Pennsylvania Climate Change Action Plan Update Appendix

Presented to:
Governor Tom Corbett

Presented by:

pennsylvania
DEPARTMENT OF ENVIRONMENTAL
PROTECTION

December 2013

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Appendix A. Pennsylvania Climate Change Act

PENNSYLVANIA CLIMATE CHANGE ACT - ENACTMENT
Act of Jul. 9, 2008, P.L. 935, No. 70 Cl. 27

Note: This document is for informational use only. Official commonwealth publication of Pennsylvania laws can be found in Smith's Laws of Pennsylvania (1700 through Nov. 30, 1801), Laws of Pennsylvania (Dec. 1, 1801 to date), and Pennsylvania Consolidated Statutes.

Source: Pennsylvania General Assembly, Unconsolidated Statutes
http://www.legis.state.pa.us/WU01/LI/LI/US/PDF/2008/0/0070..PDF

AN ACT

Providing for a report on potential climate change impacts and economic opportunities for this Commonwealth, for duties of the Department of Environmental Protection, for an inventory of greenhouse gases, for establishment of the Climate Change Advisory Committee, for a voluntary registry of greenhouse gas emissions and for a climate change action plan. The General Assembly of the Commonwealth of Pennsylvania hereby enacts as follows:

Section 1. Short title.
This act shall be known and may be cited as the Pennsylvania Climate Change Act.

Section 2. Definitions.
The following words and phrases when used in this act shall have the meanings given to them in this section unless the context clearly indicates otherwise:

"Baseline." A level of greenhouse gas emissions against which future emissions are measured.

"Carbon sequestration." The long-term storage of carbon or carbon dioxide in forests, forest products, soils, oceans or underground in depleted oil and gas reservoirs, coal seams and saline aquifers.

"Climate change." Any alteration of the earth's climate due, at least in part, to emissions of greenhouse gases associated with human activities, including, but not limited to, the burning of fossil fuels, biomass burning, cement manufacture, agriculture, deforestation and other land-use changes.

"Cobenefits." The economic, social, environmental, public health and other benefits of climate change policies that are independent of any benefits for reducing or mitigating climate change.

"Committee." The Climate Change Advisory Committee established in section 5.

"Department." The Department of Environmental Protection of the Commonwealth.

"Greenhouse gases" or **"GHGs."** Gases in the earth's atmosphere that absorb and reemit infrared radiation, including carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride.

"Secretary." The Secretary of Environmental Protection of the Commonwealth.

Section 3. Report on potential climate change impact and economic opportunities for this Commonwealth.

(a) Report required.--The department shall prepare and publish a report on the potential impact of climate change in this Commonwealth. The report shall identify the following:

(1) Scientific predictions regarding changes in temperature and precipitation patterns and amounts in this Commonwealth that could result from climate change. Such predictions shall reflect the diversity of views within the scientific community.

(2) The potential impact of climate change on human health, the economy and the management of economic risk, forests, wildlife, fisheries, recreation, agriculture and tourism in this Commonwealth and any significant uncertainties about the impact of climate change.

(3) Economic opportunities for this Commonwealth created by the potential need for alternative sources of energy, climate-related technologies, services and strategies; carbon sequestration technologies; capture and utilization of fugitive greenhouse gas emissions from any source; and other mitigation strategies.

(b) Cooperation.--In preparing the report, the department shall consult with Federal and other State agencies, academic institutions and the committee. The department may also evaluate the recommendations of climate change action plans prepared by counties and municipalities within this Commonwealth. The report shall reflect any diversity of opinion among the entities consulted by the department.

(c) Deadline.--This report shall be completed, published and distributed to the General Assembly and made available to the public in printed form and on the department's Internet website within nine months of the effective date of this act and shall be revised every three years thereafter.

Section 4. Greenhouse gases inventory.

(a) Inventory required.--In consultation with the committee, the department shall annually compile an inventory of GHGs emitted in this Commonwealth by all sources. This inventory shall establish GHG emission trends and the relative contribution of major sectors, including, but not limited to, the transportation, electricity generation, industrial, commercial, mineral and natural resources, production of alternative fuel, agricultural and domestic sectors.

(b) Baseline.--The department shall establish a baseline of GHG emissions that it shall use to project future GHG emissions in this Commonwealth in the absence of government intervention.

(c) Coordination with action plan.--The inventory and baseline shall be presented to the Governor, the General Assembly and the committee every three years as part of the climate change action plan required under section 7.

Section 5. Climate Change Advisory Committee.

(a) Establishment.--There is established within the department the Climate Change Advisory Committee. The purpose of the committee shall be to advise the department regarding the implementation of the provisions of this act.

(b) Membership.--

(1) The committee shall be composed of residents of this Commonwealth selected as set forth in this subsection. Members shall be appointed on account of their interest, knowledge or expertise regarding climate change issues. Members shall be selected to reflect a diversity of viewpoints on climate change issues from the scientific, business and industry, transportation, environmental, social, outdoor and sporting, labor and other affected communities.

(2) Eighteen members shall be appointed as follows:

(i) Six members appointed by the Governor.

(ii) Six members appointed by the Senate. Of these members, the Majority Leader of the Senate shall appoint four members, and the Minority Leader of the Senate shall appoint two members.

(iii) Six members appointed by the House of Representatives. Of these members, the Majority Leader of the House of Representatives shall appoint four members, and the Minority Leader of the House of Representatives shall appoint two members.

(3) The Secretary of Conservation and Natural Resources, the Secretary of Community and Economic Development and the Chair of the Pennsylvania Public Utility Commission, or their designees, shall be ex officio voting members of the committee.

(c) Appointment.--Members of the committee shall be appointed within 30 days of the effective date of this act.

(d) Terms of service.--A member shall be appointed for a term of four years. Of the initial members appointed by the Governor, three members shall serve initial terms of two years. Of the initial members appointed by the Majority Leader of the Senate, two members shall serve initial terms of two years. Of the initial members appointed by the Majority Leader of the House of Representatives, two members shall serve initial terms of two years. Of the initial members appointed by the Minority Leader of the Senate, one member shall serve an initial term of two years. Of the initial members appointed by the Minority Leader of the House of Representatives, one member shall serve an initial term of two years. After such initial terms, all appointments shall serve for a term of four years.

(e) Chairperson.--The chairperson of the committee shall be elected from among and by a majority vote of the members appointed under subsection (b)(2). The term of a chairperson shall be for two years, and an individual may serve no more than two consecutive terms as chairperson.

(f) Meetings.--Within 60 days of the effective date of this act, the department shall call the first meeting of the committee and shall establish a schedule for regular meetings of the committee to assist in the implementation of this act.

(g) Expenses.--Members of the committee shall serve without compensation but may be reimbursed from funds appropriated for such purposes for necessary and reasonable travel and other expenses incurred during the performance of their duties.

(h) Facilitator.--The department shall retain the services of a third-party facilitator to conduct the activities of the committee.

(i) Department responsibilities.--The department shall create and maintain an Internet website listing the membership, activities, meeting schedule, meeting agenda, expense reimbursements and other relevant information regarding the committee.

Section 6. Voluntary greenhouse gas registry.

Within 90 days of the effective date of this act, the department shall create a voluntary greenhouse gas registry through which interested businesses, governments, institutions and other entities can record any reductions in greenhouse gas emissions or any avoided emissions of greenhouse gas emissions that are achieved in the absence of any government mandate to reduce such emissions. The department shall develop guidelines and criteria for the operation of the registry and shall create a site on the department's publicly accessible Internet website for the public to examine a current list of registrants and emission reductions and avoidances.

Section 7. Climate change action plan.

(a) Action plan required.--Within 15 months from the effective date of this act and every three years thereafter, the department shall, in consultation with the committee, submit to the Governor a climate change action plan that:

(1) Identifies GHG emission and sequestration trends and baselines in this Commonwealth.

(2) Evaluates cost-effective strategies for reducing or offsetting GHG emissions from various sectors in this Commonwealth.

(3) Identifies costs, benefits and cobenefits of GHG reduction strategies recommended by the climate change action plan, including the impact on the capability of meeting future energy demand within this Commonwealth.

(4) Identifies areas of agreement and disagreement among committee members about the climate change action plan.

(5) Recommends to the General Assembly legislative changes necessary to implement the climate change action plan.

(b) Publication.--The climate change action plan shall be published and distributed to the General Assembly and made available to the public in printed form and on the department's Internet website upon submission of the plan to the Governor.

Section 8. Effect of Federal law.

(a) Duty of secretary to monitor Federal law.--The secretary shall monitor the enactment of laws by the Congress of the United States to determine whether any law has been so enacted that it establishes a program of GHG inventory, registry or reporting requirements that are as or more comprehensive than those set forth in this act.

(b) Publication in Pennsylvania Bulletin.--If the secretary determines that such a law is enacted, the secretary shall publish this determination in the Pennsylvania Bulletin. The notice shall include a statement that affected entities shall be in compliance with this act or any subsequent act which imposes GHG inventory, registry or reporting requirements by submitting the same information to the department as is required to be submitted under Federal law.

Section 9. Effective date.

This act shall take effect immediately.

Appendix B. Climate Change Advisory Committee Member Information and Voting Record

Table B – 1: Pennsylvania Climate Change Advisory Committee Member Information

Committee Member	Organization	Appointing Authority	Term Expiration
Christina Simeone, Committee Chair	PennFuture	Senate Minority	April 2, 2016
Mark Hammond, Committee Vice Chair	Land Air Water Legal Solutions LLC	Senate Majority	Aug. 23, 2016
Ellen Ferretti Designee: Seth Cassell, Rebecca Oyler	Pennsylvania Department of Conservation and Natural Resources	Ex Officio	N/A
Robert Powelson Designee: Darren Gill	Pennsylvania Utility Commission	Ex Officio	N/A
C. Alan Walker Designee: Paul Opiyo	Pennsylvania Department of Community and Economic Development	Ex Officio	N/A
Robert Bear	Alcoa, Inc	Senate Majority	July 9, 2014
James Warner Alternate: Brooks Norris	Lancaster County Solid Waste Management Authority	House Majority	Feb. 4, 2017
Edward Yankovitch	United Mine Workers of America	House Majority	July 9, 2014
Representative Greg Vitali Alternate: Sarah Clark	Pennsylvania House of Representatives	House Minority	Nov. 27, 2016
George Ellis	Pennsylvania Coal Alliance	House Minority	July 9, 2014
Laureen Boles	City of Philadelphia	Governor	July 9, 2014
Robert Graff	Delaware Valley Regional Planning Commission	Governor	July 9, 2016
J. Scott Roberts	L.R. Kimball	Governor	July 9, 2016
Scott Spiezle Alternate: A. Steven Krug	Spiezle Group	Governor	July 9, 2016
Luke Brubaker	Brubaker Farms	Governor	July 9, 2016

Table B – 2: Climate Change Advisory Committee Voting Record

Work Plan Title	Subcommittee	CCAC Voting			Bear	Boles	Brubaker	Ellis	Gill	Graff	Hammond	Krug	Opiyo	Roberts	Oyler	Simeone	Vitali	Warner	Winek	Yankovich	Date
		Yes	No	Abstain																	
Alternative Fueled Public Transit Fleets	LU&T	8	5	0	N	*	*	N	N	Y	N	Y	Y	Y	Y	Y	Y	Y	N	*	Voted 10/8/13
Alternative Fueled Taxi Cabs	LU&T	11	2	0	Y	*	*	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	*	Voted 10/8/13
Cutting Emissions from Freight Transportation	LU&T	10	1	2	A	Y	Y	N	A	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Act 129 of 2008 (HB 2200)	Energy	10	3	0	N	*	*	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	*	Voted 10/8/13
Coal Mine Methane (CMM) Recovery	Energy	12	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	Y	*	Y	Y	*	Y	*	Voted 8/27/13
Combined Heat and Power (CHP)	Energy	13	1	0	Y	*	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	*	Voted 10/8/13
Reducing Methane Leakage from Natural Gas Infrastructure	Energy	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Waste-to-Energy Digesters	Energy	14	0	0	Y	*	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	*	Voted 10/8/13
Beneficial Use of Waste	Energy	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Nuclear Uprates	Energy	11	3		N	*	N	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N	*	Voted 10/8/13
Manure Digesters	Energy	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	Y	*	Y	Y	Y	Y	*	Voted 8/27/13
Sulfur Hexafluoride (SF6) Emission Reductions from the Electric Power Industry	Energy	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	Y	*	Y	Y	Y	Y	*	Voted 8/27/13
Afforestation	Ag/Forestry	10	0	0	*	Y	Y	Y	*	Y	Y	Y	*	*	Y	Y	Y	*	Y	*	Voted 5/21/13
Durable Wood Products	Ag/Forestry	2	11	0	N	N	N	N	N	N	N	Y	*	Y	*	N	N	N	N	*	Voted 8/27/13
Forest Protection Initiative -- Easement	Ag/Forestry	9	4	0	N	Y	Y	N	Y	Y	Y	Y	*	N	*	Y	Y	Y	N	*	Voted 8/27/13
Forestland Protection and Avoided Conversion -- Acquisition	Ag/Forestry	8	5	0	N	Y	Y	N	N	Y	N	Y	*	Y	*	Y	Y	Y	N	*	Voted 8/27/13

Urban Forestry	Ag/Forestry	10	0	0	*	Y	Y	Y	*	Y	Y	Y	*	*	Y	Y	Y	*	Y	*	Voted 5/21/13
No-Till and Organic Row Crop Farming	Ag/Forestry	10	0	0	*	Y	Y	Y	*	Y	Y	Y	*	*	Y	Y	Y	*	Y	*	Voted 5/21/13
Building Commissioning	RCI	13	0	0	Y	*	Y	Y	*	Y	Y	Y	Y	Y	Y	Y	Y	*	Y	*	Voted 11/29/12
Energy Efficiency - Natural Gas	RCI	12	1	1	A	Y	Y	Y	*	Y	Y	Y	*	Y	Y	Y	Y	*	N	*	Voted 11/29/12
DSM - Water	RCI	9	3	1	N	Y	Y	N	Y	Y	Y	Y	*	*	Y	Y	Y	A	N	*	Voted 12/5/13
High Performance Buildings	RCI	13	1	0	Y	*	Y	Y	Y	Y	Y	Y	Y	N	Y	Y	Y	Y	Y	*	Voted 10/8/13
Industrial Electricity Best Management Practices	RCI	12	1	0	Y	Y	Y	N	Y	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Re-Light PA	RCI	13	0	1	Y	*	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	A	*	Voted 10/8/13
Re-Roof PA	RCI	9	4	0	N	Y	Y	N	Y	Y	Y	Y	*	N	*	Y	Y	Y	N	*	Voted 8/27/13
Heating Oil Conservation and Fuel Switching	RCI	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Improved Efficiency at Wastewater Treatment Facilities	RCI	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	*	Y	Y	Y	Y	Y	*	Voted 12/5/13
Increased Recycling Initiative	RCI	13	0	0	Y	Y	Y	Y	Y	Y	Y	Y	*	Y	*	Y	Y	Y	Y	*	Voted 8/27/13

*absent with no proxy

Appendix C. Climate Change Work Plans

C.1. Energy Production, Transmission, and Distribution Sectors Work Plans

The following work plans were discussed with the CCAC Energy Production, Transmission and Distribution Subcommittee. Members of this subcommittee include the following:

Subcommittee Chair Darren Gill, Pennsylvania Public Utility Commission

George Ellis, Pennsylvania Coal Alliance

Mark Hammond, Land Air Water Legal Solutions LLC

Christina Simeone, PennFuture

Michael Winek, Babst, Callan, Clementz, & Zomnir P.C.

Edward Yankovitch, United Mine Workers of America

Act 129 of 2008 Phases I, II & III

Summary:

This work plan identifies the carbon emission benefits associated with the megawatt-hour (MWh) reductions of electricity consumption described in Act 129 of 2008 and the ensuing implementation orders from the PA Public Utility Commission (PUC). Note, however, that the imposition of requirements of Act 129 is not inclusive of the modest consumption from electric distribution companies (EDCs) with fewer than 100,000 customers, municipalities that are service providers and the customers of rural electric cooperatives.

Background:

Phase I of Act 129 requires electricity reductions through May 31, 2013. Phase II begins at the point in time where Phase I ends and runs through May 31, 2016. Phase III has not been acted upon or yet decided by the PUC but it is expected that sufficient reduction opportunities exist for continuation of reductions through 2020. As such, a proposed Phase III schedule is included in this work plan analysis.

Following are the electricity reductions required under Act 129 for Phases I and II and proposed reductions for Phase III:

Phase I

- A reduction in total electricity consumption, by May 31, 2011, of 1 percent below consumption levels for the period June 1, 2009, through May 31, 2010.
- A reduction in total electricity consumption, by May 31, 2013, of 3 percent below consumption levels for the period June 1, 2009, through May 31, 2010.
  (Completed)

Phase II

- A reduction in total electricity consumption from June 1, 2013 through May 31, 2016 equal to 3,313,246 MWh which, if divided equally amounts to approximately 1,104,415 MWhs per year.
  (Ongoing)

Phase III

- Annual reductions equal to 0.75 percent of projected electricity consumption for years 2017 through 2020, totaling 4,660,966 MWhs in 2020.
  (At this time it is expected to be implemented)

Costs and GHG Reductions:

Table 1 depicts the cumulative benefit of Act 129 through the two prescribed phases of implementation plus the addition of what could possibly be considered for implementation of a third phase to extend to 2020. Tables 2 and 3 respectively illustrate the anticipated benefits from Phases I and II combined and for Phase III.

Table 1. Work Plan Cost and GHG Results Summary

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions (MMtCO$_2$e)	Costs (Million $)	Cost-Effectiveness ($/tCO$_2$e)	GHG Reductions (MMtCO$_2$e)	Costs (NPV, Million $)	Cost-Effectiveness ($/tCO$_2$e)
8.9	(1,139)	(127)	19.1	(2,033)	(106)

Notes: The cost estimates in columns 2 and 5 of Table 1 are incremental costs of energy-efficient measures including capital, O&M, and labor costs, above baseline measure costs. The cost estimates are calculated as the costs less avoided energy expenditures. Additionally, the difference between the 2020 cost-effectiveness in column 3 and the cumulative cost-effectiveness in column 6 is due, in part, to the effects of discounting the net cash flows over the analysis period of 2013–2020.

The net present value (NPV) of the cost savings resulting from implementation of Act 129 from 2013 through 2020 is estimated at approximately $2.0 billion. Some of this will be due to peak load reductions that result in lower wholesale energy and capacity charges, but not less energy used. Peak demand reductions are not quantified in this analysis, as discussed later in this document. There is the assumption that lower wholesale charges will be passed through to customers. Other savings will result through reducing energy consumption.

Table 2. Work Plan Cost and GHG Results Phases I & II

Annual Results (2016)			Cumulative Results (2010-2016)		
GHG Reductions (MMtCO$_2$e)	Costs (Million $)	Cost-Effectiveness ($/tCO$_2$e)	GHG Reductions (MMtCO$_2$e)	Costs (NPV, Million $)	Cost-Effectiveness ($/tCO$_2$e)
5.5	(606)	(110)	10.6	(957)	(90)

Table 3. Work Plan Cost and GHG Results Phase III

Annual Results (2020)			Cumulative Results (2017-2020)		
GHG Reductions (MMtCO$_2$e)	Costs (Million $)	Cost-Effectiveness ($/tCO$_2$e)	GHG Reductions (MMtCO$_2$e)	Costs (NPV, Million $)	Cost-Effectiveness ($/tCO$_2$e)
3.4	(532)	(155)	8.5	(1,076)	(126)

Quantification Approach and Assumptions:

- The Pennsylvania Public Utility Commission (PUC) has implementation responsibility for Act 129 and has determined the required MWh reductions for years 2011, 2013 and 2016.
- Efficiency investments installed under Act 129 are reasonably expected to have lifetimes as long as or longer than the period of analysis (2020). Efficient equipment is cost-effective to install and it is assumed that it will be replaced at the end of its life.

- A 2009 report prepared by the American Council for an Energy-Efficient Economy (ACEEE) under contract to the DEP and PUC provides the cost and energy supply data for the analysis of this work plan.[1]
- Act 129 does not specify how these reductions are to be achieved. Responses will be market-driven and are better identified in the implementation plans provided by the EDCs to the PUC. Actual savings will likely vary widely throughout the EDC territories, within the various rate classes and economic sectors and also based on socioeconomic factors for residential consumers.
- GHG reductions and costs from the peak demand reduction component of Act 129 are not quantified for the following reasons.
    - The costs and GHG reduction compliance pathways are deemed too uncertain for quantification. For instance, peak demand reductions could be met with peak shifting from peak periods where the marginal resource might be diesel-fired generators or natural gas turbines, to off-peak periods where the baseload resource is at least 50 percent coal, which has a higher carbon dioxide (CO_2) emissions intensity (metric tons per megawatt-hour [t/MWh]).
    - Other peak reductions might arise from the energy efficiency deployment obtained under the other components of Act 129. The costs of compliance equipment, such as smart meters and associated communications equipment that might also be used to meet the peak demand reduction, are also deemed too uncertain to quantify.
- The efficiency percentage targets are applied to residential, commercial, and industrial loads but this assessment does not try to identify the specific percentage of load reductions that will be met by each EDC for each of the three sectors. Instead, this assessment applies a weighted average cost ($27.61/MWh) for energy efficiency measures, which does not vary throughout the period of analysis. This value is determined by the sector costs as identified in the ACEEE study. Cost savings from avoided electricity purchases was calculated based on the retail electricity rates, by sector, multiplied by the average annual rate of growth in the retail rate from 2007 through 2011. The weighted average values used in this assessment range from $114/MWh in 2013 to $150/MWh in 2020.
- Energy efficiency costs are expressed as levelized costs over the life of the energy efficiency options over the planning period. The incremental costs (typically incurred in the first year of program implementation) are spread over all future years of the life of the energy efficiency measures.
- The cost of the work plan is calculated by estimating the annual costs of energy efficiency less avoided electricity expenditures. These cash flows are then discounted at a real rate of 5 percent. The net present value (NPV) of cash flows is calculated beginning in 2013 through 2020.
- All prices are expressed in 2010 dollars ($2010)
- The sum of capital and fixed program costs are assumed to be part of each measure’s capital cost. These include administrative, marketing, and evaluation costs of 5 percent.
- The cost of energy efficiency measures includes program and participant costs as is typically used in a total resource cost test.

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[1] Source: ACEEE et al. (2009). Energy Efficiency, Demand Response, and Onsite Solar Energy Potential in Pennsylvania. http://www.aceee.org/pubs/e093.htm

- The costs to implement Act 129 are recoverable by utilities, so customers will be funding the efficiency deployment but consumers will realize long-term cost savings. In a recent analytical assessment of the first two years of Act 129, Optimal Energy noted that every dollar spent created $8 dollars in ratepayer savings over the lifetime of those installed measures.[2]
- Electricity transmission and distribution (T&D) losses are assumed to be 6.6 percent over the analysis period.
- To estimate GHG emission reductions that are expected to displace conventional grid-supplied electricity (i.e., energy efficiency and conservation), a simple, straightforward approach is used. We assume that these policy recommendations would displace generation from an "average thermal" mix of fuel-based electricity sources of coal and natural gas. This mix is based on 50 percent natural gas and 50 percent coal from 2013 through 2020 and reflects the latest trend in Pennsylvania shifting towards a greater percentage of natural gas and less coal. The average thermal approach is preferred over alternatives because sources without significant fuel costs would not be displaced—e.g., hydro, nuclear, or renewable energy generation. Given the generation fleet's coal and gas combustion efficiencies, this equates to a CO_2 intensity of approximately 0.69 metric tons (t)/MWh.
    - This approach provides a transparent way to estimate emission reductions and to avoid double counting (by ensuring that the same MWh from a fossil fuel source are not "avoided" more than once). The approach can be considered a "first-order" approach. That is, it does not attempt to capture a number of factors, such as the distinction between peak, intermediate, and baseload generation; issues in system dispatch and control; impacts of non-dispatchable and intermittent sources, such as wind and solar; or the dynamics of regional electricity markets. These relationships are complex and could mean that policy recommendations affect generation and emissions (as well as costs) in a manner somewhat different from that estimated here. Nonetheless, this approach provides reasonable first-order approximations of emission impacts and offers the advantages of simplicity and transparency that are important for stakeholder processes.
    - Note that some renewable resources, like co-firing biomass with coal or dedicated biomass gasification have substantial fuel costs. However, because these resources are negligible in the reference case electricity supply forecast, they are not able to be "backed down" in the analysis.

