of technologies that are adopted for baseload, peaking/intermediate load and renewable portfolios respectively. It is important to point out that this Master’s Project determine the details of technologies by referring to both IOUs’ 2010 IRPs and EIA’s updated cost estimates for electricity generation, and further adjust them regarding to the model practice. In the Utilities’ Portfolio, the technology mix of future expansions was filed, mostly, on IOUs’ 2010 IRPs; in the Alternative REPS Portfolio, the selection of renewable resources are determined by taking into account of resources availabilities in North Carolina and their potential for development (La Capra’s Team, 2006; see Appendix III).

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27 The energy generation will be transformed from capacity portfolios defined previously, based on assumed capacity factors presented as follows.

28 The 10% discount rate used in this project is referred to La Capra’s 2006 Report.


30 All three IOUs have specified sizes, types and other details of technologies used for future expansion needs, while their information are not always consistent with them assumed by EIA’s analysis. To simplify the modeling process, in this Master’s Project, all other technical characteristics, except for types, are mostly referred to EIA’s latest estimates (see Table 4).

31 Among all IOUs, only Duke has filed renewable expansion plans that described the types and quantities of renewable resources needed; Progress has filed the quantities of solar, swine waste and poultry waste which are included in the REPS subsection, but not filed other renewable resources; NC power has not offered too much information like two IOUs.
### Table 4. Summary of Generation Technology Costs and Operational Characteristics

<table>
<thead>
<tr>
<th>Portfolio</th>
<th>Technology</th>
<th>Fuel</th>
<th>Capacity Factor (%)</th>
<th>Nominal Capacity (MW)</th>
<th>Nominal Heat Rate (Btu/kWh)</th>
<th>Fuel Cost ($/mmBtu)</th>
<th>Capital Cost ($/kW)</th>
<th>Fixed O&amp;M ($/kW-yr)</th>
<th>Variable O&amp;M ($/MWh)</th>
<th>Byproduct ($/MWh)</th>
<th>Byproduct Tax Credit (PTC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Baseload</td>
<td>Advanced Pulverized Coal</td>
<td>Coal</td>
<td>85</td>
<td>650</td>
<td>8800</td>
<td>3.51</td>
<td>3167</td>
<td>35.97</td>
<td>4.25</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Advanced Nuclear</td>
<td>Uranium</td>
<td>90</td>
<td>2236</td>
<td>10000</td>
<td>0.46</td>
<td>5339</td>
<td>88.75</td>
<td>2.04</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Peaking/Intermediate</td>
<td>Advanced Combined Cycle (CC)</td>
<td>Gas</td>
<td>87</td>
<td>400</td>
<td>6430</td>
<td>9.05</td>
<td>1003</td>
<td>14.62</td>
<td>3.11</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>Advanced Combustion Turbine (CT)</td>
<td>Gas</td>
<td>30</td>
<td>210</td>
<td>9750</td>
<td>8.15</td>
<td>665</td>
<td>6.7</td>
<td>9.87</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Renewables</td>
<td>Solar Photovoltaic</td>
<td>Solar</td>
<td>25</td>
<td>150</td>
<td>0</td>
<td>0</td>
<td>4755</td>
<td>16.7</td>
<td>0</td>
<td>0</td>
<td>1.1</td>
</tr>
<tr>
<td></td>
<td>Swine Waste</td>
<td>Hog Waste</td>
<td>75</td>
<td>50</td>
<td>14000</td>
<td>2.42</td>
<td>4203</td>
<td>270</td>
<td>0</td>
<td>3.46</td>
<td>1.1</td>
</tr>
<tr>
<td></td>
<td>Poultry Waste</td>
<td>Litter/Aq. Waste</td>
<td>90</td>
<td>50</td>
<td>13000</td>
<td>0</td>
<td>3075</td>
<td>75</td>
<td>10</td>
<td>2.1</td>
<td>1.1</td>
</tr>
<tr>
<td></td>
<td>Onshore Wind</td>
<td>Wind (onshore)</td>
<td>34</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>2438</td>
<td>28.07</td>
<td>0</td>
<td>N/A</td>
<td>2.2</td>
</tr>
<tr>
<td></td>
<td>Wood Biomass (co-firing)</td>
<td>Wood Block</td>
<td>83</td>
<td>20</td>
<td>12350</td>
<td>2.66</td>
<td>7894</td>
<td>338.79</td>
<td>16.64</td>
<td>N/A</td>
<td>2.2</td>
</tr>
<tr>
<td></td>
<td>Landfill Gas</td>
<td>Landfill Gas</td>
<td>80</td>
<td>50</td>
<td>0</td>
<td>0</td>
<td>5578</td>
<td>84.27</td>
<td>9.64</td>
<td>N/A</td>
<td>1.1</td>
</tr>
<tr>
<td></td>
<td>Hydroelectric</td>
<td>Hydro</td>
<td>52</td>
<td>500</td>
<td>0</td>
<td>0</td>
<td>3076</td>
<td>13.44</td>
<td>0</td>
<td>N/A</td>
<td>1.1</td>
</tr>
</tbody>
</table>

#### 2. Levelized Cost of New Generation Resources

Next, the levelized cost of new generation resources should be developed in order to assess the associated annual costs for both Utilities’ Portfolio and Alternative REPS Portfolio. In this Master’s Project, the levelized cost calculation uses EIA’s Annual Energy Outlook 2011, which presents average national levelized costs for generating technologies that are brought on line in 2016. Levelized cost estimated in EIA’s paper, based on a 30-year cost recovery period, involves

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32 The cost amount here is presented in 2010 dollars for most of technologies included in the Table 4, except swine waste and poultry waste.

