SECONDARY ECONOMIC IMPACT ANALYSIS OF GREENHOUSE GAS MITIGATION OPTIONS FOR NORTH CAROLINA

PREPARED FOR THE CENTER FOR CLIMATE STRATEGIES

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EXECUTIVE SUMMARY

In July 2007, the Center for Climate Strategies (CCS) approached the Appalachian State University (ASU) Energy Center to conduct a secondary analysis of the potential economic and jobs impacts of various greenhouse gas (GHG) emissions reduction strategies developed by the North Carolina Climate Action Plan Advisory Group (CAPAG). The ASU Energy Center examined thirty of the fifty-six mitigation options developed by the CAPAG. The thirty options were bundled into twenty-two mitigation option scenarios with similar policies grouped together for analysis. Combined these options account for more than 90% of the greenhouse gas emissions reductions and offsets identified by the CAPAG.

For the study, the ASU Energy Center utilized the N.C. Energy Scenario Economic Impact Model (NCESEIM). Originally developed in 2005 for the North Carolina Energy Policy Council, the model assesses the impacts of various energy policies on the North Carolina economy, measured in terms of employment, employee and proprietor compensation (income), and the incomes earned by labor and capital (total value-added or gross state product).

At the core of the NCESEIM is an input-output economic impact model that estimates how a given change in public policy might result in positive or negative impacts to the economy. Input-output analysis conceives of the economy as a set of interrelated sectors where the consumption of finished goods and services, or final demand, catalyzes a chain reaction of production. As final demand for goods and services change, the upstream sectors in the economy respond accordingly, creating a ripple or multiplier effect. The economic multipliers in the NCESEIM are derived from data published by the Minnesota IMPLAN Group.

While more sophisticated econometric models exist, input-output analysis is typically a reasonable approximation of the economic impacts associated with the type of modest policy changes considered by the CAPAG. Moreover, numerous national, regional, and state level studies utilize a similar approach in estimating the potential economic impacts of changes in energy policy (Laitner 2006).

Based on the technical assumptions of the CAPAG, the ASU Energy Center estimated the implications for energy consumption and public and private investments in the state's economy for each policy bundle†. A given policy can result in both positive and negative economic effects on the demand for goods and services in the economy and certain economic sectors with the particular effect varying by characteristics of the policy. Both positive and negative effects of a policy were considered when modeling its economic impacts and the reported results reflect the net effects across the economy.

As shown in the following table (Table ES-1), by 2020, the mitigation options analyzed would result in the creation of more than 15,000 jobs, \$565 million in employee and proprietor income, and \$302 million in gross state product. For the study period, 2007–2020, the mitigation options analyzed would generate more than \$2.2 billion net present value (NPV) in net additional employee and proprietor

† In some cases, the Technical working groups could not directly provide the policy inputs in the format specified in the model and it was necessary to supplement the CAPAG analysis. In these instances, the study relied on literature modeling the impacts of similar initiatives to estimate the policy impacts.

income and more than $1.2 million (NPV) in net gross state product.* The base year for the NC ESEIM is 2004; therefore all results are reported in 2004 dollars.

Table ES-1: Summary Results for All Options

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value-Added ($2004, million)			
	2010	**2015**	**2020**	**2010**	**2015**	**2020**	**2007-2020 NPV**	**2010**	**2015**	**2020**	**2007-2020 NPV**
Energy Supply Options	(409)	(384)	1,744	(41)	(53)	26	(297)	(99)	(152)	(118)	(1,046)
Residential, Commercial, and Industrial Options	3,518	6,961	9,110	136	271	364	1,942	114	125	42	937
Agriculture, Forestry, & Waste Management Options	1,202	1,960	3,318	39	75	183	649	78	145	331	1,267
Transportation and Land Use Options	783	432	871	(1)	(19)	(8)	(91)	24	7	48	128
All Options	**5,094**	**8,970**	**15,042**	**134**	**274**	**565**	**2,203**	**116**	**126**	**302**	**1,287**

Note: Values in parentheses identify loss of jobs, income, or Value-Added to the economy. FTE = full-time equivalent; NPV = net present value

* Net present value (NPV) is calculated assuming a discount rate of 5%.

Chapter 1 ANALYSIS OVERVIEW

NORTH CAROLINA CLIMATE ACTION PLAN

In 2002, North Carolina enacted the Clean Smokestacks Act which directed the state Department of Environment and Natural Resources (DENR) Division of Air Quality (DAQ) to examine potential options for reducing emissions of carbon dioxide (CO_2), a greenhouse gas that contributes to global warming, from coal-fired power plants and other stationary sources. The bill directed the DAQ to present its findings to the Environmental Management Commission (EMC), the state's environmental rulemaking authority, and the Environmental Review Commission (ERC), the legislative environmental oversight committee. In 2005, the DAQ presented a final report to these bodies describing a series of broad policy recommendations aimed primarily at encouraging voluntary measures to track and reduce greenhouse gas emissions, including CO_2. The report also called for the further study of greenhouse gas emissions reduction strategies through a formalized stakeholder process and the development of a North Carolina Climate Action Plan (N.C. Department of Environment and Natural Resources 2005).

The recommendation to craft a state-level climate action plan follows precedent set by a number of other states to inventory prospective policy options and prioritize recommendations based on their potential to reduce greenhouse gas emissions and cost effectiveness. To date, thirty-six states have initiated or completed state level climate action plans (Pew Center on Global Climate Change 2007).

Pursuant to the recommendations in the DAQ report, DENR Secretary Bill Ross convened the forty-three member North Carolina Climate Action Advisory Group (CAPAG) in February 2006. The CAPAG membership consisted of stakeholders from a wide range of interests including electric and natural gas utilities, government agencies, environmental groups, manufacturing industries, and agricultural, forestry, transportation, and tourism interests. The panel was charged with developing consensus recommendations on strategies to reduce greenhouse gas emissions with an emphasis on identifying those strategies with potential economic benefits. The CAPAG process was facilitated by the non-profit Center for Climate Strategies (CCS).

The work of developing specific recommendations was divided among five technical working groups: Energy Supply (ES), Residential, Commercial, and Industrial (RCI), Transportation and Land Use (TLU), Agriculture, Forestry, and Waste Management (AFW); and Cross-Cutting (CC) issues. Each technical working group developed a set of mitigation options designed to reduce or offset the emissions of greenhouse gases in its respective sector. For each mitigation option, the technical working groups assessed the potential greenhouse gas emissions reductions and estimated its costs and benefits over the time period 2007 to 2020.

Through this process, the CAPAG developed fifty-six mitigation options, which combined would cut North Carolina's projected greenhouse gas emissions nearly in half by 2020, from a baseline of 256 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) to 137 $MMTCO_2e$. This reduction would bring North Carolina to within 1% of its 1990 GHG emissions levels by 2020. Moreover the panel's economic analysis suggests implementation of the recommendations would result in a net cost savings (N.C. Climate Action Plan Advisory Group 2007).

The economic analysis conducted by the technical working groups was limited to the direct effects of implementing an option. For each mitigation option, the technical working groups sought to identify the direct costs borne by those entities ultimately responsible for its implementation, whether that entity is a government entity, an individual or private firm, such as an increase in energy prices. Additionally, each technical working group sought to quantify the associated direct benefits with each policy, such as the value of reduced energy consumption. The quantified benefits were subtracted from the quantified costs to produce a net cost. Of the CAPAG's fifty-six recommendations, the technical working groups quantified direct costs and benefits for thirty-five measures of which sixteen yielded cost savings. In the aggregate the thirty-five quantified measures produced net cost savings of $5.1 billion (NPV), over the period 2007-2020 (N.C. Climate Action Plan Advisory Group 2007).

Prioritization of Policies for Analysis

In July 2007, the Center for Climate Strategies (CCS) approached the Appalachian State University (ASU) Energy Center to conduct an analysis of the potential economic and jobs impacts of various greenhouse gas emissions reduction strategies developed by the CAPAG, including the potential impact on employment, personal income and gross state product. Resource limitations prevented analysis of all options so, in consultation with DAQ, the ASU Energy Center prioritized thirty options for analysis. Combined these options account for more than 90% of the GHG emissions reductions and offsets identified by the CAPAG. The thirty options were bundled into twenty-two mitigation option scenarios with similar policies grouped together for analysis (Table 1-1)

Table 1-1: Summary of Bundled CAPAG Mitigation Options

Energy Supply Options
ES-1, ES-2 & AFW-5: Renewable Energy Production Subsidy, Renewable Portfolio Standard, & Biomass Production Subsidy ES-3 & ES-9: Combined Heat and Power ES- 6a & 6b: Advanced Coal Technologies ES- 8: Municipal Biogas
Residential, Commercial, & Industrial Options
RCI-1, RCI-2 & RCI-11: Energy Efficiency Funding & Energy Audits RCI-4 & RCI-5: Market Transformation & Appliance Standards RCI-6: Energy Codes RCI-7 & RCI-3: High Performance Buildings RCI-9: Bulk Purchasing for Energy Efficient Appliances RCI-10: Solar Water Heating Only
Agriculture, Forestry, & Waste Management Options
AFW-1: Manure Digesters AFW-2: Biodiesel Production Subsidy AFW-4a & AFW-4b: Conservation Easements AFW-6: Cellulosic Ethanol Production Subsidy AFW-8: Afforestation AFW-9 & AFW-10: Forest Management AFW-11: Landfill Gas AFW-12: Recycling AFW-13: Urban Forestry
Transportation & Land Use Options
TLU-1b: Multi-modal Transportation and Promotion TLU-3a: Vehicle Registration Surcharge to Fund Multi-modal Transportation TLU-5: Tailpipe Greenhouse Gas Emissions Standards

N.C. Energy Scenario Economic Impact Model

For the study, the ASU Energy Center utilized the N.C. Energy Scenario Economic Impact Model (NCESEIM). Originally developed in 2005 for the North Carolina Energy Policy Council, the model assesses the impacts of various energy policies on the North Carolina economy, measured in terms of employment, employee and proprietor compensation (income), and the incomes earned by labor and capital (total value-added or gross state product).

The NCESEIM was originally developed by Jeffery Tiller, PE, Professor of Technology and Technical Director at the ASU Energy Center; John "Skip" Laitner, Senior Economist at the American Council for an Energy Efficient Economy; Doug Arent, Director of the Strategic Energy Analysis and Applications Center at the U.S. Department of Energy's National Renewable Energy Laboratory; and Chris Larsen, formerly of the ABB Group. Additionally, the model was peer reviewed by Adam Rose, Ph.D., Economist and Acting Director of the Energy Institute at the University of Southern California (Rose and Wei 2005). The platform for the model is a series of interconnected Microsoft Excel spreadsheets. The model consists of two main components, an input-output economic impact model and a modifiable policy design module. Each component itself consists of a subset of Excel spreadsheets.

Input-Output Economic Impact Model

At the core of the NCESEIM is an input-output economic impact model that estimates how a given change in public policy might result in positive or negative impacts to the economy, measured in terms of employment, personal income, and gross state product. These impacts are calculated using economic multipliers derived from state-level data for North Carolina published by the Minnesota IMPLAN Group, publishers of IMPLAN Professional, a computer software application for conducting input-output economic analysis. IMPLAN in turn relies on data from a number of federal and state agency sources, including the U.S. Department of Commerce, Bureau of Economic Analysis *Benchmark Input-Output Accounts*.

Input-output analysis was conceptualized by Nobel laureate Wassily Leontief to describe the economic linkages among various sectors of the U.S. economy and predict the consequences of positive and negative economic stimuli. The approach conceives of the economy as a set of interrelated sectors where the consumption of finished goods and services, or final demand, catalyzes a chain reaction of production (Leontief 1986).

According to the theory, in order to meet the final demand for goods and services, a supplying sector depends on inputs (e.g., raw materials, services, unfinished goods, capital equipment, etc.) from other sectors of the economy. In turn, those other sectors depend on goods and services from other sectors in the economy. The output of each sector is an input for another sector. As final demand for goods and services changes, the upstream sectors in the economy respond accordingly, creating a ripple or multiplier effect (Hy 1999).

Input-output models measure the multiplier effect. These impacts are expressed in terms of their direct, indirect, and induced effects on sectoral output, employment, income, and gross state product.

Direct effects are the initial effects associated with the change in the final demand for a particular sector. The indirect effects are the inter-industry impacts resulting from production changes in backward-linked industries caused when input needs change due to the impact of directly affected industry. The induced effects represent the response by local industries caused by increased expenditures of new household income. Input-output analysis quantifies the impact of these effects through the derivation of coefficients called multipliers that indicate the overall change in activity that results from an initial change in final demand. So-called Type II multipliers capture the direct, indirect, and induced effects (Schaffer 1999).

Consider for example the construction of a new school. The local school board will solicit and award a bid for a construction firm to build the new school, the direct effects. In turn, the construction firm must secure insurance, hire engineers & subcontractors, purchase construction materials and so on, the indirect effects. The increase in demand for these construction sector inputs leads to increases in household income as the supplying sectors hire and compensate employees to meet the increased demand. The expenditure of this household income in turn spurs further increases in final demand, the induced effect.

Input-output analysis, like all econometric models, makes some important simplifying assumptions to develop a parsimonious model.[*] First, it assumes discrete enterprises (e.g. a farm growing soybeans) can be grouped into common economic sectors (e.g. oil seed and grain farming) based on the type of commodities produced or services rendered (ten Raa 2006). The NCESEIM utilizes a thirty-nine sector model of the state's economy aggregated from the 2004 IMPLAN data for North Carolina.

The approach also assumes the relationship between the inputs and outputs of these aggregated sectors is linear, that is to say that as sector output increases or decreases its inputs increase or decrease proportionally. Moreover input-output analysis assumes the production recipes expressed in the economic multipliers is static. That is to say the technology used to produce a good or service does not change over time. However, some studies suggest that the technologies of core sectors, especially when aggregated to the levels in the NCESEIM, tend to remain fairly stable. The approach also assumes that an industry has unlimited access to capital, raw materials, intermediate goods and services, and labor. Thus, changes in prices for inputs do not result in substituting behavior or curtailment of production (Minnesota IMPLAN Group 2004).

The NCESEIM seeks to overcome some of these limitations by factoring in labor productivity improvements into the employment multipliers using forecasts of average rates of change from the U.S. Department of Labor, Bureau of Labor Statistics (U.S. Department of Labor 2007).

It should also be noted that the NCESEIM does not account for effects on the broader national economy and that the impacts in North Carolina may be offset by reduced activity in other regions from which

[*] For a more thorough discussion of the relative strengths and weaknesses of input-out models relative to other econometric impact models see West, G. (1995). "Comparison of Input-Output, Input-Output Econometric and Computable General Equilibrium Impact Models at the Regional Level." *Economic Systems Research,* Vol. 7, No. 2, p207-227.

resources are drawn. For example, the NCESEIM does not account for a reduction in coal mining activity in West Virginia resulting from a decrease in coal-fired electricity consumption in North Carolina.

The table below (Table 1-2) summarizes the economic multipliers utilized in the NCESEIM to calculate the impact of changes in final demand resulting from various policy changes quantified in the NCESEIM*'s* modifiable policy design module. These multipliers were derived from state-level data for 2004 compiled by the Minnesota IMPLAN Group. The detailed methodology for this derivation is spelled out in Appendix A.

Table 1-2: Employment, Income, and Gross State Product Multipliers from NCESEIM

SECTOR	Employment (Per $ Million of Final Demand)	Labor Productivity Adjustment[a]	Income (Per Million $ of Final Demand)	GSP (Per Million $ of Final Demand)
Oil Seed & Grain	11.11	2.20%	0.42	0.42
Other Ag	12.89	2.20%	0.56	0.56
Animal Production	12.25	2.20%	0.29	0.29
Forestry	7.63	2.20%	0.30	0.30
Mining	7.10	1.18%	0.31	0.31
Electric Utilities	3.58	1.80%	0.27	0.27
Natural Gas Utilities	3.84	-2.22%	0.21	0.21
Water & Sewer Utilities	9.14	0.54%	0.42	0.42
Residential Construction	13.05	1.08%	0.46	0.46
Commercial Construction	15.88	1.08%	0.57	0.57
Highway Construction	14.64	1.08%	0.55	0.55
Heavy Construction	15.13	1.08%	0.56	0.56
Food, Beverage, Tobacco	6.41	1.00%	0.26	0.26
Starch & Vegetable Fats & Oil Mfg	3.28	3.31%	0.16	0.16
Furniture & Textiles	9.77	2.39%	0.39	0.39
Wood & Paper Products	6.85	0.97%	0.32	0.32
Other Manufacturing	10.02	3.83%	0.52	0.52
Petroleum & Chemicals	4.30	1.66%	0.26	0.26
Nonmetal Materials	7.59	1.21%	0.38	0.38
Metals	6.65	2.42%	0.32	0.32
Machinery	6.14	2.23%	0.35	0.35
Computers & Electronics	4.91	11.92%	0.37	0.37
Electrical Equipment & Appliance	7.07	4.17%	0.39	0.39
Transportation Manufacturing	4.99	2.91%	0.28	0.28
Wholesale Trade	9.23	5.29%	0.47	0.47
Transportation & Warehousing	13.24	2.44%	0.56	0.56
Transit Transportation	23.70	0.70%	0.57	0.57
Retail Trade	19.51	3.36%	0.53	0.53
Information	6.20	3.89%	0.34	0.34
FIRE	8.85	2.55%	0.37	0.37
Other Services	10.25	1.60%	0.29	0.29
Professional, Scientific, Technical, Mngmt	11.42	2.19%	0.61	0.61
Administrative & Support Services	26.94	1.73%	0.62	0.62
Education	25.26	-0.22%	0.88	0.88
Health Care & Social Assistance	17.98	0.92%	0.68	0.68
Arts & Entertainment	25.58	1.42%	0.56	0.56
Accommodation & Food Services	25.67	0.54%	0.47	0.47
Government	14.02	1.42%	0.90	0.90
Waste Management	10.46	0.52%	0.38	0.38
Households	9.71	0.38%	0.32	0.32

[a] Source:(U.S. Department of Labor 2007). Used to adjust employment multipliers for gains/losses in productivity.

Energy Policy Design Module

The policy design module specifies the major features of a policy initiative including the implications for energy consumption and public and private investments in the state's economy. For this study, the resulting effects were derived from the assumptions underlying the analysis of the CAPAG technical working groups[†]. These assumptions included fuel, technology, and program costs, as well as energy prices and implementation mechanisms and policy goals.

Based on these assumptions, the module calculates incremental and annual physical energy savings, by each sector and technology, where applicable. The cash value of avoided energy consumption; incremental and annual renewable energy production; annual program implementation expenditures; direct and stimulated private and public investments; and displaced reference case revenue and expenditures are also calculated.

The values derived from this module can have either a positive or negative effect on the demand for goods and services in the economy. For example, when a policy results in a reduction in electricity consumption and a subsequent increase in disposable household income or business cash flows it has a positive impact on sectoral demand. On the other hand, the same policy will also reduce revenue to the electric utility which results in a negative effect to that sector.

The values derived in this module are then allocated across the economy as changes in the demand for goods and services, with the particular allocation varying by the characteristics of the policy. In general, the study sought the most conservative approaches presented in the literature in determining this allocation and is explained more thoroughly in Appendix B of this report. For example, when allocating the impact of investments in renewable energy and biofuel technologies the study only considers the labor portion of the investments. This likely understates the total impact of these investments on the North Carolina economy.

The distribution of the monetary value of avoided electricity and natural gas consumption as well as the impact of utility rate increases is treated similarly for all options. That is, it is assumed that these benefits and costs are distributed to a given economic sector in proportion to that sector's purchase of energy output. The calculation of these coefficients is derived from the 2004 IMPLAN data for North Carolina (Table 1-3). A sector's share of the monetary value of avoided electricity and natural gas consumption is recorded as an increase in final demand for that sector. Conversely, a sector's share of a utility rate increase is recorded as a decrease in final demand for that sector.

† In some cases, the technical working groups could not directly provide the policy inputs in the format specified in the model and it was necessary to supplement the CAPAG analysis. In these instances, the study relied on literature modeling the impacts of similar initiatives to estimate the policy impacts. The detailed methodology for each of the mitigation option considered in this report can be found in Appendix B.

Table 1-3: Energy (Electricity and Natural Gas) Consumption Coefficients

Industrial Customers	**Coefficient**
Oil Seed & Grain Farming	0.1%
Other Agriculture	0.5%
Animal Production	2.4%
Forestry	0.3%
Mining	0.7%
Electric Utilities	0.0%
Natural Gas Utilities	0.0%
Water & Sewer Utilities	2.9%
Residential Construction	1.7%
Commercial Construction	0.9%
Highway Construction	0.4%
Heavy Construction	0.4%
Food, Beverage, Tobacco Manufacturing	14.8%
Starch & Vegetable Fats & Oil Manufacturing	0.8%
Furniture & Textiles Manufacturing	14.2%
Wood & Paper Products Manufacturing	9.8%
Other Manufacturing	1.0%
Petroleum & Chemicals Manufacturing	20.6%
Nonmetal Materials Manufacturing	9.6%
Metals Manufacturing	8.3%
Machinery Manufacturing	2.3%
Computers & Electronics Manufacturing	3.6%
Electrical Equipment & Appliance Manufacturing	2.0%
Transportation Manufacturing	2.7%
Commercial Customers	
Wholesale Trade	6.2%
Transportation & Warehousing	2.2%
Transit Transportation	0.2%
Retail Trade	15.5%
Information	3.1%
Financial, Insurance, and Real Estate	18.9%
Other Services	6.6%
Professional, Scientific, Technical, Management	8.7%
Administrative & Support Services	2.0%
Education	0.7%
Health Care & Social Assistance	6.5%
Arts & Entertainment	1.7%
Accommodation & Food Services	10.3%
Government	0.0%
Waste Management	17.3%
Residential Customers	
Households	100%

Several of the mitigation options examined include subsidy payments by state government. It was assumed that these payments are paid for from existing revenue and therefore result in a reduction of other state government expenditures. Using 2004 IMPLAN data for North Carolina, the NCESEIM calculates a sector specific Government Spending Coefficient (Table 1-4). In calculating these coefficients the NCESEIM holds constant spending on education. The annual cost of a subsidy is then multiplied by the coefficient and the product recorded as a reduction in final demand.

Table 1-4: Government Spending Coefficients

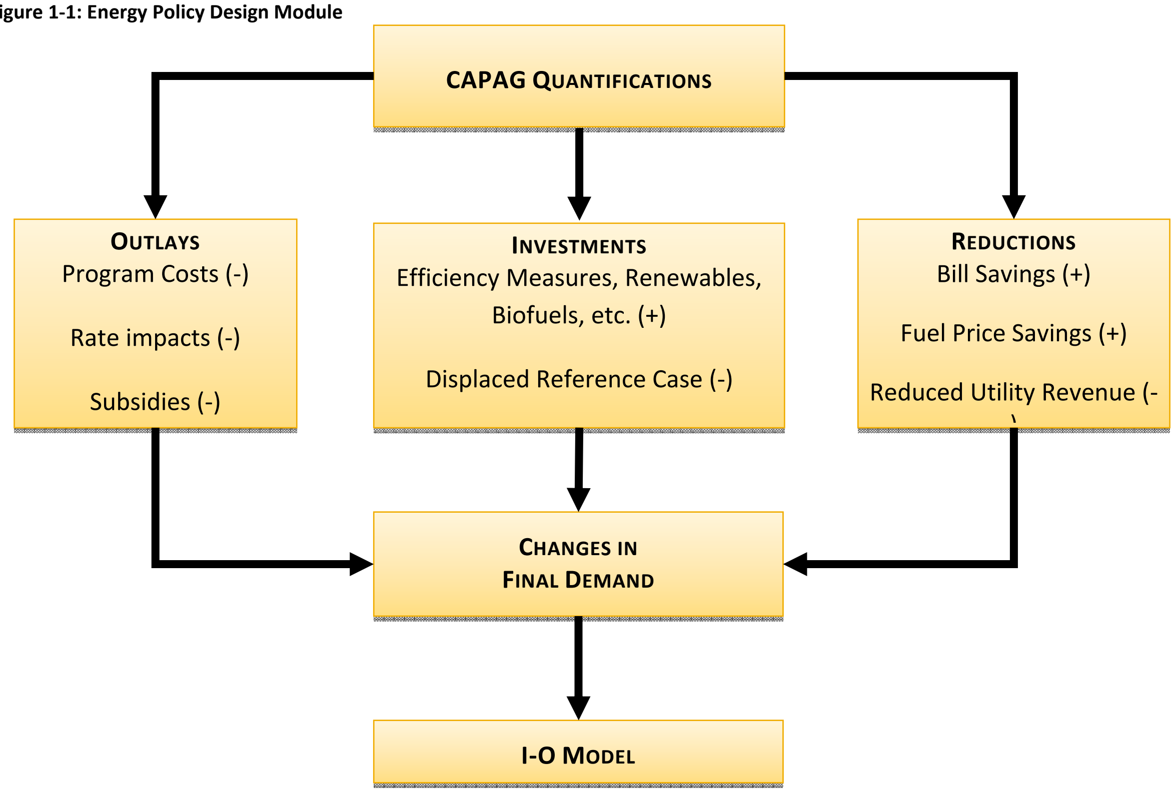
Sector	Coefficient
Oil Seed & Grain Farming	0.00%
Other Agriculture	0.06%
Animal Production	0.03%
Forestry	0.00%
Mining	0.02%
Electric Utilities	2.08%
Natural Gas Utilities	0.40%
Water & Sewer Utilities	0.57%
Residential Construction	0.87%
Commercial Construction	8.42%
Highway Construction	7.28%
Heavy Construction	5.90%
Food, Beverage, Tobacco Manufacturing	1.88%
Starch & Vegetable Fats & Oil Manufacturing	0.00%
Furniture & Textiles Manufacturing	0.55%
Wood & Paper Products Manufacturing	0.05%
Other Manufacturing	0.73%
Petroleum & Chemicals Manufacturing	4.30%
Nonmetal Materials Manufacturing	0.64%
Metals Manufacturing	0.03%
Machinery Manufacturing	0.51%
Computers & Electronics Manufacturing	0.39%
Electrical Equipment & Appliance Manufacturing	0.17%
Transportation Manufacturing	0.34%
Wholesale Trade	2.03%
Transportation & Warehousing	1.46%
Transit Transportation	0.26%
Retail Trade	0.02%
Information	1.50%
Financial, Insurance, and Real Estate	3.52%
Other Services	2.64%
Professional, Scientific, Technical, Mgmt	3.04%
Administrative & Support Services	1.36%
Education	0.00%
Health Care & Social Assistance	0.47%
Arts & Entertainment	0.06%
Accommodation & Food Services	1.48%
Government	25.21%
Waste Management	0.14%
Households	21.58%

The changes in sectoral demand generated by the Energy Policy Design Module, in turn, are utilized by the input-output economic impact model to calculate a given policy's net impact on employment, income, and gross state product[*].