Implementation Steps:

Act 129 was signed into law on October 15, 2008. On January 16, 2009, the PUC issued an Energy Efficiency and Conservation Program Implementation Order that required each EDC to develop and implement cost-effective energy efficiency and conservation plans to reduce consumption and peak load within their service territories. On August 2, 2012, the PUC issued its Phase II implementation order.

Act 129 requires the PUC to submit a five-year plan by November 30, 2013 assessing the potential of further energy efficiency requirements that are deemed cost-effective according to a total resource cost test that also considers the annual EDC budgets for these reductions not

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[2] Optimal Energy, Inc., *Pennsylvania 2013 – 2018 Energy Efficiency Goals*, 2011.

exceeding 2 percent of annual revenues. The act further stipulates that the PUC must continue this planning process every five years thereafter.

CCAC Member Comments:

One member commented that moving forward the PUC should:

- Develop new strategies to deepen the energy and emissions savings that can be cost effectively achieved by Act 129, such as: on-bill financing, joint implementation of programs by multiple EDCs (to leverage administrative investments and achieve economies of scale), rate decoupling to reduce EDC disincentives in to EE&C investments, and more.
- Eliminate the 2% revenue spending cap.
- Allow for over-compliance and banking of excess credits for subsequent year compliance.

Coal Mine Methane Recovery

Goal:
Encourage owners/operators of current longwall mines, and of any new gassy underground coal mines that are mined by any method, to capture 10 percent of the estimated total coal mine methane that is released into the atmosphere before, during, and immediately after mining operations

Initiative Background:
The release of methane gas to the atmosphere is a major component of GHG emissions. Methane gas is a fossil fuel and energy source, commonly known as natural gas, which occurs in various geologic formations in Pennsylvania, including coal formations. When coal is mined and processed for use, substantial amounts of methane gas are released. Coal bed methane (CBM) is methane contained within coal formations and may be extracted by gas exploration methods or released as part of coal mining operations. This work plan deals with coal mine methane (CMM), the methane within the coal that can be vented or recovered prior to mining the coal, during mining, and immediately after mining as some gas escapes to the surface through post-mining vents or boreholes. Methane gas that remains sequestered within an abandoned underground coal mine does not contribute to GHG emissions, but could be and sometimes is recovered by subsequent gas exploration operations.

The federal Mine Safety and Health Administration (MSHA) has promulgated a definition of the term "gassy mine." As defined in 30 CFR § 27.2 (g), the term "*gassy mine or tunnel* means a mine, tunnel, or other underground workings in which a flammable mixture has been ignited, or has been found with a permissible flame safety lamp, or has been determined by air analysis to contain 0.25 percent or more (by volume) of methane in any open workings when tested at a point not less than 12 inches from the roof, face, or rib." MSHA records coal mine methane readings with concentrations of greater than 50 parts per million (ppm) methane. Readings below this threshold are considered non-detectable.

Currently, and in recent years, approximately 85 percent of the methane gas released during the mining of coal in Pennsylvania occurs from mining in longwall underground mines. The five large longwall underground coal mines now operating in Pennsylvania extract approximately 60 percent of the 68 million tons of coal mined each year within Pennsylvania. These high amounts of longwall mine production and the fact that the longwall mines recover coal from greater depths than other mines make longwall mining the predominant current source of coal mine methane release and an important contributor to GHG emissions. In recent years several mining companies have begun to capture and utilize methane gas within longwall underground mines, resulting in a reduction of methane GHG emissions.

Surface mining of coal currently releases about 9 percent of all coal mine methane emissions in Pennsylvania. However, with the continuing decline in surface mining production as recorded over the past two decades and the ultimate depletion of the state's shallow coal reserves, it is possible that by 2025 there could be a 70 percent reduction of surface coal mine methane emissions simply as a result of lower production.

Possible New Measures:

Surface Mines and Non-gassy Underground Mines

There are no specific measurements of methane gases released from mining at individual surface coal mines in Pennsylvania. This analysis uses the most recently published U.S. Environmental Protection Agency (EPA) emission factors for surface mining of coal in Pennsylvania. In this analysis the same emission factors used for surface mines are also used for low-methane non-gassy room and pillar underground coal mines. These are underground coal mines that have no methane levels routinely reported by MSHA. The EPA emission factor is 119.0 cubic feet of methane released per ton of coal mined and an additional 19.3 cubic feet of methane released from post-mining processing of the coal. These factors are published within Annex 3 Section 3.3 *"Methodology for Estimating CH4 Emissions from Coal Mining"* of the EPA report *"Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2007,"* published April 15, 2009, as document EPA 430-R-09-004, and is available on the Internet at the website: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

Gassy Underground Mines

Methane levels reported by MSHA for gassy underground mines indicate two basic categories: gassy room and pillar mines and gassy longwall mines. Emission factors developed for these two types of gassy underground mines represent an estimate of the total methane released from the entire mining process, including pre-mining degassing and post-mining venting, as well as that liberated by ventilation systems. For both types of gassy underground mines this analysis uses EPA emission factor of 45.0 cubic feet of methane per ton of coal to account for methane released as a result of post-mining processing of the coal on the surface. This post-mining factor is published in the 2009 EPA Report referenced previously.

The total emission factor used for gassy room and pillar underground mines is 165 cubic feet of methane per ton of coal mined and processed on the surface. During the past few years, approximately 20 percent of Pennsylvania's room and pillar mines have been gassy, with these mines accounting for approximately 33 percent of the total coal production from room and pillar mines. The average methane concentrations reported for these mines during the past few years, when compared to tons of coal mined, is 120 cubic feet of methane per ton of coal mined. Room and pillar underground mines were assumed, on average, to operate 310 days per year and longwall mines to operate 330 days per year.

These emission factors represent an estimate for all methane released before, during, and after the mining of coal in these gassy underground mines. The total longwall underground mine emission factor is 445 cubic feet of methane per ton of coal mined and processed on the surface. Estimates of coal mine methane released during longwall mining are based on methane liberation and capture measurements, on horizontal degassing and capture measurements, and on pre-mining and post-mining surface drill hole degassing measurements recorded and provided by the coal industry and by MSHA.

These methane concentration measurements were correlated with tonnages of coal mined. The average coal mine methane emission level reported for the five active longwall mines, when compared to tons of coal mined, is 400 cubic feet of methane per ton of coal mined. This is an average of measurements made over several years. CONSOL provided data for three longwall mines for the years 2000 through 2006 and Foundation Coal provided data for two longwall mines for the years 2004 through 2008.

This coal mine methane recovery initiative would encourage owners/operators of current longwall mines, and of any new gassy underground coal mines that are mined by any method, to capture 10 percent of the estimated total coal mine methane that is released into the atmosphere before, during, and immediately after mining operations. At this time it is not feasible to capture methane liberated by high velocity ventilation systems, therefore the proposed and encouraged 10 percent capture of total coal mine methane from gassy underground coal mines would have to be realized from pre-mining surface drill holes, horizontal drill holes within the mine, or for a brief time from surface drill holes into the post-mining gob area.

Quantification Approach and Assumptions:

Estimates of methane emissions, expressed in thousand cubic feet (Mcf), are converted to carbon dioxide equivalents (CO2e) by multiplying the quantity of methane times its global warming potential of 21. One million cubic feet of methane is equal to 404.5 metric tons of CO_2 equivalent.

The following inputs were used in the analysis of coal mine methane GHG reductions and costs. Three cost and performance sensitivities were conducted (the summary table only reports the central estimate).

PA specific data inputs were used for the following parameters

- Coal mining emissions for longwall mining (ft^3 CH_4 per ton coal mined)
- Number of CONSOL's PA longwall mines
- Gob gas production shares from CONSOL's and Alpha Coal longwall mines
- Methane capture target from longwall mines

National data inputs were used for the following parameters:

- Natural gas Henry Hub wellhead price projections for the Lower 48 states, reported by (EIA), ranging from $3.97/MMBtu in 2013 to $4.39/MMBtu in 2020
- Financial parameters include a project life time of 20 years, 5 percent discount rate and 8.02 percent capital cost recovery factor
- Projected coal production is based on historical PA production multiplied by an average national growth trend, as provided by EIA in the Annual Energy Outlook 2012

Projected 2020 Reduction (Million Metric Tons of CO_2 Equivalents):

Concentrations of released methane are expressed as cubic feet per ton (2,000 lbs) of coal mined. One million cubic feet of methane is equal to 404.5 metric tons of CO_2 equivalent GHG. Estimates of coal mine methane released during mining are based on methane liberation and capture measurements recorded and provided by the coal industry and by the federal Mine Health and Safety Administration (MSHA), and on emission factor estimates published in the 2009 U.S. EPA report "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007." For all types of coal mines, the release of methane determined and predicted in this analysis is expressed as cubic feet of methane per ton of coal mined. Total annual methane concentrations are also expressed as metric tons of CO_2 equivalent.

Coal mine production for the years 1985 through 2010 was used to develop a trend analysis that was used to determine 2020 estimates. Production data reflects actual tonnages reported quarterly and annually to the Pennsylvania DEP Bureau of Mining and Reclamation. Coal production information is available to the public for the years 1980 through 2010 at the following website: http://www.coalmininghistorypa.org. Trend charts for annual coal production and mining permits issued are presented at: http://www.coalmininghistorypa.org/annualreport/2010/Coal_Mining_Trend_Charts_001.htm.

As illustrated in Table 1 below, in Year 2000 estimated GHG emissions from coal mining activity in Pennsylvania were 1.33 million metric tons CO_2 equivalent (MMtCO2e). Future emissions are expected to drop commensurate with projected decreases in coal mining activity. Table 2 shows that in 2020, GHG emissions are estimated at 1.29 MMtCO2e, a 3 percent decrease. This baseline value assumes no methane capture is in place. In contrast, if the 10 percent goal of this work plan is achieved the resultant emissions are estimated to be 1.18 MMtCO2e, a decrease of approximately 12 percent from the Year 2000 baseline, as noted in Table 3.

Table 1. Summary of Estimated Coal Mine Methane Emissions from Pennsylvania Coal Mines* - 2000 Levels, No Methane Capture

	Methane Emission Factor (ft3/t)	**Coal (tons)**	**Methane (Cubic Feet)**	**MMTCO2e**
Anthracite Underground Mines	138.3	220,462	30,489,895	0.00
Anthracite Surface Mines	138.3	2,332,828	322,630,112	0.02
Bituminous Surface Mines	138.3	15,024,529	2,077,892,305	0.11
Room & Pillar Bituminous Underground Mines		18,929,625		
Room & Pillar Mines with Low Methane	138.3	12,682,848	1,754,037,945	0.09
Room & Pillar Mines with High Methane	165	6,246,776	1,030,718,059	0.05
Longwall Bituminous Underground Mines	445	45,073,586	20,057,745,681	1.06
Totals for Coal Mining in Pennsylvania		**79,027,739**	**25,273,513,998**	**1.33**

*All methane emission factors include EPA’s 2009 published emission factors for post-mining processing of coal on the surface.

Table 2. Summary of Estimated and Projected Coal Mine Methane Emissions from Pennsylvania Coal Mines* - 2020 Levels with No Capture in Gassy Underground Mines

Mine Type	**Methane Emissions Factor (ft^3/ton)**	**Coal (tons)**	**Methane (ft^3)**	**MtCO2e**	**MMtCO$_2$e**
Anthracite Mines (all), Bituminous Surface Mines, Room & Pillar Mines with Low Methane	138.3	10,534,267	1,456,889,103	169,547	0.17
Room & Pillar Mines with High Methane	165.0	1,208,049	199,328,060	23,197	0.02
Longwall Bituminous Underground Mines	445.0	21,177,268	9,423,884,337	1,096,714	1.10
Totals for Coal Mining in Pennsylvania		**32,919,584**	**11,080,101,500**	**1,289,458**	**1.29**

*All methane emission factors include EPA's 2009 published emission factors for post-mining processing of coal on the surface.

Table 3. Summary of Estimated and Projected Coal Mine Methane Emissions from Pennsylvania Coal Mines* - 2020 Levels with 10 percent Methane Capture in Gassy Underground Mines

	Methane Emissions Factor (ft3/ton)	Coal (tons)	Methane (ft3)	Capture Efficiency	MtCO2e	MMtCO$_2$e
Anthracite Mines (all), Bituminous Surface Mines, Room & Pillar Mines with Low Methane	138.3	10,534,267	1,456,889,103	0%	169,547	0.17
Room & Pillar Mines with High Methane	165.0	1,208,049	199,328,060	10%	20,877	0.02
Longwall Bituminous Underground Mines	445.0	21,177,268	9,423,884,337	10%	987,043	0.99
Totals for Coal Mining in Pennsylvania		**32,919,584**	**11,080,101,500**		**1,177,467**	**1.18**

*All methane emission factors include EPA 2009 published emission factors for post-mining processing of coal on the surface.

Economic Cost:

This initiative is cost-effective. The analysis includes conservative estimations such as a methane concentration of only 50 percent, as compared modeled concentrations up to 90 percent, and for smaller units sized at 3 million standard cubic feet (MMscf), as compared to larger units (4 MMscf and 5 MMscf). The analysis assumes a parasitic load of 19 percent fuel consumption to power compressor equipment; less is needed for larger, more efficient units). Projections for Henry Hub natural gas well pricing was obtained from EIA Annual Energy Outlook 2012 to estimate sales revenue. These prices ranged from $3.69 to $4.280 per MMBtu. Capital costs are assumed to be $5.46 million per unit, amortized over an assumed useful life of 20 years. A real discount rate of 5 percent is applied to annual costs. The applied capital recovery factor is 8.02 percent. The calculated net present value of this initiative reflects a cost savings of approximately $234 million. The cost effectiveness is a savings of $4,887 per ton of CO2e reduced.

Implementation Steps:

This coal mine methane recovery initiative would encourage owners/operators of current longwall mines, and of any new gassy underground coal mines that are mined by any method, to capture 10 percent of the estimated total coal mine methane that is released into the atmosphere before, during, and immediately after mining operations. This could be accomplished by pre-mining gas exploration into the coal formation to be mined, capturing methane from pre-mining vertical degas holes, capturing methane by horizontal drilling within active underground mines, or possibly capturing methane from post-mining areas of underground mines, where for a brief period of time gas is still making its way to the surface through existing boreholes. DEP's annual coal production numbers and the MSHA gas liberation numbers will be reassessed annually, as well as new technological developments, with changes made to trend forecasts on future coal production and revisions to estimates of methane gas released per ton of coal mined.

CCAC Member Comments:

One member provided the following comments:

- It is inappropriate to account for GHG reductions from 2013 since the work plans are only being voted/proposed in late 2013 and therefore can't be generating GHG reductions throughout the entire year of 2013.
- The natural gas price figures should be consistent throughout all work plans.

Combined Heat and Power (CHP)

Summary:

This initiative encourages distributed CHP systems to reduce fossil fuel use and GHG emissions. Reductions are achieved through the improved efficiency of CHP systems, relative to separate heat and power technologies, and by avoiding the transmission and distribution (T&D) losses associated with moving power from central generation stations to distant locations where electricity is used.

Goals:

- Use of 64 million MMBtu of natural gas in CHP applications in 2020
- Use of 7 million MMBtu of biomass in CHP applications in 2020

Possible New Measure(s):

CHP is a term used to describe scenarios in which waste heat from energy production is recovered for productive use the concept of which, is embodied in Pennsylvania's Alternative Energy Portfolio Standard (AEPS) definition for distributed generation systems, which reads, "which shall mean the small-scale power generation of electricity and useful thermal energy." The theory of CHP is to maximize the energy use from fuel consumed and to avoid additional GHG's by the use of reclaimed thermal energy. The reclaimed thermal energy can be used by other nearby entities (e.g., within an industrial park or district steam loop) for productive purposes. Generating stations in urban areas may have existing opportunities or may require the co-location of new industry. For Pennsylvania, the largest source of new, cost-effective CHP potential is in industrial facilities that have continuous thermal loads for domestic hot water and process heating (ACEEE et al., 2009). CHP units are typically sized to the minimum thermal load for the facility.

Potential Work Plan Costs and GHG Reductions:

Table 1. Work Plan Costs and GHG Results ($2010)

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions (MMtCO$_2$e)	Cost (Million $)	Cost-Effectiveness ($/tCO$_2$e)	GHG Reductions (MMtCO$_2$e)	Costs (NPV, Million $)	Cost-Effectiveness ($/tCO$_2$e)
3.8	$-178	$-47	17.1	$-544	$-32

The composition of the costs differs according to the type of CHP. Commercial CHP has the highest costs, in part because of the relatively low capacity factor (47 percent in 2010, rising to 64 percent in 2020) implied in the ACEEE et al. (2009) report. These low capacity factors are somewhat unusual because CHP units, especially commercial applications, are typically sized to the meet the constant thermal demand of the facility. These units are then run at maximum capacity to generate the required thermal output.

The cost and emission estimates assume two types of technologies are representative of the CHP portfolio in the future. Table 2 reflects the assumptions for each technology.

- The CHP supply estimates in the ACEEE et al. (2009) report targets the year 2025. For interim years such as 2020, supplies are linearly interpolated. The avoided CO_2 emission rates are assumed to be the same as in the Act 129 work plan.
- As noted in the goals the two fuels analyzed for this work plan are natural gas and biomass. The sectors for deployment include commercial (includes institutions) and industrial.
- T&D losses are 6.6 percent.
- Retail electricity prices are the avoided electric prices. The associated and avoided CO_2 emissions rate is 0.69 tCO_2/MWh, from a mix of 50 percent coal, 50 percent natural gas.
- Estimating the costs of CHP into the distant future is tentative, because cost estimates are highly sensitive to natural gas prices, the cost of avoided power, and the assumption about the CO_2 intensity of displaced electricity.

CHP potentials come from ACEEE et al. (2009) Table E-14. Market Penetration Results for $500/kW Incentive Case. This is the aggressive policy case where clean public energy funds subsidize the capital costs to install CHP at a rate of $500 per kilowatt (kW). This quantification incorporates the total social costs, including private and public costs, into the cost per $MMtCO_2e$ measure.

Table 2. CHP Technology Assumptions

	Commercial	Industrial	
Demand and Energy Charge kW month	4.45	$10.83	PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
Distribution Charge kW month (commercial)	4.69		PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
Distribution Charge Customer/Month (industrial)		$891.00	PPL GS-3 charges for comm. LP-6 charges for industrial (>69 kv)
T&D Losses (%)	6.6	6.6	PA Assumption
Heat Recovered from CHP Power to heat ratio (%)	70	90	Source: Catalogue of CHP Technologies. EPA CHP Partnership. Introduction p. 7
CHP Unit Size MW	0.25	10.00	
CHP Technology	Microturbine	Gas Turbine	
Heat Rate MBTU/MWh	11,750	10,800	ACEEE, et al (2009) p. 212
Capacity Factor (%)	64%	75%	Calc for comm/ind based on ACEEE.
Installed Capital Costs $/kW	2,240	1,400	2010-2015 Costs as average for the period. Plus after treatment costs of $200/kw
O&M Costs $/kWh	0.01	0.01	2010-2015 Costs as average for the period
Economic Life/years	20.00	20.00	Assumption
Displaced boiler efficiency (%)	80%	80%	Assumption
Fixed O&M $/MBTU	0.07	0.07	Assumption
Variable O&M $/MBTU	0.07	0.07	Assumption
Net Generation Cost $/MWh	107.71	31.21	Calc
Avoided Price of Power $/MWh	97.84	76.62	Assumption
MW Capacity	386	661	Ind/Comm from ACEEE, et al (2009)
MWh Generation	2,171,000	4,345,000	Ind/Comm from ACEEE, et al (2009)

Implementation Steps:

The key to implementing CHP systems is to provide adequate incentives for the development of infrastructure to capture and use the waste heat. Such incentives could come in many forms, such as recruiting suitable end users to a centralized location to use the waste heat, tax credits, grants, zoning, and offset credits for avoided emissions. Additionally, Section 9.4.8 of the Governor's Marcellus Shale Advisory Commission report, issued on July 22, 2011, recommends the following: “The Commonwealth should promote the use of cogeneration technology (Combined Heat & Power (CHP) through the use of Permit-by-Rule, standardized utility power grid interconnection rules and direct financial incentives.” As previously mentioned, CHP systems, including those fueled by natural gas, are already an eligible Tier II resource under Pennsylvania’s AEPS. The AEPS also established a set of statewide interconnection standards.

A large group of locally financed small projects spread widely across the commonwealth could capture the value of replacing high-cost fuel imports and gain carbon benefits while limiting transportation costs of the feedstock. This model has been shown to allow displacement of significant quantities of current or projected fossil carbon release from a broad range of users—including industry, public institutions, commercial offices, and multi-family buildings—through reduced electrically driven cooling and distributed generation of electricity through CHP facilities.

The following are policies that can potentially increase the installed capacity of CHP in Pennsylvania:

- Create or expand markets for CHP units by using incentives designed to promote implementation for residential, commercial, and industrial users.
- Promote CHP technologies through provisions for tax benefits, attractive financing, utility rebates, and other incentives.
- Remove barriers to CHP development, such as utility rate structures that allow discounted electric rates to compete with CHP. Also, design interconnection standards to facilitate economical and efficient CHP connection to the grid.

Fugitive Methane:

The largest uncertainty with this assessment involves the life cycle GHG impacts of unconventional natural gas. The EPA’s latest national GHG inventory, 2009, of the amount of methane (CH^4) released from leaks and venting in the U.S. natural gas network, from production through distribution to the ultimate consumer, is 570 billion cubic feet (Bcf). This corresponds to an emissions rate equal to 2.4 percent of gross U.S. natural production. (1.9 – 3.1 percent at a 95 percent confidence level)[2]. Methane losses from natural gas extraction and delivery accounted for 32 percent of U.S. methane emissions and 3 percent of the total U.S. GHGs in 2009. According to the 2011 EIA Production Year Report, natural gas production in Pennsylvania (conventional and non-conventional) was 854,059,500 thousand cubic feet (Mcf) or 854 Bcf. Applying the EPA-derived CH_4 emissions rate of 2.4 percent to Pennsylvania’s natural gas production in 2011 reflects a total loss of approximately 20.5 BCF. Beginning about 2015, these losses and the associated methane leakage rate are expected to be significantly reduced via the implementation of federal New Source Performance Standard (NSPS) in 40 CFR Part 60, Subpart OOOO and DEP’s General Plan Approval and General Operating Permit for Natural Gas Compression and Processing Facilities (GP5).

CCAC Member Comments:

One member provided the following comments:

- I am very supportive of increasing industrial energy efficiency through combined heat and power.