33 The cost of byproduct was referred to La Capra's 2006 Report.


35 With no specified estimates, the cost assumptions of swine waste and poultry waste were referred to La Capra’s 2006 Report, and the cost amounts were in 2008 dollars.


37 In EIA’s paper, it was assumed that the technologies could not be brought on line prior to 2016 unless they were already under construction. However, to simplify the modeling process in this Master’s Project, it is assumed that the
overnight capital cost, fuel cost, fixed and variable O&M cost, financing costs and assumed capacity factors for each plant type, excluding any federal or state tax credits. On this basis, an incentive from federal tax credit, i.e. Renewable Electricity Production Tax Credit (PTC), is added and a set of adjusted total levelized cost for each generation technology is shown as below (Table 5). It should be noticed that a number of factors and uncertainties would influence the levelized cost of energy generation. For instance, for technologies with significant fuel cost, both fuel cost and overnight capital cost would significantly affect system levelized cost; other common uncertainties would be induced by regional varieties and technological change.

Table 5. Estimated U.S. Average Levelized Cost of New Generation Resources

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>Levelized Capital Cost ($/MWh)</th>
<th>Levelied Fixed O&amp;M Cost ($/MWh)</th>
<th>Levelized Variable O&amp;M Cost (including fuel) ($/MWh)</th>
<th>Transmission Investment ($/MWh)</th>
<th>Adjusted Total System Levelized Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Coal</td>
<td>74.6</td>
<td>7.9</td>
<td>25.7</td>
<td>1.2</td>
<td>109.40</td>
</tr>
<tr>
<td>Advanced Nuclear</td>
<td>90.1</td>
<td>11.1</td>
<td>11.7</td>
<td>1.0</td>
<td>113.90</td>
</tr>
<tr>
<td>Natural Gas-fired – Advanced CC</td>
<td>17.9</td>
<td>1.9</td>
<td>42.1</td>
<td>1.2</td>
<td>63.10</td>
</tr>
<tr>
<td>Natural Gas-fired – Advanced CT</td>
<td>31.6</td>
<td>5.5</td>
<td>62.9</td>
<td>3.5</td>
<td>103.50</td>
</tr>
<tr>
<td>Solar PV</td>
<td>194.6</td>
<td>12.1</td>
<td>0.0</td>
<td>4.0</td>
<td>206.54</td>
</tr>
<tr>
<td>Swine Waste</td>
<td>91.7</td>
<td>57.1</td>
<td>0.0</td>
<td>1.3</td>
<td>149.40</td>
</tr>
<tr>
<td>Poultry Waste</td>
<td>123.5</td>
<td>74.1</td>
<td>10.0</td>
<td>1.3</td>
<td>206.84</td>
</tr>
<tr>
<td>Onshore Wind</td>
<td>83.9</td>
<td>9.6</td>
<td>0.0</td>
<td>3.5</td>
<td>88.67</td>
</tr>
<tr>
<td>Wood Biomass (co-firing)</td>
<td>55.3</td>
<td>13.7</td>
<td>42.3</td>
<td>1.3</td>
<td>104.27</td>
</tr>
<tr>
<td>Landfill Gas</td>
<td>58.7</td>
<td>43.3</td>
<td>0.0</td>
<td>1.2</td>
<td>99.04</td>
</tr>
<tr>
<td>Hydro</td>
<td>74.5</td>
<td>3.8</td>
<td>6.3</td>
<td>1.9</td>
<td>82.34</td>
</tr>
</tbody>
</table>

estimates in EIA’s report could be also used for annual technology expansions that are supposed to be brought on line in the corresponding year, in the designed portfolio scenarios.

38 The levelized cost reflects real dollars and already takes into account inflation, with the annual inflation rate of 2.5%.
Sensitivity Analysis

Accompanied with the two scenarios analyzed above, this Master’s Project will also detect the impacts of different sensitivities. The Base-Case Scenario without EE is chosen as the reference case for sensitivity analysis that will examine the changes in 20-year NPV of total incremental costs relative to that of the Base-Case for each of the sensitivities. In another word, this part aims to find out if the sensitivity factors would increase or decrease the total incremental costs across the study period.

The sensitivities analyzed in this project include the following:

- **PTC Availability:** In the Base-Case Scenario, the PTC was assumed to be filed “at a qualified facility during the 10-year period beginning on the date the facility was originally placed in service”. Considering the current trend of encouraging renewable electricity production around the nationwide, there is possibility that the PTC available period could be extended after the generation unit put in service. Hence, this project will modeled a sensitivity case in which the PTC is available during the whole cost recovery period, i.e. 30-year in this project.