The module further assumes that reductions in electricity consumption or additions of new renewable electricity generation displace future additions of conventional electricity generation. While the investments associated with energy efficiency measures and renewable electricity generation result in an increase in final demand, the displaced investment in new conventional electricity generation is reflected as a reduction in final demand. The value of displaced investments is determined by multiplying incremental energy savings or renewable generation by the overnight capital cost per Megawatt-hour (MWh) of the conventional resources[†].

Figure 1-1 summarizes the *Energy Policy Design Module,* while a policy-by-policy methodology is found in Appendix B.

Figure 1-1: Energy Policy Design Module



[*] The allocation of energy savings and operating costs to a change in final demand is an admittedly coarse methodology for estimating the economic impacts associated with what in fact are fundamentally changes in intermediate demand. This is a limitation in current approach that the authors plan on addressing in future versions of the model.

† Displaced investments in conventional generation assumes a fuel mix of 60% pulverized coal and 40% combined cycle natural gas per the CAPAG Energy Supply technical working group reference case (Center for Climate Strategies 2007b). The result is a capital cost of $192.41/MWh and a operating expense of $6.00/MWh (Center for Climate Strategies 2007b). The labor share of capital investments is 26.5% while the labor share of operating expenses is 42% (LaCapra Associates 2006). It was further assumed that the full cost of conventional generation would be financed over a period of 25 year at an interest rate of 8%.

Chapter 2 RESULTS OF ENERGY SUPPLY OPTIONS ANALYSIS

Table 2-1 presents summary results for Energy Supply (ES) options analyzed. By 2020, these options would result in the creation of more than 1,700 jobs, $26 million in employee and proprietor income, but a decrease in $118 million in gross state product. Over the study period, 2007–2020, the options would decrease employee and proprietor income by $297 million (NPV) and net gross state product by $1.046 billion (NPV). The base year for the NCESEIM is 2004; therefore all results are reported in 2004 dollars.

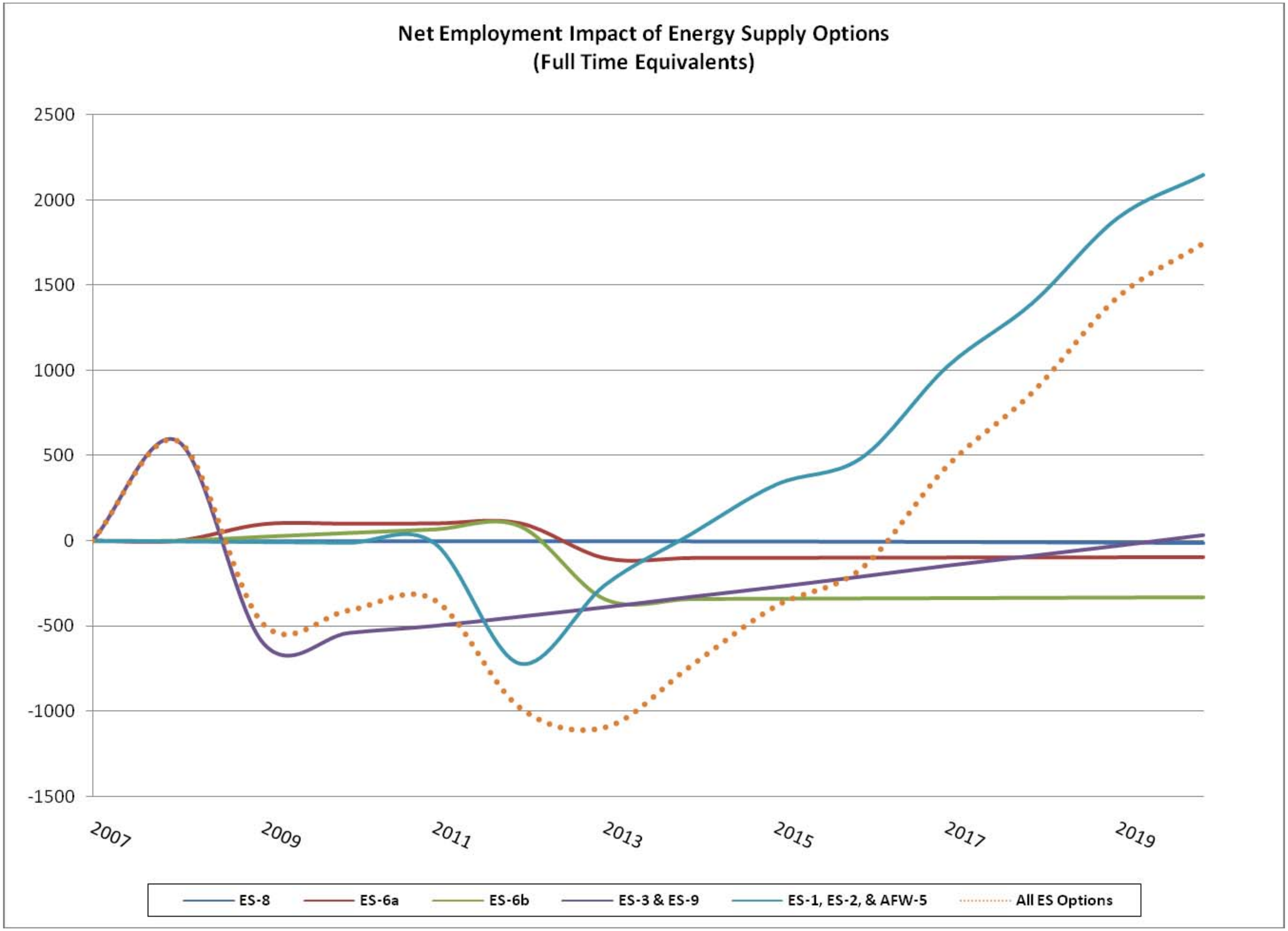
The bulk of these impacts are associated with the construction of combined heat and power (CHP) systems considered in ES 3&9. The negative effects of the CHP option are driven primarily by the technology and fuel price assumptions of the CAPAG, which result in commercial and industrial end-users spending more to install and operate CHP systems than a business as usual case. As a result, firms in these sectors reduce their final demand for endogenous goods and services, the effect of which is amplified throughout the economy, causing the negative effects.

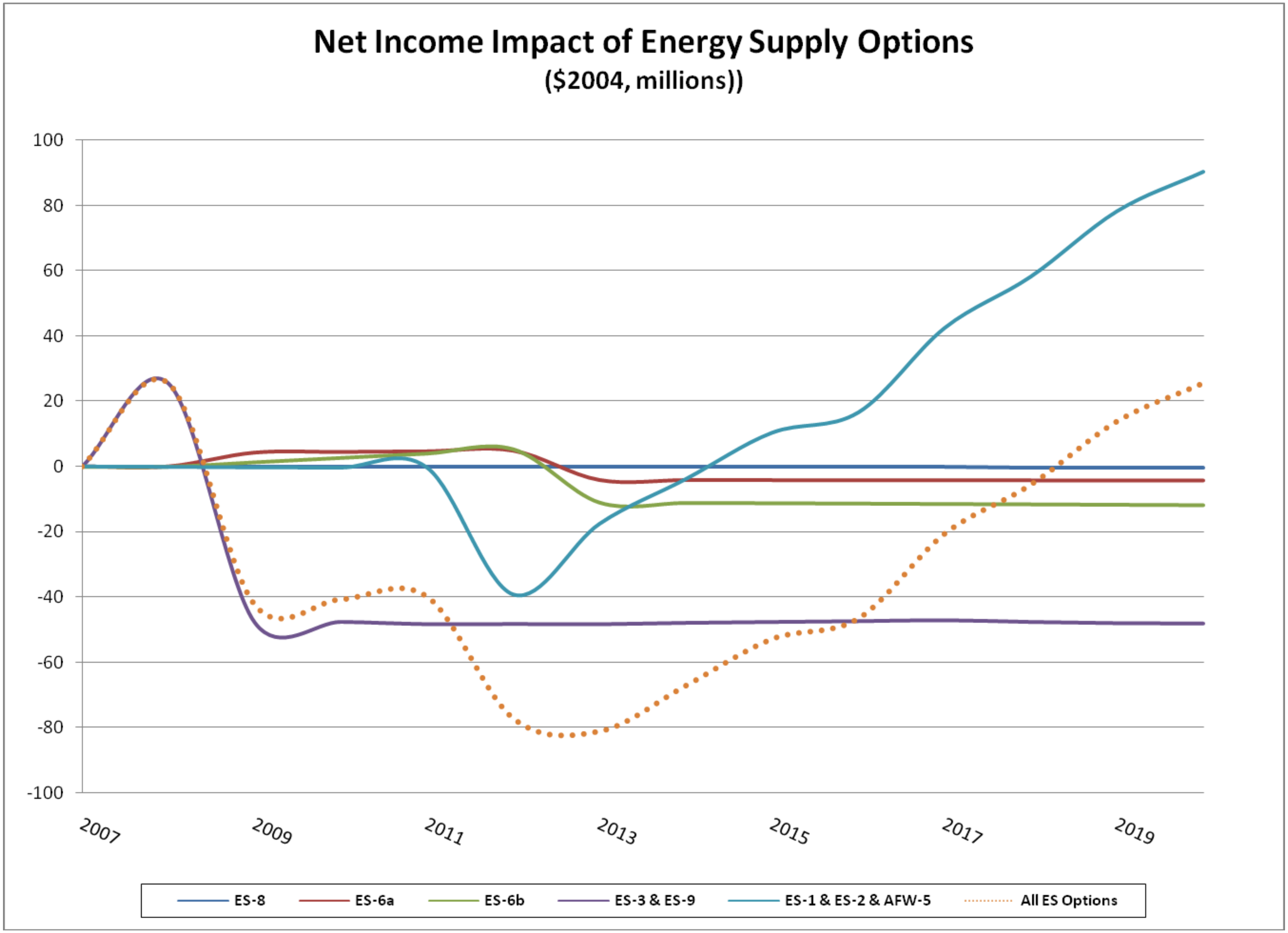
Moreover, in order to remain consistent with the final integration of all option preformed by the CAPAG, the efficiency components of ES-2 are assumed to obtained by the demand side options of the Residential, Commercial, and Industrial technical working group.

Table 2-1: Summary Results for Energy Supply Options Analyzed

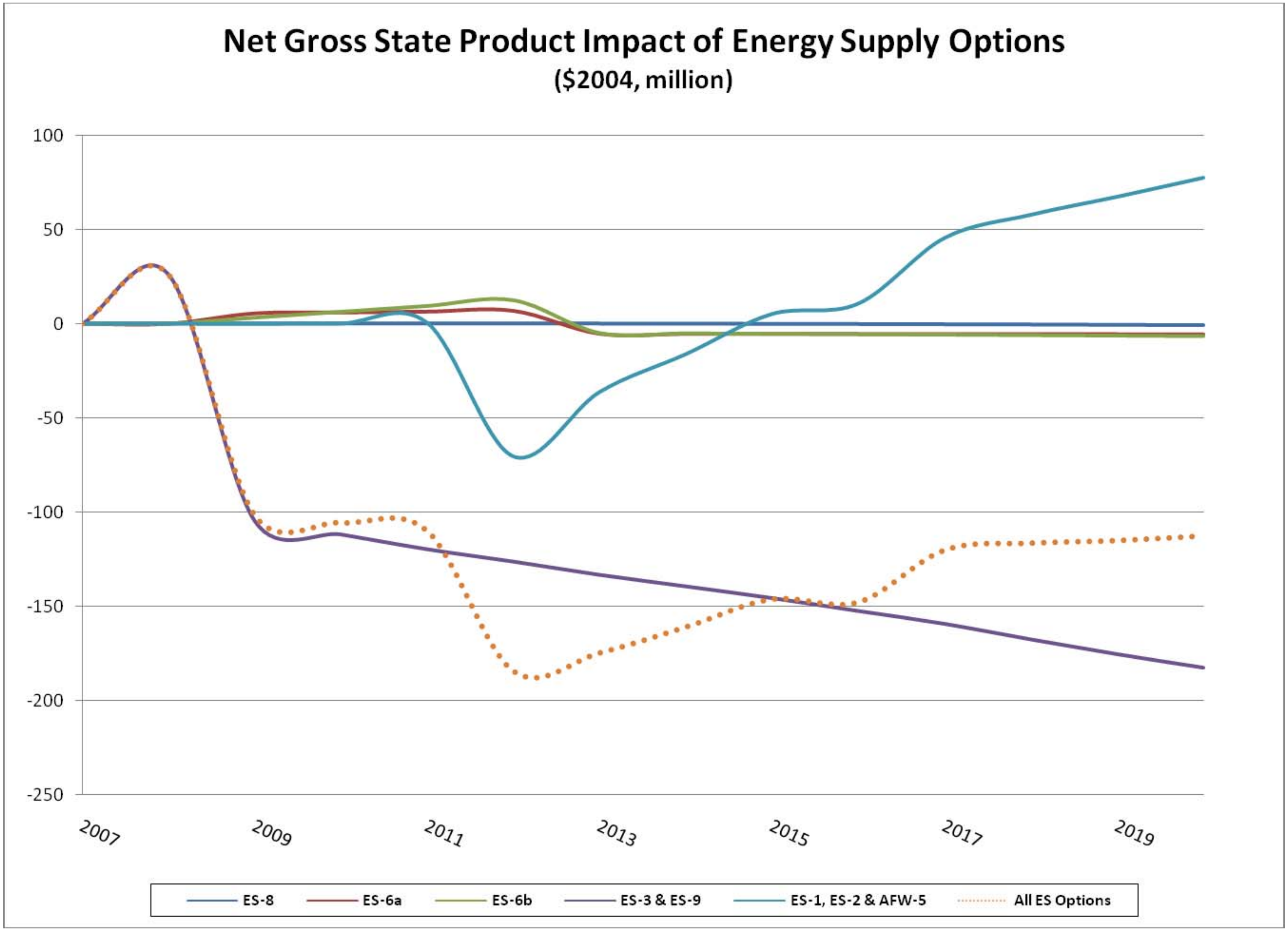
	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value-Added ($2004, million)			
Energy Supply Options	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2007-2020 NPV**	**2010**	**2015**	**2020**	**2007-2020 NPV**
ES 1 & 2 and AFW 5 (PTC, REPS, Biomass)	(11)	330	2,148	(0)	10	90	116	(0)	5	77	54
ES 3 & 9 (CHP)	(541)	(271)	34	(48)	(48)	(48)	(361)	(112)	(146)	(183)	(1,094)
ES 6a (IGCC)	98	(100)	(96)	4	(4)	(4)	(6)	6	(5)	(6)	(6)
ES 6b (IGCC)	45	(341)	(333)	3	(11)	(12)	(78)	6	(5)	(7)	(3)
ES 8 (Municipal Biogas)	0	(2)	(10)	0	(0.1)	(0.5)	(0.9)	(0)	(0.2)	(0.7)	(1.5)
All ES Policies	**(409)**	**(384)**	**1,744**	**(41)**	**(53)**	**26**	**(297)**	**(99)**	**(152)**	**(118)**	**(1,046)**

Note: Values in parentheses identify loss of jobs, income, or Value-Added to the economy. NPV = net present value. FTE=Full Time Equivalent


Net Employment Impact of Energy Supply Options
(Full Time Equivalents)
2500
2000
1500
1000
500
0
-500
-1000
-1500
2007
2009
2011
2013
2015
2017
2019
ES-8
ES-6a
ES-6b
ES-3 & ES-9
ES-1, ES-2, & AFW-5
All ES Options



Net Income Impact of Energy Supply Options
($2004, millions))
100
80
60
40
20
0
-20
-40
-60
-80
-100
2007
2009
2011
2013
2015
2017
2019
ES-8
ES-6a
ES-6b
ES-3 & ES-9
ES-1 & ES-2 & AFW-5
All ES Options


Net Gross State Product Impact of Energy Supply Options
($2004, million)
100
50
0
-50
-100
-150
-200
-250
2007
2009
2011
2013
2015
2017
2019
ES-8
ES-6a
ES-6b
ES-3 & ES-9
ES-1, ES-2 & AFW-5
All ES Options

ES-1, ES-2 & AFW-5: Renewable Energy Production Subsidy, Renewable Portfolio Standard, & Biomass Production Subsidy

These mitigation options seek to expand the generation of electricity from renewable resources like biomass, wind, and hydroelectric power. ES-1 would provide state incentives to producers of electricity from renewable resources worth $0.005 for each kilowatt-hour of electricity generated. ES-2 considers establishment of a renewable portfolio standard requiring the state's electric utilities to acquire a minimum percentage of the electricity sold to retail customers from renewable energy sources. While the ES technical working group originally considered only three sensitivities for this option, recent legislative action mandated a goal of 12.5% of retail electricity sales be acquired from a combination of renewable resources and energy efficiency measures by 2021. Therefore, the ES technical working group provided a fourth sensitivity reflecting the goals of North Carolina's new Renewable Energy and Energy Efficiency Portfolio Standard (REPS)[*]. AFW-5 would provide state subsidies to producers of biomass feedstocks from 2007-2011 worth $1.27/MMBtu.

By 2020, these policies would result in the net creation of 2,148 jobs, $90 million dollars in annual employee and proprietor income, and $77 million in annual gross state product. For the study period, 2007-2020, the mitigation options would create an additional $116 million (NPV) in employee and proprietor income and $54 million (NPV) in gross state product.

ES-3 & ES-9: Combined Heat and Power

This mitigation option calls for installation of 1000 MW of new combined heat and power (CHP) systems by 2018. By 2020, this mitigation option would result in the creation of 34 jobs but the loss of $48 million dollars in annual employee and proprietor income and $183 million in annual gross state product. For the study period, 2007-2020, this mitigation option would reduce employee and proprietor income by $361 million (NPV) and gross state product by nearly $1.1 billion (NPV).

The negative effects of the option are driven primarily by the technology and fuel price assumptions of the CAPAG, which result in a "negative payback" where commercial and industrial end-users spend more to install and operate CHP systems than a business as usual case. As a result, firms in these sectors reduce their final demand for endogenous goods and services, the effect of which is amplified throughout the economy, causing the negative effects.

ES-6a & ES- 6b: Advanced Coal Technologies

These mitigation options propose to encourage the construction of an 800 MW integrated gasification combined cycle (IGCC) coal-fired power plant to either replace a future (ES-6a) or an existing (ES-6b) conventional coal-fired power plant. In both instances, the ES technical working group also considered sensitivities for the inclusion of a carbon capture and sequestration (CCS) component. Given the

* The supplemental analysis provided by the ES technical working group did not include the technology specific mandates for renewables articulated in the law but rather continued to assume a distribution based on the 2006 La Capra Associates study of the potential of a renewable portfolio standard for N.C. Utilities Commission. Moreover, the efficiency component of the analysis is supplemental to the estimated efficiency gains in the CAPAG's final integration of ES and RCI options.

unproven potential of CCS, for this study, the ASU Energy Center examined the impacts of the "IGCC only" sensitivity for both ES-6a and ES-6b.

By 2020, ES-6a would result in the net loss of 96 jobs, $4 million in annual employee and proprietor income, and $6 million in annual gross state product. For the study period, 2007-2020, the option would decrease employee and proprietor income by $6 million (NPV) and gross state product by $6 million (NPV). By 2020, ES-6b would result in the net loss of 333 jobs, $12 million in annual employee and proprietor income, and $7 million in annual gross state product. For the study period, 2007-2020, the option would decrease employee and proprietor income by $78 million (NPV) and gross state product by $3 million (NPV).

ES-8: Municipal Biogas

This mitigation option proposes to capture methane emissions from 50% of new municipal sewage treatment facilities built in North Carolina, in order to generate electricity, by 2020. The mitigation option description assumes the cost of implementing the measure will be paid for through state government subsidies to local sewage treatment enterprises.

By 2020 this mitigation option would result in the loss of 10 jobs, $.5 million in annual employee and proprietor income, and $.7 million in annual gross state product. For the study period, 2007-2020, the mitigation option would decrease employee and proprietor income by $.9 million (NPV) and gross state product by $1.5 million (NPV). These study period reductions are a function of government subsidy payments displacing other government expenditures. As those payments are phased out it is likely the effect over a longer horizon would yield a positive impact.

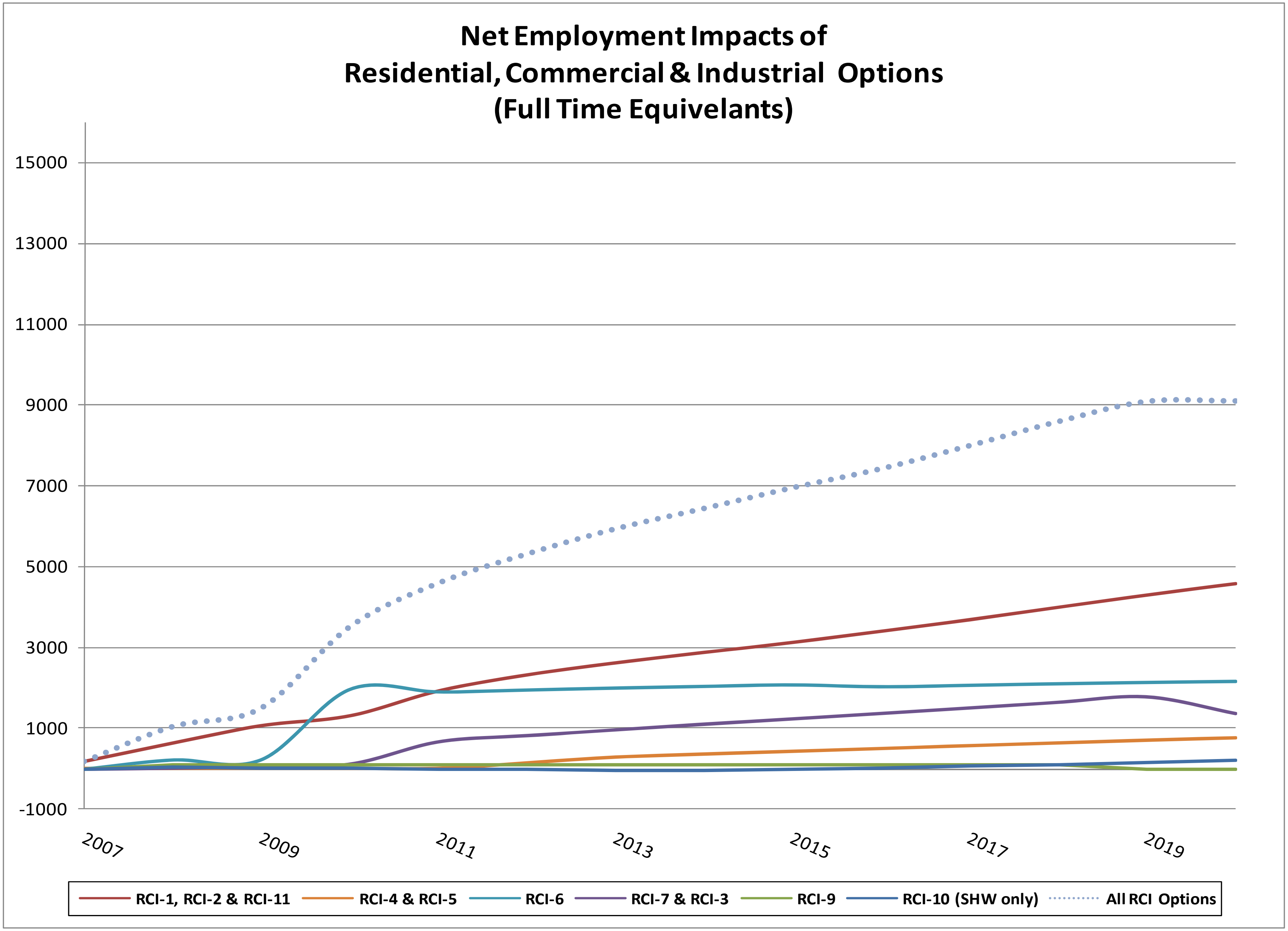
Chapter 3 RESULTS OF RESIDENTIAL, COMMERCIAL & INDUSTRIAL OPTIONS ANALYSIS

Table 3-1 presents summary results for the RCI mitigation options analyzed. By 2020, these options would result in the net creation of more than 9,100 jobs, $364 million in additional employee and proprietor income, and $42 million in net gross state product. Over the study period, 2007–2020, the options would generate $1.9 billion (NPV) in additional employee and proprietor income and $937 million (NPV) in gross state product. The economic impacts associated with these options are driven primarily by energy bill savings resulting from energy efficiency measures.