- Due to lack of clarity around methane leakage and lifecycle GHG emissions, the stated GHG reduction benefits associated with natural gas CHP may or may not be accurate.
- The assumptions about the greenhouse gas profile of biomass combustion are unclear in this work plan. The EPA has been developing a carbon dioxide accounting for emissions from biogenic sources to determine how biomass resources should be accounted for on a lifecycle greenhouse gas perspective. Previously, the assumption was that biomass is "carbon neutral".
- EPA's *Accounting Framework for Biogenic CO2 Emissions from Stationary Sources (Framework, September 2011)* explores the scientific and technical issues associated with accounting for emissions of biogenic carbon dioxide (CO2) from stationary sources and develops a method to adjust the stack emissions from bioenergy based on the induced changes in carbon stocks on land (in soils, plants and forests).
- EPA's Scientific Advisory Board (SAB) was asked to review and evaluate EPA'S Framework.
- The SAB[3] found that the agency was accurate in not utilizing the Intergovernmental Panel on Climate Change (IPCC) approach to biomass accounting. If EPA were to apply the IPCC approach, as long as carbon stocks are increasing, bioenergy would be considered carbon neutral. In other words, the assumption that biomass combustion is carbon neutral is not always true.

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[3] EPA's Scientific Advisory Board Review of EPA's Accounting Framework for Biogenic CO2 Emissions from Stationary Sources, (Sept 2011) http://yosemite.epa.gov/sab/sabproduct.nsf/0/2f9b572c712ac52e8525783100704886!OpenDocument&TableRow=2.3#2.

Reducing Methane Leakage from Natural Gas Infrastructure

Summary:

This work plan discusses opportunities for reducing methane losses associated with the production and transmission of natural gas. With the promulgation of 40 CFR PART 60 Subpart OOOO – Standard of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. (Subpart OOOO), many of the best management practices (BMPs) noted in this plan are now required by federal regulation. However, further avenues for emission reduction exist beyond those required by Subpart OOOO. Through the EPA's Gas Star Partner Program the EPA and the natural gas industry work to identify and implement cost-effective technologies and practices to reduce fugitive methane emissions. The period of analysis is 2013 through 2020. Fugitive emissions reductions are assumed to be implemented linearly until the target date is reached in 2020.

Baseline Activities for 2012[4]

- Conventional Production – 215 billion cubic feet (Bcf)
- Unconventional Production – 2.041 trillion cubic feet (Tcf)Total Production – 2.256 Tcf

Introduction:

In recent years the U.S. natural gas industry has been developing more technologically advanced methods for extraction that have resulted in increased drilling of new wells in unconventional reserves. Nowhere is this developing technology more evident than in the deep shale formations of western and northeastern Pennsylvania. In 2005, eight Marcellus Shale wells were drilled in the state. In 2012, 1,352 new unconventional wells were drilled. Continued well development within the unconventional shale formations brings the total well count to over 6,250[5]. Along with this increased well drilling and production activity, comes an increase in fugitive emissions and venting of natural gas and in reality, increased methane emissions.

Natural gas is released to the atmosphere through fugitive and vented emissions. Fugitive emissions are methane leaks often through pipeline and system components (such as compressor seals, pump seals and valve packing). Vented emissions are methane leaks from a variety of equipment and operational practices, such as well completion activities and are directly attributed to an organization's actions but also through accidental line breaks and thefts.

Natural gas is thought of by many as the future of America's energy. Many believe it is the solution for our country's energy independence while reducing air pollution/GHG in the process. However, there is also much concern about the climate implications of increased use of natural gas for electric power generation and transportation.

The climate effect that results from replacing other fossil fuels with natural gas depends largely on the sector and the type of fuel being replaced. These distinctions have been for the most part absent in the policy debate. In any case, when estimating the net climate implications of fuel-

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[4] PA Department of Environmental Protection

[5] Well development information was provided by Pa DEP, Bureau of Oil and Gas Management – 2012 Data

switching strategies, outcomes should be based on the complete fuel cycle, a Life Cycle Analysis (LCA), and account for changes in emissions of relevant radiative forcing agents.

However, LCAs are weakened by the lack of empirical data that really addresses methane (CH_4) emissions (CH_4 Leakage) throughout the system. Recently, EPA doubled its estimate of CH_4 leakage from natural gas systems[6]. Some research has reported calculated upstream CH_4 leakage rates from shale gas that imply higher lifecycle GHG emissions rates above those associated with extraction and combustion of coal. In contrast, Clark et al, base case results indicate that shale gas life-cycle emissions are 6 percent lower than those of conventional natural gas[7]. The range in values for shale and conventional gas overlap, so there is a statistical uncertainty regarding whether shale gas emissions are lower than conventional gas emissions.

Overall, natural gas systems emitted 144.7 Tg CO2 Eq. (6,893 Gg) of CH4 in 2011, a 10 percent decrease compared to 1990 emissions and 32.3 Tg CO2 Eq. (32,344 Gg) of non-combustion CO2 in 2011, a 14 percent decrease compared to 1990 emissions. The decrease in CH4 emissions is due largely to a decrease in emissions from transmission and storage due to increased voluntary reductions and a decrease in distribution emissions due to a decrease in cast iron and unprotected steel pipelines. In April 2013, EPA released the Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 - 2011, which revised the methane leakage of all natural gas systems rate from 2.4 percent to 1.2 percent.[8] The 2.4 percent leakage rate calculation was based on data compiled in 1992 and assembled in 1996.

Pennsylvania Natural Gas Production and Loss:

According to DEP, natural gas production (conventional and non-conventional) in Pennsylvania in 2012 was 2.256 Tcf. This is an increase in overall natural gas production of 706 Bcf over the 2011 production figure, with an addition of 2,375 new wells total in 2012. In 2012, there were 1,023 conventional wells drilled and 1,352 unconventional wells drilled[9]. As well development and production continue to increase in Pennsylvania the leaking and unaccounted (L&U) for natural gas is also increasing. These activities are a significant source of methane emissions and particular attention should be paid to reducing L&U natural gas throughout the network.

Using the EPA's estimate of 1.2 percent of CH_4 released to atmosphere from the natural gas network the lost volume of gas from Pennsylvania production in 2012 would be 24.492 BCF.[10]

As a GHG, methane, on a 100 year time horizon, is 21 times more powerful than CO_2 in the atmosphere[11]. With the addition of more wells and increased unconventional shale development, left unchecked, the amount of fugitive and vented CH_4 emissions will only increase. For cost analysis purposes, this analysis uses a value of approximately 116 pounds of CO2e per MCF or

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[6] U.S. Environmental Protection Agency: 2011, *Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2009* (EPA Publication 430-R-11-005

[7] Argonne National Laboratory, 2011, November 2011, *Life-Cycle Analysis of Shale Gas and Natural Gas*

[8] http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf (3-60) April 2013

[9] PA DEP Office of Oil and Gas Management. 2013

[10] http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-Main-Text.pdf

[11] http://www.epa.gov/climatechange/ghgemissions/gases/ch4.html

MMBtu of natural gas, which is consistent with EPA[12] and U.S. Energy Information Administration (EIA).[13]

Methane Emissions Reductions for Natural Gas:

The Natural Gas STAR Program is a voluntary partnership between the EPA and the oil and natural gas industry. With this program the EPA works with the industry sectors that produce, process, transmit and distribute natural gas to identify and implement cost-effective technologies and practices to reduce methane emissions. Since its inception, Natural Gas STAR partners have eliminated nearly 471 Bcf of methane emissions through the implementation of more than 70 cost-effective technologies and practices.

On August 16, 2012, Federal Regulations were promulgated by the EPA for the oil and gas sector. These regulations, Subpart OOOO, are designed to regulate and reduce volatile organic compounds (VOC) and SO2 emissions from oil and gas exploration, production, processing and transportation facilities. Subpart OOOO does not directly regulate Methane or CO2 emissions, however significant collateral emissions reductions of methane will result from the capture and control of fugitive natural gas emissions required by this subpart.

The New Source Performance Standard (NSPS) requirements for new hydraulically fractured gas wells will take place in two phases. Phase 1, will apply to gas wells drilled after Aug. 23, 2011 through Jan. 1, 2015. Under this rule, either the use of a combustion device, such as a flare, or the capture of the gas using a process called green completion or reduced emission completions (RECs) are required. Phase 2, beginning Jan. 1, 2015, will require the use of green completion except for Wildcat and low-pressure wells. In addition, other production, processing and transportation facility equipment such as new and modified compressors and pneumatic controllers are subject to standards under the NSPS.

As previously indicated, the EPA Natural Gas Star program is a voluntary initiative to reduce fugitive emissions from all aspects of natural gas production, transmission and distribution. Much of the industry’s knowledge regarding the supply and costs of mitigating fugitive methane emissions comes from this program, and appears to be the foundation for the NSPS.

Gas lost during well completion of new wells or reworked wells can be as much as 25 million cubic feet (MMcf) per well depending on individual characteristics of the well. These characteristics include production rates, the number of zones completed and the amount of time it takes to complete each zone.

Natural Gas Star partners have reported that performing RECs recovers most of the gas that is normally vented or flared during the well completion process. RECs is a gas recovery process that involves installing portable equipment that is specifically designed and sized for the initial high rate of water, sand and gas flow-back during well completion. The objective is to capture

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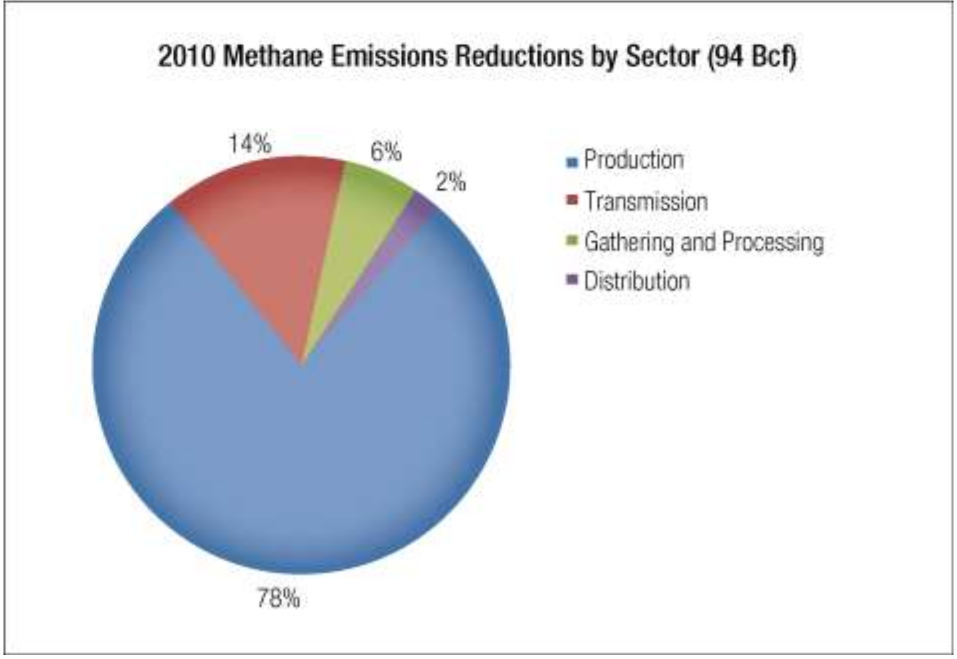
[12] U.S. EPA, November 2004, *“Unit Conversions, Emissions Factors and Other Reference Data”* http://www.epa.gov/cpd/pdf/brochure.pdf

[13] U.S. EIA, Voluntary Reporting of Greenhouse Gases Program, http://www.eia.gov/oiaf/1605/coefficients.html

and reintroduce this gas back into the system to avoid venting or flaring. Figure 1 shows a 78 percent reduction in emissions from the production sector as a result of BMPs such as RECs[14].

Natural Gas Star partners also reported significant savings and methane emissions reductions in the transmission sector as a result of initiating various BMP activities such as replacement, retrofit and maintenance of automatic control devices. Pneumatic devices, powered by natural gas, are widely used in the industry as valve controllers and pressure regulators. Methane emissions from pneumatic devices have been estimated at 51 Bcf from the production sector, 14 Bcf per year in the transmission sector and around 1Bcf from the processing sector and are considered one of the largest sources of vented methane emissions in the industry[15].

Figure 1: Reductions from Natural Gas Star partners by sector[16]



As part of normal operation pneumatic control devices release or bleed natural gas to the atmosphere and as a result are a major source of methane emissions. In the transmission sector there are an estimated 85,000 pneumatic control devices and the actual emissions level, or bleed rate, largely depends on the design of the device. Reduced methane emissions can be achieved by the following methods either alone or in combination:

- Replacing high-bleed devices with low-bleed devices having similar performance capabilities,
- Installing low-bleed retrofit kits on existing operating devices,
- Performing enhanced maintenance, cleaning and tuning, repairing or replacing leaking gaskets, tubing fittings and seals.

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[14] *US EPA. (2007). Project Opportunities Study for Partner X. Natural Gas Star Program*
[15] IBID
[16] IBID

By reducing methane emissions from high-bleed pneumatic control devices significant economic and environmental benefits can be realized. According to Natural Gas Star partner data provided to EPA, reductions in actual methane emissions can range from 45 to 260 Mcf per device per year depending on the type and specific application of the device. [17] At prices of about $4 per million Btu (MMBtu), this would equate to savings of about $180 to $1,040 per year per device.

Quantification Approach and Assumptions:

To quantify the costs and reductions associated with this work plan, the representative mitigation approaches are taken from Natural Gas Star partner experiences. Of the many possible projects possible, five are taken as representative. These are chosen because they are used across sectors and are among the largest mitigation sources. The technologies or practices include:

- Direct inspection at gate stations and surface facilities - Implementing a directed inspection and maintenance (DI&M) program is a proven, cost-effective way to detect measure, prioritize and repair equipment leaks to reduce methane emissions. A DI&M program begins with a baseline survey to identify and quantify leaks. Repairs that are cost-effective to fix are then made to the leaking components. Subsequent surveys are based on data from previous surveys, allowing operators to concentrate on the components that are most likely to leak and are profitable to repair[18]. Implementation of a DI&M program will include some of the specific opportunities noted below.
- Replace wet seals with dry Seals in centrifugal compressors - Centrifugal compressors are widely used in production and transmission of natural gas. Seals on the rotating shafts prevent the high-pressure natural gas from escaping the compressor casing. Traditionally, these seals used high-pressure oil as a barrier against escaping gas. Methane emissions from wet seals typically range from 40 to 200 standard cubic feet per minute (scfm). Natural Gas STAR partners have found that replacing these “wet” (oil) seals with dry seals significantly reduces operating costs and methane emissions. Dry seals, which use high-pressure gas to seal the compressor, allow less natural gas to escape, 6 scfm, improve compressor and pipeline efficiency and performance, enhance reliability and require less maintenance. A dry seal can save about $315,000 per year and pay for itself in as little as11 months[19]. In Pennsylvania alone there are 359 compressor stations across more than 46,000 miles of pipelines and these numbers continue to increase.
- Reduced Emissions Completions (RECs) - Now required under Subpart: OOOO for new hydraulically fractured well sites drilled after Aug. 23, 2011. Green completions is a term used to describe practices that capture natural gas during well completions and well work-overs following hydraulic fracturing. *The U.S. Inventory of Greenhouse Gas Emissions and Sinks 1990-2009* estimates that 68 billion cubic feet (Bcf) of methane are vented or flared annually from unconventional completions and work-overs. RECs have become a major source of methane emissions reductions since 2000. Between 2000 and 2009 emissions reductions form RECs (reported to Natural Gas STAR) have increased from 200 MMcf to over 218,000 MMcf. According to EPA, this represented additional

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[17] US EPA. (2006). Lessons Learned From Natural Gas Star Partners: Options for Reducing Methane Emissions From Pneumatic Devices in the Natural Gas Industry

[18] U.S. EPA, 2003: October 2003*, Directed Inspection and Maintenance at Compressor Stations.*

[19] U.S. EPA, 2006: October 2006*, Replacing Wet Seals with Dry Seals in Centrifugal Compressor.*

revenue from natural gas sales of over $126 million with gas valued then at about $7/Mcf[20].

- Replace High-Bleed Pneumatic Devices with Low-Bleed Pneumatic Devices – Pneumatic devices powered by natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators and valve controllers. High-bleed devices are those that bleed in excess of 6 scf per hour (50 Mcf/yr.). Nationally, there are an estimated 400,000 devices in the production sector 85,000 devices in the transmission sector and about 13,000 devices are used in the processing sector for compressor and dehydration control and in isolation controls. Methane emissions from these devices have been estimated at 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector and less than 1Bcf per year in the processing sector. Gas Star Partners have achieved significant savings and methane emissions reductions through replacement, retrofit and maintenance of high-bleed pneumatics. Natural Gas Star partners also report that retrofit investments pay for themselves in about a year and replacements in as little as six months. Natural Gas Star partners have reported methane emissions reductions of 36.4 Bcf by replacing or retrofitting high-bleed with low-bleed devices[21].
- Connecting the blow down vent lines to the fuel gas system for base load compressors when offline – Compressors are used throughout the natural gas system to move natural gas from production and processing sites to customer distribution systems. Compressors used throughout the natural gas system are cycled on-line and off-line to meet fluctuating demand for gas, for maintenance and during emergencies. The largest source of methane emissions associated with taking a compressor off-line is from the blow down or venting of gas remaining in the compressor. On average, a single blow down will result in the release of approximately 15 Mcf of natural gas per blow down to the atmosphere. By connecting the blow down vent lines to the fuel gas system through the addition of piping and valves to bleed gas from an idle compressor into the compressor station's fuel gas system can reduce fugitive methane losses by 1.275 Mcf/yr. Facility modification costs range between $900 and $1,600 per compressor[22].

The aggregate cost and performance assumptions for a broad category of very cost-effective technologies categorized as part of direct inspection and maintenance at compressor stations as well as reduced emissions completions at well drilling operations are provided in Tables 2A and 2B. Examples of three technology options contributing to the aggregate data provided for direct inspection and maintenance at compressor stations are provided in Table 3. The technologies in Table 3 are not included in the overall assessment because it would double-count the benefits associated with inspection and maintenance improvements at compressor stations but because they are not exclusive compressor stations the overall assessment will be somewhat conservative. Average performance costs and methane reductions per technology option were taken from EPA's "Lessons Learned from Natural Gas Star Partners. Annual average prices for natural gas were taken from the EIA's Annual Energy Outlook 2012.

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[20] U.S. EPA, 2011: January 2011, *Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells*

[21] U.S. EPA, 2006: October 2006, *Options for Reducing Methane Emissions From Pneumatic Devices In the Natural Gas Industry.*

[22] U.S. EPA, 2004: February 2004, *Reducing Emissions When Taking Compressors Off-Line.*

Table 2A: Technologies to Reduce Lost and Unaccounted for Natural Gas Emissions
2013-2020 Costs ($million) and Methane Emissions Reductions (Mcf/yr)

Direct Inspection & Maintenance	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Expected Life Years	1	1	1	1	1	1	1	1
Number of Stations	359	359	359	359	359	359	359	359
Implementation Cost per Station ($ million)	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
CH4 Emissions Reduction per Station (MMCF)	29.41	29.41	29.41	29.41	29.41	29.41	29.41	29.41
Value of Natural Gas Saved per Station ($ million)	$0.13	$0.13	$0.13	$0.13	$0.13	$0.14	$0.14	$0.14
Net Cost per Station ($ million)	-$0.11	-$0.10	-$0.11	-$0.11	-$0.11	-$0.11	-$0.12	-$0.12
Payback Period (months)	0	0	0	0	0	0	0	0
Cost per Station per CF saved ($/CF)	-0.0036	-0.0035	-0.0036	-0.0036	-0.0037	-0.0038	-0.0039	-0.0040
Total Implementation Cost ($ million)	$9.42	$9.42	$9.42	$9.42	$9.42	$9.42	$9.42	$9.42
Total CH4 Emissions Reduction (MMCF)	10,559	10,559	10,559	10,559	10,559	10,559	10,559	10,559
Total Value of Natural Gas Saved ($ million)	$47.28	$46.42	$47.92	$47.92	$48.40	$49.87	$51.04	$51.84
Total Net Cost ($ million)	-$37.85	-$37.00	-$38.50	-$38.50	-$38.98	-$40.44	-$41.61	-$42.41
Discounted Cost ($million)	-$23.24	-$22.71	-$23.64	-$23.64	-$23.93	-$24.83	-$25.55	-$26.04
CO2e Reductions (MMtCO2e)	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Cost Effectiveness ($/tCO2e)	-$42	-$41	-$43	-$43	-$43	-$45	-$46	-$47

Reduced Emissions Completions (RECs)	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Expected Life (days/well)	3-10	3-10	3-10	3-10	3-10	3-10	3-10	3-10
Number of New Unconventional Gas Wells Drilled	2,900	2,900	2,900	2,000	1,500	1,500	1,000	1,000
Implementation Cost per Well ($ million)	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
CH4 Emissions Reduction per Well (MMCF)	10.80	10.80	10.80	10.80	10.80	10.80	10.80	10.80
Value of Natural Gas Saved per Well ($ million)	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05
Additional Value from Condensate ($ million)	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01
Total Value ($ million)	$0.06	$0.05	$0.06	$0.06	$0.06	$0.06	$0.06	$0.06
Net Cost per Year per Well ($ million)	-$0.02	-$0.02	-$0.02	-$0.02	-$0.02	-$0.03	-$0.03	-$0.03
Payback Period (months)	0	0	0	0	0	0	0	0
Cost/cf saved ($/CF)	-0.0021	-0.0020	-0.0022	-0.0022	-0.0022	-0.0024	-0.0025	-0.0026
Total Implementation Cost ($ million)	$93.96	$93.96	$93.96	$64.80	$48.60	$48.60	$32.40	$32.40
Total CH4 Emissions Reduction (MMCF)	31,320	31,320	31,320	21,600	16,200	16,200	10,800	10,800
Total Value of Natural Gas Saved ($ million)	$140.23	$137.69	$142.15	$98.03	$74.26	$76.51	$52.20	$53.02
Total Additional Value from Condensate ($ million)	$20.30	$20.30	$20.30	$14.00	$10.50	$10.50	$7.00	$7.00
Total Value ($ million)	160.53	157.99	162.45	112.03	84.76	87.01	59.20	60.02
Total Net Cost ($ million)	-$67	-$64	-$68	-$47	-$36	-$38	-$27	-$28
Discounted Cost ($million)	-$41	-$39	-$42	-$29	-$22	-$24	-$16	-$17
CO2e Reductions (MMtCO2e)	1.65	1.65	1.65	1.14	0.85	0.85	0.57	0.57
Cost Effectiveness ($/tCO2e)	-$25	-$24	-$26	-$26	-$26	-$28	-$29	-$30

Replace Wet Seals with Dry Seals	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Expected Life Years	5	5	5	5	5	5	5	5
Number of Stations (359)	72	72	72	72	72	72	72	72
Number of Compressors (4 per station)	287	287	287	287	287	287	287	287
Incremental Implementation Cost per Compressor ($ million	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05	$0.05
Net O&M Savings for Dry Seals ($ million)	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
CH4 Emissions Reduction per Compressor (MMCF)	45.12	45.12	45.12	45.12	45.12	45.12	45.12	45.12
Value of Natural Gas Saved per Compressor ($ million)	$0.20	$0.20	$0.20	$0.20	$0.21	$0.21	$0.22	$0.22
Net Cost per Compressor ($ million)	-$0.24	-$0.24	-$0.24	-$0.24	-$0.25	-$0.25	-$0.26	-$0.26
Payback Period (months)	0	0	0	0	0	0	0	0
Cost/cf saved ($/CF)	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01	-$0.01
Total Implementation Cost ($ million)	13.96	13.96	13.96	13.96	13.96	13.96	13.96	13.96
Total O&M Savings for Dry Seals ($ million)	25.36	25.36	25.36	25.36	25.36	25.36	25.36	25.36
Total CH4 Emissions Reduction (MMCF)	12,958	12,95	12,95	12,95	12,95	12,95	12,95	12,95
Total Value of Natural Gas Saved ($ million)	58.02	56.97	58.81	58.81	59.40	61.20	62.63	63.62
Total Net Cost ($ million)	-69.4	-68.4	-70.2	-70.2	-70.8	-72.6	-74.0	-75.0