- **Fuel Cost of Coal:** There is great uncertainty on the future cost of fossil fuels. As mentioned previously, fuel cost plays a significant role of affecting the overall levelized cost of generation technology with coal. Under the Base-Case, the fuel cost for IOUs in North Carolina with coal is assumed at $3.51/mmBtu in 2010 dollars. Referred to Duke’s 2010 IRPs, two sensitivities with coal price are modeled here:
  - Higher coal price: 50% higher ⇒ $5.27/mmBtu in 2010 dollars;
  - Lower coal price: 20% lower ⇒ $2.81/mmBtu in 2010 dollars.

- **Fuel Cost of Natural Gas:** Similar to coal, the variability of natural gas price would have great influence on its total cost. The Base-Case assumed the natural gas price for CC

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39 In order to compare with La Capra’s 2006 Report, the methodology of sensitivity analysis adopted in this project is referred to the 2006 report.


41 This cost amount is adjusted from EIA’s 2008 summaries of electric power sector energy price, with a yearly inflation rate of 2.5%. [http://www.eia.doe.gov/emeu/states/sep_sum/html/sum_pr_eu.html](http://www.eia.doe.gov/emeu/states/sep_sum/html/sum_pr_eu.html).

42 As indicated at the beginning of the methodology part, this Master’s Project would take Duke’s 2010 IRP as primary reference due to its large market share in NC.

43 The fuel costs for CC and CT were referred to La Capra’s 2006 Report, adjusted with inflation rate of 2.5%.
generation and CT generation as $9.05/mmBtu and $8.15/mmBtu, respectively. Currently, the fuel cost remains to be the major contributor to total levelized generation cost of natural gas, taking up to 67% (OECD/IEA, 2010). It implies that a run-up in natural gas price would bring great uncertainty into all gas forecasts. Referred to sensitivity analyses designed in Duke’s 2010 IRPs, two sensitivities with natural gas prices are modeled:

- **Higher gas price**: 35% higher → \( \begin{align*}
CC: \frac{12.22}{mmBtu} \\
CT: \frac{11.00}{mmBtu}
\end{align*} \), in 2010 dollars;

- **Lower gas price**: 25% lower → \( \begin{align*}
CC: \frac{6.79}{mmBtu} \\
CT: \frac{6.11}{mmBtu}
\end{align*} \), in 2010 dollars.

**Construction Cost of Nuclear Plant:** The share of investment of nuclear plant construction in system’s total levelized generation cost is around 75% (OECD/IEA, 2010), implying a significant contribution. In this project, the construction cost is assumed to be $3231/kW in 2010 dollars. This project only models the change from increases in construction cost of nuclear plant, as Duke’s 2010 IRPs filed, so the sensitivity case analyzed here induces a 20% higher cost, i.e. $3877/kW in 2010 dollars.

**Results**

**Direct Impacts of REPS Implementation**

The impact model designed above has produced the annual incremental rate impacts (cents/kWh) for both Base-Case Scenario and EE Scenario (see Figure 6). The rate impacts in this project were derived by dividing annual incremental costs by the expected total retail sales filed by IOUs in North Carolina for each calendar year. Table 6 shows the modeling results of rate impacts in two scenarios, corresponding to yearly REPS requirement within the study period. With recall of the previous assumptions, the cost impact would be zero once the IOUs’ renewable generation filed in their resource plans already achieved/exceeded the REPS requirement; or the IOUs’ field expansion plan could cover the differential between REPS requirement and existing generation. Consequently, in Base-Case Scenario, the rate impacts appear to be zero from calendar year 2011 to 2015, with the REPS requirement ranged from 3.0% to 6.0%, implying that the REPS requirement would have no incremental cost by 2017 (excluding energy-efficiency measures).

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44 The full 2010 edition of this joint report (Projected Costs of Generating Electricity), by the International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA), has not been released to public yet, except the executive summary. The relevant information adopted in this Master’s Project is referred to the report’s executive summary.

45 The construction cost value of nuclear plant was also referred to La Capra’s 2006 Report, adjusted with inflation rate.
When taking into account energy-efficiency measures, the rate impacts have further decreased, from 0.54 cents/kWh under Base-Case Scenario at the end of study period (with 17% REPS requirement) to 0.17 cents/kWh under EE Scenario. The 2010 average retail electricity rate to ultimate customers in North Carolina was 8.7 cents/kWh\(^{46}\), and is predicted to be 15.7 cents/kWh by 2030\(^{47}\) (the projected retail rates of electricity in each year are presented in Table 6). Consequently, under the Base-Case Scenario, the projected retail rate impacts of electricity in percentage is around 3% by 2030, while the EE Scenario produced an increase of 1% on retail rate by 2030. It should be noticed that the calendar year 2021 proves to separate the whole study period into two phases: before 2021 the energy-efficiency measures are qualified to meet up 25% of REPS requirement while after 2021 up to 40% of REPS could be compensated by energy-efficiency. On such condition, the rate impacts removed from Base-Case by EE became even higher after 2021 (see Figure 6).