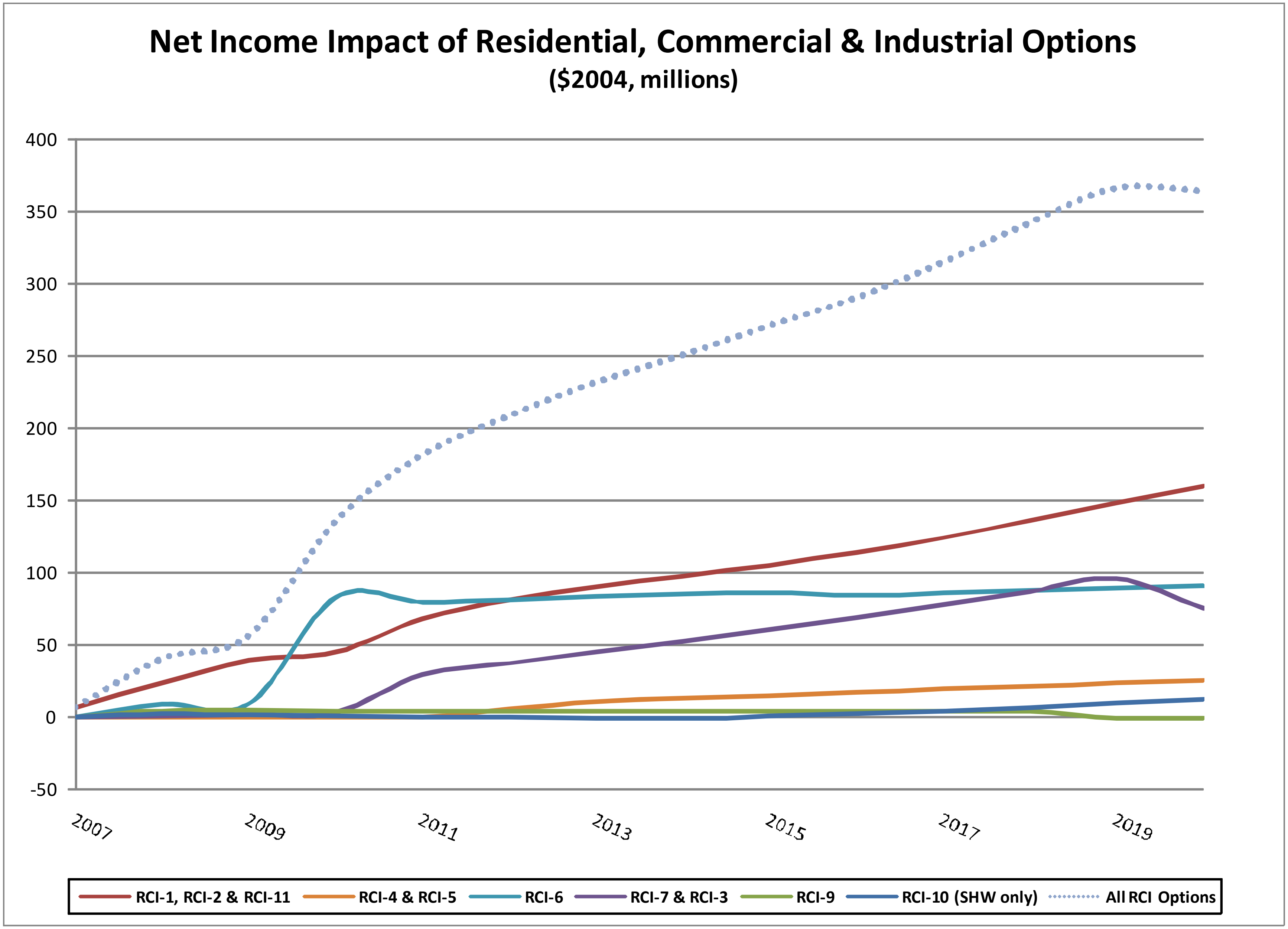
Table 3-1: Summary Results for Residential, Commercial and Industrial Options Analyzed

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value-Added ($2004, million)			
Residential, Commercial and Industrial Options	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2007-2020 NPV**	**2010**	**2015**	**2020**	**2007-2020 NPV**
RCI 1, 2 & 11 (Efficiency Funding & Energy Audits)	1,309	3,121	4,575	45	105	160	789	18	(4)	(55)	36
RCI 4 & 5 (Market Transformation & Appliance Standards)	-	430	771	-	15	26	87	-	1	(11)	(9)
RCI 6 (Energy Codes)	1,964	2,076	2,163	83	86	90	623	96	77	57	571
RCI 7 & 3 (High Performance Buildings)	126	1,239	1,372	3	61	76	388	(5)	46	32	273
RCI 9 (Bulk Purchasing & Green Power)	105	99	12	4	4	(1)	33	5	3	(5)	28
RCI 10 (Solar Water Heating)	13	(4)	218	1	0	13	21	0	1	24	37
All RCI Policies	**3,518**	**6,961**	**9,110**	**136**	**271**	**364**	**1,942**	**114**	**125**	**42**	**937**

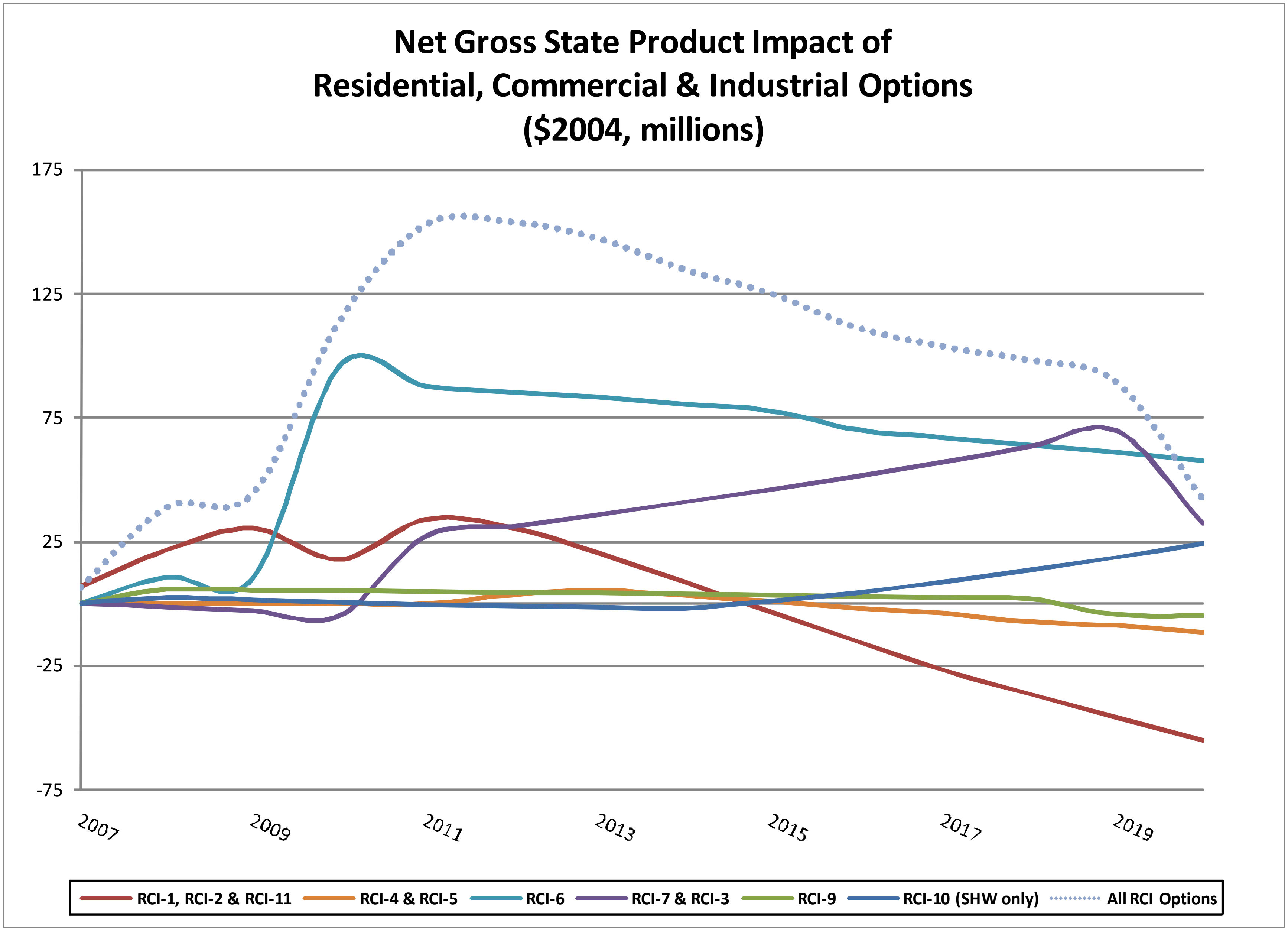
Note: Values in parentheses identify loss of jobs, income, or Value-Added to the economy. NPV = net present value. FTE=Full Time Equivalent



Net Employment Impacts of
Residential, Commercial & Industrial Options
(Full Time Equivelants)
15000
13000
11000
9000
7000
5000
3000
1000
-1000
2007
2009
2011
2013
2015
2017
2019
RCI-1, RCI-2 & RCI-11
RCI-4 & RCI-5
RCI-6
RCI-7 & RCI-3
RCI-9
RCI-10 (SHW only)
All RCI Options



Net Income Impact of Residential, Commercial & Industrial Options
($2004, millions)
400
350
300
250
200
150
100
50
0
-50
2007
2009
2011
2013
2015
2017
2019
RCI-1, RCI-2 & RCI-11
RCI-4 & RCI-5
RCI-6
RCI-7 & RCI-3
RCI-9
RCI-10 (SHW only)
All RCI Options



Net Gross State Product Impact of
Residential, Commercial & Industrial Options
($2004, millions)
175
125
75
25
-25
-75
2007
2009
2011
2013
2015
2017
2019
RCI-1, RCI-2 & RCI-11
RCI-4 & RCI-5
RCI-6
RCI-7 & RCI-3
RCI-9
RCI-10 (SHW only)
All RCI Options

RCI-1, RCI-2 & RCI-11: Energy Efficiency Funding & Energy Audits

These options propose to establish dedicated funding sources for energy efficiency and conservation measure in order to reduce demand for conventional sources of electricity and natural gas. The mitigation option design of RCI-1 seeks to increase Demand –Side Management Program (DSM) investments to 1.5% of utility revenues by 2012 while RCI-2 seeks to establish a Public Benefits Fund equivalent to 1% of utility revenues by 2010. RCI-11 seeks to direct a portion of these revenues to provide technical assistance visits to residential, commercial, and industrial customers to help identify energy efficiency measures and provide incentives to implement such measures. In consolidating these options for analysis, the ASU Energy Center applied the overlap factors identified by the RCI technical working group.

By 2020, these policies would result in the creation of more than 4,575 jobs, $160 million dollars in annual employee and proprietor income, but the loss of $55 million in annual gross state product. For the study period, 2007-2020, the mitigation options would add $789 million (NPV) in employee and proprietor income and $36 million (NPV) in gross state product. Moreover, the energy efficiency and conservation measures implemented as a result of these policies would continue pay dividends well beyond the study period.

RCI-4 & RCI-5: Market Transformation & Appliance Standards

These measures are intended to spur adoption of energy efficiency technologies through a combination of voluntary market transformation and technology development programs (RCI-4) and mandated improvements in the energy efficiency of consumer electronics, appliances, and equipment (RCI-5). RCI-4 seeks to reduce reference case electricity consumption by .2% a year beginning in 2012 through the establishment of a market transformation program to encourage the adoption of energy efficient products and services similar to the Northwest Energy Efficiency Alliance. RCI-5 calls for the adoption and enforcement of appliance and equipment energy efficiency recommended by the Appliance Standards Awareness Project and the Alliance for an Energy Efficient Economy (ASAP/ACEEE) in the joint 2006 report, "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards." In consolidating these options for analysis, the ASU Energy Center applied the overlap factors identified by the RCI technical working group.

By 2020, these policies would result in the creation of 771 jobs, $26 million dollars in annual employee and proprietor income, but the loss of $11 million in annual gross state product. For the study period, 2007-2020, the mitigation option would add $87 million (NPV) in employee and proprietor income but the loss of $9 million (NPV) in gross state product. Moreover, the energy efficiency and conservation measures implemented as a result of these policies would continue pay dividends well beyond the study period.

RCI-6: Building Codes

This mitigation option seeks to improve compliance with state building energy codes and establish a new code by 2010 that achieves a 20% energy savings over the current national building energy code standards for residential and commercial construction.

By 2020, this mitigation option would result in the creation of more than 2,163 jobs, $90 million dollars in annual employee and proprietor income, and $57 million in annual gross state product. For the study period, 2007-2020, the mitigation option would add $623 million (NPV) in employee and proprietor income and $571 million (NPV) in gross state product.

RCI-7 & RCI-3: High Performance Buildings

These policies seek to encourage advanced construction technologies and the installation of distributed renewable systems in residential, commercial, and government building. RCI-7 calls for the energy performance of 5% of new residential and 2% of new commercial annual construction to exceed the upgraded building energy codes called for in RCI-6 by 30% by 2010 and by 32% by 2020. The mitigation option also calls for 20% existing residential and commercial building stock to meet current building energy codes resulting in performance gains of 20% for commercial buildings and 15% for residential buildings. RCI-3 addresses new state government construction and renovation projects, calling for a 16% reduction in energy consumption for new project and a 12% reduction in existing building beyond the upgraded building codes called for in RCI-6 by 2020. The RCI analysis assumed the performance gains for each mitigation option would be achieved through investments in energy efficiency improvements, solar thermal hot water systems, and on-site photovoltaic installations and on-site bioenergy projects such as biomass, biogas, and landfill gas systems with different implementation rates for each customer class. In consolidating these options for analysis, the ASU Energy Center applied the overlap factors identified by the RCI technical working group.

By 2020, this mitigation option would result in the creation of more than 1,362 jobs, $76 million dollars in annual employee and proprietor income, and $32 million in annual gross state product. For the study period, 2007-2020, the mitigation option would add $388 million (NPV) in employee and proprietor income and $273 million (NPV) in additional gross state product.

RCI-9: Bulk Purchasing for Energy Efficient Appliances & Green Power Purchases for State Agencies

This option calls for the expansion of state government purchases of electricity produced from renewable resources and the establishment of a bulk purchasing program to facilitate the purchase of energy efficient appliances and equipment for both the private and public sectors. The operationalization of the bulk purchasing component of the mitigation option by the RCI technical working group assumes an annual electricity savings of 2% for the public sector and .1% for the private sector by 2018. The green power purchase component sets a goal of 20% of all state agency electricity purchases to be derived from renewable resources by 2018.

By 2020, this mitigation option would result in the creation of 12 jobs but the loss of $1 million dollars in annual employee and proprietor income, and $5 million in annual gross state product. For the study

period, 2007-2020, the mitigation option would increase employee and proprietor income by $33 million (NPV) and gross state product by $28 million (NPV).

RCI 10: Solar Hot Water Heating Only

This mitigation option calls for the installation of distributed renewable and combined heat and power (CHP) systems smaller than 10 MW with goals of a taking advantage of 29% of North Carolina's CHP potential, installing 35 MW of distributed renewable generation, and installing solar hot water heating (SHW) systems in 3% of all homes, all by 2020. Considerable overlap exists between this mitigation option and the CHP option developed by the ES technical working group. Moreover, the CAPAG's final estimate of greenhouse gas emissions reductions only includes the SHW component of RCI-10 and is therefore the only component considered in this study.

By 2020, the SHW component of this mitigation option would result in the net creation of more than 218 jobs, $13 million dollars in annual employee and proprietor income, and $24 million in annual gross state product. For the study period, 2007-2020, the mitigation option would create an additional $21 million (NPV) in employee and proprietor income and $37 million (NPV) in additional gross state product.

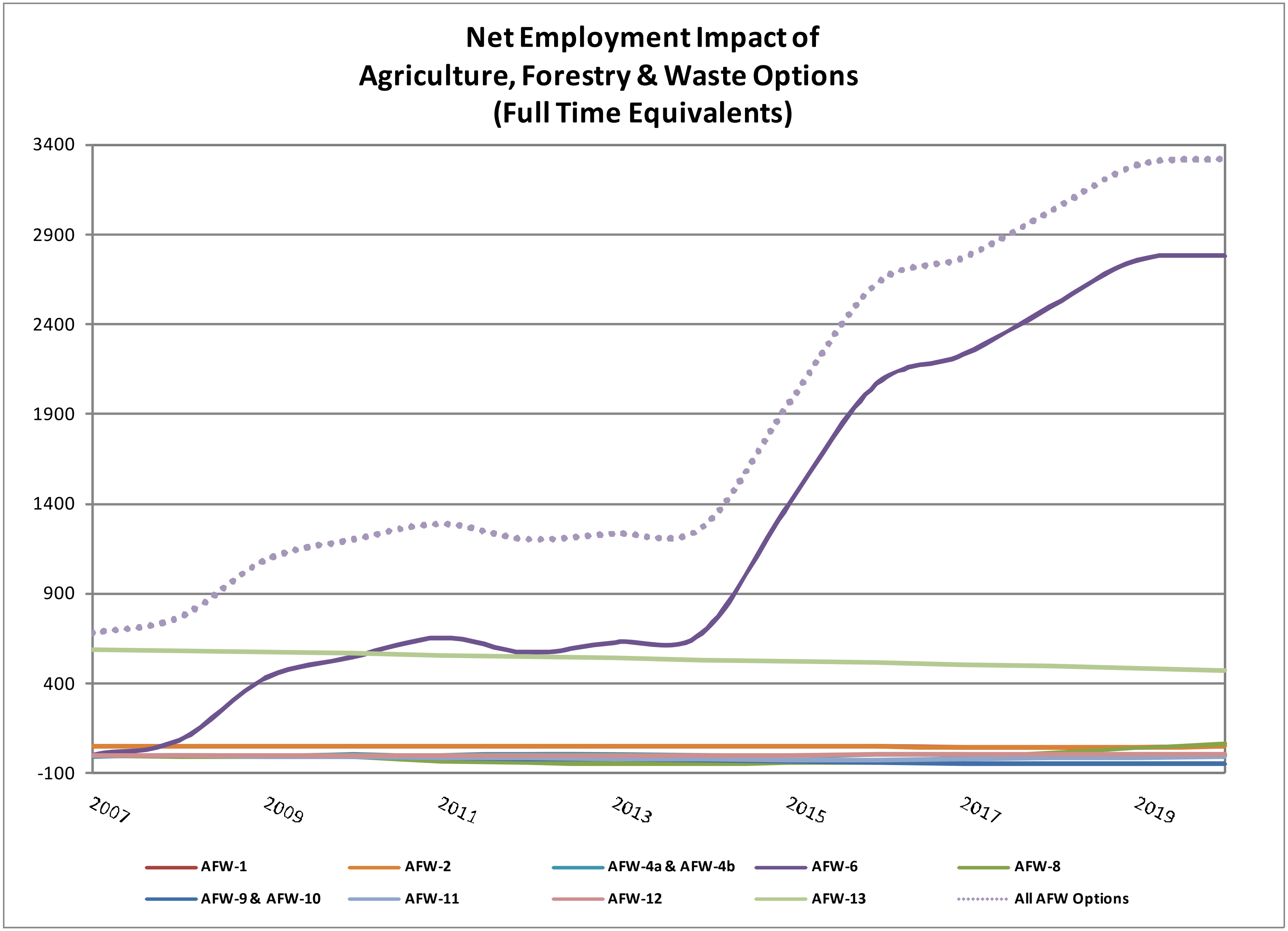
Chapter 4 Analysis Results of Agricultural, Forestry & Waste Management Options

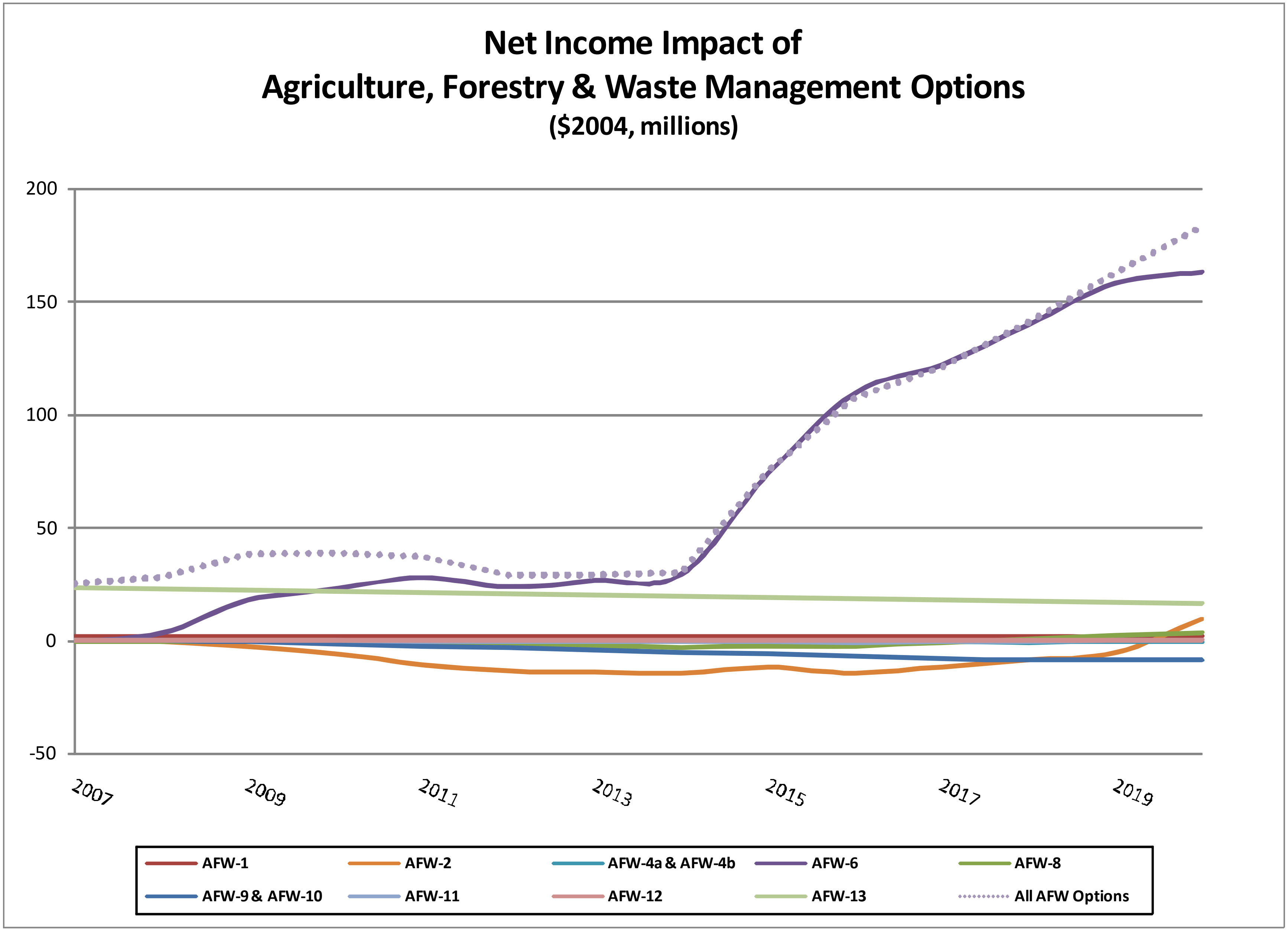
Table 4-1 presents summary results for AFW options analyzed. By 2020, these options would result in the net creation of more than 3,300 jobs, $183 million in additional employee and proprietor income, and $331 billion in gross state product. Over the study period, 2007–2020, the options would generate nearly $649 million (NPV) in additional employee and proprietor income and $1.2 billion (NPV) in gross state product. The positive economic impacts associated with these options are driven primarily by capital investments to build manufacturing capacity to meet the biofuels production goals articulated in the mitigation options.