Replace Pneumatic Devices	Annual $	2013	2014	2015	2016	2017	2018	2019
Expected Life Years		5	5	5	5	5	5	5
Implementation Cost per Device ($ million)								
End-of-Life* ($275.00)	$55	.00006	.00006	.00006	.00006	.00006	.00006	.00006
Early Replacement ($1,850.00)	$370	.00037	.00037	.00037	.00037	.00037	.00037	.00037
Net Annual O&M Savings per Device ($ million)	$36	.00004	.00004	.00004	.00004	.00004	.00004	.00004
Annual CH4 Emissions Reduction per Device (MMCF)								
End-of-Life	125	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Early Replacement	260	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003	0.0003
Annual Value of Natural Gas Saved per Device ($ million)								
End-of-Life	$560	.000001	.000001	.000001	.000001	.000001	.000001	.000001
Early Replacement	$1,164	.000001	.000001	000001	.000001	.000001	.000001	.000001
Net Cost per Device ($ million)								
End-of-Life	-$541	$00002	.00002	.00002	.00002	.00002	.00002	.00002
Early Replacement	-$830	.00033	.00033	.00033	.00033	.00033	.00033	.00033
Payback Period (months)								
End-of-Life		2	2	2	2	2	2	2
Early Replacement		10	10	10	10	10	10	10
Lifetime CH4 Emissions Reduction per Unit (MMCF)								
End-of-Life	625	0.0006	0.0000	0.0000	0.0000	0.0000	0.0006	0.0000
Early Replacement	1300	0.0013	0.0000	0.0000	0.0000	0.0000	0.0013	0.0000
Total Value of Natural Gas Saved per Unit ($ million)								
End-of-Life	$2,798,323.13	$0.000003	.0	.0	.0	0	000003	.0
Early Replacement	$5,820,512.10	$0.000006	0	.0	0	.0	.000006	.0

*Incremental cost

Injecting Blowdown Gas into Low Pressure Mains	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Expected Life Years	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Number of Compressor Stations (359)	359	359	359	359	359	359	359	359
Blowdown / Depressurizations (10 per Station)	3,590	3,590	3,590	3,590	3,590	3,590	3,590	3,590
Implementation Cost per Blowdown ($1,250.00 @) ($ million)	.001	.0013	.0013	.0013	.0013	.0013	.0013	.0013
CH4 Emissions Reductions per Blowdown (150 Mcf)	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Value of Natural Gas Saved per Blowdown	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
Net Cost per Blowdown / Depressurization	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001	$0.001
Payback Period per Blowdown (months)	2	2	2	2	2	2	2	2
Cost/cf Saved	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.004	$0.003
Total Implementation Cost	$4.49	$4.49	$4.49	$4.49	$4.49	$4.49	$4.49	$4.49
Total CH4 Emissions Reductions	54	54	54	54	54	54	54	54
Total Value of Natural Gas Saved	$2.41	$2.37	$2.44	$2.44	$2.47	$2.54	$2.60	$2.64
Total Net Cost	$2.08	$0.21	$0.20	$0.20	$0.20	$0.19	$0.19	$0.18

Natural Gas Prices ($/MMBtu)	$4.48	$4.40	$4.54	$4.54	$4.58	$4.72	$4.83	$4.91
Pounds CO2 per MMBtu Natural Gas	116							

Summary Totals	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
CO2e Reductions (MMtCO2e)	2.20	2.20	2.20	1.69	1.41	1.41	1.12	1.12
Net Cost ($million)	-$104	-$101	-$107	-$86	-$75	-$79	-$68	-$70
Discounted Cost ($million)	-$64	-$62	-$66	-$53	-$46	-$48	-$42	-$43
							2013 - 2020 Total Cost / Savings ($million)	-$424
							Cost Effectiveness ($/tCO2e)	-$32

Table 2B. Work Plan Costs and GHG Results

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	**Cost (Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**	**GHG Reductions ($MMtCO_2e$)**	**Costs (NPV, Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**
2.20	-$104	-$143.039	11.94	-$424	-$32

The cost of emissions reductions is calculated by:

1. Summing the average annual implementation and operation and maintenance (O&M) costs of each measure, with the value of recovered/reduced natural gas losses. Reduced methane losses and implementation and O&M costs are provided by EPA's Natural Gas Star program, based on data collected by industry partners.

2. The value of reduced natural gas losses is calculated by multiplying the quantity of natural gas by projected annual costs for natural gas, as reported by EIA in the Annual Energy Outlook 2012.

3. The result is the net cost or savings (expressed as a negative cost value). The multi-year (2013 – 2020) stream of net costs (or savings) is discounted to arrive at the net present value cost of the work plan by using a 5 percent annual real discount rate with the result expressed in 2010 dollars.

Table 3. Example Opportunities for Cost-Effective CH4 Reductions

Replace Wet Seals with Dry Seals	**Per Unit, Per Year**
Expected Life Years	5
Incremental Cost of Implementation per Compressor (amortized)	$48,600
Net O&M Savings for Dry Seals	$88,300
CH4 Emissions Reduction per Compressor (Mcf)	45,120
Value of Natural Gas Saved per Compressor @ $4.48/MMBtu	$202,017
Net Cost per Compressor	-$241,717
Injecting Blowdown Gas into Low Pressure Mains	**Per Unit, Per Year**
Expected Life Years	N/A
Implementation Cost per Blowdown	$1,250
CH4 Emissions Reductions per Blowdown (Mcf)	150
Value of Natural Gas Saved per Blowdown @ $4.48/MMBtu	$672
Net Cost per Blowdown / Depressurization	$578
Replace Pneumatic Devices	**Per Unit, Per Year**
Expected Life Years	5
Implementation Cost per Device	
End-of-Life (amortized)	$55
Early Replacement (amortized)	$370
Net O&M Savings per Device	$36
CH4 Emissions Reduction per Device (Mcf)	
End-of-Life	$125
Early Replacement	$260
Value of Natural Gas Saved per Device @ $4.48/MMBtu	
End-of-Life	$560
Early Replacement	$1,164
Net Cost per Device	
End-of-Life	-$541
Early Replacement	-$830

Implementation Steps:

The following recommended steps include measures that will directly result in decreased methane losses and other measures that will facilitate improved accounting and tracking of methane losses.

- Encourage companies in all sectors of the natural gas industry to become Gas Star Partners. EPA’s Natural Gas STAR Program, which is focused on reducing methane emissions through technology transfer using best management practices in operation and maintenance. Natural Gas STAR provides analytical tools and services to assist companies in calculating their methane emissions.
- Encourage earlier compliance with Subpart OOOO Phase 2 requirements.

Potential Overlap:

While there are similarities and shared types of equipment among the production, transmission and distribution systems there is no overlap in the quantification of the methane emissions losses accounted for in this work plan document and from the Reducing Lost and Unaccounted for Natural Gas in Distribution Systems work plan.

Key Assertions:

- GHG / CH4 emission will be reduced as a result of the promulgation of the NSPS Subpart OOOO requirements.
- GHG emissions could be further reduced if more of the natural gas industry participated in the Natural Gas STAR program.

Key Uncertainties:

- The largest uncertainty with this assessment involves the life cycle GHG impacts of unconventional natural gas.
- Life span of unconventional natural gas well
- The number of gas wells to be drilled and related infrastructure deployed in future years
- Future dollar value of natural gas

References:

U.S. Energy Information System query – 2010 Data.

U.S. Energy Information Administration, 2011: April 2011, *Annual Energy Outlook 2011with Projections to 2035.*

U.S. EPA, 2011: January 2011, *Global Methane Initiative.*

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US EPA, 2007: *Project Opportunities Study for Partner X. Natural Gas Star Program.*

Waste-to-Energy Digesters

Summary:
This initiative encourages an expansion of regional digesters that can offer larger-scale and higher technology treatment for a mixture of feedstocks including: organic municipal solid waste (MSW), organic residual waste, manure, and biosolids.

Goals:
Install four digesters, fitting the above description, by 2020.

Implementation Period:
2013 through 2020

Background Discussion on Anaerobic Digestion:
Thermophilic anaerobic digestion is the preferred strategy for future digestion facility planning, rather than the common mesophilic technologies that predominate on U.S. farms and wastewater treatment plants. Technologies common in Europe provide for mixed feedstocks, yield more gas, and are more efficient than manure-only digesters. The effluent (digestate) is closely monitored and can yield precision-agriculture soil amendment with a guaranteed nitrogen-phosphorus-potassium analysis for fertilizer application. Depending on the exact technology/vendor selected for these digesters, about 50 percent of the input is manure, and the remainder is some combination of food residues, crop residues, yard wastes, organic fraction of MSW or sewage sludge. The European model for centralized digestion relies on processes that digest waste that has a moisture content of less than 25 percent. Utilizing drier feedstocks provides for a higher biogas yield and allows for a more stable digestion process that requires less mixing and disposal of wastewater.

Based on data provided by DEP on residual waste availability, it appears that York and Adams counties are potential locations for digestion facilities. These data, in addition to the availability of manure and organic MSW in PA, suggest that there would be ample feedstock to support four advanced, centralized, mixed-feedstock, anaerobic digesters, each requiring 25,000 tons of waste residuals per year. For a digester project to reach its full environmental and economic potential, a constant feedstock supply is required.

In the regional (centralized) model,

- New feedstocks for digesters include food waste and yard waste, as well as conventional manure and sludge.
- WTE digesters produce electrical power, along with high-grade solid and liquid end products.
- The business community can participate as both user and investor.
- Food companies would have an outlet for food waste.
- The concept expands upon local on-farm digesters that produce power for farm use and treated solid and liquid fertilizers.

Two known vendors of anaerobic digesters are Waste-to-Energy Solutions and BioFerm Energy Systems. Waste-to-Energy Solutions is a licensed vendor in PA and sells Niras[23] Danish digesters.

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[23] http://www.niras.com/Services/Energy.aspx

BioFerm Energy Systems[24] is a German company that has recently expanded operations to North America.

Information received from a consultation with a representative of BioFerm Energy Systems was used to provide a reference case for the analysis of this work plan. The BioFerm system utilizes a dry fermentation technology, optimal for feedstocks with less than 25 percent moisture content. The minimum methane content of the resulting biogas is 55 percent, although higher levels have been realized. The elimination of most liquid from the digester input eliminates the need for mixing of the input. Therefore, dry fermentation anaerobic digestion facilities use much less energy (5 percent of electricity and 3 percent of heat generated by the digestion process) than traditional digesters. BioFerm Energy Systems has completed construction on 27 digesters worldwide, with many more in development. A byproduct of all anaerobic digestion is a nutrient-rich digestate that, after processing, may be used as an organic soil amendment. If markets for electricity and direct heat are not available for a given anaerobic digestion facility, it is possible to process the biogas into a liquid vehicle fuel substitute for compressed natural gas. Further information on BioFerm's dry fermentation process is available on its website.[25]

Data sources/Assumptions/Methods for GHG:

The reference case digestion facility converts 25,000 tons per year in eight fermentation chambers into 5.4 million kWh electricity and almost 22 MMBtu of direct heat through the dry fermentation anaerobic digestion process. In addition, 17,543 tons of marketable compost is produced as a result of the process. The methane displacement as a result of the combustion of the biogas is nearly 21 tCO_2e/yr.[26] The assumed GHG reduction from offset grid electricity is based on the assumption that this initiative would displace generation from an "average thermal" mix of fuel-based electricity sources of coal and gas. This mix is based on 50 percent natural gas and 50 percent coal from 2013 through 2020 and reflects the latest trend in Pennsylvania shifting towards a greater percentage of natural gas and less coal. The average thermal approach is preferred over alternatives because sources without significant fuel costs would not be displaced—e.g., hydro, nuclear or renewable energy generation. Given the generation fleet's coal and gas combustion efficiencies, this equates to a CO_2 intensity of approximately 0.69 metric tons (t)/MWh. A natural gas emission factor of approximately 0.058 tCO_2e/MMBtu was used to estimate the GHG reduction from offset direct heat.

Data Sources/Assumptions/Methods for Costs:

The assumed capital cost for a reference case dry fermentation anaerobic digestion facility is $5.8 million. Approximate O&M costs include a front loader ($4,790 per year), compost processing ($16 per ton compost), maintenance ($4,200 per fermentation chamber per year), and facility operation (1 full-time-equivalent position per year: $52,600). Revenues received by the facility include the value of compost ($31.58/ton)[27], the wholesale value of electricity ($0.05/kWh) and thermal energy from the capture and use of excess heat ($6.28 per MMBtu).

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[24] http://www.bioferm-es.com/us/

[25] http://www.bioferm-es.com/us/wp-content/uploads/2009/03/bioferm-dry-fermentation.pdf

[26] Information regarding energy and compost outputs, as well as methane offset was provided by BioFerm Energy Systems. BioFerm asserts that these values are based on the average results of dry fermentation anaerobic digestion systems. Actual yields may differ depending on feedstock mix, facility location, and other factors.

[27] Based on discussion with BioFerm, but not a PA-specific value.

The value of waste heat utilization reflects the 2011 average City Gate price for natural gas in Pennsylvania. The analysis is somewhat conservative in that no other projections for increasing revenues from other commodities (electricity and compost) have been contemplated.

GHG Emissions Reduction Analysis:

The GHG reduction is estimated by computing the sum of the methane displacement, offset grid electricity, and avoided natural gas combustion for direct heat. The methane displacement is found by multiplying the number of digesters on line by the annual methane displacement value. The electricity generated per year in a single digester is multiplied by the projected grid-based, thermal mix, electricity emission factor, as referenced above, for each year and the number of digesters on line in each year to yield the GHG reduction from offset electricity generation. The GHG reduction from avoided natural gas combustion for direct heat is found by multiplying the direct heat produced per digester by the natural gas emission factor and the number of facilities on line in each year. The resulting cumulative GHG reduction for 2013–2020 is 0.33 $MMtCO_2e$ (see Table 1).

Table 1. Annual and Cumulative GHG Reductions

Year	Cumulative Number of Facilities	Methane Displacement ($MMtCO_2e$)	Offset Grid Electricity ($MMtCO_2e$)	Offset Heat Generation ($MMtCO_2e$)	Total ($MMtCO_2e$)
2013	0	-	-	-	-
2014	0	-	-	-	-
2015	1	0.02	0.004	0.001	0.03
2016	1	0.02	0.004	0.001	0.03
2017	2	0.04	0.008	0.003	0.05
2018	2	0.04	0.008	0.003	0.05
2019	3	0.06	0.011	0.004	0.08
2020	4	0.08	0.015	0.005	0.10
Total (2013-2020)		**0.27**	**0.05**	**0.02**	**0.33**

Cost-Effectiveness Analysis:

The project costs include capital cost and operating and maintenance (O&M) costs highlighted in the Data Sources for Costs section. The annualized capital cost is found by multiplying the assumed capital cost by the number of facilities on line and an annualization factor.[28] The O&M costs are found for each of the four O&M cost elements using the following calculations, with the sum of the products being the total annual O&M cost:

- Multiply the cost of the front loader by the number of facilities on line in each year.
- Multiply the compost processing cost by the per-facility quantity of compost produced and the number of facilities on line in each year.

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[28] The Capital Recovery Factor method of animalization is used, assuming a 5 percent interest rate and 15 year loan period.

- Multiply the maintenance cost per fermentation chamber by the number of fermentation chambers per facility (8) and the number of facilities on line in each year.
- Multiply the facility operation cost by the number of facilities on line in each year.

The revenues are calculated by taking the sum of the following products:

- Multiply the annual waste received (25,000 tons) by $10/ton
- Multiply the value of compost by the tons of compost produced and the number of facilities on line in each year
- Multiply the value of electricity by the amount of electricity generated per facility and the number of facilities on line in each year
- Multiply the value of direct heat by the amount of direct heat generated per facility and the number of facilities on line in each year and dividing by half (assumes only 50 percent utilization rate)

The cost analysis produces an estimated cost of $0.26 million ($2010, NPV) for the project period 2013–2020. The cost-effectiveness over this time period is equal to $0.77 $/t$CO_2$e. The results of the cost-effectiveness analysis are presented in Table 2.

Table 2. Annual and Cumulative Costs and Cost-Effectiveness

Year	Cumulative Number of Facilities	Annualized Capital Cost ($MM)	Annual O&M Cost ($MM)	Annual Revenue ($MM)	Net Project Cost ($MM)	Discounted Project Cost ($MM)	Cost-Effectiveness $/tCO2e
2013	0	$0.00	$0.00	$0.00	$0.00	$0.00	
2014	0	$0.00	$0.00	$0.00	$0.00	$0.00	
2015	1	$0.56	$0.40	$1.14	-$0.19	-$0.15	
2016	1	$0.56	$0.40	$1.14	-$0.19	-$0.14	
2017	2	$1.12	$0.80	$2.29	-$0.37	-$0.26	
2018	2	$1.12	$0.80	$2.29	-$0.37	-$0.25	
2019	3	$1.67	$1.20	$3.43	-$0.56	-$0.36	
2020	4	$2.23	$1.61	$4.58	-$0.74	-$0.35	
Total (2013-2020)		**$7.25**	**$5.22**	**$14.88**	**-$2.41**	**-$1.61**	**-$4.82**

Implementation Steps:

Projects of this type are far more complex than typical renewable or alternative energy projects because of the need to involve multiple stakeholders to source the feedstock and host the facility. Educating multiple parties to the benefits of these projects and project facilitation are key elements to successful implementation.

Centralized mixed-feedstock anaerobic digestion projects are more viable if the following incentives are available:

- Allowance of renewable energy credits for carbon offset trading.
- Provision of renewable energy grants and loans from federal, state and municipal funds.

- Purchasing agreements with utilities for electricity and direct heat provided by digestion facilities.

Potential Overlap:

No overlap is anticipated because despite utilizing manure for a portion of the feedstock energy resource for these projects it is envisioned that the manure-only digesters will be self-supporting, on-farm projects and not likely not participate or need to participate in the projects discussed in this initiative.

Beneficial Use of Municipal Solid Waste

Summary:

Pennsylvania is second in the country in terms of generation of the amount of electricity from landfill-gas-to-energy projects. Waste-to-energy (WTE) facilities in the Commonwealth also contributed to GHG reductions through the production of up to 276.5 MW, and generated 1,604,742 MWh in 2011 according to the U. S. Department of Energy, Energy Information Agency's (EIA) database. This strategy considers additional GHG emissions reductions associated with the disposal of municipal solid waste (MSW) in the state from these types of facilities, and identifies emerging technologies that may lead to further GHG reductions in the future once these technologies are successfully commercialized.

Effective waste management practices affect GHG emissions in five ways:

1. Minimizing landfill emissions of methane;
2. Reductions in fossil fuel use through energy recovery from waste combustion (as well as use of captured landfill gas);
3. Reduction in energy consumption and process gas release in industrial operations, from recycling;
4. Forest carbon sequestration from a decrease in paper demand; and
5. Energy used in waste disposal or recycling transport. [29]

Goal:

Ensure that all MSW generated or disposed within the state is disposed of at a permitted waste disposal facility and increase the amount of energy generated by existing waste disposal facilities.

Implementation Period:

2015 through 2020

Background Discussion:

The MSW management industry is a comparatively small emitter of GHG. The EPA estimates that all types of waste (including industrial, water and construction waste) account for only 1.9 percent of the United States' aggregate GHG emissions, measured in carbon dioxide (CO_2) equivalents[30]. When one considers the impact of the MSW disposal industry, including recycling, electricity and other energy generation from waste, and carbon sequestration, that number falls to a mere 0.1 percent of total domestic GHG emissions.[31]

GHG emissions from the MSW industry have decreased dramatically in recent years as a direct result of the MSW industry's development of improved technologies. A study commissioned by the National Solid Wastes Management Association ("NSWMA") found that while the volume of MSW disposed increased steadily since 1970, GHG emissions from all MSW management

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[29] IPCC, Working Group III: Mitigation. http://www.ipcc.ch/ipccreports/tar/wg3/index.php?idp=120

[30] US EPA *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2011*, April 12, 2013, page 20, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2013-ES.pdf

[31] NSWMA, (2005) Municipal Solid Waste Industry Reduces Greenhouse Gases through Technical Innovation and Operational Improvements.

activities fell from about 60.5 million metric tons carbon dioxide equivalents in 1970 to just 7.8 million metric tons in 2003.[32,33]

Specifically, MSW management industry has made strides in reducing GHG emissions for three main reasons: 1. the proliferation of landfill gas to energy systems that generate significant quantities of renewable energy, 2. the effective and permanent sequestration of large amounts of biogenic carbon within landfills, and 3. the destruction of methane through landfill gas collection and landfill cover systems. Similarly, the combustion of MSW by WTE facilities generates significant amounts of clean, baseload electricity with significantly lower GHG emissions than traditional fossil-fueled generation because approximately 50 percent of the GHG emissions from WTE facilities are biogenic in origin[34].

The Pennsylvania Alternative Portfolio Standards Act recognizes electricity generated from landfill gas as a Tier I resource, and electricity generated by the state's six WTE facilities is recognized as a Tier II resource. Unlike most other renewable energy resources, baseload electricity is generated from both of these types of facilities. This is a tremendous asset to electric grid integration and operation.

Moreover, several international and domestic protocols, including the Intergovernmental Panel on Climate Change ("IPCC") and the EPA, recognize landfilled material as a "sink" in calculating carbon emissions inventories. In fact, EPA reports that the national average of net GHG emissions for landfills is actually a *negative* amount when factoring in the fact that landfills are carbon sinks.[35] As a result, many international and domestic protocols and programs either ignore landfills because they are insignificant sources of GHG emissions or treat them as sources of emissions reductions. Similarly, the IPCC recognizes that waste combustion with energy recovery as one of the "complementary mitigation measures to landfill gas recovery" as a strategy for reducing GHG emissions from waste disposal.[36]

As an indirect option, waste minimization (i.e. avoided waste generation, reuse/repurposing materials instead of disposal, etc.) and recycling offer significant GHG emission reductions and are preferable to waste generation and/or disposal. This work plan focuses on ensuring that to the extent that waste is generated, the maximum GHG emission reductions from its disposal/use are achieved. Increasing recycling rates in Pennsylvania is the focus of a separate GHG emission reduction strategy set forth in this action plan. In addition to the recommendations in that work

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[32] NSWMA, (2005) Municipal Solid Waste Industry Reduces Greenhouse Gases through Technical Innovation and Operational Improvements

[33] In addition, it is documented that the MSW management industry has decreased GHG emissions from MSW management by over 75 percent from 1974 and 1997. *K. Weitz et al.*, The Impact of Municipal Solid Waste Management on Greenhouse Gas Emissions in the United States, Journal of Air and Waste Management Association, Volume 52, September 2002.

[34] http://www.epa.gov/cleanenergy/energy-and-you/affect/municipal-sw.html

[35] USEPA 1998. Greenhouse Gas Emissions from Management of Selected Materials in Municipal Solid Waste. EPA 530-R-98-013, Exhibit 7-6.

[36] Waste Management, In Climate Change 2007: Mitigation. Contribution of Working Group III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change; page 587. See http://www.ipcc.ch/pdf/assessment-report/ar4/wg3/ar4-wg3-chapter10.pdf

plan, WTE facilities offer additional recycling opportunities for certain materials, primarily metals, which are inherent to their operations.