---

\(^{46}\) By end-use sector, the retail prices of electricity in four categories of ultimate customers are summarized: residential, commercial, industrial and transportation, whose data are collected by EIA, in their Electric Power Monthly report. [http://www.eia.gov/cneaf/electricity/epm/table5_6_b.html](http://www.eia.gov/cneaf/electricity/epm/table5_6_b.html). The average retail rate used in this project is averaged across these four sectors.

\(^{47}\) Referring to ACEEE’s report about North Carolina’s energy future (American Council for an Energy-Efficient Economy, 2010) and the updated information in recently years from EIA, the future retail price of electricity in North Carolina is assumed to increase at 0.3% annually from 2010’s price of 8.7 cents/kWh, within the study period (from 2011 to 2030).
Additionally, the total 20-year NPV cost impacts for each scenario were also calculated with assumed 10% discount rate. Table 7 shows 20-year NPV net incremental cost due to REPS implementation, implying the total cost of REPS during the whole study period\textsuperscript{48}. Over 20 years, the implementation of Alternative REPS Portfolio has added $1634 million dollars to the Utilities’ Portfolio, and this part could be defined as the total cost of REPS practice of IOUs in North Carolina. By adding the energy-efficiency measures, the REPS cost over 20 years could be reduced to $487 million dollars.

Table 7. Incremental Cost Over 20 Years in NPV

<table>
<thead>
<tr>
<th>REPS Scenario</th>
<th>Utilities’ Portfolio</th>
<th>Alternative REPS Portfolio</th>
<th>Net Incremental Cost (with avoided energy cost)</th>
</tr>
</thead>
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<tr>
<td>Base-Case</td>
<td>$27570</td>
<td>$29979</td>
<td>$1634</td>
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<td>Energy-Efficiency</td>
<td>$26862</td>
<td>$27325</td>
<td>$487</td>
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\textsuperscript{48} Detailed annual costs can be found in Appendix IV.
Indirect Impacts of REPS Implementation

To meet the NC REPS requirement during 20 years, basically all practical land-based renewable resources are utilized in the Alternative REPS Portfolio. On the other hand, in the Utilities’ Portfolio all three IOUs filed renewable generation with different resource mix regarding to their own development planning. Figure 7 compares the renewable resource mix in two portfolios, detecting the change of resource mix result from REPS implementation.

![Figure 7. Comparison of Renewable Resource Mixes for Two Portfolios](image)

One obvious difference between the two resource mixes is that the landfill gas was included into Alternative REPS Portfolio for the purpose of resource diversity. A bump-up of onshore wind generation in Utilities’ Portfolio is detected and it was induced by Progress largely increasing its filed wind generation since 2018. The differences shown on the Figure 7 might result from a main reason: the three IOUs forecasted resource mixes on their own way respectively and considering their own practical conditions while the resource mix for Alternative Portfolio was determined on a united basis and in a continuous pattern. However, generation cost and resource availability in North Carolina would be the primary concerns for both two portfolios when deciding the resource mix.

Sensitivity Analysis

Sensitivity analyses were conducted using the Base-Case as reference case, which produced a 20-year NPV of $1634 million in net incremental cost. Figure 8 shows the change in 20-year NPV relative to that of the reference case for each of the sensitivities, in order to detect whether the

---

49 In its 2010 IRP, Progress specified its expansion plan on renewable generation, with type and size of selected technologies. Referring to its plan, the wind capacity contribution would jump from around 5 MW in 2018 to 427 MW in 2019. Accordingly, the energy generation from wind would reflect a similar sudden increase.
sensitivity analyzed in this project would increase or reduce the REPS incremental cost over 20 years. The major results from the sensitivity analysis are summarized as below:

- **Extended PTC:** Once the PTC of eligible renewable resources could be extended from the first 10 years to be in use within the whole cost recovery period, this extended availability clearly reduce the total incremental cost, in form of 20-year NPV, of the REPS implementation by $318 million, almost 20%.

- **Fuel Price Uncertainty:** Consistent with other similar state RPS analysis, higher fuel prices (either coal or natural gas) will result in declines of the incremental cost of REPS practice, while the lower fuel prices will further increase the incremental cost over 20 years. It is straightforward that due to the REPS implementation, fewer conventional technologies were adopted and an even higher fuel price will make IOUs to cut the share of conventional fuels, and vice versa. Although the sensitivity analysis here suggested reductions of incremental costs due to high fuel prices (either coal or natural gas), implying that neither of them could completely offset the cost of REPS implementation ($1634 million, in 20-year NPV), it proved that the REPS practice over 20 years can help mitigate some risks related to high fuel prices (La Capra’s Team, 2006).