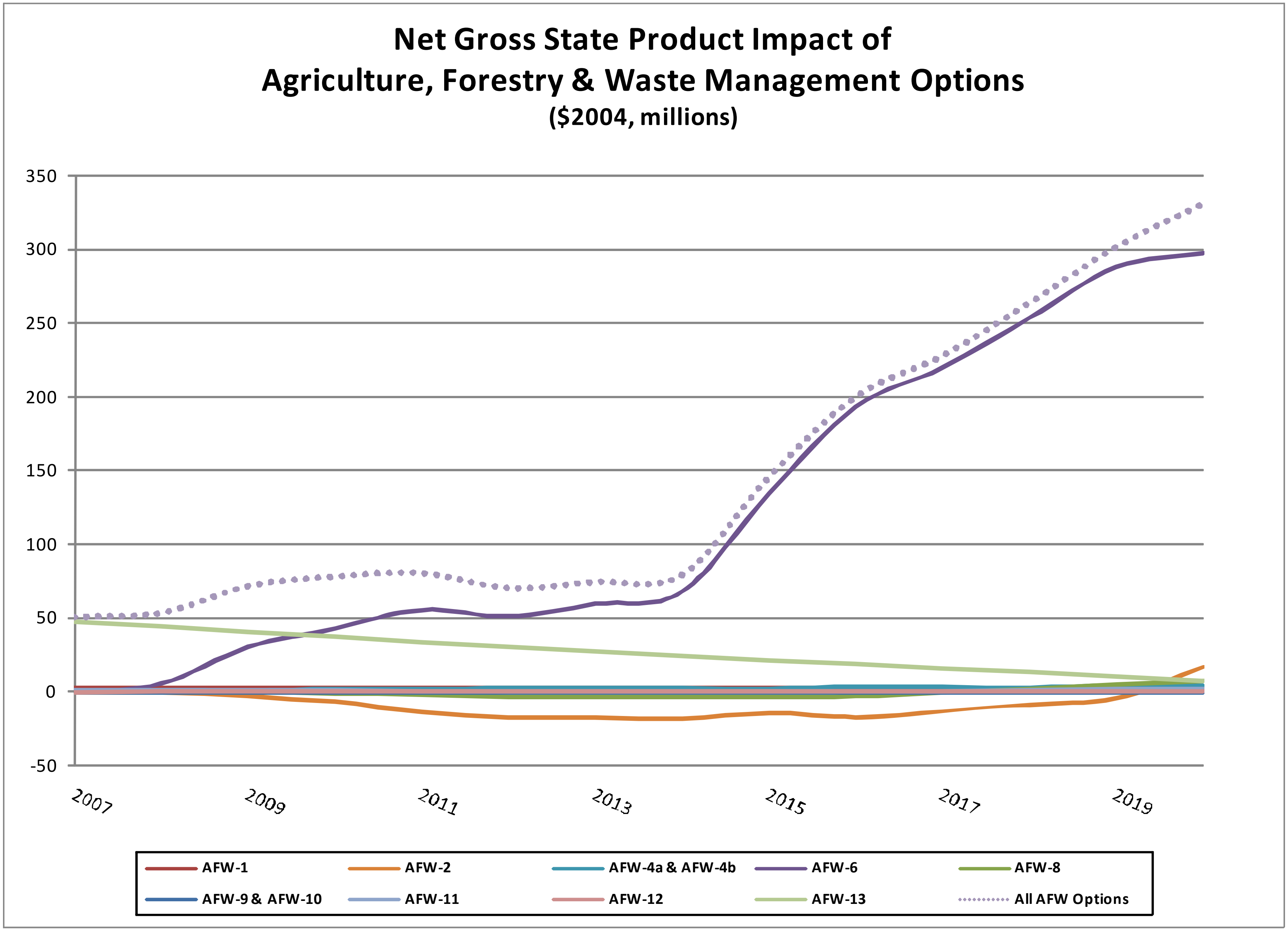
Table 4-1: Summary Results for Agriculture, Forestry & Waste Management Options Analyzed

	Net Annual Employment (FTE)			**Net Income ($2004, million)**				**Total Value-Added ($2004, million)**			
Agriculture, Forestry and Waste Options	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2007-2020 NPV**	**2010**	**2015**	**2020**	**2007-2020 NPV**
AFW 1 (Manure Digesters)	51	48	53	2	2	2	19	3	2	2	24
AFW 2 (Biodiesel)	51	48	53	(6)	(12)	10	(72)	(7)	(15)	17	(85)
AFW 4a & 4b (Easements)	2	(4)	3	(.2)	(1)	(1)	(4)	1	2	4	18
AFW 6 (Cellulosic Ethanol)	547	1,399	2,781	23	74	163	547	43	135	298	1,016
AFW 8 (Afforestation)	(13)	(45)	66	(1)	(2)	4	(9)	(1)	(3)	8	(8)
AFW 9 & 10 (Forest Management)	(9)	(33)	(48)	(2)	(6)	(9)	(41)	(.1)	(.3)	(.4)	(2)
AFW 11 (Landfill Gas)	(6)	(24)	(5)	(.1)	(1)	0.4	(2)	1	(.3)	2	4
AFW 12 (Recycling)	1	2	6	.1	.1	.3	2	.3	.3	1	3
AFW 13 (Urban Forestry)	566	524	475	22	19	17	106	37	22	8	115
All AFW Policies	**1,202**	**1,960**	**3,318**	**39**	**75**	**183**	**649**	**78**	**145**	**331**	**1,267**

Note: Values in parentheses identify loss of jobs, income, or Value-Added to the economy. NPV = net present value. FTE=Full Time Equivalent


Net Employment Impact of
Agriculture, Forestry & Waste Options
(Full Time Equivalents)
3400
2900
2400
1900
1400
900
400
-100
2007
2009
2011
2013
2015
2017
2019
AFW-1
AFW-2
AFW-4a & AFW-4b
AFW-6
AFW-8
AFW-9 & AFW-10
AFW-11
AFW-12
AFW-13
All AFW Options


Net Income Impact of
Agriculture, Forestry & Waste Management Options
($2004, millions)
200
150
100
50
0
-50
2007
2009
2011
2013
2015
2017
2019
AFW-1
AFW-2
AFW-4a & AFW-4b
AFW-6
AFW-8
AFW-9 & AFW-10
AFW-11
AFW-12
AFW-13
All AFW Options


Net Gross State Product Impact of
Agriculture, Forestry & Waste Management Options
($2004, millions)
350
300
250
200
150
100
50
0
-50
2007
2009
2011
2013
2015
2017
2019
AFW-1
AFW-2
AFW-4a & AFW-4b
AFW-6
AFW-8
AFW-9 & AFW-10
AFW-11
AFW-12
AFW-13
All AFW Options

AFW-1: Manure Digesters

This option proposes to capture twenty percent of the methane emissions from Concentrated Animal Feeding Operations (CAFO) in North Carolina, such as hog and dairy farms, in order to generate electricity, by 2020. By 2020, this mitigation option would result in the creation of more than 53 jobs, $2 million in additional annual employee and proprietor income, and $2 million in annual gross state product. For the study period, 2007-2020, the mitigation option would generate $19 million (NPV) in additional employee and proprietor income and $24 million (NPV) in gross state product.

AFW-2: Biodiesel Production Subsidy

This option proposes to displace 5% of North Carolina's petroleum diesel fuel consumption with biodiesel by 2010 ramping up to 12.5% by 2020. The option assumes a state subsidy to support biodiesel producers worth $.34 per gallon for the first five years of production in order to drive technological advances that will make biodiesel production costs more competitive with petroleum diesel. Since the AFW technical working group analysis only quantified the cost of the subsidy and not the value of the capital investments and operating expenses, including feedstocks, required to meet the production targets, this study relied on additional research and literature to quantify these values.

When these additional investments are considered, by 2020 this mitigation option would result in the creation of 53 jobs, $10 million in additional annual employee and proprietor income, and $17 million in annual gross state product. For the study period, 2007-2020, the mitigation option would decrease employee and proprietor income by $72 million (NPV) and gross state product by $85 million (NPV). These study period reductions are a function of government subsidy payments displacing other government expenditures and as those payments are phased out, it is likely the effect over a longer horizon would yield a positive impact.

AFW-4A & AFW-4B: Farmland and Forestland Conservation Easements

These options seek to reduce the rate of conversion of North Carolina's forests and farmland to development through public funding of conservation easements. The mitigation option designs articulate a goal of reducing the current rate of conversion by 20% by 2010 and 50% by 2020. By 2020 this mitigation option would result in the creation of 3 jobs and $4 million in annual gross state product but the loss of $1 million in annual employee and proprietor income. For the study period, 2007-2020, the mitigation option would generate $18 million (NPV) in additional gross state product but the loss of $4 million (NPV) in employee and proprietor income.

AFW-6: Cellulosic Ethanol Production Subsidy

This option proposes to displace 10% of North Carolina's gasoline consumption with starch and cellulosic derived ethanol by 2010 ramping up to 25% by 2025. The option assumes a state subsidy to support ethanol producers worth $.23 per gallon through 2015, at which time it is assumed technological advances will make cellulosic ethanol production costs more competitive. Since the AFW technical working group analysis only quantified the cost of the subsidy and not the value of the capital investments and operating expenses, including feedstocks, required to meet the production targets, this study relied on additional research and literature to quantify these values.

When these additional investments are considered, this mitigation option would result in the creation of more than 2,781 jobs, $163 million in additional annual employee and proprietor income, and more than $298 million in annual gross state product by 2020. For the study period, 2007-2020, the mitigation option would increase employee and proprietor income by $547 million (NPV) and gross state product by more than $1 billion (NPV).

AFW-8: Afforestation

This option seeks to convert 540,000 acres of nonforested lands and degraded habitats in North Carolina to forests by 2020 through an expansion of the N.C. Dept of Environment and Natural Resources, Division of Forest Resource's Forest Development Program. The mitigation option design envisions a public subsidy consisting of a 100% cost share rate for establishments worth $140 per acre and a Conservation Reserve Program (CRP)-type payment of $40/acre for five years. Since the AFW technical working group analysis only quantified the cost of the subsidy and not the change in value of rent payments for forested lands, this study relied on additional research and literature to quantify these values.

When these changes in rent are considered, this mitigation option would result in the creation of 66 jobs, $4 million in additional annual employee and proprietor income, and $8 million in annual gross state product by 2020. For the study period, 2007-2020, the mitigation option would decrease employee and proprietor income by $9 million (NPV) and gross state product by $8 million (NPV).

AFW-9 & AFW-10: Forest Management

These options seek to increase forest stand productivity through intensive forest management practices with a goal of doubling forest productivity on half of North Carolina timberlands by 2020 through an expansion of the N.C. Dept of Environment and Natural Resources, Division of Forest Resource's Forest Development Program. To achieve this goal the mitigation option design assumes a state investment of $8.80 per acre per year. The AFW technical working group analysis assumes these investments would result in additional revenues from hardwood forest products sales worth of a future value of $390 per acre.

By the year 2020, this mitigation option would result in the loss of 48 jobs, $9 million in annual employee and proprietor income, and $.4 million in annual gross state product. For the study period, 2007-2020, the mitigation option would decrease employee and proprietor income by $41 million (NPV) and gross state product by $2 million (NPV).

AFW-11: Landfill Gas

This option proposes to capture fifty percent of the methane emissions from North Carolina's solid waste facilities for energy use by 2020. The mitigation option design assumes that 63% of the captured landfill gas (LFG) will be used to fuel small engine generators to produce electricity, 20% will be used in direct use applications, and 17% will be used to fuel standard engine generators. By 2020 this mitigation option would result in the loss of 5 jobs but the creation of $.4 million in additional annual employee and proprietor income and $2 million in annual gross state product. For the study period, 2007-2020, the mitigation option would result in the loss of $2 million (NPV) in employee and proprietor income but the creation of $4 million in gross state product.

AFW-12: Recycling

This option seeks to increase per capita recycling rates in North Carolina above current levels by 10% by 2010 and 25% by 2020 through expansion of curbside collection programs and enhancement of educational programs. By 2020 this mitigation option would result in the creation of 6 jobs, $.3 million dollars in annual employee and proprietor income, and $1 million in annual gross state product. For the study period, 2007-2020, the mitigation option would create $2 million (NPV) in employee and proprietor income and $3 million (NPV) in gross state product.

AFW-13: Urban Forestry

This option seeks to increase urban tree cover by planting three additional trees on all new residential construction sites starting in 2008, and by planting three new additional trees at one quarter of existing housing units by 2020, with the goal of achieving a $150 per unit per year in energy savings. By 2020, this mitigation option would result in the creation of more than 475 jobs, $17 million dollars in annual employee and proprietor income, and $8 million in annual gross state product. For the study period, 2007-2020, the mitigation option would add $649 million (NPV) in employee and proprietor income and $115 million (NPV) in gross state product.

Chapter 5 RESULTS OF TRANSPORTATION AND LAND USE OPTIONS ANALYSIS

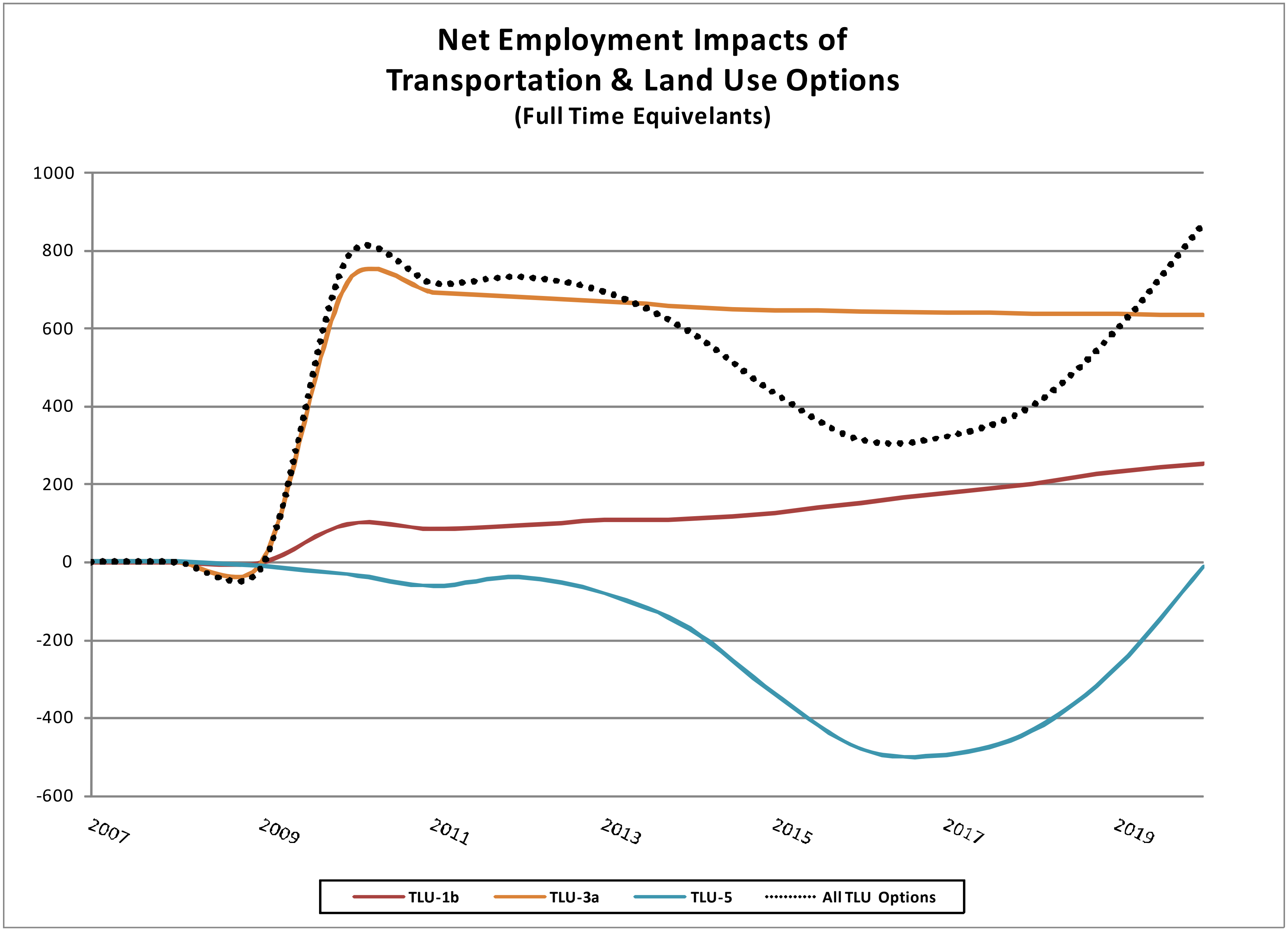
Table 5-1 presents summary results for Transportation and Land Use options analyzed. By 2020, these options would result in the creation of more than 870 net jobs and $48 million in net gross state product but the loss of $8 million in employee and proprietor income. Over the study period, 2007–2020, the options would generate $128 million (NPV) in gross state product but the loss of $91 million (NPV) in employee and proprietor income. The bulk of the economic impacts associated with these options are driven by consumer re-spending of reduced vehicle operating costs.

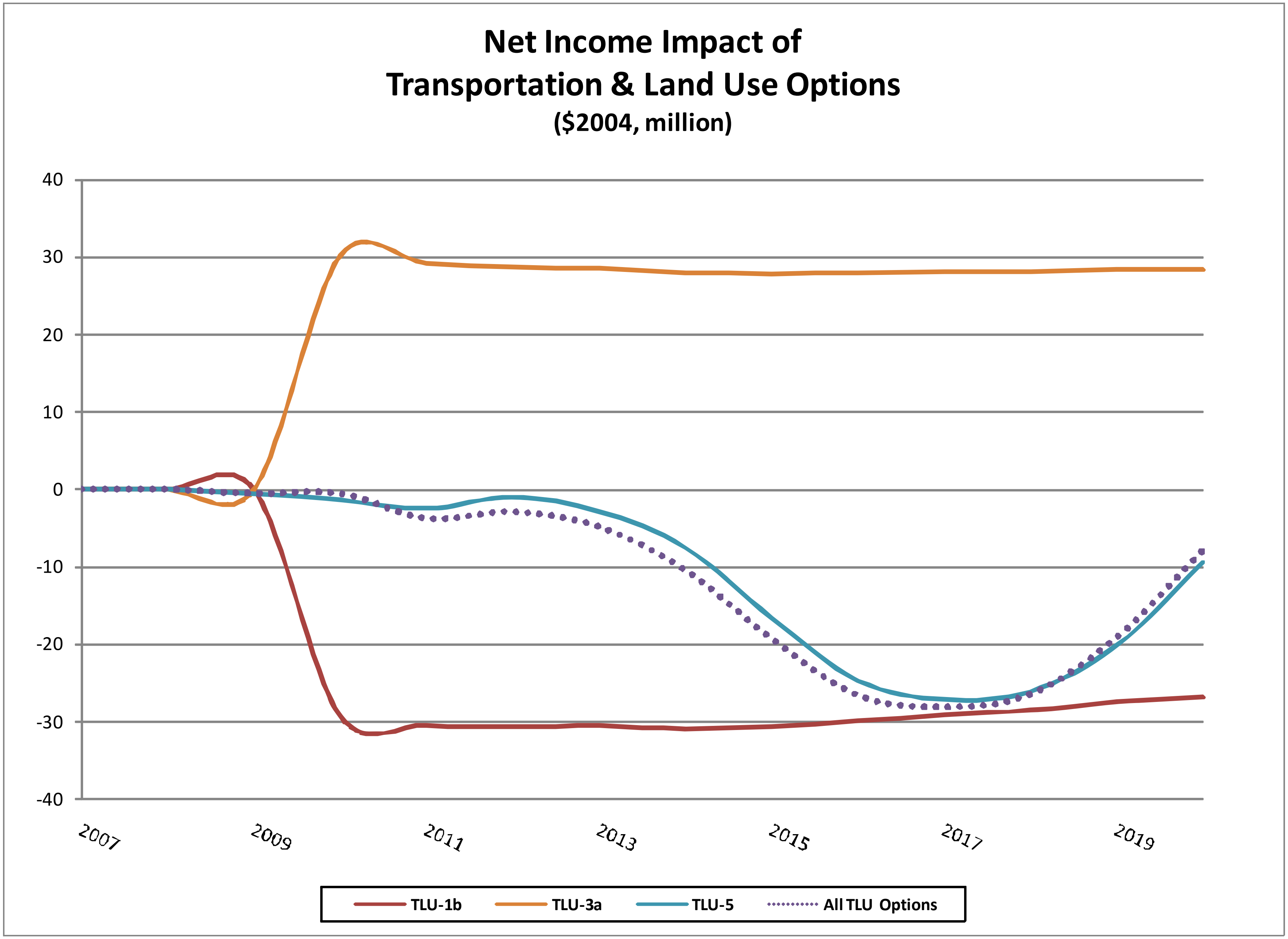
The negative impacts associated with TLU-5 are largely the result of the relative effect of reduced vehicle operating costs versus the displacement of retail gasoline sales. While TLU-5 results in a net savings to vehicle owners, the positive multiplier effect of these savings do not outweigh the constrictive multiplier effect of displaced retail gasoline sales. However, it should be noted that the modeling assumptions of this option are intentionally conservative. For example, it assumes as the U.S. Energy Information Administration's 2007 regional retail fuel price forecast for gasoline, which averages $2.21 per gallon over the study period and is considerably lower than the current market prices. Variability in the baseline fuel price assumption is considered and discussed in Chapter 6. These sensitivities suggest that if energy prices remain at, or near, their recent highs then vehicle greenhouse emissions standards would result in substantial positive economic impacts.