To the extent that waste disposal occurs in landfills, the most important factors for reducing GHG emissions is that an operating landfill gas collection and control system is present to minimize landfill gas emissions. Additional GHG emission reduction benefits occur if the collected gas is beneficially used to create electricity or other forms of energy. These types of projects generally fall into three categories—electrical generation, direct use of medium-BTU gas, and processing landfill gas into natural gas-pipeline quality high-BTU gas (collectively "landfill gas-to-energy" or "LFGTE" projects). To the extent that waste disposal occurs through combustion, the most important factor for reducing GHG emissions is ensuring that the combustion occurs in a properly permitted WTE facility that generates electricity and/or other forms of energy.

The Pennsylvania Department of Environmental Protection has considerably more stringent requirements for the installation and operation of landfill gas collection and control systems than those set forth by EPA. EPA requires gas collection in certain MSW landfills with waste disposal capacities of 2.5 million megagrams.[37] DEP requires gas collection in all MSW landfills with waste disposal capacities of 1.0 million megagrams.[38] EPA requires installation of those gas collection systems the earlier of two years from reaching final fill grade, or 5 years from the start of active filling.[39] DEP requires installation of those gas collection systems as soon as practical to prevent odor migration, typically 10 months from the start of filling. In addition, in certain circumstances, EPA allows direct venting of landfill gas in a variety of short-term operational scenarios. However, DEP strictly forbids short-term venting of landfill gas. As a result, all active MSW landfills in Pennsylvania have operating gas collection and control systems. Pennsylvania landfills collect a much higher percentage of landfill gas generated by its landfills as compared to landfills in other states and a higher percentage of that collected gas is beneficially used.

For waste combustion, all six of the operating WTE facilities in the state produce electricity from their waste combustion activities. The WTE facilities are all subject to, and comply with, stringent air emission control requirements, set forth generally in 40 CFR Part 60 and Part 63, as applicable; the requirements are enforced by EPA and DEP. Construction of facilities that mimic the operations of WTE facilities, but which evade the air emission control requirements which the WTE facilities are subject, represent a serious threat to maintaining the GHG emission reductions that have been achieved.

Energy recovery from excess heat generated from WTE facilities represents a largely untapped option to further increase the GHG emission reductions that occur from these facilities. Close proximity of a potential end-user for the excess heat is an important factor in developing these

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[37] See 40 CFR Part 60, Subpart WWW.

[38] See the Department's *Best Available Technology and Other Permitting Criteria for Municipal Solid Waste Landfills*, Document No. 275-2101-007. http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-75264/7.10%20Best%20Available%20Technology%20and%20Other%20Permitting%20Criteria%20for%20Municipal%20Solid%20Waste%20Landfills.pdf

[39] See 40 CFR Part 60, Subpart WWW.

projects, and for certain industries, use of excess heat (typically in the form of steam) is a significant economic benefit. Recently, manufacturers and other types of business with significant process heating requirements have evaluated co-locating at or near WTE facilities.

Landfill gas represents another alternative source of energy production that has been used primarily for the generation of electricity, but has also been used for other purposes such as direct thermal and for the conversion of liquefaction into transportation fuels. The most recent survey in 2010 indicated 42 active projects, four planned projects, and the potential for another 17 projects occurring at the various 28 landfill sites. If all planned and potential projects were realized, the state could have a total of 74 projects by 2017.

Using landfill gas as a fuel is beneficial to the environment since it prevents the release of methane and carbon dioxide into the atmosphere and offsets the consumption of other fuels. In the past, it was simply collected and flared, but now many landfills are taking advantage of their waste gas, using it to produce heat and power. Landfill gas is similar to natural gas, but with a smaller percentage of methane and half the BTU content resulting in fewer emissions.

Landfills in Pennsylvania were an early adopter of LFGTE projects. The state has 40 operating projects[40] and is second in the nation (behind only California) in the number of LFGTE projects operating. Pennsylvania's electrical projects generate 171 MW of baseload electricity. The engines and turbines used to produce this electricity typically have annual utilization factors of 95-98 percent. In addition, there are four medium-BTU pipeline projects, where the landfill gas is piped and directly used as a replacement fuel by asphalt plants, cement kilns, industrial boilers, commercial heating, potato dehydration and greenhouses. The state has eight landfills with high-BTU operations, more than any other state in the country and nearly 25 percent of all high-BTU projects in the country.[41] High BTU operations process the collected landfill gas into "pipeline grade" natural gas standards by essentially removing all non-methane components.

According to EPA's Landfill Methane Outreach Program's (LMOP's) website, in most states, there are more landfills that are "candidates" for an LFGTE project than there are landfills with operating LFGTE projects. Pennsylvania stands in stark contrast to the national landscape—LMOP reports that as of July 2013, 43 out of 51 landfills in Pennsylvania have operating LFGTE projects, a rate that significantly exceeds California's rate and is in the top-4 nationally. Despite all of these successes, only 59 percent of collected landfill gas at Pennsylvania landfills was used for beneficial use in 2011.[42] The annual generating capacity of the 42 active plants in Pennsylvania exceeds 37 billion cubic feet. If all currently planned projects were developed, this generating capacity would increase to more than 40 billion cubic feet per year by 2015. An additional 28 projects with a total capacity of over 17 billion cubic feet per year are described as "potential projects." These potential projects would not come online until approximately 2017.

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[40] Differences in the reported number of projects in Pennsylvania is due to competing methodologies on classifying "projects" at landfills with multiple beneficial use operations.

[41] US EPA's LMOP website reports that there are 33 high-BTU projects operating at a total of 34 landfills nationwide. See *Upgraded LFG (XLS)* spreadsheet at http://www.epa.gov/lmop/projects-candidates/operational.html .

[42] Based on an analysis of 2011 Annual Reports on file at DEP's Bureau of Solid Waste.

Clearly, there are significant opportunities to improve the rate of LFGTE generation in Pennsylvania.

The primary barriers to increasing landfill gas use include the following:

1. For all electricity generating projects, low wholesale electric prices[43].
2. For medium and high-BTU projects, low natural gas prices.
3. DEP regional emission testing requirements that exceed US EPA requirements as well as those set forth in the Department's *Best Available Technology and Other Permitting Criteria for Municipal Solid Waste Landfills*.
4. Engine overhaul and core change-out requirements that exceed federal standards, which reduce operation at existing LFGTE projects.
5. The remaining few landfills without LFGTE projects are smaller sites, with smaller quantities of landfill gas generation. Economies of scale make development of these projects more difficult.
6. Obtaining right-of-way easements for pipelines and power lines.
7. Uncertainty over long-term LFG supply (waste volumes down, diversion of organics, etc.)

For existing LFGTE projects, GHG emission reductions can occur from:

1. Reducing project downtime.
2. Beneficial use of waste heat.
3. Incremental increases in projects as landfill gas generation warrants (for example, installation of a 4th engine at an existing three-engine project).

For landfills without LFGTE projects, GHG emission reductions can occur from the installation of an LFGTE project.

For existing WTE facilities, GHG emission reductions can occur from:

1. Reducing WTE facility downtime
2. Beneficial use of waste heat.

According to the EPA's landfill methane outreach program's benefits calculator, the electricity produced at LFGTE facilities from PA landfills reduces GHGs by 7.23 million metric tons per year[44]. The GHG emission reductions from the state's medium-BTU and high-BTU projects are not quantified at this time, but those reductions are meaningful, and those projects have provided an economical source of energy for numerous Pennsylvania manufacturing facilities, as well as providing the basis for "green" marketing claims relating to the use of renewable energy.

The six WTE facilities in the state generated approximately 1,604,742 MWh of electricity in 2011, directly offsetting consumption of other fuels for electricity generation. Electricity generated using WTE facilities are assumed to have a GHG emission value of 1843 lbs/MWh.[45]

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[43] By way of comparison, California leads the country in LFGTE generation. California's wholesale electricity prices are typically double to triple Pennsylvania's prices.

[44] See slide 19 of the PA DEP Landfill Gas to Energy presentation, February 7, 2013.

[45] US EPA notes, at http://www.epa.gov/cleanenergy/energy-and-you/affect/municipal-sw.html, that "the average air emission rates in the United States from municipal solid waste-fired generation are: 3685 lbs/MWh of carbon

<u>Recommended Actions/Implementation Steps</u>

In 2011 the Keep Pennsylvania Beautiful program identified nearly 5,800 illegal dump sites in Pennsylvania, accounting for more than seventeen thousand tons of illegally dumped trash. Eliminating illegal dumping will reduce GHG emissions, which occur when the waste in these sites breaks down without any gas collection or control. The state does not have any statutes or regulations banning open burning of household generated solid waste, although some municipalities do have local ordinances that set forth bans. Clearly, many communities in Pennsylvania either allow, or do not enforce restrictions, on the open burning of waste by residents. Open burning of waste generates significantly more GHG emissions than disposal through permitted landfills or WTE facilities.

Through the LMOP program, DEP signed a Memorandum of Understanding with US EPA establishing a partnership to promote the use of landfill gas, including the removal of unnecessary state barriers. DEP should convene a working group of representatives from the Bureau of Air Quality, the Bureau of Solid Waste, and industry stakeholders to identify existing barriers to further development of LFGTE projects. This working group should specifically address the necessity of continued regional deviations from the Department's *Best Available Technology and Other Permitting Criteria for Municipal Solid Waste Landfills* policy that currently occur. The working group should also consider whether a revision to the Landfill Gas Primer, published by the Department in 2004 but currently unavailable, would be an appropriate vehicle for removing any identified barriers.

The transition to competitive electric generation supply, as well as the development of natural gas resources in Pennsylvania, has contributed to a decline in the wholesale price of electricity. In addition, the current regulatory preference for short term wholesale electric supply contracts between electric generation suppliers (EGSs) and electric distribution companies (EDCs) undermines the predictability and stability of revenues for LFGTE projects and WTE facilities. It may be possible to mitigate this impact by providing facilitated access to retail energy markets and by encouraging EDCs to enter into long-term procurement contracts with alternative energy sources generally and these sources specifically. The ability to enter into long-term contracts for electricity sales could provide a hedge against low wholesale electricity prices for LFGTE projects and WTE facilities. In addition, the ability to enter into such contracts would assist in obtaining financing for the development/expansion of LFGTE projects.

Pennsylvania, through its various economic development arms, should encourage co-locating industrial and institutional facilities and commercial business centers to facilitate the utilization of waste heat from LFGTE projects and WTE facilities. Such efforts would offset consumption of fossil fuels, and would also provide additional revenue to these facilities. Generally, the focus should be on promoting co-development at WTE facilities, which have higher waste heat loads and more centrally located facilities.

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dioxide, (it is estimated that the fossil fuel-derived portion of carbon dioxide emissions represent approximately one-half of the total carbon emissions)…". Because 50% of the carbon emissions would occur regardless of combustion, half of the emission rate has been used. This is consistent with other calculation methodologies set forth on US EPA's website.

Municipal solid waste is a valuable feedstock for generation of electricity by landfills and WTE facilities. Currently, significant quantities of MSW travel from New York and New Jersey, through Pennsylvania, to Ohio and Virginia landfills. DEP should adopt policies to capture this trans-state transported MSW for beneficial use inside the state. This would have the added benefit of significantly increasing revenue to the Department and funding of statewide recycling programs.

Processing of landfill gas into a mobile source fuel has occurred in other states. Because trash pickup trucks travel routes that by definition include a waste disposal facility, conversion of trash pickup trucks to compressed natural gas (including fuel produced from landfill gas) is a viable option. In Pennsylvania, the primary barrier to these conversions is Chapter 90 of the Pennsylvania Vehicle Code, the Liquid Fuels and Fuels Tax Act, which requires alternative fueled vehicles to pay tax on use of alternative fuels at the same rate of fossil fueled vehicles. This tax essentially eliminates any economic incentive to produce mobile source fuel from landfill gas. The state should survey other state's fuel taxing provisions and determine if changes to the Liquid Fuels and Fuels Tax Act should be considered by the General Assembly to promote natural gas-type fuels as a mobile source fuel.

The Future

Pennsylvania has been a very good partner in helping many of these projects come to fruition. Many LFGTE projects, particularly those at smaller landfills, were seeded with Energy Harvest and other grant money. Industry stakeholders note that the central office of DEP's Bureau of Air Quality has been particularly helpful in removing air permitting hurdles for these projects, and the PUC has similarly been helpful in assisting with landfill gas pipeline siting and distribution issues, as well as interconnection issues for electricity generating projects. Continued assistance from these stakeholders is critical.

Though not widely deployed in Pennsylvania, new technologies beyond WTE and LFGTE are in active development and should be evaluated for future deployment in the disposal of MSW. Such emerging technologies include gasification, pyrolysis, and legitimate fuel production. MSW can be processed into a fuel, and the city of Philadelphia has recently contracted with Waste Management, Inc. for such a project. The CCAC has recommended that these emerging technologies be actively evaluated during preparation of the next Climate Change Action Plan.

GHG Emissions Reduction Analysis:

Increasing the amount of landfill gas utilized for electricity generation by 10 percent would decrease GHG emissions by 0.723 million metric tons per year. This is a reasonable goal, beginning in 2015, assuming adoption of some, but not all, of the recommendations in this work plan specific to electricity generation form LFGTE projects at landfills.

Increasing the amount of electricity generated by the existing WTE facilities through increased operational efficiency will result in an additional decrease in GHG emissions. A 1 percent increase in efficiency—i.e. generating 1 percent more electricity from the same amount of waste—would correlates to an increase of approximately 16,000 MWh of electricity per year. Using the average thermal mix (50 percent coal, 50 percent natural gas) and a CO_2 intensity of approximately 0.69 metric tons (t)/MWh, this would reduce GHG emissions by 11,040 metric tons (0.011 million metric tons) GHG reduction. Co-locating facilities that require process heat will generate additional GHG emission reductions. Each 1 mmBTU of fossil fuel generation from waste heat reduces GHG emissions by 0.0003 million metric tons per year, and as average waste heat usage rate of 2 mmBTU per hour for 4000 hours per year, combined industry-wide, would yield an additional annual GHG reduction of 2.4 million metric tons per year. Implementation of the other recommendations in this work plan all would result in GHG emission reductions, although they are not quantified at this time. These three potential GHG emission reductions total just less than 3.2 million metric tons per year.

Based on the amount of reductions possible, and assuming that some but not all of the work plan's recommendations are adopted (and/or fully implemented), it is reasonable to assume a decrease of at least 1.0 million metric tons of GHG emissions per year, starting in 2015.

Cost-Effectiveness Analysis:

The costs associated with most of these recommendations are minimal—primarily Commonwealth staff time (DEP and/or DCED). Several recommendations would generate additional revenue for the Commonwealth and industry while reducing GHG emissions, particularly the two strategies with the largest reductions—waste heat use and increasing LFGTE deployment. Additional cost-effectiveness occurs due to reduced illegal dumping and trans-state transported waste. The costs that would occur from changes to the Liquid Fuels and Fuels Tax Act are not quantified, as no specific change is recommended, but could be substantial.

Overall, it appears that an annual 1.0 million metric ton GHG reduction could be achieved on a cost-neutral or better basis.

Potential Overlap:

- Statewide Recycling Initiative

No backsliding of mandated recycling requirements is envisioned or suggested in this work plan. Furthermore, the Statewide Recycling Initiative focuses on venues that currently have limited or no recycling programs in place, aiding in reaching the goal of that work plan. An overlap may exist between this work plan and the Statewide Recycling Initiative work plan, but it is not quantifiable based on the limited data available at this time. Overlap would exist only to the extent that the same waste would be subject to both work plans.

The Alternative Fueled Transit Bus Fleet and Alternative Fueled Taxicab Fleet work plans may work synergistically with this work plan, depending on the specific implementation steps taken to implement those work plans and the potential for additional fueling stations.

Nuclear Capacity Uprates

Summary:

This work plan focuses on capacity uprates at existing nuclear plants in Pennsylvania. Using data from the PJM planning queue and data from the U. S. Department of Energy, Energy Information Agency's (EIA) 860 database, DEP estimates 551 MW of additional potential capacity at PA nuclear power plants (Limerick, Peach Bottom, Susquehanna, Three Mile Island), as compared to nameplate capacities in 2008. The data also suggests that since the year 2000, the baseline year from which GHG reductions are being compared in the action plan, a total of 1,000 MW may be online before 2020.

Possible New Measure(s):

Nuclear Uprates—To increase the power output of a reactor, typically a more highly enriched uranium fuel is added. This enables the reactor to produce more thermal energy and therefore more steam, driving a turbine generator to produce electricity. To accomplish this, such components as pipes, valves, pumps, heat exchangers, electrical transformers, and generators must be able to accommodate the conditions that would exist at the higher power level. For example, a higher power level usually involves higher steam and water flow through the systems used in converting the thermal power into electric power. These systems must be capable of accommodating the higher flows.

In some instances, facilities will modify and/or replace components to accommodate a higher power level. Depending on the desired increase in power level and original equipment design, this can involve major and costly modifications to the plant, such as the replacement of main turbines. All of these factors must be analyzed by the facility as part of a request for a power uprate, which is accomplished by amending the plant's operating license. The analyses must demonstrate that the proposed new configuration remains safe and that measures continue to be in place to protect the health and safety of the public. Before a request for a power uprate is approved, the Nuclear Regulatory Commission must review these analyses.

Potential GHG Reduction:

Avoided emissions are calculated on the basis of known potential uprates displacing a mix of 50 percent coal and 50 percent gas at a combined average of 1,523 lb/MWh.

The costs and GHG reductions for this work plan are estimated in Table 1.

Table 1. Work Plan Costs and GHG Results

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effectiveness ($/$tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($/$tCO_2e$)
5.4	$840	$155.25	30.4	$3,553	$117

- Nuclear uprate costs are based on FPL Energy's proposed uprate of its Florida-based Turkey Point and St. Lucie pressurized water reactor units. Pressurized water reactors exist at the Beaver Valley and Three Mile Island plants.

- The generation resources that are assumed to be avoided under this work plan are 50 percent existing pulverized coal, and 50 percent existing natural gas. The weighted-average cost of generation for the avoided mix is $92.50 in 2020. The avoided CO_2 emissions associated with this mix is 0.69 metric tons CO_2/MWh.

Table 2: Nuclear Technology Assumptions

Nuclear Characteristics	For Year 2020	Source
Unit Size MW	varies	Communications with First Energy, PPL and Exelon staff, PJM queue and EIA sources
Capacity Factor	90%	Assumption
Installed Capital Costs $/kW	$3,892	Uprate: FPL proposed 2011 uprate for Turkey Point and St. Lucie plants.
O&M Costs $/kWh	$3.1	Uprate: FPL proposed 2011 uprate data for Turkey Point and St. Lucie plants.
Fuel $/MBTU	$1	Assumption
Net Generation Cost $/MWh	$66.20	Calculation
Avoided Price of Power $/MWh	$48.73	Calculation based on 50% existing coal and 50% existing gas plant mix.
MW Capacity	949	Described Above
MWh Generation	7,485,070	Calculation

<u>Implementation Steps:</u>

- Market forces will drive investments into infrastructure, to uprate capacity. These up-front costs will yield greater energy generation capacity and efficiency, leading to increased sales and, eventually, increased profits.
- The Pennsylvania Public Utility Commission should speak with nuclear power plant operators to better understand what impediments may delay these uprates and what, if any, actions the state can take to facilitate these actions by 2020.
- Some of these actions may currently be being implemented.
- Market-driven initiative
- Are cost savings realized from this initiative?—Not directly. Indirect savings to the commonwealth will accrue subject to in-state low-carbon electricity development

(manufacturing, installation, sales and service, etc.). Indirect costs include displaced coal industry jobs and other fossil fuel-related economic production and consumption.

Potential Overlap:

None

Manure Digesters

Initiative Summary:
Anaerobic digestion is a biological treatment process that reduces manure odor, produces biogas, which can be converted to heat or electrical energy, and improves the storage and handling characteristics of manure. This work plan recommendation or initiative analyzes the potential for increasing anaerobic digester deployment at medium to large-sized dairy and swine farms.

Currently, there are 26 manure digesters in Pennsylvania and at least three more under construction. At least 14 of these have been funded, in part, through DEP and other commonwealth-supported financing programs. These digesters are converting the effluent from more than 14,000 dairy cows and 29,000 hogs into useable thermal energy and electricity.

Goals:
Install a total of 25 anaerobic digesters on dairy farms of 500 or greater cows and 10 digesters at swine operations with 3,000 or more animals.

Implementation Period: 2013 through 2020. Implementation will increase steadily between 2013 and 2020.

Implementation Steps: Continuation of financial assistance through state, federal and private programs to help overcome the burden of up-front capital costs. Potential operators of anaerobic digesters could rely on several different funding programs/mechanisms, including grants, cash reimbursements, loan guarantees, industrial bonds, private funding, and other cost-sharing agreements. Many anaerobic digester operators apply for and receive a combination of funding mechanisms (e.g., loan guarantees and grants) to fund their projects. Some examples of programs where federal and state agencies provide grant funding for the construction and operation of anaerobic digesters include the DEP, U.S. Department of Agriculture (USDA) and the Rural Energy for America Program (REAP) to mention a few. In addition there are accelerated outreach programs through state and federal institutions, such as the PSU Cooperative Extension Units, educating the agricultural community as to the multiple economic and environmental benefits associated with energy production and nutrient reduction strategies.

Data Sources/Assumptions/Methods for GHG:

Dairy Cow Anaerobic Digesters

This type of technology could be applied to beef cattle, although their methane emissions in Pennsylvania are far lower than emissions from dairy cattle. Swine manure emissions are considered later in this analysis.

Anaerobic digestion (AD) systems result in three areas of GHG emissions reductions. The first results from the collection and digestion of manure, which actually serves to increase methane emissions above business as usual without deployment of a digester. The difference in generated emissions beyond baseline levels is netted out. It is the destruction of the net balance of this methane that results in the first source of emissions reductions.

The second area of GHG reductions is obtained by offsetting fossil fuels used in the generation of electricity or for direct use as thermal energy. For the purposes of this analysis, it is assumed that the methane is used to create electricity, displacing fossil-based electricity generation, which is the norm.

Manure digesters operate most efficiently at about 120 to 130 degrees Fahrenheit, which is the approximate temperature at which most digesters are maintained. Since it never approaches this temperature in Pennsylvania, more methane will be created and captured in the digester than was previously released before digester installation. The increase in methane produced (and captured) was estimated by comparing the amount of methane captured in an AD, as found in the AA Dairy and Knoblehurst farms in New York, with the amount of methane created in a typical dairy farm (as found in the EPA's State GHG Inventory Tool module). This module found that nearly four times as much methane was generated in ADs than would have been created under normal environmental conditions. This figure is applied to calculate the amount of methane captured and used to generate electricity in all ADs.

The policy objective begins in 2013 with two new digesters and ramps up linearly to a total of 25 new digesters in 2020. Table 1 shows the GHG reductions possible by installing this number of ADs at Pennsylvania dairy farms.

Table 1. GHG Reductions from Methane Utilization

Year	**Cumulative Digester Total**	**Cumulative Dairy Herd Size Served**	**Baseline CH4 Capture (MtCO2e/Yr)**	**CO2 Offset from Electricity Generation (MtCO2e/yr.)**	**CO2 Reductions from Waste Heat Utilization (MtCO2)**	**Total CH4 Emission Reductions (MMtCO$_2$e)**
2013	2	1,500	469	1.96	4	0.0005
2014	4	3,000	938	3.91	9	0.0010
2015	156	4,500	1,407	5.87	13	0.0014
2016	208	6,000	1,877	7.82	17	0.0019
2017	2511	8,250	2,581	10.75	24	0.0026
2018	3015	11,250	3,519	14.66	32	0.0036
2019	35520	15,000	4,692	19.55	43	0.0048
2020	4025	18,750	5,865	24.44	54	0.0059
					Total	**0.0216**

Use Costs

The costs for dairy farm AD systems for farms with 500 or more cows is based on data and experiences from DEP, which has provided financing to several digesters in this size class, as well as those in New York. Both states are leaders in the numbers of farm digesters installed. That data indicates that an average total cost for farms of this size is approximately $1,371 per head in $2010. Projected capital costs were made based on an assumed average 2.5 percent annual rate of inflation. Smaller-scale farm digesters, while feasible for those with centralized manure collection and handling systems, are generally less cost effective, hence the focus on larger farm installations. Table 2 provides perspective of Pennsylvania dairy farm size distribution and the projected trend toward larger farms due to improved economics.