- **High Construction Cost of Nuclear Plant:** Similar to sensitivities of high fuel prices, a higher construction cost of nuclear plant would largely reduce the 20-year NPV incremental cost of REPS practice. The potential reason of this cost declines could be that regarding to the originally high construction cost of nuclear plant, an even higher cost would induce more advanced nuclear facilities replaced by new renewable resources, to reduce the total expansion cost. But it worth noting that an REPS implementation cost could depend highly on the actual cost of a new nuclear facility (La Capra’s Team, 2006), which is hard to predict. Hence, uncertainties relevant to this sensitivity analysis still remain.
Discussion

Discussion Based on La Capra’s 2006 Report

As emphasized at the beginning of this project, the technical report of RPS analysis prepared for North Carolina Utilities Commission in 2006 proved to be the only authoritative report in North Carolina so far. Consequently, it is inevitable to discuss based on 2006’s Report when conducting a similar analysis of REPS in North Carolina, like this Master’s Project. Although this project designed the impact models primarily referred to 2006’s Report and used a number of assumptions in it, there still present many adjustments and improvements in this project.

Firstly, it should be clarified the changes of assumptions in this project relative to La Capra’s 2006 Report:

The fundamental adjustment made in this project is the RPS design for North Carolina. Due to the fact that the 2006’s Report was created before the official REPS enacted in NC in the coming year, they assumed two scenarios of RPS policy: 1) 5% RPS by 2017; 2) 10% RPS by 2017, accompanied with the assumed study period of 10 years (2008 ~ 2017). They also assumed all utilities in North Carolina should follow the same schedule of RPS while no specific requirement for each year in the study period. In contrast, this project adopted the published REPS requirement and
its schedule (see Appendix I). The current REPS policy requires a 10% RPES by 2018 for all utilities and a 12.5% REPS by 2021 for Investor-Owned Utilities.\(^{50}\) Adjusted for this project, the study period is defined from 2011 to 2030, and a 17% REPS would be reached by the end of study period with an annual increase rate of 0.5% from 12.5% in 2021. It is worth mentioning that La Capra’s Team has taken the 5% RPS as major forecast scenario while they didn’t expect a RPS as high as 10% practical in NC, considering the resource availability and other factors at that time. Hence, this basic difference of REPS design between 2006’s Report and this project might induce other changes of assumptions and model results in this project relative to the former report.

Another great difference of assumption is the design of Utilities’ Portfolio. La Capra’s Team defined the Utilities’ Portfolio with no renewable contribution to the expansion plan, consequently, the RPS exerted positive cost impact (i.e. increased the expansion cost) since the start of RPS practice (year 2008). Different from their assumption, this project extracted cumulative resource additions filed in three IOUs’ 2010 IRPs and obviously all IOUs have already added a certain amount renewable resources into their expansion plan to respond to the state REPS policy. Such design of Utilities’ Portfolio caused the result that the IOUs might have already reached the REPS requirement in a certain calendar year, implying no cost impact at that year.

Last but not least, another difference exists in the energy-efficiency measure. In 2006’s Report, it was assumed that 25% of a RPS target (either 5% or 10%) could be met with energy efficiency throughout the whole study period, 10 years. The enacted REPS policy in 2007, nevertheless, indicates that up to 25% of the REPS requirement can be met by EE before 2021; furthermore after 2021 EE is allowed to meet up to 40% of REPS. Consequently, this higher proportion of EE contributed to REPS implementation could potentially reduce the cost impact after 2021 to a greater degree in this project.

Then the major difference of model results would be presented as follows, on the basis of the assumption differences discussed above. Figure 9 below suggests the difference of rate impacts modeled in 2006’s Report\(^{51}\) and this Master’s Project. As mentioned above, the adjusted design of the Utilities’ Portfolio in this project estimated the cost impact in Base-Case Scenario as zero during

\(^{50}\) To simplify the modeling process, this Master’s Project merely take IOUs as study objects.

\(^{51}\) Compared to the conservative assumption of the 5% RPS in 2006’s Report, the 10% RPS by 2017 scenario proved to be more comparable with this project in which an 8.6% REPS target was assigned in calendar year 2017. Therefore, Figure 9 compares the model results under the 10% RPS in 2006’s Report instead of the 5% RPS.
the first 5 years of study period, similar condition happening in EE Scenario. It also explains why modeled rate impact for year 2017 in 2006’s Report (0.31 cents/kWh) was much higher than the model result for year 2018 in this project (0.08 cents/kWh). But the basic trend of characteristics of modeled rate impacts in two papers presents to be the same: 1) the higher the REPS requirement is the larger rate impact would be; 2) energy efficiency measures included in REPS implementation could effectively reduce the cost and, accordingly, rate impact of REPS.

Model Result in La Capra’s 2006 Report

Model Result in this Master’s Project

![Figure 9. Comparison of Model Results on Annual Rate Impact of REPS by 2006’s Report and This Project](image)

It should be further pointed out that the negative rate impact modeled in 2006’s Report (see Figure 9) implied a cost/rate decrease due to the 10% RPS target. When a 25% EE included in the 10% RPS scenario, the renewable contribution to the overall generation would possibly reach/exceed the assigned RPS target and furthermore reduce the expansion cost. Contrarily, in this Master’s Project, the similar condition was handled as keeping the Alternative REPS Portfolio with EE unchanged relative to Utilities’ Portfolio so the cost/rate impact was estimated to be zero under such situation (i.e. from the calendar year 2011 to 2016).