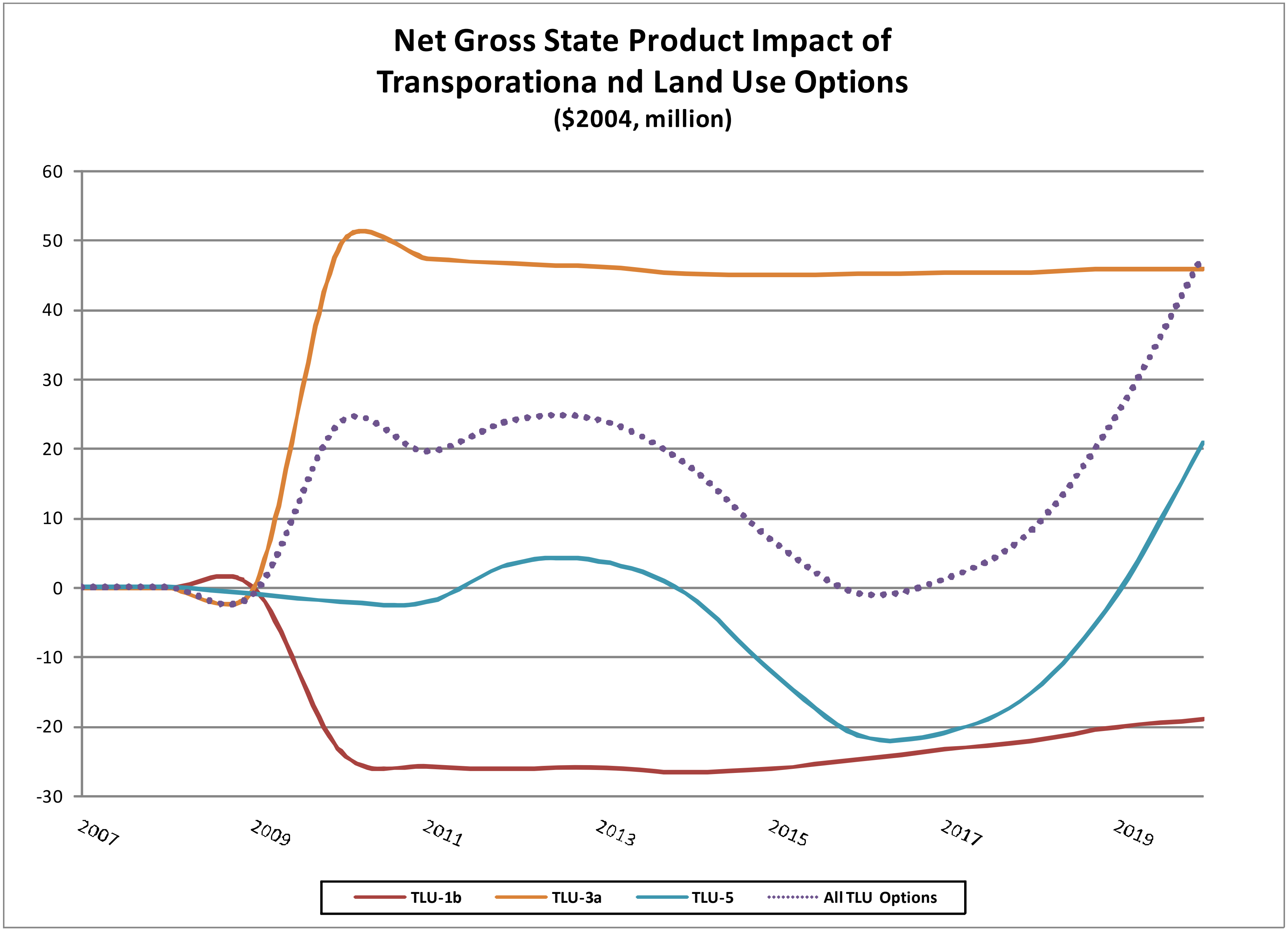
Table 5-1: Summary Results for Transportation and Land Use Options Analyzed

	Net Annual Employment (FTE)			**Net Income ($2004, million)**				**Total Value-Added ($2004, million)**			
Transportation and Land Use Options	**2010**	**2015**	**2020**	**2010**	**2015**	**2020**	**2007-2020 NPV**	**2010**	**2015**	**2020**	**2007-2020 NPV**
TLU 1b (Shift to Transit Spending)	98	127	252	(29)	(31)	(27)	(213)	(23)	(26)	(19)	(173)
TLU 3a (Registration Surcharge)	718	646	632	30	28	28	205	49	45	46	332
TLU 5 (Vehicle GHG Standard)	(32)	(341)	(14)	(1)	(17)	(9)	(83)	(2)	(12)	21	(31)
All TLU Policies	**783**	**432**	**871**	**(1)**	**(19)**	**(8)**	**(91)**	**24**	**7**	**48**	**128**

Note: Values in parentheses identify loss of jobs, income, or Value-Added to the economy. NPV = net present value. FTE=Full Time Equivalent


Net Employment Impacts of
Transportation & Land Use Options
(Full Time Equivelants)
1000
800
600
400
200
0
-200
-400
-600
2007
2009
2011
2013
2015
2017
2019
TLU-1b
TLU-3a
TLU-5
All TLU Options


Net Income Impact of
Transportation & Land Use Options
($2004, million)
40
30
20
10
0
-10
-20
-30
-40
2007
2009
2011
2013
2015
2017
2019
TLU-1b
TLU-3a
TLU-5
All TLU Options


Net Gross State Product Impact of
Transporationa nd Land Use Options
($2004, million)
60
50
40
30
20
10
0
-10
-20
-30
2007
2009
2011
2013
2015
2017
2019
TLU-1b
TLU-3a
TLU-5
All TLU Options

TLU-1B: Multi-modal Transportation and Promotion

This mitigation option recommends shifting 13% of North Carolina's transportation funding from spending on highway & roads to multi-modal transportation projects such as bus service, passenger and commuter rail, and bicycle and pedestrian programs starting in 2010, per the recommendations in the N.C. Department of Transportation's (DOT) *Long-Range Statewide Multimodal Transportation Plan*. The TLU technical working group analysis assumes a constant budget for the N.C. DOT over the study period of $2.5 billion a year, yielding a $325 million a year investment in multi-modal transportation projects. Furthermore, the TLU technical working group assumed this shift in spending would result in a 2.97% reduction in vehicle miles traveled (VMT) by light duty vehicles (LDV) by 2010 and a 2.76% reduction LDV VMT by 2020.

By 2020, this mitigation option would result in the net creation of 252 jobs but the loss of $27 million in annual employee and proprietor income and $19 million in annual gross state product. For the study period, 2007-2020, the mitigation option would reduce employee and proprietor income by $213 million (NPV) but increase net gross state product by $173 million (NPV).

TLU-3A: Vehicle Registration Surcharge to Fund Multi-modal Transportation

This mitigation option recommends establishing a variable surcharge to motor vehicle registration fees in order to fund multi-modal transportation projects such as bus service, passenger and commuter rail, and bicycle and pedestrian programs, starting in 2010. The amount of the surcharge would vary based on a vehicle's fuel economy and emissions performance. The TLU working group assumed such a program would raise $37 million per year and would result in a 1.5% reduction in vehicle miles traveled (VMT) by light duty vehicles (LDV) by 2010 and a 2.5% reduction LDV VMT by 2020.

By 2020, this mitigation option would result in the net creation of 632 jobs, $28 million in annual employee and proprietor income, and $46 million in annual gross state product. For the study period, 2007-2020, the mitigation option would increase employee and proprietor income by $205 million (NPV) and net gross state product by $332 million (NPV).

TLU-5: Tailpipe Greenhouse Gas Emissions Standards

This mitigation option contemplates adoption of regulations to reduce the greenhouse gas emissions associated with operating a motor vehicle similar to those adopted by California and sixteen other states. By 2020, this mitigation option would result in the net loss of 14 jobs and $9 million in annual employee and proprietor income but create $21 million in annual gross state product. For the study period, 2007-2020, the mitigation option would decrease employee and proprietor income by $83 million (NPV) and net gross state product by $31 million (NPV).

Chapter 6 Sensitivity Analyses

In addition to the baseline scenarios presented in the previous chapters, the ASU Energy Center prepared a set of sensitivity analyses for two individual options. These sensitivities reveal how changes in the baseline scenario assumptions may impact results.

RCI-1: Energy Efficiency Funding Sensitivities

This option seeks to increase investments in energy efficiency and Demand-side Management (DSM) to 1.5% of utility revenues by 2012. The ASU Energy Center conducted sensitivity analyses for three key variables for this option: program effectiveness, portion of local investment, and the NCESEIM employment multipliers.

Program Effectiveness

The RCI TWG assumed that every dollar spent on energy efficiency and DSM programs would result in 8 kilowatt-hours of incremental first-year energy savings. The Energy Center considered sensitivities of this key variable of 10% more energy savings, 25% more energy savings, 10% less energy savings, and 25% less energy savings. Table 6-1 presents summary results for the baseline scenario, as well as, each sensitivity analyzed.

Table 6-1: RCI-1 Program Effectiveness Sensitivities

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value Added ($2004, million)			
	2010	2015	2020	2010	2015	2020	2007-2020 NPV	2010	2015	2020	2007-2020 NPV
Base Case	763	2,062	3,068	25	69	108	516	8	(3)	(37)	15
10% More Energy Savings	836	2,244	3,352	28	75	117	560	9	(3)	(41)	13
25% More Energy Savings	946	2,517	3,777	32	84	132	626	11	(5)	(47)	9
10% Less Energy Savings	690	1,880	2,784	23	64	98	472	6	(2)	(32)	17
25% Less Energy Savings	580	1,606	2,359	19	55	83	405	4	(0)	(26)	20

As the bulk of the job creation associated with option is driven by consumer and industry re-spending of energy bill savings, job, income, and total value-added creation depends directly on program effectiveness. This pattern likely holds true for other energy efficiency related options as well.

Local Investment

The baseline scenario assumes that 90% of the program spending would occur within the North Carolina Economy, based on a weighted average of IMPLAN regional purchase coefficients for the affected sectors. The Energy Center also considered sensitivities of 95% local program spending, 85% local program spending, 80% local program spending, and 75% local program spending. Table 6-2 presents summary results for the baseline scenario, as well as, each sensitivity analyzed. Intuitively, as the share of local investment declines so does the effect on the local economy.

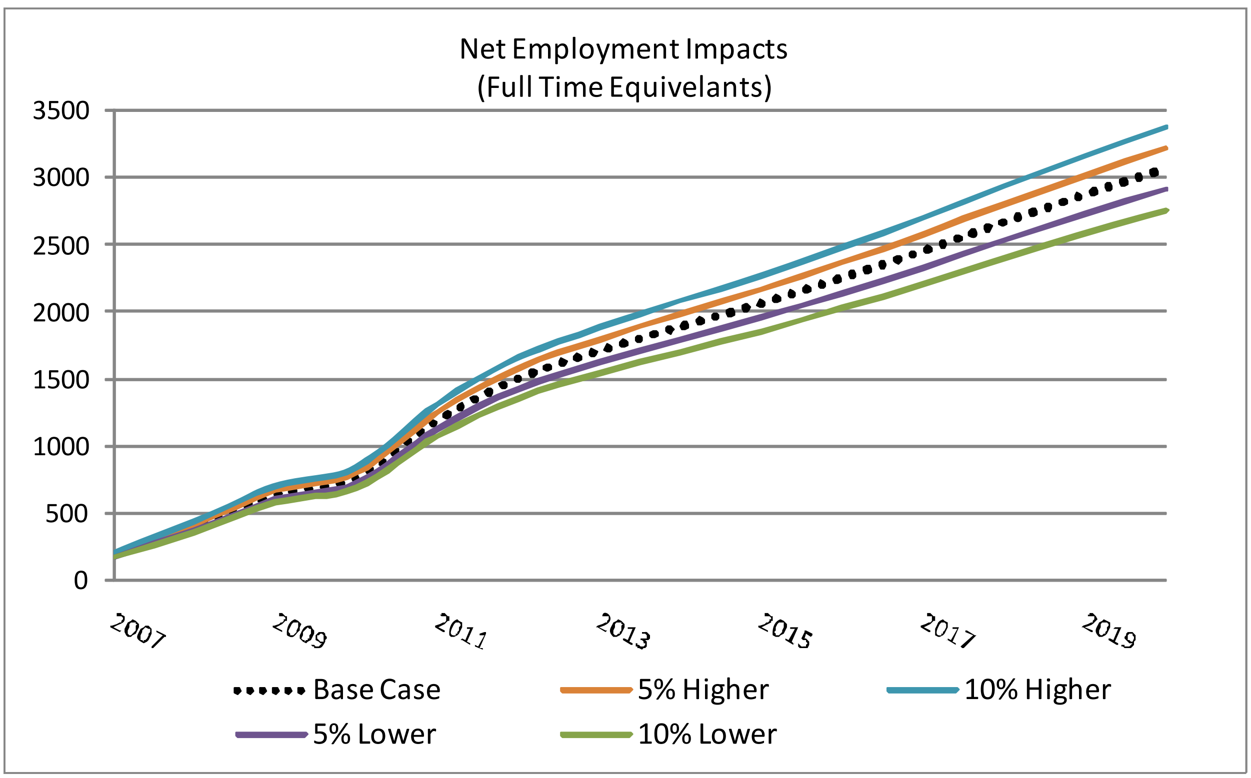
Table 6-2: RCI-1 Local Investment Sensitivities

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value Added ($2004, million)			
	2010	2015	2020	201 0	2015	2020	2007-2020 NPV	201 0	2015	2020	2007-2020 NPV
Base Case (90% local)	763	2,062	3,068	25	69	108	516	8	(3)	(37)	15
95% local	855	2,206	3,217	30	77	116	573	14	9	(24)	99
85% local	671	1,917	2,920	21	62	99	458	1	(14)	(49)	(70)
80 % local	579	1,773	2,771	17	55	91	401	(5)	(25)	(61)	(154)
75% local	487	1,628	2,623	12	47	82	344	(11)	(36)	(74)	(239)

Employment Multipliers

The baseline employment multipliers were derived scenario from state-level data for 2004 compiled by the Minnesota IMPLAN Group as spelled out in Appendix A. The Energy Center also examined the effect of changing the underlying multipliers in the input-output framework by looking at 5% higher, 10% higher, 5% lower, and 10% lower employment multipliers. Figure XX shows the effects of adjusting the employment multipliers and reveals no substantial change in orders of magnitude, a pattern that likely holds true for other options and multipliers.

Figure 6-1: RCI-1Employment Multiplier Sensitivities



TLU-5: GHG Standards for Automobiles Sensitivities

This mitigation options calls for the adoption of California's GHG tailpipe emission standards which require light duty motor vehicles to reduce GHG emissions 36% per mile by 2016. The ASU Energy Center conducted sensitivity analyses for two key variables for this option: compliance cost and fuel price.

Compliance Cost

The baseline scenario adopts the California Air Resource Board's (CARB) estimate of the cost of compliance for the passenger cars and small trucks/sport utility vehicles (SUVs) to calculate the increased costs of the regulation borne by the consumer. While some suggest that both regulators and the automobile industry actually tend to *overstate* the cost of complying with pollution standards (see Hwang and Doniger 2004), the ASU Energy Center considered compliance cost sensitivities of 110%, 125% and 150% of the baseline scenario. Table 6-3 presents summary results for the baseline scenario, as well as, each sensitivity analyzed.

Table 6-3: TLU-5 Compliance Cost Sensitivities

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value Added ($2004, million)			
	2010	2015	2020	2010	2015	2020	2007-2020 NPV	2010	2015	2020	2007-2020 NPV
Base Case	(32)	(341)	(14)	(1)	(17)	(9)	(83)	(2)	(12)	21	(31)
10% Higher Compliance Cost	(37)	(503)	(344)	(2)	(25)	(27)	(137)	(2)	(25)	(8)	(120)
25% Higher Compliance Cost	(45)	(746)	(839)	(2)	(37)	(54)	(219)	(3)	(45)	(52)	(254)
50% Higher Compliance Cost	(58)	(1,152)	(1,664)	(3)	(57)	(98)	(355)	(4)	(78)	(125)	(477)

Higher compliance costs may result in modest economic losses; as the cost of pollution controls exceed any vehicle operating savings from fuel efficiency resulting with a resulting contraction in household spending. However, it should be noted that these sensitivities also amplify the effect of the modeling's conservative assumption that additional compliance costs have no effect on local manufacturing.

Fuel Prices

Notably, the baseline scenario is predicated on Energy Information Administration's 2007 regional retail fuel price forecast for gasoline, which averages $2.21 per gallon over the study period and is considerably lower than the current market prices; therefore, the ASU Energy Center considered fuel price sensitivities of 110%, 125% and 150% above the baseline scenario, or, respectively, averages of $2.43, $2.76, and $3.32 per gallon over the study period. Table 6-4 presents summary results for the baseline scenario, as well as, each sensitivity analyzed.

Table 6-4: -5 Fuel Price Sensitivities

	Net Annual Employment (FTE)			Net Income ($2004, million)				Total Value Added ($2004, million)			
	2010	2015	2020	2010	2015	2020	2007-2020 NPV	2010	2015	2020	2007-2020 NPV
Base Case ($2.21/gln)	(32)	(341)	(14)	(1)	(17)	(9)	(83)	(2)	(12)	21	(31)
10% Higher ($2.43/gln)	(30)	(212)	315	(1)	(10)	7	(37)	(2)	(0)	52	55
25% Higher ($2.76/gln)	(28)	(20)	808	(1)	(1)	32	32	(2)	18	99	184
50% Higher ($3.32/gln)	(23)	301	1,629	(1)	15	74	147	(1)	48	177	399

As expected, the fuel price sensitivities result in greater job, income, and total value added creation since higher fuel prices result in larger vehicle operating cost savings and suggests that if energy prices remain at or near their recent highs then vehicle greenhouse emissions standards would actually result in the positive economic impacts.

Chapter 7 QUANTIFICATION OF UPFRONT INVESTMENT COSTS

In addition to the economic impact analysis, CCS requested a summary of the potential annual upfront public and private investments associated with the mitigation options (Table 7-1). The annual investment costs associated with the options are based on the methods used to estimate the costs or cost savings of each option analyzed during the CAPAG process, and supplemental research conducted by the ASU Energy Center in the course of conducting the economic impact analysis.

While implementation of some of the mitigation options may require significant upfront investments of public and/or private resources, these investments, in many cases, also result in significant savings over time. Moreover, many of the mitigation options result in ongoing savings beyond the period included in the CAPAG and ASU Energy Center analyses. Finally, almost all of these initial investment costs will be financed over time reducing the actual annual costs borne by the public and private sectors.

Consider for example TLU-5 (Tailpipe GHG Standards). As noted above, this mitigation option would require automakers to install additional pollution control technologies increasing the purchase price of a new vehicle and monthly car payments. However these same pollution control technologies will increase fuel economy and reduce the vehicle operating expenses, which tend to offset the increased purchase price.

Table 7-1: Projected Potential Upfront Investment Costs of Mitigation Options ($million, 2005)

Energy Supply Options	**2010**	**2015**	**2020**	**2007–2020 (NPV)**
ES-1 (Renewable Energy Incentives)				
Private investment	10	61	124	414
Public investment	1	2	2	13
Total investment	10	63	127	426
ES-2 (Environmental Portfolio Standard, SB3 Analysis)				
Private investment	-	676	911	4,310
Total investment	-	676	911	4,310
ES-3 & 9 (Combined Heat and Power)				
Private investment	238	396	570	3,082
Total investment	238	396	570	3,082
ES-6a (IGCC versus new pulverized coal)				
Private investment	47	9	9	195
Total investment	47	9	9	195
ES-6b (IGCC displacing existing pulverized coal)				
Private investment	318	69	69	1,353
Total investment	318	69	69	1,353
ES-8 (Municipal Biogas)				
Public investment	0.2	1	3	9
Total investment	-	1	3	9
ALL ES POLICIES				
PRIVATE INVESTMENT	**613**	**1,211**	**1,686**	**9,037**
PUBLIC INVESTMENT	**1**	**3**	**5**	**21**
TOTAL INVESTMENT	**614**	**1,214**	**1,692**	**9,058**

Residential, Commercial and Industrial Options	2010	2015	2020	2007–2020 (NPV)
RCI-1 (Efficiency Funding)				
Private investment	208	329	368	2,527
Total investment	208	329	368	2,527
RCI-2 (1% PBF)				
Private investment	146	154	173	1,242
Total investment	146	154	173	1,242
RCI-11 (Energy Audits)				
Private investment	9	10	10	84
Total investment	9	10	10	84
RCI-4 (Market Transformation)				
Private investment	-	8	19	53
Total investment	-	8	19	53
RCI-5 (Appliance Standards)				
Private investment	-	25	25	141
Total investment	-	25	25	141
RCI-6 (Energy Codes)				
Private investment	225	227	231	1,640
Total investment	225	227	231	1,640
RCI-3 (Energy Efficient Government Buildings)				
Public investment	-	63	71	397
Total investment	-	63	71	397
RCI-7 (High-Performance Buildings)				
Private investment	56	93	93	671
Total investment	56	93	93	671
RCI-9 (Bulk Purchasing & State Government Green Power Purchases)				
Private investment	59	59	-	470
Public investment	2	4	5	26
Total investment	**61**	**63**	**5**	**496**
RCI-10 (Residential Solar Hot Water Heating Only)				
Private investment	37	41	44	351
Total investment	37	41	44	351
ALL RCI POLICIES				
PRIVATE INVESTMENT	**740**	**947**	**964**	**7,188**
PUBLIC INVESTMENT	**1.686**	**66**	**76**	**423**
TOTAL INVESTMENT	**742**	**1,014**	**1,040**	**7,611**

Agriculture, Forestry, and Waste Management Options	2010	2015	2020	2007–2020 (NPV)
AFW-1 (Manure Digesters)				
Private investment	19	28	39	238
Total investment	**19**	**28**	**39**	**238**
AFW-2 (Biodiesel)				
Private investment	45	88	93	414
Public investment	24	49	15	273
Total investment	69	138	107	686
AFW-4a (Farmland Easements)				
Public investment	21	31	51	263
Total investment	**21**	**31**	**51**	**263**
AFW-4b (Forestland Easements)				
Public investment	8	14	20	107
Total investment	8	14	20	107
AFW-5 (Biomass Subsidy)				
Public investment	3	-	-	10
Total investment	3	-	-	10
AFW-6 (Cellulosic Ethanol)				
Private investment	188	339	742	3,008
Public investment	25	-	-	190
Total investment	213	339	742	3,198
AFW-8 (Afforestation)				
Public investment	3	15	15	98
Total investment	3	15	15	98
AFW-9 & -10 (Forest Management)				
Public investment	16	54	78	358
Total investment	16	54	78	358
AFW-11 (Landfill Gas)				
Private investment	12	12	15	112
Total investment	12	12	15	112
AFW-12 (Recycling)				
Private investment	6	10	15	79
Total investment	6	10	15	79
AFW-13 (Urban Forestry)				
Private investment	96	84	76	896
Total investment	96	84	76	896
ALL AFW POLICIES				
PRIVATE INVESTMENT	**382**	**616**	**1,057**	**5,105**
PUBLIC INVESTMENT	**81**	**167**	**255**	**1,353**
TOTAL INVESTMENT	**463**	**784**	**1,312**	**6,459**

Transportation and Land Use Options	**2010**	**2015**	**2020**	**2007–2020 (NPV)**
TLU-1b (Shift to Transit Spending)				
Public investment	347	347	347	2,487
Total investment	358	358	358	2,572
TLU-3a (Registration Surcharge for Transit $)				
Public investment	33	33	33	239
Total investment	34	34	34	247
TLU-5 (CO_2 Tailpipe Standard)				
Private investment	26	401	553	2,341
Total investment	26	401	553	2,341
ALL TLU OPTIONS				
PRIVATE INVESTMENT	**26**	**401**	**553**	**2,702**
PUBLIC INVESTMENT	**380**	**380**	**380**	**3,156**
TOTAL INVESTMENT	**406**	**781**	**933**	**5,858**

NPV = net present value; SB = Senate Bill; CHP = combined heat and power; IGCC = integrated gasification combined cycle; PBF = Public Benefits Fund; CO_2 = carbon dioxide.

Appendix A: Derivation of Economic Multipliers and Predictive Model

In input-output analysis, the derivation of economic multipliers begins with a transactions table. The transaction table is an accounting of the value of inter-industry exchanges in an economy within a fixed period of time, typically a year. The table below (Figure 0-1) is an example of a hypothetical three sector economy.

Figure 0-1: Transactions Table[a]

	A	B	C	Final Demand	Total Output
A	.06	.06	.44	9.44	10
B	.25	.75	0	29	30
C	1.4	2.07	1.56	34.97	40
Value Added	6.5	24	30		
Total Inputs	10	30	40		

[a]Source: (Minnesota IMPLAN Group, Inc. 2004)

The rows in the transaction table represent the direct sale of outputs from a given sector to other sectors in the economy, while the columns in the table represent the purchase of inputs by a given sector from other sectors needed to produce its outputs. Direct sales of finished goods to consumers and exports are recorded as entries in the final demand column. Employee compensation, stockholder dividends, and tax payments are recorded as entries in the Value-Added row. A sector's total inputs equal its total output, hence input-output (Schaffer 1999).

This relationship can be expressed algebraically as:

$$X_i = \sum_{j=1}^{n} x_{ij} + Y_i \qquad (1)$$

Where

$n \ldots$ number of sectors
$i \ldots$ row vector
$j \ldots$ column vector
$X_i =$ total input/output of sector i
$x_{ij} =$ output of sector i sold to sector j
$Y_i =$ output of sector i sold to final demand

The values in a transactions table and its derivatives typically come from government or private sector data sources. The NCESEIM utilizes state-level data from 2004 compiled by the Minnesota IMPLAN

Group, which in turn is derived from a number of federal and state agency sources, including as the U.S. Department of Commerce's Bureau of Economic Analysis *Benchmark Input-Output Accounts*.

Dividing each column entry in the transaction table by the sum of all the entries in the column reveals a production recipe describing where an industry purchases inputs and in what proportions for each dollar of its total output. The resulting matrix of values is known as the direct requirements coefficient table, or A Matrix (Figure 0-2).

Figure 0-2: A Matrix[a]

	A	B	C
A	.006	.002	.011
B	.025	.025	0
C	.14	.069	.039
Value Added	6.5	.8	.75
Industry Output	1	1	1

[a]Source: (Minnesota IMPLAN Group, Inc. 2004)

While the NCESEIM bypasses the calculation of the direct requirements coefficients, extracting them directly from the North Carolina IMPLAN data set, the algebra underlying the values is important in deriving multipliers that represent both the direct and interindustry effects.