Table 2. Estimated Breakdown of Dairy Farm Size (head)

Year	Percentage in Large Farms (>500)	Percentage in Medium Farms (100-500)	Percentage in Small Farms (<=100)
2013	6%	43%	52%
2014	6%	43%	51%
2015	6%	44%	50%
2016	6%	45%	49%
2017	6%	45%	48%
2018	7%	46%	47%
2019	7%	47%	46%
2020	7%	48%	45%

Annual operations and maintenance (O&M) costs come from a USDA study comparing several types of digesters for both dairy and swine. This study reports O&M costs as a percentage of capital costs. Typical AD systems at Pennsylvania dairy farms are plug-flow digesters with reported annual O&M costs identified as 2.4 percent of capital costs. Electricity generated is calculated based on the average annual electricity generated/head on farms with ADs already installed. Data from DEP suggests that this value is approximately 1,887 kWh/head/year, which is then multiplied by the number of dairy cattle with a new AD system in place to determine total electricity generated. DEP estimates that on average about 35 percent of this electricity is used on the farm. Pennsylvania has among the best net metering laws in the country, and the revenue of this electricity generation is split between the value of what is used on site and that which is delivered into the electric grid. The value of electricity consumed on site was calculated based on actual statewide average rates and projected forward using projection estimates from the US Energy Information Agency. In this analysis, the rate class chosen was commercial and valued at a retail price of 10.56 cents per kWh in 2013, increasing to 12.47 cents in 2020. The rate at which electricity is sold back to the local electric distribution company is a wholesale rate and is determined by market forces but was estimated at 5 cents per kWh and does not change through 2020.

Use of waste heat from the engine jacket and generator from dairy digester systems represents a significant cost savings measure. Data from DEP suggests that an average system may yield 22.3 MMBtu (equivalent to about 170 gallons of heating oil) of recoverable heat that is typically used to offset heating oil needs. Carbon offsets associated with the displacement of fossil fuels (typically heating oil) used for heating and absorption chillers provides another source of revenue as does the revenue for carbon offsets associated with the capture and destruction of methane, as compared to baseline values if no digester were in installed.

The costs and revenues associated with the dairy digester aspect of this work plan recommendation are provided below in Table 3. All costs are reported in 2010 dollars and discounted using a 5 percent discount rate.

Table 3. Net Costs / Savings of Anaerobic Digesters for Dairy Cows

Year	Annualized Capital Cost (MM$)	Annual O&M Costs of Anaerobic Digesters (MM$)	Carbon Offset Revenue (MM$)	Value of kWh Used on Farm (MM$)	Revenue from Electricity Sales (MM$)	Value of Fossil Fuel Displaced by Waste Heat (MM$)	Net Annual Costs Savings (MM$)	Discounted Net Costs of Program (MM$)
2013	0.18	0.05	1,426	0.10	.09	0.001	0.03	0.03
2014	0.36	0.11	2,853	0.21	0.18	0.002	0.07	0.06
2015	0.56	017	4,279	0.33	0.28	7.60.003	0.11	0.09
2016	0.76	.23	5,705	0.45	0.37	10.30.004	0.17	0.12
2017	1.08	0.32	7,845	0.63	0.51	0.006	0.25	0. 18
2018	1.51	045	10,698	0.88	0.69	15.80.008	0.36	0.25
2019	2.06	0.62	14,264	1.21	0.92	0.011	0.52	0.34
2020	2.64	0.79	17,830	1.54	1.15	0.013	0.70	0.43
						Total	2.21	1.48

Cost-effectiveness is calculated by dividing total, discounted costs (over the entire period) by the cumulative GHG savings of the project to get a $/metric ton (t) figure. For example, in this analysis, the net cost is $2.21 million (found at the bottom of Table 3), and the GHG savings are 0.0216 MMt (located at the bottom of Table 1). This means that the cost-effectiveness of the implementation scenario is $93/ton.

Swine Anaerobic Digesters

Pennsylvania currently has anaerobic digesters operating at seven swine operations. This work plan recommendation analyzes the potential of adding two additional ADs per year for a total of 16 through the end of year 2020. Among the benefits of farm-based digesters is their ability to control odors. Odor control has a very real value even if it cannot be effectively monetized. In fact, one of the longest running anaerobic digesters in Pennsylvania was installed at the Rocky Knoll Swine Farm in 1985 primarily for odor control.

The GHG reductions of this policy were estimated for Pennsylvania pig farms, which yield approximately 39 percent of total manure methane emissions. The emissions from pig farms were taken from the Pennsylvania GHG inventory. A manure management survey by the U.S. Department of Agriculture (USDA) found that 58 percent of large-scale (>1,000 head) pig farms used anaerobic lagoons. The availability of Pennsylvania-specific information on the breakdown of manure management technologies and farm size would improve this analysis.

CAFO farms are assumed to have more than 1,000 head of pigs. Most of these farms have anaerobic lagoons and those that don't are believed to have anaerobic pits that can be replaced with ADs. Based on previous discussions with the Pennsylvania National Agricultural Statistics Service (NASS), it is assumed that swine population figures will remain constant between 2010 and 2020.[46] This analysis is based on swine farms with 3,000 pigs. Table 4 shows the implementation path used for this policy and the GHG reductions expected.

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[46] Personal Communication with Mark Linstedt by Jackson Schreiber, PA Office of NASS. 5/21/09.

Table 4. GHG Emissions Reductions from Swine Farm Digesters

Year	Cumulative Digester Total	Cumulative Swine Herd Served	Baseline CH4 Digester (MtCO2e/Yr)	CO2 Offset from Electricity Generation (MtCO2e/yr.)	Total GHG Reductions (MMtCO2e)
2013	1	3,000	,802	0.08	0.0008
2014	2	6,000	1,604	0.17	0.0016
2015	3	9,000	2,406	0.25	0.0024
2016	4	12,000	3,208	0.34	0.0032
2017	5	15,000	4,010	0.42	0.0042
2018	6	18,000	4,812	0.51	0.0048
2019	8	24,000	6,415	0.68	0.0064
2020	10	30,000	8,019	0.85	0.0080
				Total	**0.0313**

BAU = business as usual; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Swine Manure Management Costs

The costs of this policy were estimated from data obtained from Moser, et.al.[47] a USDA Economic Research Service Report by Key and Sneeringer,[48] and data from DEP. The average capital costs for swine digesters was estimated at $42.49 per head ($2010) and projected forward at an assumed average annual rate of inflation of 2.5 percent. O &M costs were determined to be $0.02 per head. Table 5 presents more information on the costs/cost savings analyzed in this aspect of the work plan strategy.

Table 5. Net Costs / Savings of Anaerobic Digesters for Swine

Year	Annualized Capital Costs (MM$)	Annual O&M Costs (MM$)	Revenue from Carbon Credits (MM$)	Value of kWh Used on Farm (MM$)	Revenue from Electricity Sales ($MM)	Net Costs / Savings ($MM)	Discounted Net Costs / Savings ($MM)
2013	0.01	0.00	2,406	0.01	.0003	(0.001)	(0.001)
2014	0.02	0.01	4,812	0.02	.001	(0.001)	(0.001)
2015	0.03	0.01	7,218	0.04	.001	(0.001)	(0.000)
2016	0.05	0.01	9,624	0.05	.001	0.001	0.001
2017	0.06	0.02	12,030	0.06	.002	0.003	0.002
2018	0.07	0.02	14,436	0.07	.002	.006	0.004
2019	0.10	0.03	19,248	0.10	.002	0.011	0.007
2020	0.13	0.04	24,060	0.12	.3	.018	0.011
					Total	0.03	0.02

<u>Key Assumptions and Uncertainties:</u> The analysis for swine digesters is based on limited availability of data and specific for complete mix anaerobic digester technology. Costs would vary for other digester designs such as plug-flow systems. Also, if the amount of methane gas

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[47] Moser, Mark A., Mattocks, Richard P., Gettier, Stacy and Roos, Kurt “Benefits, Costs and Operating Experience at Seven New Agricultural Anaerobic Digesters” http://www.epa.gov/agstar/documents/lib-ben.pdf

[48] Nigel, Key and Sneeringer, Stacy. **“**Climate Change Policy and the Adoption of Methane Digesters on Livestock Operations” http://www.ers.usda.gov/media/131839/err111.pdf

being generated pre and post anaerobic digester is significantly different it stands that the differences in the outcomes will be amplified. Different from dairy anaerobic digestion systems, swine operations in this analysis are assumed to use all of the waste heat captured to keep the digesters in homeostasis with no remaining waste heat being utilized on the farm. Carbon offsets or credits may be too few for a single or smaller project to pursue marketing. As such, it may be necessary for multiple owners of anaerobic digestion systems to pool their carbon credits to aggregate sufficiently large volumes for more efficient marketing.

Potential Overlap:

This work plan is recognized as potentially overlapping with the analysis of the Alternative Energy Portfolio Standard work plan. The degree of specificity and detail in this digester work plan is not used in the more macro-level analysis performed for the AEPS. The digester work plan necessarily requires a full accounting for implementation purposes and to remove costs and/or cost savings data related to electricity generation would prevent a transparent appreciation for the overall economics. Instead the assumption used here is that the farms would benefit only from the aspects of net metering and the sale of carbon offsets. The value of AEPS credits was appropriately not included in the digester work plan to avoid overlap. Analysis for the AEPS is based on operational costs and a mix of weighted average prices for the purchase of AEPS credits.

The potential for overlap between this work plan and the work plan for Waste-to-Energy Digesters was evaluated and determined that there is sufficient manure feedstock for both work plans so no overlap was calculated.

Grants and Cost-Sharing:

To help overcome the burden of up-front capital costs, operators of anaerobic digesters may rely on several different funding mechanisms, including grants, cash reimbursements, loan guarantees, industrial bonds, private funding, and other cost-sharing agreements. Many anaerobic digester operators apply for and receive a combination of funding mechanisms (e.g., loan guarantees and grants) to fund their projects.

Some examples of programs where federal and state agencies provide grant funding for the construction and operation of anaerobic digesters include the USDA REAP, PA Department of Agriculture (PDA) and DEP.

Other Cost-Sharing Agreements:

In other cost-sharing agreements, the farm operator and another entity (e.g., an electric utility, other company) share the capital and/or operating costs of the anaerobic digester. In exchange for providing funding, the entity receives a tangible return (e.g., owning the electricity generated) or receives environmental credits, such as the renewable energy credits/certificates (RECs) or the carbon offset credits.

Private Funding Sources:

Because grants and cost-sharing agreements may not cover the full costs, most farm operators interested in anaerobic digestion will have to provide at least some up-front capital to cover the capital cost of the digester. In these situations, farm operators will have to secure funds in a more traditional sense. Private funding or financing may come in the form of equity financing, debt financing, or some combination of both.

Loan Guarantees and Industrial Bonds:

A federal or state loan guarantee is a funding mechanism in which a federal agency guarantees the loan (i.e., full repayment of a loan). Loan guarantees typically lower the cost of financing an anaerobic digester by effectively reducing the interest rate required on a loan to purchase and install the digester. Loan guarantees also allow digester projects to attract a larger number of potential lenders than traditional loans. With the loan guarantee, potential lenders are guaranteed full repayment of the loan, even if the digester operator defaults on the loan.

CCAC Member Comments:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.

Sulfur Hexafluoride (SF_6) Emission Reductions from the Electric Power Industry

Summary:

This initiative uses a pollution prevention approach, including a best management practice (BMP) manual and recordkeeping and reporting requirements, to ensure that all SF_6 emission reductions are quantified and permanent.

Background:

SF_6 is identified as the most potent non-CO_2 GHG, with the ability to trap heat in the atmosphere 23,900 times more effectively than CO_2. Approximately 80 percent of SF_6 gas produced is used by the electric power industry in high-voltage electrical equipment as an insulator or arc-quenching medium. SF_6 is emitted to the atmosphere during various stages of the equipment's life cycle. Leaks increase as equipment ages. The gas can also be accidentally released at the time of equipment installation and during servicing. Table 1 presents annual SF_6 emissions from the Pennsylvania electricity sector. The trend illustrates an approximate annual rate of decline of 2.8 percent

Table 1. Annual SF_6 Emissions from Pennsylvania's Electric Power Sector (MMtCO2e)

Year	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
MMtCO2e	0.628	0.650	0.629	0.608	0.609	0.613	0.561	0.533	0.538	0.513

Work Plan Costs and GHG Reductions:

EPA identifies several categories of reduction measures. The following text is from the EPA Web site:[49]

- **Recycling Equipment**
  - The capital costs of recycling equipment range from around $5,000 to over $100,000 per utility. For this analysis, typical recycling expenditures have been set at $25,500 per utility. However, this capital investment produces O&M savings of nearly $1,600 per year per utility due to reduced purchases of SF6.
- **Leak Detection and Repair**
  - There are no capital costs associated with leak detection and repair and O&M costs are estimated to be $2,190 per utility due to the increased labor costs associated with this option.
- **Equipment Replacement/Accelerated Capital Turnover**
  - The capital costs of this option vary by equipment type. Circuit breakers (below 34.5 kV) may be replaced with vacuum breakers. The replacement cost varies from $25,000 to $75,000 per unit. Medium and high voltage breakers are expected to continue to use SF6 because no other option is currently available. Older breakers are assumed to leak more and are being replaced by new

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[49] US EPA. Final Report on U.S. High Global Warming Potential (High GWP) Emissions 1990-2010: Inventories, Projections, and Opportunities for Reductions. Chapter 3: Cost And Emission Reduction Analysis Of Sf6 Emissions From Electric Power Transmission And Distribution Systems In The United States. http://www.epa.gov/highgwp/pdfs/chap3_elec.pdf

equipment (as part of routine turnover) at a cost of approximately $200,000 to $750,000 per unit. Additional research into the existing equipment stock and potential for replacement will be necessary to develop cost estimates for emission reductions.

- **Advanced Leak Detection Technologies**
    - The capital cost per GasVue leak detection camera is approximately $100,000. Additional research into the potential emission reductions from this option will be necessary to develop estimates for O&M costs and the total cost of emission reductions.

Summary of Measures and Costs

The most promising options to reduce SF_6 emissions from electric power systems are SF_6 recycling and SF_6 leak detection and repair. SF_6 recycling could reduce emissions by about 10 percent, and is currently cost-effective. Leak detection and repair could reduce emissions cost-effectively by 20 percent.[50]

Actual EPA partnership experience shows that even greater reductions have been experienced. The 2010 annual report shows that partner emission rates have declined by 62 percent, from more than 14 percent of consumption to 3.8 percent.[51]

Table 2. Work Plan Cost and GHG Results

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effectiveness ($\$/tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($\$/tCO_2e$)
0.11	0.07	0.59	0.86	0.34	0.39

Quantification Approach and Assumptions:

- The SF_6 program is assumed to be implemented linearly over a five year period beginning in 2013. By the end of 2017, SF_6 reductions are assumed to be 30 percent of forecasted emissions from the electricity sector. The reductions are split into 20 percent leak detection and 10 percent recycling.
    - Note that future reductions could be much larger than this, based on actual experiences by SF_6 partner utilities.
- The cost estimates employ an 8 percent discount rate, a 10-year project lifetime, and an SF6 price of $8/lb. Mitigation costs for leak detection are estimated at $\$0.44/tCO_2e$, and recycling equipment at $\$0.90/tCO_2e$.[52]
- SF_6 emissions from the electric power sector are estimated at 0.63 $MMtCO_2e$ in 2000 and at 0.38 $MMtCO_2e$ in 2020. Emissions in the interim period are linearly interpolated.

Implementation Steps:

DEP and the Public Utility Commission should work with the Energy Association of PA (EAP) to encourage greater participation in EPA's SF6 emission reduction partnership. The partnership

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[50] http://www.epa.gov/highgwp/pdfs/chap3_elec.pdf p. 3-3.
[51] http://www.epa.gov/electricpower-sf6/documents/sf6_2010_ann_report.pdf page 3.
[52] http://www.epa.gov/highgwp/pdfs/chap3_elec.pdf Exhibit 3.4.

is a voluntary program summarized at http://www.epa.gov/electricpower-sf6/. Participation in this program entails taking the following actions:

- Estimate current annual SF6 emissions;
- Annually inventory emissions of SF6 using an emissions inventory protocol;
- Establish a strategy for replacing older, leakier pieces of equipment;
- Implement SF6 recycling;
- Ensure that only knowledgeable personnel handle SF6; and
- Submit annual progress reports.

The Pennsylvania electric distribution companies participating in the partnership include:

- Allegheny Power
- Duquesne Light Company
- PECO Energy

The EAP should work with and encourage all of Pennsylvania’s distribution companies to participate in this voluntary program.

C.2 Residential, Commercial, and Industrial Sectors Work Plans

The following work plans were discussed with the CCAC Residential, Commercial, and Industrial (RCI) Subcommittee. Members of this subcommittee include in the following:

Subcommittee Chair A. Steven Krug, Spiezle Group

Robert Bear, Alcoa, Inc

Robert Graff, Delaware Valley Regional Planning Commission

Mark Hammond, Air Land Water Legal Solutions LLC

Building Commissioning

Summary:

Promote the common practice of performing commissioning and retro-commissioning processes on newly constructed and renovated buildings for the purpose of ensuring optimal performance of building systems.

Commissioning is tuning a building to operate as it was intended. It requires testing, monitoring and adjusting the building systems to operate at optimum efficiency. It is similar to having your car tuned-up.

Goals:

Commission or retro-commission non-commonwealth new and renovated commercial buildings greater than 25,000 square feet. within eight years and, commission or retro-commission commonwealth new and renovated buildings greater than 25,000 square feet within five years.

Possible Vehicles:

Promote the common practice of performing commissioning processes on newly constructed and/or renovated buildings for the purpose of ensuring optimal performance of building systems.

Building project teams are currently familiar with American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) standards, which cite building commissioning as good practice (Guideline 0-2005).

Expand existing training for building operators to include energy management training. Building operators, such as maintenance technicians, lead custodians, and plant engineers, currently have little formal training in building efficiency.

Implementation Steps:

This program may be implemented through stricter municipal/state building codes.

- Consider adopting the International Green Construction Code (IgCC) in 2015, which incorporates commercial performance standards consistent with goals and commercial building performance standards listed above, including the prerequisite requirement for commissioning. Support educational and training sessions about the IgCC provided by professional associations and providers.
- Alternatively, amend the Pennsylvania Uniform Construction Code (UCC) to include commissioning requirements.

Certain tax incentives and/or credits may also be assigned to assist in full implementation. Several mainstream certification standards also promote the practice of performing building commissioning, making the activity seem more attractive.

An example of such a program is the California Governor's Green Building Executive Order and AB 32, which calls for all California state buildings greater than 50,000 square feet to be retro-commissioned (RCx) by June 30, 2013, and re-commissioned every 5 years. Nearly 25 RCx buildings are at or near completion. The energy efficiency measures implemented through this program to date have a verified electricity savings of approximately 10 percent.

Key Assumptions:

Key Data and Assumptions	**2013**	**2020**	**Units**
First Year Results Accrue		2013	
Building size threshold		25,000	sq.ft.
Eligibility[1]		68.9%	% of all commercial bldgs.
Avoided Costs			
Avoided Electricity Cost		130.2	$/MWh
Avoided Natural Gas Cost		4.6	$/MMBtu
Avoided Electricity Emissions Rate	0.69	0.69	tCO2e / MWh
Avoided Natural Gas Emissions Rate	0.05	0.05	tCO2e / MMBtu

Other Data and Assumptions	**2013**	**2020**	**Units**
Eligible non-Commonwealth, commercial floor space	3,603	3,862	million sq.ft.
Eligible Commonwealth floor space	132	141	million sq.ft.
Electricity savings[1]		961	GWh
		0.24	kWh / sq.ft.
Implied number of square feet recommissioned		4,003,679,007	sq.ft.
Commercial non-Commonwealth			
Number of years to full uptake		8	
Annual rate of uptake	15%	50%	
Building area recommissioned	1,802	3,862	million sq.ft.
Electricity savings	432,362,305	926,945,655	kWh
Natural gas savings[2]	5,602,695	12,011,671	MMBtu
Natural gas savings rate		3.11	MBtu / sq.ft
Commonwealth			
Number of years to full uptake		8	
Annual rate of uptake	15%	50%	
Building area recommissioned	66	141	sq.ft.
Electricity savings	15,829,636	33,937,307	kWh
Natural gas savings[2]	205,126	439,771	MMBtu
Natural gas savings rate		3.11	MBtu / sq.ft
GHG reductions	0.62	1.33	MMtCO2e /yr

Levelized cost of recommissioning (electricity)[3]		0.07	$ / kWh ($2010)
Levelized cost of recommissioning (natural gas)[4]		4.62	$ / MMBtu ($2010)
Gross annual cost	58	125	$ million ($2010)
Annual savings	85	182	$ million ($2010)
Net annual cost	-27	-58	$ million ($2010)

[1] ACEEE (2009) Potential for Energy Efficiency, Demand Response and Onsite Solar in Pennsylvania - Table B-10

[2] ACEEE (2009) Potential for Energy Efficiency, Demand Response and Onsite Solar in Pennsylvania - Table B-13

[3] Calculated from ACEEE (2009) Table B-10

[4] Calculated from ACEEE (2009) Table B-13

Potential GHG Reduction:

Table 1. Estimated GHG Reductions and Cost-effectiveness

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	**Costs (Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**	**GHG Reductions ($MMtCO_2e$)**	**Costs (NPV, Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**
1.3	-$57.68	-$43.30	8.7	-$298	-$34.10

Economic Cost:

See Table 1, above.

Potential Overlap:

Some overlap with Higher Performance Buildings work plan

CCAC Member Comments:

One member commented that accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.

Energy Efficiency —Natural Gas

Summary:

This initiative analyzes the replacement of older, less efficient household appliances that utilize natural gas with more energy-efficient models, as well as looking at improvements in overall system efficiency for heating and hot water heating.