In addition to the assumptions mentioned above, the detailed portfolio design, particularly the alternative portfolio design, would produce different model results. However, without a universal rule of portfolio outcomes (La Capra’s Team, 2006), either 2006’s Report or this Master’s Project mainly aimed to offer a reference for estimating representative cost differentials between

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52 The REPS target in calendar year 2018 was assigned as 10% in this Master’s Project, as the same as the 10% RPS by 2017 in 2006’s Report.
the Utilities’ Portfolio and Alternative REPS Portfolio that would reflect the assumptions used in each study respectively.

**Policy Discussion**

In this Master’s Project, the REPS policy was modeled to increase the base-case retail rate around 3% by the end of study period, 2030, through compliance with a 17% REPS requirement by IOUs. Referring to RPS studies relying on exploratory analyses (Kydes, 2006; Palmer and Burtraw, 2005), the RPS-induced rate impacts were modeled as about 3% increase under a design of 20% RPS, and as 2.1% at a 15% RPS target respectively. It should be noticed that these two studies conducted analyses by compiling data from various states and assuming a united RPS requirement in nationwide. Compared to the state-level studies summarized previously, the exploratory analyses might be a more appropriate reference to determine the quality of model results in this project. From this perspective, the base-case retail rate impact modeled here is reasonable under the REPS policy in North Carolina.

On the other side, the 2006’s Report prepared by La Capra’s Team assumed two RPS targets for North Carolina from 2008 to 2017: 5% and 10%. This study reported the 10% RPS requirement to be more aggressive, with more than 4000 MW renewable expansions projected. This 10% RPS excluding energy efficiency would require a large amount of development of off-shore wind, while presently no off-shore wind projects have been installed in the U.S. due to many permitting obstacles (La Capra’s Team, 2006). Referring to the Alternative REPS Portfolio design under Base-Case Scenario, around 3800 MW renewables would be expanded to meet a 17% REPS target assumed in this Master’s Project. Regarding to the practical potential of renewable resources in North Carolina (see Appendix III), a certain amount of off-shore wind might be added into the resource mix as well to fulfill the expansion plan, since most practical on-land resources would already be developed. In the view of resources availability, the assumption of 17% REPS target by 2030 seems to be less rational.

The discussion above shows that a modest cost impact of REPS implementation would not necessarily imply a rational or effective policy design of REPS for North Carolina. An assumed 17% REPS target by 2030 proved to be cost-moderate but aggressive regarding to in-state renewables availability. It implies an assumption for argument that the REPS requirement would increase with annual growth of 0.5% when beginning in 2022 and thereafter. However, the official REPS policy didn’t propose clear guidance for compliance after 2021. The expression of policy reserved a question whether the IOUs should be subject to a growing requirement in a long-run, or to a stable
target after 2021 ever. More detailed guidance would need to be developed for IOUs to comply with the RESP policy in North Carolina.

**Model Uncertainties**

This Master’s Project concluded a potential impact on retail electricity rate result in REPS practice in North Carolina. Obviously, it proves to be a complex process to determine the retail electricity rate and the REPS implementation would not be the dominant influencing factor in this process. Therefore the rate impact calculated in this project could merely describe a trend of retail rate varying over years which was affected by REPS practice.

On the other side, the cost assumptions are taken the major uncertainties in the modeling process. First of all, as the main model inputs, the levelized cost of new generation resources were extracted from EIA’s report at national average level. Without regional adjustment for North Carolina, it would introduce uncertainty when using national data as model inputs in this project to estimate cost impact in North Carolina.\(^{53}\)

Great uncertainty also appears around the future cost of fossil fuels. Referred to 2006’s Report, fuel costs were supposed to rise at a rate of inflation. But according to the historical records, the cost of fossil fuels have been increasing at a rate greater than inflation and that is why the sensitivities of high fossil fuel costs should be analyzed in the project. Similar uncertainties would be induced by construction cost of nuclear plants. The construction cost estimates for new nuclear power plants are very uncertain and have increased significantly in recent years, which has been unexpected previously (Schlissel and Biewald, 2008). Thus when to design relevant cost-impact analysis of nuclear plant construction would also induce the study uncertainty.

**Further Improvement**

As summarized in Berkeley lab’s 2007 report, among the existing studies of state RPS, some treated the energy resource mix as an input to their cost estimation model, whereas others treated the mix as a model output (Chen et al., 2007). Under the former circumstances, the resource mix would be estimated according to the existing information and author’s knowledge of the specific situation in the states being modeled. This Master’s Project belongs to this category of studies. In another case, the resource mix, when treated as model output, is usually estimated by constructing

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\(^{53}\) Compared to a combination of information used in 2006’s Report, including confidential data from actual projects, striving for realistic, current assumptions at that time (La Capra’s Team, 2006), this Master’s Project has adopted the latest data most of which are published by U.S. Energy Information Administration, while the data in 2006’s Report might fit the model better since they were specially collected for North Carolina.
an aggregate renewable resource supply curve models that should be built from original research on the cost and availability of different generation options (Chen et al., 2007). To further improve the model used in this project, it will be a great modification to also treat the resource mix as model output, accordingly making the alternative portfolio better fit, as well as helping to evaluate the policy design through the resource mix projected result in REPS practice.