Therefore let,

$$a_{ij} = \frac{x_{ij}}{X_i} \qquad \textbf{(2)}$$

Where,

a_{ij} = direct requirements coefficient $0 \leq a_{ij} \leq 1$

x_{ij} = output of industry i sold to sector j

X_i = total input/output of sector i

This relationship can also be written as $x_{ij} = a_{ij} X_i$ and substituted in the total output equation as:

$$X_i = \sum_{j=1}^{n} a_{ij} X_i + Y_i \qquad \textbf{(3)}$$

Or expressed in matrix notation as:

$$X = A \cdot X + Y \qquad \textbf{(4)}$$

Where,

$$A = \text{the A Matrix } (a_{ij \to n})$$
$$X = \text{total sector outputs } (X_{i \to n})$$
$$Y = \text{final demands } (Y_{j \to n})$$

Solving for Y results in:

$$Y = X - A \cdot X \qquad \textbf{(5)}$$

X is then isolated by factoring to get:

$$Y = (I - A) \cdot X \qquad \textbf{(6)}$$

Where I is the identity matrix, the matrix algebra equivalent of 1.

To solve for X, both sides of the equation are multiplied by the inverse of $I - A$ or $(I - A)^{-1}$ resulting in:

$$(I - A)^{-1} \cdot Y = (I - A)^{-1} \cdot (I - A) \cdot X \qquad \textbf{(7)}$$

Simplified as:

$$X = (I - A)^{-1} \cdot Y \qquad \textbf{(8)}$$

And interpreted as changes in total industry output (X) equal changes in final demand multiplied by $(I - A)^{-1}$ or

$$\Delta X = (I - A)^{-1} \cdot \Delta Y \qquad \textbf{(9)}$$

Consequently, $(I - A)^{-1}$ is the table of total requirements coefficients or the Leontief inverse (Figure 0-3). The coefficients represent the total purchase of outputs for a given sector from another sector for each dollar of output to meet that sector's final demand. In other words, the coefficients capture both the direct and indirect effects. When households are included in the matrix of industry sectors, the matrix yields the direct, indirect, and induced multiplier effects, or Type II multiplier (Schaffer 1999). To calculate the Type II multiplier, the NCESEIM divides household consumption by total labor income in the region to create household consumption coefficients.

Figure 0-3: Table of Total Requirements Coefficients[a]

	A	B	C
A	1.008	.003	.011
B	.026	1.026	0
C	.148	.074	1.042
Total Activity	1.182	1.103	1.054

[a] Source: (Minnesota IMPLAN Group, Inc. 2004)

From the table of total requirements it is possible to derive multipliers for employment, employee compensation, and gross state product that predict the consequences of changes in final demand. According to the logic of input-output analysis, a change in sectoral final demand will result in a change in sectoral total output. Likewise, input-output analysis assumes a linear relationship between changes in final demand and employment, employee compensation, and gross state product (Schaffer 1999).

Employment multipliers measure the relationship between the value of the output of a sector and employment in that sector. The direct effect is calculated by dividing total sector employment by total sector output, or:

$$w_i = \frac{W_i}{X_i} \qquad \textbf{(10)}$$

Where,

$w_i =$ direct employment ratio
$W_i =$ total sector employement
$X_i =$ total sector output

To calculate the total employment multiplier effect, the direct employment ratio is multiplied by the corresponding column vector in the $(I - A)^{-1}$ matrix, or:

$$M_{employment,j} = \sum_{i=1}^{n} w_i \alpha_{ij} \qquad \textbf{(11)}$$

Where,

$\alpha_{ij} =$ Leontief inverse matrix
$\text{M}_{employment,j} =$ total employment requirements

The multipliers for income and gross state product can be derived in a likewise fashion (Schaffer 1999). Income multipliers measure the impact of changes to final demand on income received by households (both employee and proprietor compensation) and show the direct, indirect, and induced effects of a dollar's worth of output in terms of a dollar's worth of new household income. The equation is expressed as:

$$M_{income,j} = \sum_{i=1}^{n} a_i \alpha_{ij} \qquad \textbf{(12)}$$

Where,

$a_i =$ sector i income per dollar of output
$\alpha_{ij} =$ Leontief inverse matrix
$\mathrm{M}_{income,j} =$ total income requirements

Gross state product multipliers measure the impact of changes to final demand on incomes earned by labor and capital and show the direct, indirect, and induced effects of a dollar's worth of output in terms of a dollar's worth of final demand delivieries by sector *j*. The equation is expressed as:

$$M_{GSP,j} = \sum_{i=1}^{n} a_i \alpha_{ij} \qquad \textbf{(13)}$$

Where,

$a_i =$ sector i GSP per dollar of output
$\alpha_{ij} =$ Leontief inverse matrix
$\mathrm{M}_{GSP,j} =$ total GSP requirements

Thus, the total number of jobs, income, and gross state product created per dollar of new final demand for a given sector thus can then be expressed as:

$$\Delta Z = \Delta Y \cdot M_Z \qquad (14)$$

Where,

$M_z =$ the direct requirements matrix for employment, income, or GSP ($\mathrm{M}_{ij\to n}$)
$\Delta Z =$ change in total sector employment, income, or GSP ($Z_{i\to n}$)
$\Delta Y =$ change in final demand ($Y_{j\to n}$)

Appendix B: Methodology

ES-1, ES-2 & AFW-5: Renewable Energy Production Subsidy, Renewable Portfolio Standard, & Biomass Production Subsidy

The cost to ratepayers, private investments, and public subsidies resulting from the implementation of these mitigation options was based on the technical assumptions of the ES and AFW technical working groups. The cost to ratepayers for ES-1 was calculated by multiplying the "rate impact" by the "total sales after mitigation option." The cost to ratepayer for ES-2 was calculated by taking the difference in total sales between the reference case and mitigation case scenarios and multiplying by the "rate impact"*. Since the ES technical working group did not break down sales by customer class, the ASU Energy Center utilized the RCI technical working group's sales forecast by customer class to determine the proportion of these costs borne by a given customer class. The distribution of these costs to a given economic sector was based on that sector's Energy Consumption Coefficient and treated as a decrease in final demand.

Due to the reduction in electricity sales from energy efficiency component of ES-2 by the end of the study period, customers realize a net savings. Moreover, the value of avoided fuel costs, resulting from the displacement of conventional generation, is assumed to be passed along to customers as an adjustment to utility fuel cost adjustment riders. These savings are treated as an increase in final demand while the resulting reduction in revenue for utility sectors is treated as a reduction in final demand for those sectors. Significantly, it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

The energy efficiency component of ES-2 is expected to cause energy customers to incur costs beyond the ratepayer impact, as customers make outlays for their share of efficiency measures. To calculate the annual value of these participant measure costs, the ASU Energy Center multiplied physical energy savings by customer class by the first-year participant cost by customer class. First-year participant costs were derived by computing the present value of the levelized cost of the participant's share of the efficiency measure, as reported by the RCI technical working group, assuming a 5% discount rate and a term of ten years for each customer class. These costs were then allocated as reductions in final demand according to a sector's Energy Consumption Coefficient. Energy efficiency investments were allocated as increase in final demand according to the methodology described for RCI-1, RCI-2 & RCI-11.

The value of private investment associated with implementation of renewable energy components of ES-1 and ES-2 consists of annual capital investments and operating expenses, including the value of feedstocks to fuel biomass systems. Annual capital investments by technology type were calculated by

* See (GDS Associates 2006) which suggests cost sharing approach where the utility pays for a portion of an efficiency measure to induce participation by a customer, as in a rebate program. Therefore, the REPS sensitivity assumes the rate impact associated with energy efficiency component of mitigation option only includes the utility's share of the efficiency measure and overhead, as reported in (Center for Climate Strategies 2007b).

multiplying incremental renewable generation by technology type by the calculated capital investment cost by technology type. The calculated capital investment costs were computed by decomposing the ES technical working group's "Levelized Renewable Technology Costs," based on the annualization factors cited by the ES technical working group. Annual fuel costs and operating expenses by technology type were calculated in a similar fashion.

The value of public subsidies was taken directly from the ES technical working group analysis. It was assumed these subsidies would come from existing state revenues and therefore would result in a reduction in state government expenditures to each economic sector, and in final demand, according to a sector's Government Spending Coefficient.

Conservatively, it was assumed that only the labor portion of the capital investments and operating expenses associated with private investments in renewable energy generation would impact the North Carolina economy. The labor share of capital investments increases final demand for Heavy Construction while the labor share of operating expenses increases final demand for the Electric Utility sectors. The value of feedstocks to supply biomass facilities increases final demand for the Forestry sector. It was also assumed that a portion of the financing costs associated with investments would benefit the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Rate Impact, ES-1 ($/MWh)[a]	$0.0143 (in 2020)
Rate Impact, ES-2 ($/MWh)[a]	$0.628 (in 2020)
First-year Participant Measure Cost, Residential[b]	$105.79
First-year Participant Measure Cost, Commercial[c]	$156.72
First-year Participant Measure Cost, Industrial[d]	$70.52
Decomposed Capital Cost, Hydroelectric ($/MWh-first year)[e]	$879.79
Decomposed Capital Cost, Wind ($/MWh-first year)[e]	$602.57
Decomposed Capital Cost, Hog Waste ($/MWh-first year)[e]	$346.32
Decomposed Capital Cost, Poultry Litter ($/MWh)[e]	$550.80
Decomposed Capital Cost, Biomass Co-firing($/MWh-first year)[e]	$52.32
Decomposed Capital Cost, Dedicated Biomass ($/MWh-first year)[e]	$424.58
Decomposed Operating Cost, Hydroelectric ($/MWh)[e]	$4.89
Decomposed Operating Cost, Wind ($/MWh)[e]	$13.31
Decomposed Operating Cost, Hog Waste ($/MWh)[e]	$41.50
Decomposed Operating Cost, Poultry Litter ($/MWh)[e]	$22.69
Decomposed Operating Cost, Biomass Co-firing ($/MWh)[e]	$1.95
Decomposed Operating Cost, Dedicated Biomass($/MWh)[e]	$15.80
Decomposed Fuel Cost, Biomass Co-firing ($/MWh)[e]	$4.45 (in 2007), $4.57 (in 2020)
Decomposed Operating Cost, Dedicated Biomass($/MWh)[e]	$36.10 (in 2007), $37.11(in 2020)

Share of Renewable Generation, Hydroelectric[f]	11%
Share of Renewable Generation, Hydroelectric [f]	11%
Share of Renewable Generation, Wind [f]	25%
Share of Renewable Generation, Hog Waste [f]	4%
Share of Renewable Generation, Poultry Litter [f]	5%
Share of Renewable Generation, Biomass Co-firing [f]	16%
Share of Renewable Generation, Dedicated Biomass [f]	39%
Share of Renewable Capital Investments to Heavy Construction[g]	10%
Share of Renewable Operating Expenses to Electric Utilities [g]	26%
Share of Renewable Fuel & Feedstock to Forestry [g]	90%
Share of Total Energy Efficiency Investments to Residential Construction[h]	26.8%
Share of Total Energy Efficiency Investments to Commercial Construction[i]	32.2%
Share of Total Energy Efficiency Investments to Wholesale Trade [i]	8.6%
Share of Total Energy Efficiency Investments to Retail Trade [h]	15.5%
Share of Total Energy Efficiency Investments to Professional, Scientific, Technical & Management Services [i]	4.3%
Share of Total Energy Efficiency Investments to Other Services [i]	8.6%
Financing Assumptions, Residential [j] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 75% 5 years 64.2%
Financing Assumptions, Commercial [j] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 75% 5 years 64.2%
Financing Assumptions, Industrial [j] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 75% 10 years 64.2%
Financing Assumptions, Renewables [j] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 50% 15 years 64.2%

[a] Source: (Center for Climate Strategies 2007a).
[b] Calculation based on levelized cost of $13.70/MWh cited in (Center for Climate Strategies 2007c).
[c] Calculation based on levelized cost of $20.30/MWh cited in (Center for Climate Strategies 2007c).
[d] Calculation based on levelized cost of $9.13/MWh cited in (Center for Climate Strategies 2007c).
[e] Source: Calculation based on levelized costs & annualization factors cited in (Center for Climate Strategies 2007b).
[f] Source: (Center for Climate Strategies 2007b).
[g] Source: (LaCapra Associates 2006).
[h] Source:(GDS Associates 2006). Weighted for distribution of spending among customer classes.
[i] Source: (Sedano 2005).Weighted for distribution of spending among customer classes.
[j] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

ES-3 & ES-9: Combined Heat and Power

The value of energy savings and private investments, including annual capital costs and operating expenses, resulting from the implementation of this mitigation option were based on the technical assumptions of the ES and RCI technical working group. Annual capital investments by technology type were calculated by multiplying incremental CHP generation by technology type by its calculated capital investment cost. Calculated capital investment costs were computed by decomposing the RCI technical working group's "Estimated Average Installed Capital Costs by System Type," based on the annualization factors cited by the RCI technical working group. Annual fuel costs and operating expenses by technology type were calculated in a similar fashion, except they were calculated using cumulative CHP generation. These investment costs were distributed to the commercial and industrial customer classes and, in turn, to a given economic sector based on its Energy Consumption coefficient*.

CHP systems utilize the thermal energy produced when generating electricity in applications such as space heating, cooling, and dehumidification; displacing the consumption of other fuels normally used to power these applications. The ES technical working group calculated these energy savings by fuel type and the ASU Energy Center distributed them to the commercial and industrial customer classes. The monetary value of these savings was then calculated by multiplying energy savings by fuel type by the ES technical working groups "Industrial Sector Energy Costs in the South Atlantic Region" forecast†. These energy savings were then allocated to a given economic sector based on its Energy Consumption coefficient. Conversely, the resulting reduction in revenue for energy utilities results in a reduction in final demand for those sectors, while reduced consumption of other fuels decrease final demand for the Forestry (biomass), Retail Trade (fuel oil), and Wholesale Trade (coal) sectors.

Conservatively, it was assumed that only the labor portion of the capital investments and operating expenses associated with private investments in CHP generation would impact the North Carolina economy. The labor shares of capital investments increase final demand for Heavy Construction while the labor shares of operating expenses increase final demand for the Electric Utility sectors. The value of fuels and feedstocks to supply CHP facilities increases final demand for the Natural Gas, Wholesale Trade (coal), Retail Trade (fuel oil) and Forestry (biomass) sectors. It was also assumed that a portion of the financing costs associated with investments would benefit the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

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* It was assumed two-thirds of the CHP systems would be installed by commercial customers and one third by industrial customers, per email correspondence with RCI technical working group facilitator David Von Hippel.

† Natural Gas and Electricity savings were multiplied by the RCI technical working group's retail electricity price forecast (Center for Climate Strategies 2007c).

Variable/Assumption	Value
Decomposed CHP Capital Cost, Natural Gas ($/MWh-first year)[a]	$309.30 (in 2007), $226.82 (in 2020)
Decomposed CHP Capital Cost, Biomass ($/MWh-first year) [a]	$494.88 (in 2007), $412.40 (in 2020)
Decomposed CHP Capital Cost, Coal ($/MWh-first year) [a]	$453.64 (in 2007), $412.40 (in 2020)
Decomposed CHP Operating Expense, Natural Gas ($/MWh) [a]	$10.00
Decomposed CHP Operating Expense, Biomass ($/MWh) [a]	$25.00
Decomposed CHP Operating Expense, Coal ($/MWh) [a]	$20.00
Labor Share of CHP Capital Investment, Natural Gas[b]	23%
Labor Share of CHP Capital Investment, Biomass [b]	50%
Labor Share of CHP Capital Investment, Coal [b]	50%
Labor Share of CHP Operating Expenses, Natural Gas [b]	45.0%
Labor Share of CHP Operating Expenses, Biomass [b]	13.0%
Labor Share of CHP Operating Expenses, Coal [b]	39.0%
Share of Biomass Feedstock to Forestry [b]	90%

[a] Source: Calculation based on levelized costs & annualization factors cited in (Center for Climate Strategies 2007c).
[b] Source: (LaCapra Associates 2006). Assumes CHP from natural gas is equivalent to “combustion turbine.” Assumes CHP from biomass is equivalent to “dedicated biomass combustion.” Assumes CHP from coal is equivalent to “pulverized coal.”

ES-6A & ES-6B: ADVANCED COAL TECHNOLOGIES

The cost to ratepayers, private investments, and public subsidies resulting from the implementation of these mitigation options was based on the technical assumptions of the ES technical working group. The cost to ratepayers for both ES-6a and ES-6b was calculated by multiplying the ES technical working group's "Rate Impact" by the "Total Sales after Mitigation Option." Since the ES technical working group did not provide sales by customer class, the ASU Energy Center utilized the RCI technical working group's sales forecast by customer class to determine the proportion of these costs borne by a given customer class. The distribution of these costs to a given economic sector was based on that sector's Energy Consumption Coefficient and treated as a decrease in final demand.

The value of private investment associated with implementation of ES-6a and ES-6b consists of annual capital investments and operating expenses. Net annual capital investments were calculated by multiplying the difference in incremental generation by technology type by the calculated capital investment cost by technology type. Calculated capital investment costs for conventional generation was computed by decomposing the ES technical working group's "Levelized New Fossil Technology Costs," based on the annualization factors cited by the ES technical working group. Net annual fuel costs and net annual operating expenses by technology type were calculated in a similar fashion, except they were calculated using the difference in cumulative generation by technology type.

Conservatively, it was assumed that only the labor portion of the net capital investments and net operating expenses associated with the mitigation option would impact the North Carolina economy. The labor shares of net capital investments increase final demand for Heavy Construction while the labor shares of net operating expenses increase final demand for the Electric Utility sectors. It was also assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	Value
Decomposed Capital Cost, IGCC ($/MWh-first year)[a]	$241.84
Decomposed Capital Cost, Conventional Coal ($/MWh-first year) [a]	$206.23
Decomposed Operating Cost, IGCC ($/MWh) [a]	$7.92
Decomposed Operating Cost, Conventional Coal ($/MWh) [a]	$7.51
Labor Share of IGCC Capital Investment[b]	23%
Labor Share of Conventional Coal Capital Investment [b]	30%
Labor Share of IGCC Operating Expenses [b]	45%
Labor Share of Conventional Coal Operating Expenses [b]	39%
Financing Assumptions, Advanced Coal[c] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 50% 25 years 64.2%

[a] Source: Calculation based on levelized costs & annualization factors cited in (Center for Climate Strategies 2007b).
[b] Source:(LaCapra Associates 2006). Assumes IGCC is equivalent to "Combined Cycle."
[c] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

ES-8: Municipal Biogas

Utilizing the technology cost and performance assumptions developed by the ES technical working group, the Energy Center calculated the cost of subsidy payments and annual capital investments and operating costs required to meet the implementation schedule articulated in the mitigation option description. Annual capital investments were calculated by multiplying incremental generation by the calculated capital investment cost. The calculated capital investments cost was computed by decomposing the ES technical working group's "Levelized Renewable Technology Costs," based on the annualization factors cited by the ES technical working group. Annual operating expenses were calculated in a similar fashion, except they were multiplied by cumulative generation.

Conservatively, it was assumed that only the labor portion of the capital investments and operating expenses associated with the mitigation option would impact the North Carolina economy. The labor share of capital investments increases final demand for Heavy Construction while the labor share of operating expenses increases final demand for Electric Utilities. Further, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The value of electricity generated by the mitigation option was calculated by multiplying cumulative generation by the RCI technical working group's levelized electricity price forecast for the commercial sector. It was assumed that the value of electricity generated by the mitigation option would accrue to the Water & Sewer sector as an increase in final demand. The cost of subsidy payments was assumed to be the sum of annual capital and operating expenses. It was assumed that the subsidy payments come from existing state revenues and therefore will result in corresponding reduction in other state government expenditures, excluding education. Moreover, the value of avoided fuel costs, resulting from the displacement of conventional generation, is assumed to be passed along to customers as an adjustment to utility fuel cost adjustment riders.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Decomposed Capital Cost, Biogas ($/MWh-first year)[a]	$259.76
Decomposed Operating Cost, Biogas ($/MWh) [a]	$10.25
Labor Share of Biogas Capital Investment[b]	30%
Labor Share of Biogas Operating Expenses [b]	30%

[a] Source: Calculation based on levelized costs & annualization factors cited in (Center for Climate Strategies 2007b).
[b] Source:(LaCapra Associates 2006). Assumes municipal biogas equivalent to "hog waste."

RCI-1, RCI-2 & RCI-11: Energy Efficiency Funding & Energy Audits

Utilizing the values developed by the RCI technical working group for RCI-1 and RCI-2, the ASU Energy Center calculated program costs by customer class. These program costs include the program administrator's share of an efficiency measure and their overhead expenses. In its analysis, the RCI technical working group only calculated the aggregate program costs associated with a given mitigation option. So in order to estimate the impact of these costs on a particular customer class, the ASU Energy Center simply distributed the program costs in proportion to customer class' share of reference case sales.

The program costs, the program administrator's share of the efficiency measures and their overhead expenses, by customer class for RCI-11 were calculated by multiplying the class' physical energy savings achieved by the measure by its "Levelized Cost of Electricity Savings from Technical Assistance Recommendations," as determined by the RCI technical working group. The distribution of these program costs to a given economic sector was based on that sector's Energy Consumption Coefficient and treated as a decrease in final demand.

An analogous approach was used to determine the distribution of energy savings by customer class and economic sector for RCI-1 and RCI-2. The RCI technical working group's stated cumulative physical energy savings were divided among each customer class in proportion to its share of reference case sales. In turn, these physical energy savings by customer class were multiplied by the RCI technical working group's retail price forecast to yield a monetary value of avoided energy consumption. These values were then allocated to each economic sector according to its Energy Consumption Coefficient and treated as an increase in final demand while the resulting reduction in revenue for utility sectors is treated as a reduction in final demand for those sectors. Significantly it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

Notably, RCI-1, RCI-2, and RCI-11 are expected to cause energy customers to incur additional costs beyond the program costs, as customers make outlays for their share of efficiency measures*. To calculate the annual value of these participant measure costs, the ASU Energy Center calculated the present value of the RCI technical working group's stated "Levelized Cost per Megawatt-hour for Participant Measure" assuming a 5% discount rate and a term of ten years for each customer class. The resulting first-year participant cost per megawatt-hour was in turn multiplied by physical energy savings by customer class and then allocated as reductions in final demand according to a sector's Energy Consumption Coefficient.

While both the program costs and participant measure costs are negative stimuli, the resulting investments in efficiency measures are positive stimuli to the North Carolina economy. In modeling the

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* See (LaCapra Associates 2006). Report suggests cost sharing approach where the utility pays for a portion of an efficiency measure to induce participation by a customer, as in a rebate program.

distribution of these investments across the economy the ASU Energy Center relied on additional research. This approach to allocating energy efficiency investments is utilized in the analysis of several other RCI options.

The distribution of residential energy efficiency investments were based on a study of the cost effectiveness of various efficiency measures conducted for the North Carolina Utilities Commission (GDS Associates 2006). Depending on the characteristics of each residential measure, a portion of the investment was then allocated to either the Residential Construction or Retail Trade sector. For example, lighting and appliance measures were allocated entirely to Retail Trade while weatherization measures were allocated to Residential Construction.

The distribution of commercial and industrial efficiency measures were based on an economic impact study of similar energy efficiency programs (Sedano 2005). Modeling assumes commercial and industrial efficiency spending will parallel the report's "Allocation of Efficiency Program Outlays" and that this spending will be split equally among "new construction" and "retrofit/products and services" measures. Further, the modeling follows the report's allocation to final demand scheme.

Additionally, it was assumed these programs would be administered by the utilities and that a share of the program costs would accrue to these sectors. It was also assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
First-year Participant Measure Cost, Residential ($/MWh)[a]	$105.79
First-year Participant Measure Cost, Commercial ($/MWh)[b]	$156.72
First-year Participant Measure Cost, Industrial ($/MWh)[c]	$70.52
First-year Participant Measure Cost, All Sector ($/MMBtu)[d]	$5.95
Share of Program Administrator Costs for Administration & Education[e]	16%
Share of Program Administrator Costs for Measures [d]	84%
Share of Total Energy Efficiency Investments to Residential Construction[f]	25.5%
Share of Total Energy Efficiency Investments to Commercial Construction[g]	37.4%
Share of Total Energy Efficiency Investments to Wholesale Trade [f]	8.9%
Share of Total Energy Efficiency Investments to Retail Trade [e]	14.7%
Share of Total Energy Efficiency Investments to Professional, Scientific, Technical & Management Services [f]	4.5%
Share of Total Energy Efficiency Investments to Other Services [f]	8.9%
Financing Assumptions, Residential [h] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 10 years 64.2%

Financing Assumptions, Commercial [g] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 15 years 64.2%
Financing Assumptions, Industrial [g] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 15 years 64.2%

[a] Calculation based on levelized cost of $13.70/MWh cited in(Center for Climate Strategies 2007c).
[b] Calculation based on levelized cost of $20.30/MWh cited in (Center for Climate Strategies 2007c).
[c] Calculation based on levelized cost of $9.13/MWh cited in (Center for Climate Strategies 2007c).
[d] Calculation based on levelized cost of $9.13/MWh cited in (Center for Climate Strategies 2007c).
[e] Calculation based on Program Administrator costs cited (Center for Climate Strategies 2007c).
[f] Source: (GDS Associates 2006). Weighted for distribution of spending among customer classes.
[g] Source: (Sedano 2005). Weighted for distribution of spending among customer classes.
[h] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

RCI-4 & RCI-5: Market Transformation & Appliance Standards

Utilizing the technical assumptions developed by the RCI technical working group for RCI-4, the ASU Energy Center calculated program administrator and participant costs by customer class. In its analysis, the RCI technical working group first determined the total physical energy savings achieved by the program. The ASU Energy Center distributed these energy savings in proportion to each customer class' share of reference case sales with extra weight given to the residential and commercial sectors*. To calculate program administrator and participant costs, the distribution of physical energy savings by customer class was multiplying by the assumed program administrator's and participant's share of the RCI's "Cost of Market Transformation Program Savings." The distribution of these program costs to a given economic sector was based on that sector's Energy Consumption Coefficient and reflected as a reduction in final demand. Investments in energy efficiency measures resulting from the implementation of RCI-4 were allocated across the economy according to the approach described for RCI-1, RCI-2 & RCI-11.