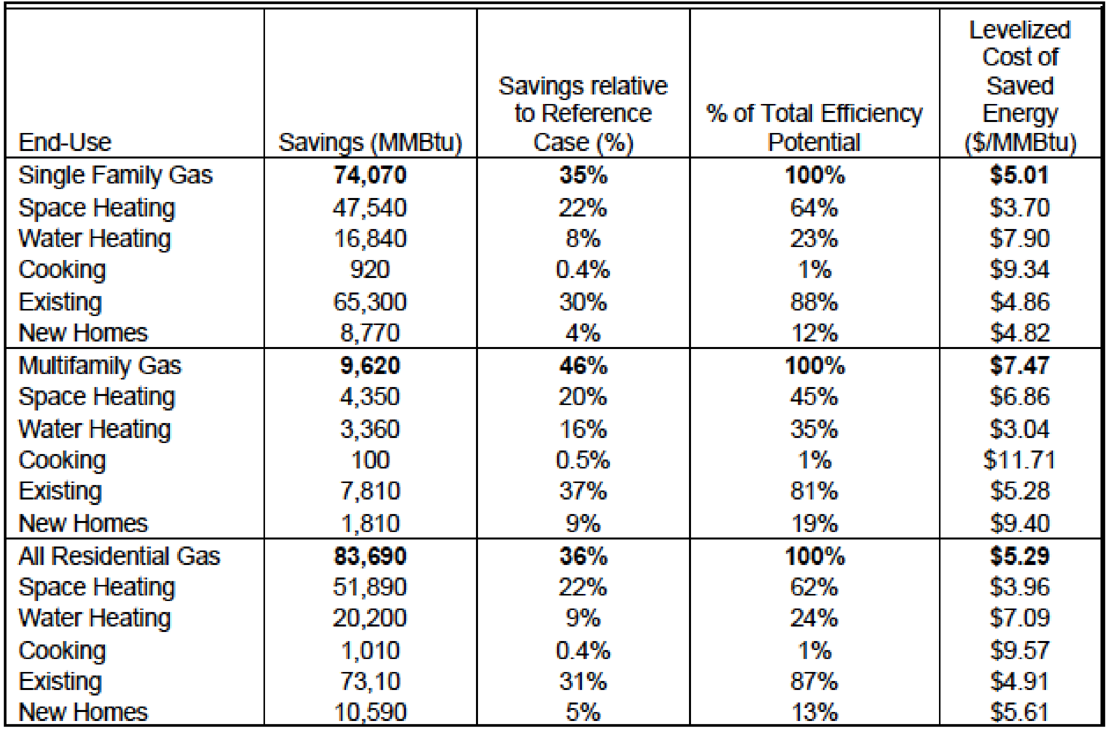
Goals:

Residential sector: Achieve 36 percent reductions from reference case natural gas demand in 2020.
Commercial sector: Achieve 28 percent reductions from reference case natural gas demand in 2020.

Analysis:

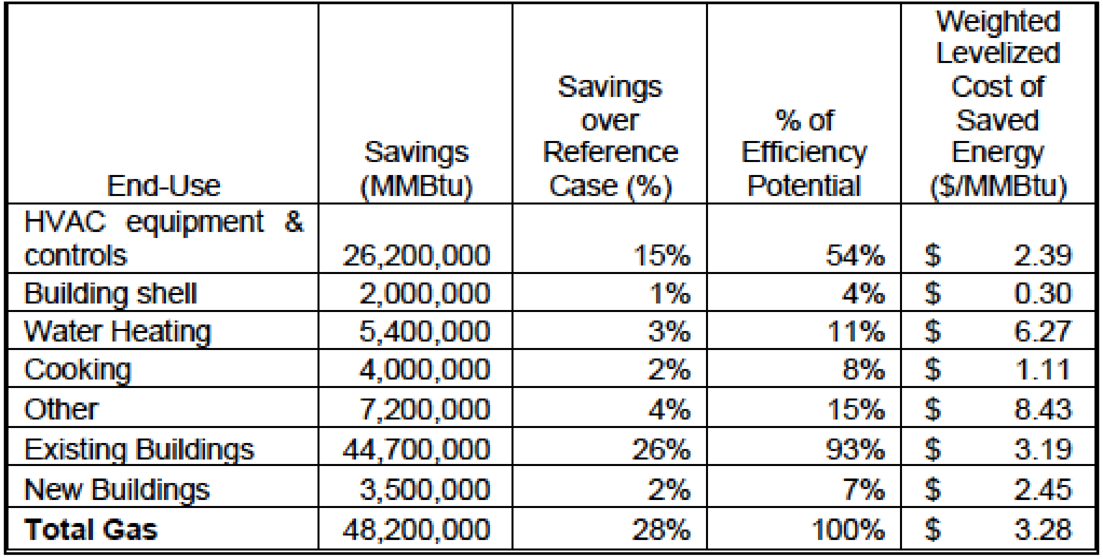
Key Data and Assumptions	2013	2020	Units
First Year Results Accrue		**2013**	
Savings Targets			
Natural Gas			
Achievable cost-effective savings in natural gas use as a fraction of total gas demand:			
Residential		**36%**	
Commercial		**28%**	
Fraction of achievable savings reached under program		**100%**	
Year in which target fraction reached		**2020**	
Year in which programs fully "ramped in"		**2013**	
Fraction of full program savings by year	0%	100%	
Implied fractional annual gas demand savings, residential	0.0%	4.5%	
Implied fractional annual gas demand savings, commercial	0.0%	3.5%	
Weighted Levelized Cost of Saved Energy			
Residential		**$5.29**	$/MMBTU
Commercial		**$3.28**	$/MMBTU
Value from Pennsylvania: Energy Efficiency, Demand Response and On-Site Solar Potential. ACEEE 2009. See page 19 for residential and page 26 for commercial.			
Avoided Delivered Natural Gas Cost		**$4.6**	$/MMBtu

Table 1. Residential Natural Gas Efficiency Potential and Costs by End-Use (2025)



End-Use	Savings (MMBtu)	Savings relative to Reference Case (%)	% of Total Efficiency Potential	Levelized Cost of Saved Energy ($/MMBtu)
Single Family Gas	**74,070**	**35%**	**100%**	**$5.01**
Space Heating	47,540	22%	64%	$3.70
Water Heating	16,840	8%	23%	$7.90
Cooking	920	0.4%	1%	$9.34
Existing	65,300	30%	88%	$4.86
New Homes	8,770	4%	12%	$4.82
Multifamily Gas	**9,620**	**46%**	**100%**	**$7.47**
Space Heating	4,350	20%	45%	$6.86
Water Heating	3,360	16%	35%	$3.04
Cooking	100	0.5%	1%	$11.71
Existing	7,810	37%	81%	$5.28
New Homes	1,810	9%	19%	$9.40
All Residential Gas	**83,690**	**36%**	**100%**	**$5.29**
Space Heating	51,890	22%	62%	$3.96
Water Heating	20,200	9%	24%	$7.09
Cooking	1,010	0.4%	1%	$9.57
Existing	73,10	31%	87%	$4.91
New Homes	10,590	5%	13%	$5.61

Table 2. Commercial Natural Gas Efficiency Potential and Costs by End-Use (2025)



End-Use	Savings (MMBtu)	Savings over Reference Case (%)	% of Efficiency Potential	Weighted Levelized Cost of Saved Energy ($/MMBtu)
HVAC equipment & controls	26,200,000	15%	54%	$ 2.39
Building shell	2,000,000	1%	4%	$ 0.30
Water Heating	5,400,000	3%	11%	$ 6.27
Cooking	4,000,000	2%	8%	$ 1.11
Other	7,200,000	4%	15%	$ 8.43
Existing Buildings	44,700,000	26%	93%	$ 3.19
New Buildings	3,500,000	2%	7%	$ 2.45
Total Gas	48,200,000	28%	100%	$ 3.28

Source: ACEEE 2009

GHG Reductions and Economic Costs:

Table 3. Estimated GHG Reductions and Cost-effectiveness

Work Plan Name	Annual Results (2020)			Cumulative Results (2013-2020)		
	GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effective-ness ($\$/tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($\$/tCO_2e$)
Energy Efficiency - Natural Gas	7.3	-$0.18	-$0.02	32.9	$1	$0.02

Economic Cost:
See Table 3 above.

Opportunities for Advancement of this Initiative:

1. Air Sealing and Insulation (10 percent–40 percent annual energy savings)
    - Pennsylvanians using natural gas for heating use about 600 therms per household.
    - By air sealing & insulation, consumers could probably save 25 percent of this.
2. Increased furnace and boiler efficiency to >95 AFUE
    - Nationwide and in PA, about 50 percent of homes use natural gas for heating.
    - The minimum allowed annual fuel utilization efficiency (AFUE) rating for a non-condensing, fossil-fueled, warm-air furnace is 78 percent; the minimum rating for a fossil-fueled boiler is 80 percent; and the minimum rating for a gas-fueled steam boiler is 75 percent.
    - Although older furnace and boiler systems had efficiencies in the range of 56-70 percent, modern conventional heating systems can achieve efficiencies as high as 97 percent, converting nearly all the fuel to useful heat for the home. Energy efficiency upgrades and a new high-efficiency heating system can often cut fuel bills and a furnace's pollution output in half. Upgrading a furnace or boiler from 56 to 90 percent efficiency in an average cold-climate house will save 1.5 tCO_2 emissions each year if heated with gas, or 2.5 tCO_2 if heated with oil (DOE, Energy Savers).
    - Therefore consumers could expect to see a 15 –50 percent range in energy savings from "heating season" improvements (depending on age and efficiency of equipment being replaced).
3. Solar domestic hot water heaters
    - Heating water accounts for 14 –25 percent of total household energy consumption. Solar water heaters can provide 85 percent of DHW needs.
4. Instantaneous hot water heaters with an energy factor >0.80
    - For homes that use 41 gallons or less of hot water daily, demand water heaters can be 24 –34 percent more energy efficient than conventional storage tank water heaters.
    - They can be 8 –14 percent more energy efficient for homes that use a lot of hot water—around 86 gallons per day. You can achieve even greater energy savings of 27 —50 percent if you install a demand water heater at each hot water outlet.

5. Energy Star high-efficiency washing machines
    - Most Energy Star qualified clothes washers extract more water from clothes during the spin cycle. This reduces the drying time and saves energy and wear and tear on your clothes.
    - Energy Star qualified clothes washers clean clothes using 50 percent less energy than standard washers (including energy used in the washing process, including machine energy, water heating energy, and dryer energy).
6. Pilot lights
    - Standing pilot lights may use over 7 therms (700,000 British thermal units) of gas per appliance, if left on year round.
    - Replacing old appliances that have pilot lights on full time with appliances that have electronic (intermittent) ignitions could create savings.
    - Some people feel that standing pilot lights on appliances are gradually becoming the exception, instead of the rule, with new appliances on the market using electronic ignitions. However, even though electronic ignition pilot lights are becoming increasingly common, without legislation, standing pilots may not disappear by 2020 because they are cheaper to manufacturer, and the appliance is sometimes viewed as a solution to emergency heat when the electricity fails, because they do not need electric power to start.

Implementation Steps:

- Encourage natural gas utilities to engage in consumer education initiatives regarding these efficient technologies.
- Passage of new legislation structured around the concept of Act 129 of 2008 that would require natural gas distribution companies to reduce overall consumption by minimum percentages.

Potential Overlap:

- Appliance Standards Work Plan
- High Performance Buildings Work Plans

CCAC Member Comments:

Demand side management of natural gas appliances and equipment in residential and commercial buildings offer excellent GHG reduction potential and excellent cost savings. This is especially important since aging equipment may be subject to replacement by electric alternatives which would increase PA electricity use and commensurate GHGs.

The technologies to achieve these goals are available now.

The real challenge for energy efficiency of gas equipment is upfront cost to the building owners. Federal and state incentives may significantly reduce this challenge, although many home owners do not have the ready cash. It may be imperative for utility sponsored retrofits with pre-certified installers and constant fuel bills until the energy efficiency is paid for.

Replacement of gas appliances and equipment have health benefits as well since older equipment is more subject to fumes and leakage in occupied spaces. Homes may also benefit from appropriately matched equipment sizing to the load, ensuring adequate temperatures are met, and reducing 'cycling'.

The GHG and energy cost savings benefits are excellent, but the upfront cost implications must be addressed through utility programs.

One committee member cast a "no" vote for the energy efficiency natural gas work plan based on the mandatory nature of legislation included in that work plan. He does not support additional regulatory burdens being imposed when not necessary.

Demand-Side Management (DSM) – Water

Summary:

This initiative supports water conservation and yields energy savings. To achieve 25 percent potable water conservation through new utility incentives, conservation credits, smart metering, building codes and education programs. The energy impact of water use is estimated at 4 percent of all electricity consumption nationwide.

Background Discussion:

Landscaping, toilet flushing, showers and sinks and washing machines are the most significant contributors to building water loads. These water costs have measurable GHG implications (4 percent of all energy use) because of the processing energy costs and the pumping energy costs. Faucets and washing machines also have hot water loads, gas or electric, with GHG implications.

As a result, water-conserving alternatives benefit building owners both in water cost savings and in domestic hot water heating cost savings.

Conservation can be achieved through state efforts to promote rain capture for landscaping, dual-flush toilets, low-flow faucets and shower heads, and high efficiency washing machines. This can be achieved by: point of sale education and U.S. EPA WaterSense product performance standards; elimination of code barriers; and utility-managed programs that combine certified installers with equitable utility rate financing.

Goals and Implementation Steps:

- Reduction of per-capita water use by 20 percent statewide by 2020.
- Achieving a 5 percent overall water savings by 2020.
- Installing WaterSense or similarly efficient fixtures for all new construction.

Implementation:

- Low-water landscaping:
  - Irrigation (low-water landscaping, soil moisture detection systems, rain capture).
  - Encourage drought-tolerant species selection.
- Low-water plumbing:
  - Toilets (WaterSense uses 1.28–1.6 gallons per flush).
  - Faucets
  - Washing machines.
- More efficient hot water delivery:
  - On demand/tankless hot water heaters
  - High efficiency gas hot water heaters
  - Plumbing configuration and insulation
- Education brochures and training to promote water conservation
- Training sessions for water companies and water authority operators to learn about water conservation opportunities and programs
- Encourage consumers to work with electricity distribution companies to save water for increased efficiencies and to take advantage of Act 129 funding

Calculations and Assumptions:

Population, and baseline water consumption data, and the percentage goals were used to establish the numeric (million gallon) goals. The baseline data and numeric goals were then multiplied by the costs and avoided costs to estimate the costs and cost-effectiveness results shown in Table 1. Assumptions and values used in these calculations are contained below.

Assumptions:

Population	12,751,886	12,569,017	persons
Population (2010)		12,702,379	persons
Baseline (2010) per capita water use *Assumes no change in per capita use*		29,729	gal/person/yr
Baseline (2010) total water use *Assumes no change in per capita use*		377,627	million gal/yr
Energy Intensity (excluding heating) *Griffiths-Satenspiel and Wilson (2009.04) The Carbon Footprint of Water* *Savings from water heating will be captured by the Act 129 and Energy Efficiency -Natural Gas Work Plans*		4	MWh/million gal

Goals

Water use avoided (per capita)	2.5	20.0	percent
Water use avoided (per capita)	9,477	74,732	million gal
Water use avoided (absolute)	0.6	5.0	percent
Water use avoided (absolute)	2,360	18,881	million gal
Water use avoided (greater of per capita and absolute)	9,477	74,732	million gal

Costs

Levelized cost of measure - landscaping		$4.84	$/thousand gal
Levelized cost of measure - fixtures		$2.62	$/thousand gal
Levelized cost of measure - washing machine		$0.01	$/thousand gal
Levelized cost of measure - toilet		$4.98	$/thousand gal
Avoided cost of water	*Residential*	$8.08	$/thousand gal
Pittsburgh water and sewer authority	*Commercial*	$7.74	$/thousand gal
http://www.pgh2o.com/fees.htm	*Weighted average*	$8.00	$/thousand gal

Buildings/Appliances/Fixtures

Buildings undergoing irrigation retrofits annually	10,000	buildings
Washing machines replaced annually	50,000	machines
Homes retrofitting fixtures annually	250,000	housing units
Toilets replaced annually	250,000	toilets

Overall avoided water use	9,618	26,448	million gal
Overall avoided electricity use	37,268	102,487	MWh

Note: additional measures and/or higher rates of implementation of the measures analyzed are necessary to meet the overall goals of this work plan.

Potential GHG Reduction:

Table 1. Estimated GHG Reductions and Cost-effectiveness

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	**Costs (Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**	**GHG Reductions ($MMtCO_2e$)**	**Costs (NPV, Million $)**	**Cost-Effectiveness ($\$/tCO_2e$)**
0.1	-$135	-$1,225	0.4	-$576	-$1,306

Economic Cost:

See Table 1 above.

Committee Comments

One committee member provided the following comments:

- I support the concept of this work plan.
- Additional implementation steps should be explored to ensure this initiative meets its stated goals.

High-Performance Buildings

Summary:

This initiative embodies the goals of "The 2030 Challenge," that would establish higher efficiency and therefore lower operating cost buildings. These high-performance buildings include new and existing buildings in the residential, commercial, institutional and government sectors.

Background and Overview:

Buildings are a major source of demand for energy and materials that produce by-product GHGs. It will require immediate and significant action in the building sector to slow the growth rate of GHG emissions in Pennsylvania.

Recently, Architecture 2030 has issued **The 2030 Challenge** asking the global architecture and building community to adopt the following targets:

- All new buildings, developments and major renovations shall be designed to meet a fossil fuel, GHG-emitting, energy consumption performance standard of 50 percent of the regional (or country) average for that building type, as defined in The 2030 Challenge.
- At a minimum, an equal amount of existing building area shall be renovated annually to meet a fossil fuel, GHG-emitting, energy consumption performance standard of 50 percent of the regional (or country) average for that building type, as defined in The 2030 Challenge.
- Architecture 2030 established the following fossil fuel reduction standard for all new buildings and major renovations:

  70 percent of buildings in 2015
  80 percent of buildings in 2020
  90 percent of buildings in 2025
  Carbon neutral in 2030

Architecture 2030 envisioned that these targets would be accomplished by implementing innovative sustainable design strategies, generating on-site renewable power and/or purchasing (20 percent maximum) renewable energy and/or certified renewable energy credits. However, no such renewable power goals have been established.

The main goals for this work plan generally come from the Architecture 2030 Challenge building goals, with some revisions from the subcommittee. These goals are summarized in Tables 1 and 2. Following the tables are proposed implementation steps to meeting these goals. The GHG emission reductions for Pennsylvania through 2020 were estimated assuming that these goals are met. The key assumptions and results of that analysis are provided later in this work plan initiative.

The quantification analysis helps provide an overall indication of potential GHG emission reductions. However, to better understand the changes to Pennsylvania's building sector equipment and practices, analysis on individual work plans is also needed. The other work plans for quantification will help indicate the ability for the state to meet the goals listed here, and will also provide estimates of the costs for meeting these goals.

Goals:

Table 1. New Buildings Goals and Standards

		2015	2020
New Commercial (Commonwealth owned or operated)	Overall goal (relative to 2005 building)	60% fossil fuel and electricity reduction	80% fossil fuel and electricity reduction
	Performance standard	LEED Silver ENERGY STAR 85	LEED Silver ENERGY STAR 85
	Fraction of buildings that meet standard	100% of new	100% of new
New Commercial (Schools)	Overall goal (relative to 2005 building)	50% fossil fuel and electricity reduction	70% fossil fuel and electricity reduction
	Performance standard	LEED Silver ENERGY STAR 85	LEED Silver ENERGY STAR 85
	Fraction of buildings that meet standard	100% of new	100% of new
New Commercial (private)	Overall goal (relative to 2005 building)	50% fossil fuel and electricity reduction	70% fossil fuel and electricity reduction
	Performance standard	LEED Silver ENERGY STAR 75	LEED Silver ENERGY STAR 85
	Fraction of buildings that meet standard	100% of new	100% of new
New Residential	Overall goal (relative to 2005 building)	50% fossil fuel and electricity reduction	70% fossil fuel and electricity reduction
	Performance standard	HERS 50	HERS 40
	Fraction of buildings that meet standard	100% of new	100% of new

Table 2. Existing Buildings Goals and Standards

		2015	2020
Existing Commercial (Commonwealth owned or operated)	Overall goal (relative to 2005 building)	40% fossil fuel and electricity reduction	50% fossil fuel and electricity reduction
	Performance standard	ENERGY STAR 75	LEED EB Silver ENERGY STAR 80
	Fraction of buildings that meet standard	20% of existing	50% of existing
Existing Commercial (Schools)	Overall goal (relative to 2005 building)	30% fossil fuel and electricity reduction	50% fossil fuel and electricity reduction
	Performance standard	ENERGY STAR 75	LEED EB Silver ENERGY STAR 80
	Fraction of buildings that meet standard	20% of existing	50% of existing
Existing Commercial (private)	Overall goal (relative to 2005 building)	30% fossil fuel and electricity reduction	40% fossil fuel and electricity reduction
	Performance standard	ENERGY STAR 75	LEED EB Silver ENERGY STAR 80
	Fraction of buildings that meet standard	20% of existing	50% of existing
Existing Residential	Overall goal (relative to 2005 building)	60% fossil fuel and electricity reduction	80% fossil fuel and electricity reduction
	Performance standard	HERS 50	HERS 40
	Fraction of buildings that meet standard	20% of existing	50% of existing

Notes: Energy reductions refer to on-site energy consumption.

Pennsylvania established a statewide building code in Act 45 of 2005. The PA Uniform Construction Code (UCC) incorporates the International Construction Code (ICC) family of codes, such as the building code, plumbing codes, and electrical codes. The 2009 ICC includes a basic energy code that commercial buildings must achieve. Pennsylvania did not adopt 2012 ICC and, therefore, 2009 ICC will be the state building code in the Commonwealth until 2015.

The **Residential Green Building Code 2010 (NGBS) ICC-700** is available for adoption by local municipalities in Pennsylvania to meet the goals above. Some PA municipalities have adopted the ICC-700 as an option (such as West Chester Borough).

The ICC has recently developed an overlay code, the **International Green Construction Code (IgCC)**, that incorporates commercial performance standards consistent with goals and commercial building performance standards listed above. The IgCC was developed using a collaborative approach of the public, code officials, builders, developers, architects, engineers, insurance, and real estate agents. The IgCC was first available for consideration by Pennsylvania in 2012 and has already been adopted by a number of states (such as Maryland and Arizona). Adoption of the IgCC will provide municipalities in Pennsylvania the option to implement energy savings that meet the goals above. Pennsylvania did not adopt the IgCC in 2012. The next scheduled version is IgCC 2015.

The Pennsylvania Uniform Construction Code (UCC) Review and Advisory Council (RAC) was established by Act 106 of 2008. The council is composed of code officials, builders, developers, architects, engineers, insurance, and real estate agents. The council is charged with making recommendations to the governor, the General Assembly and the Department of Labor and Industry regarding proposed changes to Act 45, The Pennsylvania Construction Code Act, and reviewing the latest triennial code revisions (2012, 2015, 2018…) issued by the International Code Council contained in the International Codes enforceable under the PA Uniform Construction Code. The council is required to submit a report to the secretary of Labor and Industry within 12 months following publication of the latest triennial codes specifying each code revision that is to be adopted as part of the Uniform Construction Code.

Possible Implementation Steps:

In addition to the other efficiency work plans, which are technology and action-based work plans that may contribute to meeting the goals of this High-Performance Buildings initiative, the following implementation steps are presented for consideration in each of the four categories:

High-Performance State and Local Government Buildings

- "High-Performance PA Buildings"—All Commonwealth of Pennsylvania-owned or -funded construction projects must meet a performance level equivalent to a minimum of LEED Silver plus an Energy Star rating of 85. Versions of this bill have been introduced in 2009/10 session and again in 2011/12 session. The House Environmental Resources and Energy Committee approved Representative Kate Harper's green building legislation by a 21-4 vote in 2011/12. House Bill 193 would require high-performance green building standards in most major construction projects involving state-owned buildings. Additionally in 2011/12, Senate Bill 1136 (Rafferty) was similar companion State Owned Green Building bill. Consider adopting the **International Green Construction Code (IgCC) in 2015**, which incorporates commercial performance standards consistent with goals and commercial building performance standards listed above. Support educational and training sessions about the IgCC provided by professional associations and providers.