It is the fact that the IOUs do make a large contribution to the electricity market in North Carolina, but effects from other utilities, like electric membership corporations and municipalities can't be ignored. The reason to exclude other utilities from this Master's Project is because the limited time and data sources. Nevertheless, in the future study, it would be an advantage to involve other utilities so that the model result of cost/rate impacts might better reflect the overall RESP impacts on retail electricity rate in the state of North Carolina.

Although the current REPS policy in North Carolina proposed a 12.5% requirement for IOUs reached by 2021 and thereafter, it is not clear whether the standard would become higher or keep unchanged after 2021. It might create obstacles especially for a longer-period study of REPS. Consequently to assume and propose some more appropriate REPS targets for IOUs in a long-term after 2021 would effectively improve the future study on cost-impact analysis of REPS in North Carolina.

Conclusions

- North Carolina promulgated Renewable Energy and Energy Efficiency Portfolio Standards (REPS) in 2007, specifying detailed requirement and schedule for utilities. For Investor-Owned Utilities (IOUs), it is required to meet a 12.5% REPS target by 2021 and in this Master’s Project, a 17% REPS target is designed for IOUs by the end of study period the calendar year 2030. Additionally, the REPS policy also included energy-efficiency measures that could meet up to 25% of REPS requirement and up to 40% after 2021.
- To meet the REPS requirement, this project designed a combined portfolio of both conventional and renewable technologies, defining it as Alternative REPS Portfolio. Based on the alternative portfolio, 3848 MW of renewable resources are needed after 20 years for expansion and it could replace around 1100 MW capacity of baseload assigned in the Utilities’ Portfolio, but 1988 MW of peaking/intermediate load should be added to meet the
remaining capacity and energy needs. When adding energy-efficiency measures, 1972 MW of renewables are needed by 2030.

- Regarding to the fact that all three IOUs have already filed certain amount of renewable expansion in their 2010 IRPs since the calendar year 2011, it is estimated that no rate impact of REPS implementation appears until 2016. As REPS target rises, the rate impact increases from 0.03 cents/kWh in 2016 up to 0.54 cents/kWh in 2030, the end of study period. Under the EE Scenario, the rate impact has been reduced, especially after calendar year 2021. Compared to the predicted retail price of electricity by 2030, the base-case induced rate impact is 3.4% in terms of percentage while the EE scenario produces a 1.1% increase of retail rate.

- Through the sensitivity analyses on Production Tax Credit (PTC) availability, fossil fuel costs and construction cost of nuclear for the Base-Case Scenario, it is found that the extended availability of PTC to IOUs would reduce the total incremental cost of REPS in 20-year net present value (NPV). Additionally, it is detected that an REPS practice can help mitigate some risks related to high fuel prices (coal and natural gas), but even high fuel costs in the sensitivity analyses would not completely offset all the expansion cost of the Base-Case REPS scenario.

- The assumed 17% REPS target at the end of study period might be too aggressive for North Carolina when taking the in-state renewable resources potential into account, although its cost impact was modest. The REPS policy in North Carolina needs to include more detailed guidance for utilities to comply with the requirements, particularly in a long-term practice.

- Levelized cost of generation resources, as well as forecast of future fossil fuel cost would bring uncertainties of the model results in this Master's Project. To further improve this impact analysis, the resource mix could be treated as model output for future study; involvement of other utilities would produce a more comprehensive impact estimate to reflect the overall REPS impacts on retail electricity rate in North Carolina.
Reference


Appendix

Appendix I: Detailed Schedule and Requirement of REPS for IOUs in North Carolina

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<tr>
<td>Overall REPS Requirement (%)</td>
<td>3%</td>
<td>3%</td>
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<td>13.00%</td>
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<td>0.26%</td>
<td>0.28%</td>
<td>0.30%</td>
<td>0.32%</td>
<td>0.34%</td>
<td>0.36%</td>
<td>0.38%</td>
<td>0.40%</td>
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<td>0.11%</td>
<td>0.14%</td>
<td>0.16%</td>
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<td>0.20%</td>
<td>0.22%</td>
<td>0.24%</td>
<td>0.26%</td>
<td>0.28%</td>
<td>0.30%</td>
<td>0.32%</td>
<td>0.34%</td>
<td>0.36%</td>
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<td>770000</td>
<td>910000</td>
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<td>2450000</td>
<td>2590000</td>
<td>2730000</td>
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\(^{54}\) NC G.S. 62-133.8 proposed the requirement of poultry waste use in unit of megawatt hours, instead of percentage. The required megawatt hours published on G.S. 62-133.8 should be met through all utilities in NC, so this project multiplies the overall requirement by the IOUs' market share (around 70%) in retail electricity sales, in other to produce the specified requirements for IOUs.
**Appendix II: IOUs’ Combined Cumulative Alternative REPS Portfolio Additions from 2011 to 2030 (Base-Case)**

<table>
<thead>
<tr>
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**Energy (GWh)**

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### Appendix III: Renewable Resources Potential in North Carolina (update in 2006)