The distribution of physical energy savings referenced above was also used to calculate the monetary value of energy savings realized by the mitigation option. These physical energy savings by customer class were multiplied by the RCI technical working group's retail price forecast to yield a monetary value of avoided energy consumption. These values were then allocated to each economic sector according to its Energy Consumption Coefficient and treated as an increase in final demand while the resulting reduction in revenue for utility sectors is treated as a reduction in final demand for those sectors. Significantly, it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

The RCI technical working group analysis did not present annual participant costs or savings for RCI-5, but rather adjusted the stated cost effectiveness through 2030 cited in the joint Appliance Standards Awareness Project/American Council for an Energy Efficient Economy (ASAP/ACEEE) report (Nadel, deLaski et al. 2006) to the 2007-2020 study period of the CAPAG analysis. Therefore, the ASU Energy Center replicated the ASAP/ACEEE methodology to determine annual costs and savings by customer class.

* Per email correspondence with the RCI technical working group facilitator David Von Hippel, the ASU Energy Center applied weighting factors of 1, 1, and .25 respectively to the reference case sales projection for residential, commercial, and industrial customer classes.

The table below summarizes the key variables used in the replication.

	Sector[a]	Annual Savings per Unit (kWh/ [MMBtu])[b]	Incremental Cost per Unit ($)[b]	Annual Energy Savings from 1 yr of Sales (GWh/ [MMBTU])[b]	Product lifetime [b]	Calculated Annual Unit Sales[c]
ELECTRIC MEASURES						
Bottle-type water dispensers	Commercial	266	12	0.9	8	3,383
Commercial hot food cabinets	Commercial	1815	453	0.9	15	496
Liquid-immersed distribution transformers	Commercial	6	2	18.5	30	3,083,333
Dry distribution transformers	Commercial	4.5	1.6	1.1	30	21,256
Metal halide lamp fixtures	Commercial	307	30	20.6	20	67,101
Incandescent reflector lamps	Commercial	61	1	175.5	0.94	2,877,049
Walk-in refrigerators & freezers	Commercial	8200	957	10	12	1,220
Electric spas & hot tubs	Residential	250	100	0.3	10	1,200
Residential furnaces & boilers (electric)	Residential	585	100	34.6	18	59,145
External AC/DC power supplies	Residential	4	0.5	19.8	7	4,950,000
Compact audio products	Residential	53	1	9.8	5	184,906
DVD players & recorders	Residential	11	1	1.4	5	127,273
Natural Gas Measures						
Commercial boilers	Commercial	15.9	2968	13,815.40	30	869
Residential furnaces & boilers (gas)	Residential	0.8	6	3396.114	18	4,245
Pool heaters	Residential	5.8	295	26806	15	4,622

[a] Assumption.
[b] Source:(Nadel, deLaski et al. 2006).
[c] Calculation.

First, the ASU Energy Center categorized the ASAP/ACEEE's efficiency standards as either a commercial or residential standard based on a content analysis of the measure's description. Next, annual participant costs by customer class were calculated by summing the products of each measure's incremental cost per unit by the calculated number of annual unit sales. The calculated number of annual unit sales was computed by dividing each measure's "annual energy savings from one year's sales" by the "annual savings per unit." As with the ASAP/ACEEE methodology, it was assumed that annual unit sales remained constant over the study period. The distribution of these program costs to a given economic sector was based on that sector's Energy Consumption Coefficient and treated as a decrease in final demand.

The cumulative physical energy savings in a given year for a given measure was, in most instances, computed by multiplying annual unit sales by per unit energy savings by the number of years from the mitigation option implementation minus half a year. In instances where the expected lifetime of the measure was less than the number of years from mitigation option implementation, physical energy savings in a given year were calculated by multiplying annual unit sales by the expected product lifetime by per unit energy savings. This avoids double counting of savings after full market penetration. These physical energy savings were then summed by customer class and multiplied by the RCI technical working group's retail price forecast to determine the monetary value of avoided energy consumption. In turn, a portion of these monetary savings were allocated to each economic sector according to its Energy Consumption Coefficient and treated as an increase in final demand. Reductions in revenue to utility sectors were treated as a reduction in final demand for those sectors.

For both RCI-4 and RCI-5, it was also assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
RCI-4 Participant Measure Cost, all sectors($/MWh)[a]	$46.33
RCI-4 Program Administrator Cost, all sectors($/MWh) [a]	$6
Financing Assumptions, Residential [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 10 years 64.2%
Financing Assumptions, Commercial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 15 years 64.2%
Financing Assumptions, Industrial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 15 years 64.2%

[a] Calculation based on levelized cost of $6.00/MWh cited in(Center for Climate Strategies 2007c).
[b] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

RCI 6: Building Codes

Utilizing the values developed by the RCI technical working group the ASU Energy Center calculated annual program costs and savings by customer class. To calculate the annual value of the program costs, the ASU Energy Center calculated the present value of the RCI technical working group's stated "Levelized Cost of Electricity Savings" assuming a 5% discount rate and a term of twenty-five years. The resulting first-year participant cost per megawatt-hour was in turn multiplied by physical energy savings by customer class, as determined by the RCI technical working group, and then allocated as reductions in final demand according to a sector's Energy Consumption Coefficient. Investments in energy efficiency measures resulting from the implementation of RCI 6 were allocated to the Residential and Commercial Construction sectors.

As with other energy saving options examined in this study, the value of the physical energy savings achieved by the mitigation option were calculated by multiplying physical energy savings by customer class by the RCI technical working group's retail price forecast. Again, these values were allocated to each economic sector according to its Energy Consumption Coefficient and treated as an increase in final demand. The resulting reduction in revenue for utility sectors was treated as a reduction in final demand for those sectors. Significantly it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

Finally it was assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector and that the displacement of new conventional electricity generation results in a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	Value
First-year Participant Measure Cost, Electric[a]	$492.79
First-year Participant Measure Cost, Natural Gas [a]	$71.23
Financing Assumptions, Residential [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%
Financing Assumptions, Commercial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%
Financing Assumptions, Industrial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%

[a] Calculation based on levelized cost of $34.97/MWh (electric) and $5.05/MMBtu (natural gas) cited in (Center for Climate Strategies 2007c).
[b] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

RCI-7 & RCI-3: High Performance Buildings

Utilizing the values developed by the RCI technical working group the ASU Energy Center calculated annual program costs and savings by customer class. Program costs for both RCI-7 and RCI-3 were computed by multiplying the annual energy savings achieved by a given technology, as determined by the RCI technical working group, by the first-year investment costs for that technology. First-year investment costs were calculated by the ASU Energy Center by decomposing each technology's "Levelized Cost per Unit of Output," based on the annualization factors cited by the RCI technical working group*. In a similar fashion, annual fuels costs associated with bioenergy technologies were calculated by multiplying annual energy savings by the RCI technical working group's state fuel prices. These costs were then summed by customer class and allocated as reductions in final demand according to a given sector's Energy Consumption Coefficient.

The distribution of energy savings by customer class and economic sector for RCI-7 and RCI-3 were calculated by summing the cumulative energy savings achieved by a given technology for a given customer class, as determined by the RCI technical working group, multiplying by the RCI technical working group's retail price forecast. These values were then allocated to each economic sector according to its Energy Consumption Coefficient and treated as an increase in final demand. The resulting reduction in revenue for utility sectors is treated as a reduction in final demand for those sectors. Significantly it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

Investments resulting from the implementation of RCI-7 and RCI-3 were allocated according to the characteristics of the technology. Energy efficiency investments were allocated according to the methodology described for RCI 1, 2 & 11. Conservatively it was assumed that only the labor share of capital expenditures for distributed renewable energy systems would impact the North Carolina economy. The labor share of capital investments in solar thermal and photovoltaic systems were distributed to the Residential Construction sector, while the labor share of bioenergy systems were distributed to Heavy Construction. Notably, the RCI technical working group analysis does not consider ongoing operating and maintenance costs. Fuel and feedstock expenditures associated with bioenergy investments were distributed equally among the Animal Production, Forestry, and Waste Management sectors.

Finally it was assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector and that the displacement of new conventional electricity generation results in a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

* The RCI technical working group analysis only considers fuel costs associated with bioenergy technologies and does not specify a levelized cost for capital investments, therefore the ASU Energy Center relied on the levelized cost estimates derived by the Energy Supply technical working group for bioenergy technologies (Center for Climate Strategies 2007b).

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	Value
Decomposed First-year Cost, Energy Efficiency, Electric ($/MWh)[a]	$492.79
Decomposed First-year Cost, Energy Efficiency, Natural Gas ($/MWh) [a]	$71.23
Decomposed First-year Cost, Solar Hot Water ($/MMBtu) [a]	$203.95 (in 2007), 183.55 (in 2020)
Decomposed First-year Cost, On-site Photovoltaic ($/MWh) [a]	$203.95 (in 2007), 183.55 (in 2020)
Decomposed First-year Cost, On-site Bioenergy ($/MWh)[b]	$331 (in 2007),$328 (in 2020)
Fuel Cost for On-site Bioenergy ($/MMBtu)[c]	$2.38
Share of Total Energy Efficiency Investments to Residential Construction[d]	35.9%
Share of Total Energy Efficiency Investments to Commercial Construction[e]	27.2%
Share of Total Energy Efficiency Investments to Wholesale Trade [e]	6.5%
Share of Total Energy Efficiency Investments to Retail Trade[d]	20.7%
Share of Total Energy Efficiency Investments to Professional, Scientific, Technical & Management Services [e]	3.2%
Share of Energy Efficiency Investments to Other Services [e]	6.5%
Share of Solar Hot Water and Photovoltaic Investments to Residential Construction[f]	30%
Share of Bioenergy Investments to Residential Construction[g]	16.7%
Share of Fuel and Feedstocks to Animal Waste, Forestry, and Waste Management [h]	33.3%
Financing Assumptions, Residential [i] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%
Financing Assumptions, Commercial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%
Financing Assumptions, Industrial [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 80% 25 years 64.2%

[a] Source: Calculation based on levelized cost of $34.97/MWh (electric) and $5.05/MMBtu (natural gas) cited in (Center for Climate Strategies 2007c).
[b] Source: Calculation based on an equally weighted hybrid of levelized costs of municipal biogas, dedicated biomass, and hog waste biomass cited in(Center for Climate Strategies 2007b).
[c] Source: (Center for Climate Strategies 2007b).
[d] Source: (GDS Associates 2006). Weighted for distribution of spending among customer classes.
[e] Source: (Sedano 2005). Weighted for distribution of spending among customer classes.
[f] Source: (LaCapra Associates 2006). Assumes solar thermal and photovoltaic have similar labor shares.
[g] Source: (LaCapra Associates 2006). Assumes average of landfill gas, hog waste, and direct biomass labor shares.
[h] Assumption.
[i] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

RCI-9: Bulk Purchasing for Energy Efficient Appliances

Using the assumptions of the RCI technical working group, the ASU Energy Center computed annual program costs and savings by customer class. In its analysis of the bulk purchasing component, the RCI technical working group calculated annual energy savings for government and nongovernmental participants. The ASU Energy Center distributed nongovernmental energy savings to the residential, commercial, and industrial customer classes in proportion to a customer class' share of reference case sales. Program costs by customer class for the bulk purchasing component were then calculated by multiplying energy savings by customer class by the RCI technical working group's "assumed cost of bulk purchase program savings." Nongovernmental program costs were allocated as a reduction in final demand according to a sector's Energy Consumption Coefficient. Governmental program costs were assumed to come from existing state revenues and therefore will result in a reduction in state government expenditures, and in final demand, according to a sector's Government Spending Coefficient. Investments in energy efficiency measures resulting from the implementation of the bulk purchasing component were allocated to Retail Trade.

In a similar fashion, the ASU Energy Center calculated the monetary value of physical energy saving from the bulk purchasing component with nongovernmental energy saving by customer class multiplied by the RCI technical working group's energy price forecast by customer class and governmental energy savings multiplied by the price forecast for the commercial sector. The monetary value of nongovernmental energy savings was then allocated to each economic sector according to its Energy Consumption Coefficient; while the value of governmental savings was allocated directly to the government sector. In both instances the savings were treated as an increase in final demand. The resulting reduction in revenue for utility sectors is treated as a reduction in final demand for those sectors. Significantly it was assumed that only a portion of the monetary value of energy savings would impact the North Carolina economy, as industries and consumers import a percentage of goods and services from outside the state.

Finally it was also assumed that a portion of the financing costs associated with investments would benefit the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	Value
Assumed cost of bulk purchase program savings, ($/MWh)[a]	$12.00
Financing Assumptions, Residential [b] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 10 years 64.2%

Financing Assumptions, Commercial [b]	
Interest rate	8%
Fraction financed	85%
Term	15 years
Fraction Local Borrowing	64.2%
Financing Assumptions, Industrial [b]	
Interest rate	8%
Fraction financed	85%
Term	15 years
Fraction Local Borrowing	64.2%

[a] Source:(Center for Climate Strategies 2007c).
[b] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

RCI-10: Solar Hot Water Heating Only

Utilizing the values developed by the RCI technical working group the ASU Energy Center calculated annual program costs and savings by customer class. Annual program costs were determined by multiplying the annual number of additional households using Solar Hot Water Heating (SHW) systems as a result of the mitigation option by the incremental capital cost of the system, as determined by the RCI technical working group. It was assumed that these investments would be financed by the program participants and that a portion of the financing costs would benefit the local Financial, Insurance, and Real Estate sector. Conservatively, it was assumed that only the labor portion of the capital investments associated with the mitigation option implementation would impact the North Carolina economy, increasing final demand for Residential Construction.

The dollar value of avoided energy consumption was calculated by multiplying the physical energy savings by fuel type by the retail price forecast, as stated by the RCI technical working group. It was assumed these savings would benefit the Household sector as an increase in final demand, while the resulting reduction in revenue for energy utilities would result in a reduction in final demand for those sectors. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Incremental Capital Cost of SHW Installation, ($/installation) [a]	$3,500 (in 2007), $3,050 (in 2020)
Share of Solar Hot Water Investments to Residential Construction[b]	30%
Financing Assumptions [c] Interest rate Fraction financed Term Fraction Local Borrowing	 8% 85% 7 years 64.2%

[a] Source: (Center for Climate Strategies 2007c).
[b] Source:(LaCapra Associates 2006). Assumes solar thermal and photovoltaic have similar labor shares.
[c] Assumption. Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).

AFW-1: Manure Digesters

Utilizing the technology cost and performance assumptions developed by the AFW technical working group, the ASU Energy Center calculated annual capital investments and operating costs required to meet the implementation schedule articulated in the mitigation option description. Likewise, the assumptions of the AFW technical working group were used to derive the dollar value of electricity generated from the implementation of the mitigation option.

In modeling this option, it was assumed the costs of implementation would be borne by the Animal Production sector of the economy and be reflected as a reduction in final demand for this sector. In turn, it was assumed the value of electricity produced by this mitigation option would benefit the Animal Production sector as an increase in final demand for this sector while the resulting reduction in revenue for the Electric Utility sector would result in a reduction in final demand for that sector.

Conservatively, it was assumed that only the labor portion of the capital investments and operating expenses associated with the mitigation option implementation would impact the North Carolina economy. The labor share of capital investments increases final demand for Heavy Construction while the labor share of operating expenses increases final demand for Animal Production. It was also assumed that a portion of the financing costs associated with investments would benefit the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable /Assumption	**Value**
Capital Cost ($/head, dairy cattle)[a]	$394
Annual O&M ($/head, dairy cattle)[b]	$38
Capital Cost ($/head, swine)[c]	$72
Annual O&M ($/head, swine)[b]	$8
Value of Electricity Savings ($/MWh)[b]	$50
Financing Assumptions (interest rate, fraction borrowed, term)[d]	5%, 100%, 15 years
Labor Share of Renewables Capital Investment[e]	30%
Labor Share of Renewables O&M Expenses[e]	30%
Labor Share of Displaced Conventional Capital Investment[e]	26.5%
Labor Share of Displaced Conventional Operating Expenses[e]	42%

[a] Source:(Center for Climate Strategies 2007a). Assumes midpoint of “low” and “high” capital cost.
[b] Source: (Center for Climate Strategies 2007a).
[c] Source:(Center for Climate Strategies 2007a). Outlays attributable to Animal Production reflect 30% federal subsidy.
[d] Assumption.
[e] Source: (LaCapra Associates 2006).

AFW-2: Biodiesel Production Subsidy*

The annual cost of providing the subsidy was obtained from the AFW technical working group analysis. To determine the value of annual capital investments, operating costs and feedstock production the Energy Center conducted additional research. The capital costs and operating expenses per gallon of biodiesel production were derived from the same U.S. Department of Energy, Energy Information Administration study used by the AFW technical working group to estimate the per gallon subsidy. The value of feedstock production was derived from a U.S. Department of Agriculture forecast of corn and soybean commodity prices (U.S. Department of Agriculture 2007) and assumed a yield of .13 gallons of oil per pound soybean feedstock (Duffield and Shapouri 1998).

Conservatively, it was assumed that only the construction portion of the capital investments and labor portion of operating expenses associated with the mitigation option implementation would impact the North Carolina economy. The construction portion of capital investments increase final demand for Commercial Construction while the labor share of O&M expenses increase final demand for the Fats and Oils Manufacturing sector. The value of feedstock production was distributed to various agricultural sub-sectors according to the proportions listed in the AFW technical working group's technical appendix. It was also assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector. Finally, it was assumed that the easement payments come from existing state revenues and therefore will result in corresponding reduction in other state government expenditures, excluding education.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable /Assumption	**Value**
State Subsidy ($/gallon) [a]	$0.34
Capital Cost ($/gallon of production)[b]	$1.13
Annual O&M ($/gallon of production) [b]	$0.34
Value of Feedstock Oil ($/gallon of production)[c]	$.04
Share of Capital Investment Attributable to Commercial Construction[d]	19.2%
Labor Share of O&M Expenses Attributable to Fats & Oils Manufacturing[e]	27%
Financing Assumptions (interest rate, fraction borrowed, term)[f]	8%, 50%, 15 years

[a] Source: (Center for Climate Strategies 2007a).
[b] Source: (Radich 2004). Adjusted to 2004 dollars.
[c] Source: (Duffield and Shapouri 1998; U.S. Department of Agriculture 2007)
[d] Source: (De La Toore Ugarte 2006).
[e] Source:(Swenson 2006; Paulson and Ginder 2007).
[f] Assumption.

* The CAPAG's baseline estimates of biodiesel production do not reflect the increases in biodiesel production mandated by the December 2007 passage of the Energy Independence and Security Act which requires the nationwide production of 36 billion gallons of renewable transportation fuels by 2022.

AFW-4a & AFW-4b: Farmland and Forestland Conservation Easements

Utilizing the program cost assumptions and implementation schedule developed by the AFW technical working group, the Energy Center calculated the annual public investment required to meet the goals articulated in the mitigation option descriptions. Relying on similar studies that modeled the economic impacts of land conservation programs, easement payments are treated as income transfers to households (Cartwright 2006). Notably, the AFW technical working group assumes that farmland easements are supplemented through a cost share with the U.S. Department of Agriculture's Natural Resource Conservation Service or some other source. In modeling this option, it was assumed that this cost share is from an exogenous source. Finally, it was assumed that the easement payments come from existing state revenues and therefore will result in corresponding reduction in other state government expenditures, excluding education.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
State Farmland Easement Payment ($/acre under easement)[a]	$1,029.50
Exogenous Farmland Easement Payment ($/acre under easement) [a]	$1,029.50
State Forestland Easement Payment ($/acre under easement) [a]	$1,300

[a] Source: (Center for Climate Strategies 2007a).

AFW-6: CELLULOSIC ETHANOL PRODUCTION SUBSIDY

The annual cost of providing the subsidy was obtained from the AFW technical working group analysis. To determine the value of annual capital investments, operating costs and feedstock production the Energy Center conducted additional research. Precise figures for capital investment per gallon of cellulosic ethanol production were difficult to obtain, as no large-scale commercial plants are currently operating. Instead, the ASU Energy Center applied the AFW technical working group's assumption of a 15% differential between the costs of producing starch-based and those of cellulosic ethanol production to capital cost estimates for starch-based ethanol plants compiled by the U.S. Department of Agriculture (Gallagher and Shapouri 2005). The same source and procedure is used to derive the labor share of operating expenses. The value of feedstock production was based on the price of biomass feedstocks utilized by the CAPAG's Energy Supply technical working group (Center for Climate Strategies 2007b).

Conservatively, it was assumed that only the construction portion of the capital investments and labor portion of operating expenses associated with the mitigation option implementation would impact the North Carolina economy. The construction portion of capital investments increase final demand for Commercial Construction while the labor share of O&M expenses increase final demand for the Fats and Oils Manufacturing sector. The value of feedstock production was allocated to the Forestry sector. It was also assumed that a portion of the financing costs associated with investments would benefit the local Financial, Insurance, and Real Estate sector. Finally, it was assumed that the subsidy payments come from existing state revenues and therefore will result in corresponding reductions in other state government expenditures.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
State Subsidy ($/gallon of production through 2015)[a]	$0.23
Capital Cost through 2015 ($/gallon of production)[b]	$2.50
Capital Cost after 2015 ($/gallon of production) [b]	$2.17
Labor share of O&M expenses through 2015 ($/gallon of production) [b]	6.8%
Labor share of O&M expenses after 2015 ($/gallon of production) [b]	5.9%
Value of Feedstock ($/gallon of production)[c]	$51
Share of Capital Investment Attributable to Commercial Construction[d]	17.5%
Financing Assumptions (interest rate, fraction borrowed, term)[e]	8%, 50%, 20 years

[a] Source: (Center for Climate Strategies 2007a).
[b] Source: (Gallagher and Shapouri 2005). Assumes 15% increase applied to midpoint of $2.00/gallon and adjusts for inflation using U.S. Consumer Price Index. After 2015, modeling assumes cellulosic ethanol capital cost per gallon is equal to starch-based costs per the assumptions of the AFW technical working group.
[c] Source: (Hag 2002; Center for Climate Strategies 2007b). Price per MMBtu converted to price per dry ton based on heat content of 8,600 Btu per pound.
[d] Source: (Swenson 2006).
[e] Assumption.

AFW-8: Afforestation

Utilizing the program cost assumptions and implementation schedule developed by the AFW technical working group, the Energy Center calculated the annual public investment required to meet the goals articulated in the mitigation option descriptions. It was assumed that the cost of the subsidy comes from existing state revenues and therefore will result in corresponding reduction in other state government expenditures, excluding education.

To determine the value of change in rent payment for affected lands the Energy Center conducted additional research. The impact on households of the CRP-type rent payments was determined by taking the difference in the subsidy payment and the average statewide cash rent value of "low productivity" agricultural lands and multiplying it by the number of acres affected. After five years, the value of land rent is based on an Annual Equivalent Value (AEV) estimate from the literature. The resulting net rent is reflected as income transfers to households. It was further assumed that the annual value of the establishment costs would result in an increase in final demand for the Forestry sector.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
State Cost Share for Establishment ($/acre)[a]	$140
State CRP type Rent Payment ($/acre for first five years) [a]	$40
Average Statewide Cash Rent Value of "Low Productivity" Agricultural Lands ($/acre)[b]	$28.40
Annual Equivalent Value of Afforested Lands ($/acre)[c]	$159.53

[a] Source:(Center for Climate Strategies 2007a).
[b] Source:(N.C. Department of Agriculture and Consumer Services 2006).
[c] Source:(Dangerfield 1998). Modeling assumes AEV for future forest harvest is annuity payment and adjusts for inflation using U.S. Consumer Price Index.

AFW-9 & AFW-10: Forest Management

Utilizing the program cost assumptions and implementation schedule developed by the AFW technical working group, the Energy Center calculated the annual public investment required to meet the goals articulated in the mitigation option descriptions. It was assumed that the cost of the subsidy comes from existing state revenues and therefore will result in corresponding reduction in other state government expenditures, excluding education. It was further assumed that the annual value of the productivity improvement costs would result in an increase in final demand for the Forestry sector. The future value of the higher yields predicted to result from the mitigation option were converted to an Annual Equivalent Value basis and treated as an annuity payment split among the Household and the Forestry sectors based on the share of private forest ownership in North Carolina.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
State Cost Share for Productivity Improvements ($/acre)[a]	$8.80
Annual Equivalent Value of Future Value of Increased Forest Product Yields ($/acre)[b]	$15.09
Private Landowner Share of North Carolina Private Forest Ownership [c]	89.7%
Forestry Industry Share of North Carolina Private Forest Ownership [c]	10.3%

[a] Source:(Center for Climate Strategies 2007a).
b Source:Calculation based on values in(Center for Climate Strategies 2007a). Assumes investment period of 17 years and discount rate of 5%.
[c] Source:(Brown 2004).

AFW-11: Landfill Gas

Utilizing the technology cost and performance assumptions developed by the AFW technical working group, the Energy Center calculated annual capital investments and operating costs required to meet the implementation schedule articulated in the mitigation option description. First, the ASU Energy Center determined the annual number of projects by technology type that would have to be implemented to meet the emissions reductions assumed by the AFW technical working group. This was done by multiplying the total annual emissions reduction by the stated share of those reductions by technology type and dividing the technology's average annual emissions reduction rate.

For example, assume the total annual emissions reduction for a given year is .073 MMTCO2e. According to the AFW technical working group, 63% of these emissions reductions come from small engine generator projects which achieve an average annual emissions reduction of .023 MMTCO2e. Therefore, in this example, it would be necessary to install two small engine generator projects in this year to meet the emissions reductions target. Once the annual number of project equivalents was determined, the ASU Energy Center then multiplied this number by the total capital cost and average annual operating costs derived by the AFW technical working group from the EPA's Landfill Gas Cost Model.

Likewise, the assumptions of the CAPAG and AFW technical working group were used to derive the dollar value of electricity generated from the implementation of the mitigation option. The annual energy consumption by technology type stated by the AFW technical working group was multiplied by the industrial energy prices from the Residential, Commercial, and Industrial technical working group.

In modeling this option, it was assumed the costs of implementation would be borne by the Waste Management sector and are reflected as a reduction in final demand for this sector. In turn, it was assumed the value of electricity produced by this mitigation option would benefit the Waste Management sector as an increase in final demand, while the resulting reduction in revenue for the Electric Utility sector would result in a reduction in final demand for that sector.

Conservatively, it was assumed that only the labor portion of the capital investments and operating expenses associated with the mitigation option implementation would impact the North Carolina economy. The labor share of capital investments increases final demand for Heavy Construction while the labor share of operating expenses increases final demand for the Electric Utility sector. It was also assumed that a portion of the financing costs associated with investments would benefit the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	Value
Average Annual Emissions Reductions for Small Engine Generator Installations (MMTCO2e/project equivalent)[a]	0.023
Capital Cost for Small Engine Generator Installations ($/project equivalent) [a]	753,365
Operating Expense for Small Engine Generators ($/project equivalent) [a]	102,141
Average Annual Emissions Reductions for Direct Use Installations (MMTCO2e/project equivalent) [a]	0.024
Capital Cost for Direct Use Installations ($/project equivalent) [a]	621,573
Operating Expense for Direct Use Installations ($/project equivalent) [a]	105,474
Average Annual Emissions Reductions for Small Engine Generator Installations (MMTCO2e /project equivalent) [a]	0.088
Capital Cost for Standard Engine Generators Installations ($/project equivalent) [a]	2,612,674
Operating Expense for Standard Engine Generators Installations ($/project equivalent) [a]	335,475
Financing Assumptions (interest rate, fraction financed, term, local borrowing)[b]	8%,100%, 10 years, 64.2%
Labor Share of LFG Capital Investment [c]	10%
Labor Share of LFG O&M Expenses [b]	40%
Labor Share of Displaced Conventional Capital Investment [b]	26.5%
Labor Share of Displaced Conventional Operating Expenses [b]	42%

[a] Source:(Center for Climate Strategies 2007a).
[b] Financing assumption based on (Center for Climate Strategies 2007a) . Local borrowing based on regional purchase coefficient for Financial, Insurance, and real estate sector in (Minnesota IMPLAN Group 2005).
[c] Source:(LaCapra Associates 2006). Displaced investments in conventional generation assumes a fuel mix of 60% pulverized coal and 40% combined cycle natural gas per the CAPAG Energy Supply technical working group reference case(Center for Climate Strategies 2007b).

AFW-12: Recycling

Utilizing the program cost assumptions and implementation schedule developed by the AFW technical working group, the ASU Energy Center calculated the annual private investment required to meet the goals articulated in the mitigation option description and the resulting savings. Notably, the AFW technical working group assumes a constant program implementation cost based on full achievement of the mitigation option goal. This assumption likely overstates the actual costs incurred in a given year. Therefore, the ASU Energy Center calculated the annual private investment based on the annual achievement of GHG emission reductions reported by the AFW technical working group. The incremental GHG reductions in a given year were divided by the GHG reductions in 2020 yielding an "implementation coefficient" (see table below). This coefficient was then used to calculate the number of existing and new households participating in the program as well as the incremental recycled tonnage in a given year. These values in turn were multiplied to by the program costs and savings stated by the AFW technical working group to yield annual private investment and savings.

Year	CO_2 Reduced (MMte)[a]	Implementation Coefficient
2007	0.05	0.10
2008	0.10	0.20
2009	0.15	0.30
2010	0.20	0.40
2011	0.23	0.46
2012	0.25	0.52
2013	0.28	0.58
2014	0.31	0.64
2015	0.34	0.70
2016	0.37	0.76
2017	0.40	0.82
2018	0.43	0.88
2019	0.46	0.94
2020	0.49	1.00

[a] Source:(Center for Climate Strategies 2007a).

In modeling this option, it was assumed that the program costs would be borne by the Household sector of the economy and conversely savings would accrue to the Household sector. It was also assumed that the private expenditures associated with the program would benefit the Waste Management sector and conversely program savings would cost the Waste Management sector.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Household Subject to Mitigation option at Full Implementation with Existing Recycling Services [a]	1,384,653
Household Subject to Mitigation option at Full Implementation without Existing Recycling Services [a]	516,914
Recycled Tonnage at Full Mitigation option Implementation [a]	134,539
Program Cost for Enhanced Service ($/Household with existing service) [a]	$.60
Program Cost for New Service ($/Household without existing service) [a]	$27.00
Avoided Tipping Fee ($/ton) [a]	$35.00

[a] Source:(Center for Climate Strategies 2007a).

AFW-13: Urban Forestry

Utilizing the program cost assumptions and implementation schedule developed by the AFW technical working group, the ASU Energy Center calculated the annual private investment required to meet the goals articulated in the mitigation option descriptions and the resulting energy savings. In modeling this option, it was assumed that the program costs would be borne by the Household sector of the economy and that conversely savings would also accrue to this sector. The cost savings realized by the program are lost revenue for energy providers and are reflected as reductions in final demand based on the share of energy savings by fuel type.

To determine the impact of the program expenditures on a given sector of the economy, the Energy Center conducted additional research. The AFW technical working group assumes a program cost of $250 per tree, based on a U.S. Department of Agriculture, U.S. Forest Service study of urban forestry programs in Chicago, IL. describing a range of urban forestry programs and their costs (planting, pruning, infrastructure repair, liability, etc.) (McPherson 1994). In modeling this option it was assumed that a North Carolina program would mirror the Residential Yard Tree program described in this study. The share of the program costs attributable to planting costs was allocated to the Retail Trade sector of the economy, which includes building and garden store retailers. The share of the program costs attributable to pruning was allocated to the Other Services sector of the economy, which includes services to buildings and dwellings. The share of program costs attributable to infrastructure repair was allocated to Residential Construction sector. The share of program costs attributable to liability was allocated to the Financial, Insurance, and Real Estate sector. Finally, the displacement of new conventional electricity generation is reflected as a reduction in Final Demand for the Heavy Construction and Electric Utility sectors.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Share of Program Costs for Planting [a]	49%
Share of Program Costs for Pruning [a]	38%
Share of Program Costs for Infrastructure Repair [a]	10%
Share of Program Costs for Liability [a]	3%
Share of Energy Savings, Electricity [b]	61.1%
Share of Energy Savings, Natural Gas [b]	30.8%
Share of Energy Savings, Propane [b]	5.3%
Share of Energy Savings, Fuel Oil [b]	2.4%
Financing Assumptions (interest rate, fraction borrowed, term)[c]	8%, 80%, 30 years

[a] Source:(McPherson 1994).
[b] Source:(Center for Climate Strategies 2007a).
[c] Assumption.

TLU-1B: MULTI-MODAL TRANSPORTATION AND PROMOTION

In order to estimate the economic impacts associated with the shift in transportation funding proposed by the mitigation option, the ASU Energy Center conducted additional research to determine the likely allocation of investments in particular multimodal projects and the subsequent distribution of these investments across the North Carolina economy. The allocation of investments in particular multimodal projects were based on the goals articulated in the Statewide Transportation Plan (N.C. Department of Transportation 2004)[*]. The subsequent distribution of these investments across the economy was based on a comprehensive economic impact study of public transportation investments (Cambridge Systematics 1999).

Conservatively, the ASU Energy Center assumed the monetary savings associated with the implementation of the mitigation option were limited to fuel savings resulting from projected VMT reductions rather than the TLU technical working group's more generous assumption of a 1.5x cost savings multiplier. The value of avoided fuel consumption was calculated by dividing projected annual VMT reductions by the U.S. Department of Energy, Energy Information Administration's (EIA) light duty vehicle fuel economy forecast (Energy Information Administration 2007b) and multiplying the result by the EIA's retail gasoline price forecast for the South Atlantic Region (Energy Information Administration 2007d)[†]. Since the TLU technical working group only presented projected annual VMT reductions for 2010 and 2020, to calculate annual VMT reduction for the intervening period the ASU Energy Center assumed VMT reductions occurred in equal incremental steps. The monetary savings associated with these reduced vehicle operating costs were treated as an increase in final demand for the Household sector. Conversely, the reduction in retail gasoline sales was treated as a decrease in final demand for the Retail sector. Notably, only the value of the retail margin or markup, as determined by IMPLAN coefficients, was considered.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

* It was assumed that spending under the "recommended scenario" would parallel the type of investments articulated in the report's description of the "25-year needs." For example, it was assumed "transit" funding would include both a mix of light rail and bus service.

† The EIA's 2007 light duty vehicle fuel economy forecast does not account for the mandated increase in vehicle fuel economy mandated by December 2007 passage of the Energy Independence and Security Act which requires a Corporate Average Fuel Economy of 35 miles per gallon for light duty vehicles by 2020.

Variable/Assumption	Value
Share of Transit Funding, Bus Service, Capital Expenditures[a]	33%
Share of Transit Funding, Bus Service, Operating Expenditures [a]	14%
Share of Transit Funding, Light Rail, Capital Expenditures [a]	37%
Share of Transit Funding, Light Rail, Operating Expenditures [a]	14%
Share of Transit Funding, Bike & Pedestrian, Capital Expenditures [a]	3%
Share of Total Transit Investments to Vehicle Manufacturing[b]	7%
Share of Total Transit Investments to Heavy Construction [b]	27%
Share of Total Transit Investments to Commercial Construction [b]	6%
Share of Total Transit Investments to Transit Transportation [b]	28%

[a] Source: Calculation based goals in (N.C. Department of Transportation 2004).
[b] Source: Calculation based conversion of REMI sectors in (Cambridge Systematics 1999) to IMPLAN sectors; includes accounting for regional purchase coefficients.

TLU-3A: VEHICLE REGISTRATION SURCHARGE TO FUND MULTI-MODAL TRANSPORTATION

In modeling this option the ASU Energy Center assumed that additional investments in multi-modal transportation projects would follow the recommendations set forth in the Statewide Transportation Plan. The allocation and distribution of these investments, the annual VMT reductions, and the monetary savings associated with reduced vehicle operating costs followed the same methodology as utilized in the analysis of TLU 1b. Additionally it was assumed the cost of compliance would be borne by the Household sector of the economy.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Share of Transit Funding, Bus Service, Capital Expenditures[a]	33%
Share of Transit Funding, Bus Service, Operating Expenditures [a]	14%
Share of Transit Funding, Light Rail, Capital Expenditures [a]	37%
Share of Transit Funding, Light Rail, Operating Expenditures [a]	14%
Share of Transit Funding, Bike & Pedestrian, Capital Expenditures [a]	3%
Share of Total Transit Investments to Vehicle Manufacturing[b]	7%
Share of Total Transit Investments to Heavy Construction [b]	27%
Share of Total Transit Investments to Commercial Construction [b]	6%
Share of Total Transit Investments to Transit Transportation [b]	28%

[a] Source: Calculation based goals in (N.C. Department of Transportation 2004).
[b] Source: Calculation based conversion of REMI sectors in (Cambridge Systematics 1999) to IMPLAN sectors; includes accounting for regional purchase coefficients.

TLU-5: Tailpipe Greenhouse Gas Emissions Standards

The TLU technical working group analysis did not provide inputs in the format required for the NCESEIM, therefore the ASU Energy Center conducted additional research. Overall, this approach yields a slightly more optimistic estimate of greenhouse gas reductions than estimated by the CAPAG.

The California tailpipe greenhouse gas emissions regulations, also known as Pavley standards, require light duty vehicles to achieve an emissions factor of 205 grams of CO_2e per mile traveled by 2016 down from 323 grams of CO_2e in 2009 (California Environmental Protection Agency 2005). These emissions reductions are expected to be achieved primarily through gains in fuel economy, air conditioning system performance, and advances in other vehicle technologies. The ASU Energy Center assumed that 95% of the greenhouse gas emissions reductions would be achieved through fuel economy improvements that would reduce vehicle fuel consumption and operating costs.

To convert the target emissions factors required by the Pavley standards into fuel savings, the ASU Energy Center first divided the U.S. Environmental Protection Agency, Office of Transportation and Air Quality's average carbon dioxide emissions rate from a gallon of gasoline (8,788 grams per gallon) by the adjusted target emission factors assumed by the ASU Energy Center. The result is a quasi-fuel economy standard measured in miles per gallon. Next, annual fuel consumption under Pavley-type regulations was calculated by dividing the product of the U.S. Department of Energy, Energy Information Administration's(EIA) projected average annual vehicle miles traveled (Energy Information Administration 2007c) and the calculated number of vehicles subject to the regulation by the quasi-fuel economy standards[*].

The number of vehicles subject to regulation in a given year was determined by estimating North Carolina's share of EIA's projected regional new vehicle sales (Energy Information Administration 2007a). According to data published by the National Automobile Dealers Association, North Carolina's share of regional new vehicle sales is approximately 14% (Taylor 2007). The ASU Energy Center assumed this share remains constant over the study period.

The resulting Pavley-fleet fuel consumption projections were then compared to a baseline assessment calculated in a similar fashion but using EIA's projected fuel economy performance for light duty vehicles (Energy Information Administration 2007b) [†]. The difference between these two values represents the net fuel savings associated with a Pavley-type regulation. The monetary value of these net savings was then calculated using EIA's projected retail fuel price forecast for gasoline (Energy Information Administration 2007d). Notably, the EIA fuel price forecasts are considerably lower than current market prices.

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[*] The EIA's projected average annual vehicle miles traveled does not account for any "rebound effect," that is the effect of drivers increasing miles travelled because driving on a per unit basis has become cheaper. Some studies suggest that the rebound effect may be as high 10-20% over the long run (see for example Small and Dender 2007).

[†] The EIA's 2007 light duty vehicle fuel economy forecast does not account for the mandated increase in vehicle fuel economy mandated by December 2007 passage of the Energy Independence and Security Act which requires a Corporate Average Fuel Economy of 35 miles per gallon for light duty vehicles by 2020.

These monetary savings, in turn, were treated as an increase in final demand for the Household sector. Conversely, the reduction in retail gasoline sales was treated as a decrease in final demand for the Retail sector. Notably, only the value of the retail margin or markup, as determined by IMPLAN coefficients, was considered.

Adoption of Pavley-type regulations will increase the upfront purchase price of new vehicles. In modeling the impact of these compliance costs to North Carolina consumers, the ASU Energy Center utilized the California Air Resources Board's annual per vehicle cost estimates and multiplied it by the number of vehicles subject to regulation in a given year (California Environmental Protection Agency 2005). It was assumed this cost of compliance would be borne by the Household sector of the economy. Additionally it was assumed that these costs would be financed as part of consumer automobile loan and that a portion of the financing costs would benefit the Financial, Insurance, and Real Estate sector.

The table below summarizes the key variables and assumptions used to derive the net annual changes in final demand resulting from implementation of the mitigation option.

Variable/Assumption	**Value**
Calculated Pavley quasi-fuel economy standard (miles per gallon)[a]	26.9 (in 2009), 40.7 (in 2020)
EIA projected fuel economy (miles per gallon)[b]	26.9 (in 2009), 28.2 (in 2020)
EIA Projected Fuel Price, gasoline ($/gallon, 2004)[c]	$2.14 (in 2009), $1.90 (in 2020)
Estimated New Vehicle Sales in North Carolina (thousands) [d]	436.6 (in 2009), 519.4 (in 2020)
EIA Annual Vehicle Miles Traveled[e]	13,000 (in 2009), 15,100 (in 2020)
Financing Assumptions (interest rate, fraction borrowed, term)[f]	8%, 95%, 5 years

[a] Calculation.
[b] Source:(Energy Information Administration 2007b).
[c] Source:(Energy Information Administration 2007d).
[d] Calculation.
[e] Source:(Energy Information Administration 2007c).
[f] Assumption.

Appendix C: Summary of Peer Review Comments and Responses

The Appalachian State University (ASU) Energy Center has received six anonymous reviews of the Draft Secondary Economic Impact Analysis of Greenhouse Gas (GHG) Mitigation Options for North Carolina ("Draft Report").

On the whole, reviewers were generally positive in their comments noting "the scope of the economic impacts that this research attempts to measure is impressive and ambitious;" that the written report was both "comprehensive and satisfactory;" and concluding "the ASU study reasonably captures the likely economic impacts of implementing the options identified by CAPAG." Additional positive comments include:

- "The use of an IMPLAN-based modeling approach is, therefore, reasonable for these magnitudes of policy changes relative to the North Carolina's economy as a whole."

- "Overall, the strength of the linked modeling approach lies in the expertise and procedures applied to the translation of policy options into direct economic impacts. Elements of each option were assessed for their impacts on industry behavior and final demand."

- "This manuscript summarizes an ambitious research effort to build a bridge between a multitude of greenhouse gas reduction options in North Carolina and the IO modeling framework so that state level economic impacts from adopting one or more of these options can be evaluated. There is an abundance of careful and thoughtful work on converting the options to reduce greenhouse gases to some accounting measures."

- "This paper is relatively clear to a professional steeped in interindustry models. I find no logical errors and am impressed by the sophistication of the analysis; it is superior to most impact analyses written over the last decade."

- "I must say that the document is superior to many I see. The logic seems sound and the inclusion of both positive and negative impacts of climate-mitigation options clearly shows that considerable thought has gone into this work."

- "Using input output analysis to quantify the total (direct, indirect and induced) effects of the various mitigation strategies is standard practice and appropriate if the basic assumptions for the use of input-output analysis are met."

- "the specification of the input-output model follows similarly standard justification – using the best available studies and expert judgments to modify parameters in the existing IMPLAN and NCESEIM models. The impacts themselves were limited to those associated with the labor portion of any investment in new technology or capacity, essentially assuming that the impacts of the capital component of such investments on the economy are negligible. As the authors emphasize, this makes their study of contributions of mitigation strategies to the state's economy a rather conservative one."

That said, several of reviewers offered comments areas on how "the modeling approach might be enhanced, extended, and improved." The discussion below summarizes the primary points of concern raised by the reviewers and provides the Energy Center's response.

Comments relating to editorial-issues
A number of the reviewers made specific recommendations for editorial points of clarification as well as more general suggestions regarding "better documentation of assumptions, methodologies, and data taken from the literature."

- The Energy Center has made editorial corrections where appropriate and sought to clarify sections of the report identified as ambiguous or confusing. The Energy Center feels the request for additional documentation is unnecessary, as Appendix B provides substantial detail of the methodology and sources utilized by the Energy Center to prepare the report. However, the Energy Center inserted additional references in the main body of the report directing readers to Appendix B for more detail.

Comments relating to the Input-Output Model
Several of the reviews focused on the input-output economic model underlying the study and identified two basic sets of concerns: 1) the process by which the induced or Type II multipliers were computed and 2) the allocation of the monetary value of energy savings and operating costs to final demand. These reviews also made a number of clarifying suggestions related to the explanation of the derivation of the predictive multipliers in Appendix A.

- The Energy Center followed the advice of the reviewers related to the explanation of the derivation of the predictive multipliers in Appendix A and added a number of clarifying remarks.

- The questions raised by the reviewers related to the Type II multipliers revealed a computational error in the calculation of the household personal consumption expenditure (PCE) coefficients. This error resulted in an overstatement of the employment, income, and total value-added multipliers in the Draft Report. This error has been corrected and a new set of multipliers calculated. As a result, the magnitude of the impacts reported in final version of the report is considerably smaller. In some instances, options that were originally reported as having positive impacts, in fact, result in negative impacts.

- The allocation of energy savings and operating costs to a change in final demand is an admittedly coarse methodology for estimating the economic impacts associated with what in fact are fundamentally changes in intermediate demand. However, addressing this concern would require substantially greater modeling effort that is outside the scope of this analysis but is an issue the Energy Center plans on addressing in future versions of the model.

Comments relating to the lack of sensitivity analyses
Several of the reviews criticize both the Draft Report as well as the CAPAG report for a lack of sensitivity analyses.

- In fact, the Energy Center did prepare and present a limited set of sensitivity analyses for the April 22, 2008 Legislative Commission on Global Climate Change. However, these sensitivities were not incorporated into the Draft Report considered by the reviewers. The Energy Center has added an additional chapter to the final version that includes these sensitivities.

Comments relating to retail margins

At least one reviewer noted the distinction between producer and consumer prices associated with retail transactions and wondered about the utilization of retail margin factors.

- In fact, the NCESEIM does utilize retail margin factors when allocating transactions to retail sectors although the methodological description omitted this point. This is corrected in the final version of the report.

Comments related to local spending coefficients

At least one reviewer wondered how the NCESEIM determined local spending coefficients.

- Local spending coefficients are based on a weighted average of IMPLAN regional purchase coefficients for the affected sectors.

Comments related to discussion of model strengths and weaknesses

At least one reviewer suggested a more thorough discussion of the relative strengths and weaknesses of the modeling approach.

- The draft report does include a brief discussion of the limitations of input-output analysis. In the final report a footnote was added directing readers to additional sources to compare the input-output approach to the computable general equilibrium approach.

Comments related to discount rates

At least one reviewer was unable to locate the discount rate used to calculate Net Present Value.

- The discount rate used to calculate NPV is in a footnote on page 2 of the Executive Summary.

Several of these reviews took a broader approach and focused on how the NCESEIM translated the assumptions underlying the analysis of the N.C. Climate Action Plan Advisory (CAPAG) Technical Working Groups into the accounting framework required for the input-output model.

Comments related to the disaggregation of direct, indirect, and induced effects

At least one reviewer suggested results be presented in terms of their direct, indirect, and induced effects.

- This is not possible in the current version of the NCESEIM, but is an issue the Energy Center will address in future versions of the model.

Comments related to the relationship between impact results and GHG reductions

At least one reviewer suggested results be presented in terms of their GHG reductions.

- The draft report is intended to be a secondary analysis of the potential economic and jobs impacts of various GHG emissions reduction strategies developed by the North Carolina Climate Action Plan Advisory Group (CAPAG). The CAPAG has issued its own report detailing the potential GHG emissions reductions associated with a given policy option. To include these GHG reductions in the Draft Report is beyond the scope of analysis.

Comments related to baseline scenarios

At least one reviewer raised questions about the baseline scenarios used for analysis, especially in light of the passage of Energy Independence and Security Act in December 2007.

- The baseline scenarios were developed by the CAPAG Technical Working Groups (TWGs) prior to the passage of the Energy Independence and Security Act and reflected the best available information at the time. The Energy Center relied on the assumptions and analysis of the TWGs and therefore the Draft Results, likewise, do not reflect the passage of the Energy Independence and Security Act.

Comments related to the use "labor share" for capital investments and operating expenses
At least one reviewer raised questions about the use of labor shares.

- The use of labor shares follows the methodology of LaCapra and Associates in their assessment for the N.C. Utilities Commission of the economic impacts of the adoptions of a renewable energy portfolio standard. The Energy Center followed the same approach because we understood that while it may understated impacts it also provided a balance to some of the limitations of the input-output methodology.

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