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<tr>
<th>Resources</th>
<th>Technical Potential (MW)</th>
<th>Practical Potential (MW)</th>
<th>Practical Energy Potential (GWh)</th>
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<td>Landfill Gas</td>
<td>240</td>
<td>150</td>
<td>1000</td>
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<tr>
<td>Biomass (co-firing wood block)</td>
<td>1875</td>
<td>384</td>
<td>2500</td>
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<td>Poultry Litter</td>
<td>175</td>
<td>105</td>
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<td>Hog Waste (swine)</td>
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<td>Wind (on-shore)</td>
<td>9600</td>
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<td>Wind (off-shore)(^{55})</td>
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<td>N/A</td>
</tr>
<tr>
<td>Hydro</td>
<td>508</td>
<td>66 – 425</td>
<td>300 – 1700</td>
</tr>
<tr>
<td>Solar PV(^{56})</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
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<tr>
<td><strong>TOTAL IN-STATE POTENTIAL</strong></td>
<td><strong>12615 – 13206</strong></td>
<td><strong>1867 – 3512</strong></td>
<td><strong>11500 – 16100</strong></td>
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</tbody>
</table>

\(^{55}\) Theoretically, the offshore wind can have much larger potential than onshore wind has, but it is hard to estimate its potential effectively since so far no such projects have been permitted or installed in the U.S. (La Capra’s Team, 2006).

\(^{56}\) Similar to the offshore wind resource, the solar PV potential in the U.S. was not estimated either, because its estimates would depend more on current levels of installed costs, rather than on technical or practical considerations (La Capra’s Team, 2006).
### Appendix IV: Scenarios Annual Costs

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<tbody>
<tr>
<td><strong>Base-Case Scenario</strong></td>
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<tr>
<td>Utilities’ Portfolio Cost</td>
<td>$27,570</td>
<td>$368</td>
<td>$575</td>
<td>$1,106</td>
<td>$1,594</td>
<td>$1,901</td>
<td>$2,258</td>
<td>$2,786</td>
<td>$3,311</td>
<td>$3,698</td>
<td>$5,242</td>
<td>$5,709</td>
<td>$6,887</td>
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<td>$7,425</td>
<td>$7,928</td>
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<td>$8,939</td>
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<tr>
<td>Alternative Portfolio Cost</td>
<td>$29,980</td>
<td>$368</td>
<td>$575</td>
<td>$1,106</td>
<td>$1,594</td>
<td>$1,998</td>
<td>$2,508</td>
<td>$2,956</td>
<td>$3,559</td>
<td>$4,074</td>
<td>$5,781</td>
<td>$6,297</td>
<td>$7,547</td>
<td>$7,913</td>
<td>$8,254</td>
<td>$8,849</td>
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<td>$9,966</td>
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<tr>
<td>Avoided Cost</td>
<td>($776)</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>($61)</td>
<td>($172)</td>
<td>($63)</td>
<td>($93)</td>
<td>($156)</td>
<td>($146)</td>
<td>($188)</td>
<td>($180)</td>
<td>($206)</td>
<td>($204)</td>
<td>($223)</td>
<td>($268)</td>
<td>($291)</td>
<td>($327)</td>
<td>($343)</td>
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<tr>
<td>Delta Between Portfolios</td>
<td>$1634</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
<td>$96</td>
<td>$250</td>
<td>$170</td>
<td>$248</td>
<td>$375</td>
<td>$539</td>
<td>$588</td>
<td>$660</td>
<td>$775</td>
<td>$829</td>
<td>$921</td>
<td>$945</td>
<td>$1,027</td>
<td>$1,111</td>
<td>$1,169</td>
</tr>
</tbody>
</table>

| **Energy-Efficiency Scenario** | | | | | | | | | | | | | | | | | | | | | | | |
| Utilities’ Portfolio Cost | $26,863 | $368 | $573 | $1,098 | $1,578 | $1,769 | $1,870 | $2,212 | $2,721 | $3,229 | $3,597 | $5,081 | $5,533 | $6,675 | $6,917 | $7,195 | $7,686 | $8,449 | $8,674 | $9,157 | $9,517 |
| Alternative Portfolio Cost | $27,325 | $368 | $573 | $1,098 | $1,578 | $1,769 | $1,870 | $2,227 | $2,763 | $3,297 | $3,692 | $5,229 | $5,635 | $6,775 | $7,043 | $7,343 | $7,844 | $8,895 | $9,861 | $9,415 | $9,845 |
| Avoided Cost | $25 | $0 | $0 | $0 | $0 | $0 | $11 | $17 | $22 | $6 | $17 | $20 | $17 | $17 | $9 | $2 | $13 | $17 | $59 |
| Delta Between Portfolios | $487 | $0 | $0 | $0 | $0 | $0 | $4 | $59 | $91 | $101 | $165 | $122 | $117 | $141 | $166 | $168 | $147 | $174 | $221 | $269 |

57 The negative value of avoided cost here indicates the cost amount that could be removed from alternative portfolio cost, implying that the avoided cost could reduce the REPS cost by a certain amount, and vice versa.
Appendix V: Bibliography of State RPS Cost Studies Update by 2009
(Studies listed in alphabetical order by state.)