- The Department of General Services (DGS) is building a benchmarking database and will be using existing contract capacity with the Penn State Facilities Engineering Institute to begin the auditing/benchmarking process for Commonwealth-owned facilities. Other implementation steps could include:
    - Revise facility manager job descriptions and train staff to incorporate benchmarking into their standard operating procedures.
    - Revise Guaranteed Energy Savings Act (GESA)/energy service company (ESCO) language to incorporate Energy Star performance-based requirements.
    - Mandate that all FY 2013–2014 and future GESA/ ESCO projects adopt the Energy Star performance-based requirements.
    - Continue working with EPA to streamline the work process and minimize the costs associated with implementing Energy Star performance requirements into building operational procedures.
    - Ask the PUC to develop and mandate that all PA utilities conform to a uniform billing structure and format to allow automated billing data entry into the Energy Star Portfolio Manager database.
    - Hire and train in-house staff to run program, or educate existing qualified ESCOs on new requirements.
- "Green Strings" - All commonwealth funding programs, whether grants, loans, tax credits, tax incentives, etc., will have at least a minimal expectation of energy/resource conservation results.
    - The intent of this initiative is to educate involved parties, inform the state, and potentially reduce the GHG impacts of building projects. If projects with similar costs and benefits are proposed, the project with the lowest GHG impact will be given preference.
    - State agencies should include in their decision-making processes appropriate and careful consideration of GHG emission effects from proposed actions, and their alternatives. This will be done to understand, minimize, and/or avoid potential adverse effects from GHG emissions from the proposed actions, as much as possible. Commonwealth agencies will integrate the GHG emission impacts as early in their planning processes as possible.
    - State agencies to require analysis of GHG impacts in all building-related award and approval (permits, grants, procurements, etc.) decisions. Entities submitting applications for consideration will be required to include a comprehensive analysis of the GHG impacts of the proposed project. The state agencies are only requiring an analysis be performed.
- Require EPA Energy Star Portfolio Manager benchmarking for all commonwealth-owned and -leased facilities by 2020.
- Establish a goal of minimum Energy Star rating of 75 for all commonwealth-owned buildings by 2020.
- Implement the equivalent of LEED for Existing Buildings (LEED-EB), Green Globes, or other certification for ongoing operation and maintenance (O&M) and Energy Star ratings for all state buildings. Meet at least the equivalent of LEED-EB Silver certification and an Energy Star score of 75 for all existing buildings by 2020.

- Revise GESA/ESCO language to incorporate the equivalent of LEED-EB and Energy Star performance-based requirements.
- Require all current and future GESA/ESCO projects to adopt the equivalent of LEED-EB and Energy Star performance-based requirements.
- Establish a Pennsylvania Community and Local Government Climate Change Collaborative Clearinghouse to overcome barriers to progress on climate change actions. The project would do the following:
  - Assist communities to develop comprehensive plans that include buildings, transportation, agriculture, land-use planning, and commercial and industrial operations.
  - Provide grants and incentives for communities to conduct inventories and develop plans to monitor their progress.
  - Compile data and offer awards to communities that exceed their goals or demonstrate other significant progress.
  - Assist DEP in achieving Act 70 requirements.

High-Performance School Buildings

- Require EPA Energy Star Portfolio Manager benchmarking for all commonwealth-owned and leased educational facilities by 2020.
- Establish a goal of minimum Energy Star rating of 75 for all public school buildings by 2020.
- Consider adopting the **International Green Construction Code (IgCC) in 2015** that incorporates commercial performance standards consistent with goals and commercial building performance standards listed above. Support educational and training sessions about the IgCC provided by professional associations and providers.
- Continue implementation of *Illuminating Education* program—Governor's Green Government Council/Office of Energy and Technology Development (GGGC/OETD) program to distribute compact fluorescent lamps (CFLs) to middle school students in PA as part of an overall energy curriculum program.
- Continue efforts of *Pennsylvania State System of Higher Education (PASSHE*) *Energy Consumption Reduction*—Continue emphasis on existing efforts to reduce energy consumption at Pennsylvania state universities through full implementation and seek new energy saving initiatives to meet or exceed the 1.5 percent annual energy use intensity (EUI) reduction goal. The following are some of the tools available to achieve this goal (Projected GHG reduction from PASSCHE EUI goal as estimated by DEP are included; these projected reductions are not included in the quantitative analysis):
  - Guaranteed Energy Saving Program (GESA) (0.04 MMtCO$_2$e))
  - Aggressive building operating system control (0.005 MMtCO$_2$e)
  - Behavioral changes (0.02 MMtCO$_2$e)
  - LEED and Energy Star efforts (0.01 MMtCO$_2$e)
  - Total Reduction: 0.075 MMtCO$_2$e
- Increase use of campus energy managers.
  - About half of the PASSHE universities have established positions for energy managers. These positions are typically funded out of energy consumption and unit cost savings achieved through the work of the energy manager.
  - Energy managers use the building control systems to aggressively manage the heating, ventilation, and air conditioning systems (and sometimes lighting) to minimize energy consumption while maintaining an environment conducive to the university's mission.

  - Energy managers are also instrumental in managing and successfully implementing university GESA projects.
- Implement a *Green Campus Initiative* for all Pennsylvania colleges, universities, private schools, and secondary schools to minimize environmental impacts and create "learning labs" for sustainability. Develop and support an effective process to promote energy and sustainability concepts.
- Provide leadership and resources to schools for a comprehensive approach to lower energy use and energy costs, reduce GHG emissions from buildings and transportation, improve water and wastewater management, increase recycling, reduce disposal of hazardous waste, and promote procurement of environmentally friendly products.
- Use a team-based approach that engages administrative staff, students, faculty and technical experts.

High-Performance Commercial Buildings (Private) Buildings

- Incorporate green building requirements in the statewide building code (Uniform Construction Code [UCC]). Consider adopting the **International Green Construction Code (IgCC) in 2015, as an option,** which incorporates commercial performance standards consistent with goals and commercial building performance standards listed above. Support educational and training sessions about the IgCC provided by professional associations and providers.
  - This could be a phased-in approach that begins in the first years with Energy Star standards, and expands to cover high-performance standards for energy, water, stormwater, materials, etc. The ultimate goal will be zero-carbon buildings[53] throughout the Commonwealth – a goal that is aligned with the 2030 Challenge.
  - UCC improvements will need to include a much higher level of administration and enforcement than what currently exists. Statewide emphasis on training must occur.
- *High-Performance Tax Credits*—Tax credits for private-sector construction projects that meet a performance level equivalent to a minimum of LEED Silver plus an Energy Star rating of 85.
- Require energy information to be included in a "seller's disclosure" for commercial real estate transfers. Alternatively, require an Energy Star portfolio manager energy use index. The "seller's disclosure" consists of a property disclosure statement; the seller is currently not obligated by the statute to make any specific investigation. A third-party-verified energy audit should be an additional document and not part of "seller's disclosure."
- Implement an *Airport Efficiency Initiative* - Under this initiative, the Governor of Pennsylvania would issue an Executive Order requesting all Federal Aviation Regulation (FAR) Part 139 airports to improve their energy efficiency by 10 percent. The individual airports (which include all facilities leased or owned by the airport) will be given flexibility to achieve the efficiency goal. This will allow each facility to find the most cost-effective options to meet the target. Under the Executive Order, applicable airports would be encouraged to coordinate with Pennsylvania Department of Transportation's (PennDOT's) Air Services Committee to develop plans to achieve the energy efficiency goal. An example of a similar initiative includes Washington State Governor Gary Locke's 10 percent energy

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[53] A zero-carbon house is a building where net carbon dioxide emissions resulting from all energy used in the dwelling are zero or better. This includes the energy consumed in the operation of the space heating/cooling and hot-water systems, ventilation, all internal lighting, cooking and all electrical appliances.

efficiency goal for airports. The Seattle Tacoma International Airport (SEA-TAC) achieved this goal by installing 60 motor controllers on escalators, replacing inefficient lighting with energy-efficient fixtures, and retrofitting older heating and cooling systems with more efficient equipment.

RC-4: High-Performance Homes (Residential)

- Incorporate green building requirements in the statewide building code (UCC).
- Consider adopting the **Residential Green Building Code 2010 (NGBS) ICC-700** across the state, as an option for municipalities to meet the residential goals and residential building performance standards listed above Support educational and training sessions about the IgCC provided by professional associations and providers.
    - Require all new residential construction in Pennsylvania to achieve a minimum of LEED certification.
    - This could be a phased-in approach that begins in the first years with Energy Star standards, and expands to cover high-performance standards for energy, water, stormwater, materials, etc. The ultimate goal will be zero-carbon residential buildings[54] throughout the state.
    - UCC improvements will need to include a much higher level of administration and enforcement than what currently exists. Statewide emphasis on training must occur.
- Provide tax credits for private-sector construction projects that meet a performance level equivalent to a minimum of LEED Silver plus an Energy Star rating of 85. Several current legislative proposals based on this objective are being considered. (See HB 46, SB 673.)
- *Energy Audits at Real Estate Transfer*—Energy audit required as part of “seller’s disclosure” information in a residential sales transaction.
- *Keystone Home Performance*—Retooling of the Keystone HELP program to offer a greater degree of assistance (much lower loan rates) to homeowners implementing energy-saving measures based on a whole-house energy audit. (See also the Pennsylvania Housing Finance Agency's (PHFA’s) Keystone Renovate and Repair program and Maine Home Performance Program).
- *LEED for Homes*—Require that all new homes have an Energy Star rating (15 percent more energy efficient than code-compliant construction). Increase the efficiency requirement every 5 years until all new homes are carbon-neutral.
- Implement a *Pennsylvania Home Climate Champion Collaborative* to provide vision, clarity, and access to human and physical resources so that 100,000 homes will achieve substantial (greater than 60 percent) energy reductions, while maintaining or improving indoor air quality, resilience to storms and power outages, adaptability, comfort, and affordability between now and 2025. Five percent of these demonstration projects should achieve the German PassivHaus energy independence goals of 90 percent energy reduction, with 10 percent met by renewable energy.
- Require energy information to be included in a “seller’s disclosure” for residential real estate transfers.
- Require building performance labels that reflect actual utility use.

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[54] A zero-carbon house is a building where net carbon dioxide emissions resulting from all energy used in the dwelling are zero or better. This includes the energy consumed in the operation of the space heating/cooling and hot-water systems, ventilation, all internal lighting, cooking and all electrical appliances.

- Develop energy improvement mortgages or energy-efficient mortgages and promote these products in PA.
- Offer the Pennsylvania residential sector an incentive for implementing whole-house performance, provide consumer and contractor education, create jobs, spur marketplace development, and significantly improve PA's existing housing stock while reducing energy consumption and associated GHG emissions. Propose blending all existing programs and efforts, applying for federal loan guarantees and special project funding, and seeking partnerships with utilities and others (manufacturers, contractors, nonprofit organizations, etc.).

Supporting Steps to Meet Targeted Goals:

- Support the integrity of the UCC as it gets negotiated in the General Assembly.
  - Consider adopting the **Residential Green Building Code 2010 (NGBS) ICC-700** developed with the National Home Builders Association across the state, as an option for municipalities to meet the residential goals and residential building performance standards listed above.
  - Consider adopting the **International Green Construction Code (IgCC) in 2015** as an option that incorporates commercial performance standards consistent with goals and commercial building performance standards listed above. Support educational and training sessions about the IgCC provided by professional associations and providers.
- Develop an accreditation system for energy auditors.
  - Companies with the appropriate expertise should conduct energy audits. While the requirements for determining expertise exist as guidelines for reputable companies, third-party-verified requirements are ill defined and span a broad spectrum of energy efficiency.
- Educate the mortgage industry on the benefits of recognizing a standardized home rating system and adjust the current mortgage profile to include value realized as a result of increased energy efficiency.
  - Energy audits coupled with energy mortgages could increase the number of families qualified for mortgages. Energy mortgages credit a home's efficiency rating into the loan by proportionately increasing the value of the home. To have a Pennsylvania policy of requiring lenders to provide energy mortgages, it is necessary to adopt a standardized home rating system, like the one adopted by the Residential Energy Services Network (RESNET). Home energy ratings provide a standard measurement of a home's energy efficiency. Ratings can be used for both new and existing homes. An effective rating system will include all information necessary for a lender to judge the worthiness of a home to meet the criteria for an energy mortgage. The program is already established through the mortgage industry and the National Association of State Energy Officials; however, it is not that widespread, with only 19 accredited providers in Pennsylvania.
  - Basing a mortgage on the home efficiency rating allows the buyer to borrow more on the basis that the monthly utility bills will be proportionally less. In cases where the home is in need of energy-efficient upgrades, an Energy Improvement Mortgage could help finance the upgrades in an existing home by allowing the owner to use a portion of the mortgage payment to pay for the cost of the upgrades.

- Continue working with the U.S. Green Building Council (USGBC) and EPA to streamline work processes and minimize the costs associated with implementing LEED and Energy Star principles and performance requirements into building operational procedures.
- Modify the DGS Architect/Engineer Request for Proposal (RFP)/contract to require a higher standard of competency for design professionals performing state-funded design work.
- Secure an agreement with a developer of rating systems (e.g., USGBC) for acceptance of portfolio standards for the state, reducing costs to register, certify, and commission the projects.
- Require all current and future GESA/ESCO projects to adopt the Energy Star performance-based requirements.
    - Continue working with EPA to streamline work processes and minimize the costs associated with implementing Energy Star performance requirements into building operational procedures.
    - Ask the PUC to develop and mandate that all PA utilities conform to a uniform billing structure and format to allow automated billing data entry into the Energy Star Portfolio Manager database (based upon California Assembly Bill 1103).
    - Advocate and increase participation in the Build Green Schools initiative and the Green Schools Pledge.

Existing Measures:

- No LEED or high-performance requirements exist in PA. Energy Policy Act (EPAct) 2005 tax credits for certain Energy Star measures do exist.
- The Keystone HELP Program offers reduced-interest unsecured loans for Pennsylvania residents to purchase energy-efficient equipment, such as HVAC, windows, hot water heaters, etc.
- *PHFA*—Keystone Renovate & Repair Loan Program can be used to pay for repairs and improvements that increase the basic livability of the home, including additions and construction, that makes the home safer, more energy efficient, or more accessible to people with disabilities or people who are elderly.
- *EPA and DOE*—The model Home Performance with Energy Star program uses a comprehensive, whole-house approach to improving energy efficiency and comfort at home, while helping to protect the environment.
- *PUC*—As part of the AEPS, PA utilities are required to explore energy efficiency measures prior to applying for capacity increases.
- *DCED*—The department currently runs PA’s Weatherization Assistance Program (WAP), and has contractors, auditors, and program administration in place.
- *PA Home Energy*—A nonprofit organization-sponsored residential energy audit and performance evaluation program serving WPP utility customers.
- *ECA (unnamed program)*—This start-up program is similar to PA Home Energy, serving the Philadelphia and Pittsburgh metro areas.
- *Alternative Energy Investment Act*— This Act originally provided $92.5 million for residential and commercial energy efficiency activities and other initiatives. A portion of this money will be integrated into the Keystone HELP Program and the PHFA.

Key Assumptions:

High Performance State and Local Buildings

Other Data, Assumptions, Calculations	2013	2020	Units
Total Commercial Floor space in Pennsylvania (million square feet)	**866**	**928**	
Estimated based on USDOE EIA CBECS (commercial survey) data for the Mid-Atlantic region, extrapolated.			
Annual demolition of commercial floor space		**0.58%**	
Based on analysis by AIA research corporation for Architecture 2030, national values.			
Est. area of new commercial space per year in PA (million square feet)	**13.8**	**14.4**	
Calculated based on annual floor space estimates above. Note high growth in 2006 and 2007 based on article from American Institute of Architects.			
Estimated number of new residential units per year	**86,013**	**85,701**	
Calculated based on estimates above.			
Implied average electricity consumption per sq. ft. commercial space		10.60	kWh/yr
Implied average natural gas consumption per sq. ft. commercial space		34.57	kBtu/yr
Estimate based on Reference case forecast, using average intensity of all commercial buildings in PA			
Calculation of Savings	**2013**	**2020**	**Units**
New construction floor space covered by program, annual	**5**	**14**	million sq ft
Existing building floor space covered by program, annual	**54**	**44**	million sq ft
Energy consumption, Reference case			
Energy consumption in new commercial buildings			
Electricity	332	313	billion BTU
Natural gas	270	284	billion BTU
Total	601	597	billion BTU
Estimate based on Reference case forecast			
Energy consumption in new commercial buildings, per sq foot			
Electricity	24	22	Th. BTU/sq ft
Natural gas	19	20	Th. BTU/sq ft
Total	43	42	Th. BTU/sq ft
Estimate based on Reference case forecast, using average intensity of all commercial buildings in PA			

High Performance School Buildings

Other Data, Assumptions, Calculations	2013	2020	Units
Total School Building Floor space in PA (million sq. ft.)	**728**	**780**	million sq ft
Estimated based on USDOE EIA CBECS (commercial survey) data for the Mid-Atlantic region, extrapolated using DEP approach.			
Annual demolition of commercial floor space		**0.58%**	
Based on analysis by AIA research corporation for Architecture 2030, national values.			
Est. area of new school building space per year in PA (million sq. ft.)	**4.2**	**12.1**	million sq ft
Calculated based on annual floor space estimates above.			
Implied avg. electricity consumption per sq. ft. school building space		10.60	kWh/yr
Implied avg. natural gas consumption per sq. ft. school building space		34.57	kBtu/yr

Calculation of Savings	2013	2020	Units
New construction floor space covered by program, annual	**1**	**12**	million sq ft
Existing building floor space covered by program, annual	**48**	**40**	million sq ft
Energy consumption, Reference case			
Energy consumption in new school building buildings			
Electricity	101	263	billion BTU
Natural gas	82	239	billion BTU
Total	184	502	billion BTU
Estimate based on Reference case forecast			
Energy consumption in new school building buildings, per sq foot			
Electricity	24	22	Th. BTU/sq ft
Natural gas	19	20	Th. BTU/sq ft
Total	43	42	Th. BTU/sq ft
Estimate based on Reference case forecast, using average intensity of all commercial buildings in PA			

High Performance Commercial Buildings

Other Data, Assumptions, Calculations	2013	2020	Units
Total Commercial (Private) Floor space in Pennsylvania (million sq. ft.)	**3,634**	**3,895**	
Estimated based on USDOE EIA CBECS (commercial survey) data for the Mid-Atlantic region.			
Annual demolition of commercial floor space		**0.58%**	
Based on analysis by AIA research corporation for Architecture 2030, national values.			
Est. area of new commercial (private) space per year in PA (million sq. ft.)	**58.1**	**60.3**	
Calculated based on annual floor space estimates above.			
Implied average electricity consumption per sq. ft. commercial space		10.60	kWh/yr
Implied average natural gas consumption per sq. ft. commercial space		34.57	kBtu/yr
Calculation of Savings	**2013**	**2020**	**Units**
New construction floor space covered by program, annual	**39**	**60**	million sq ft
Existing building floor space covered by program, annual	**111**	**185**	million sq ft
Energy consumption, Reference case			
Energy consumption in new commercial buildings			
Electricity	2,002	1,891	billion BTU
Natural gas	1,628	1,713	billion BTU
Total	3,631	3,604	billion BTU
Estimate based on Reference case forecast			
Energy consumption in new commercial buildings, per sq foot			
Electricity	24	22	Th. BTU/sq ft
Natural gas	19	20	Th. BTU/sq ft
Total	43	42	Th. BTU/sq ft
Estimate based on Reference case forecast			
Energy consumption in existing commercial buildings, per sq foot			
Electricity		36.17	Th. BTU/sq ft
Natural gas		34.57	Th. BTU/sq ft
Estimate based on Reference case forecast			

High Performance Homes

Other Data, Assumptions, Calculations	2013	2020	Units
Total Residential Housing Units in Pennsylvania	5,520,197	5,570,337	
Assumes 2007 number of homes to increase following population through 2020. Based on 2007 PA housing units as provided in U.S Census Bureau annual data, http://www.census.gov/popest/housing/HU-EST2005.html.			
Annual demolition of residential floor space		**1.43%**	
Based on average lifespan of home of 70 years			
Estimated number of new residential units per year	**86,013**	**85,701**	
Calculated based on estimates above.			
Implied average electricity consumption per housing unit		**9.90**	MWh/yr
Implied average natural gas consumption per housing unit		**46.56**	MMBtu/yr
Implied average petroleum consumption per housing unit		**27.88**	MMBtu/yr
Calculation of Savings	**2013**	**2020**	**Units**
New construction housing units covered by program, annual	57,342	85,701	housing units
Existing building housing units covered by program, annual	164,689	242,325	housing units
Energy consumption, Reference case			
Energy consumption in new residential buildings			
Electricity	2,373	2,240	billion BTU
Natural gas	3,279	3,262	billion BTU
Total	5,651	5,502	billion BTU
Estimate based on Reference case forecast			
Energy consumption in new residential buildings, per housing unit			
Electricity	27.6	26.1	MMBTU/housing unit
Natural gas	38.1	38.1	MMBTU/housing unit
Total	65.7	64.2	MMBTU/housing unit
Estimate based on Reference case forecast			
Energy consumption in existing commercial buildings, per sq foot			
Electricity		33.77	MMBTU/housing unit
Natural gas		46.56	MMBTU/housing unit
Petroleum		27.88	MMBTU/housing unit
Total		108	
Estimate based on Reference case forecast			

GHG Reductions:

Table 3. Estimated GHG Reductions and Cost-effectiveness

Work Plan Name	Annual Results (2020)			Cumulative Results (2013-2020)		
	GHG Reductions (MMtCO$_2$e)	Costs (Million $)	Cost-Effectiveness ($/tCO$_2$e)	GHG Reductions (MMtCO$_2$e)	Costs (NPV, Million $)	Cost-Effectiveness ($/tCO$_2$e)
High-Performance State and Local Government Buildings	0.7			-1.3		
High-Performance School Buildings	1.2			4.6		
High-Performance Commercial (Private) Buildings	8.0			32.9		
High Performance Homes (Residential)	11.8			49.9		
Total High Performance Buildings	21.7	-$362.9	-$16.7	86.1	-$2,542	-$29.5

Economic Costs:

See Table 3, above.

Potential Overlap:

Overlaps with the following:

- Building Commissioning
- Re-Roof PA
- Re-Light PA
- Energy Efficient Appliances
- Geothermal Heating and Cooling
- Energy Efficiency – Natural Gas
- Heating Oil Conservation and Fuel Switching
- Act 129 Phases I, II & III

CCAC Member Comments:

One member provided the following comments:

- I am supportive of this work plan, but have concerns about some of its assumptions.

- Since the passage of Act 1 of 2011, the Uniform Construction Code Review and Advisory Council (RAC) has been granted greater authority in determine whether or not Pennsylvania updates it building codes. Subsequently, the RAC choose not to adopt the 2012 International Construction Code (ICC) updated building codes, which included energy code requirements. This work plan recommends that the state adopt International Green Construction Codes (IGCC), which I strongly support. However, these codes are generally more stringent than the standard ICC codes. In the absence of changing the code adoption process in Pennsylvania, it is unclear whether or not adopting the IGCC would be possible. To accompany the work plan recommendation to adopt statewide the

IGCC, there should be a recommendation to either adopt the IGCC through legislation or change the state’s code adoption process to make it more likely that the IGCC could be implemented.

- This work plan promotes the use of energy savings performance contracts (also known as ESCO contracts) in the Commonwealth, which I strongly support. However, the Energy Management Office at the Department of General Services (DGS) that used to provide technical assistance to school districts, municipalities and commonwealth agencies on ESCO contracts was eliminated. As a result, these government units do not have an unbiased source of information to help them navigate the complex ESCO process. Since the elimination of the Energy Management Office, there has been a sharp decline in the number of ESCO contracts endorsed in PA. DGS has tried to develop alternative approaches to ESCO contracting, but at the time of these comments I am not aware of a feasible alternative model that is operating in the commonwealth. In order to be consistent with the recommendations in this report to promote and increase ESCO contracting, a government office dedicated to facilitating ESCO contracts and providing technical assistance should be re-established.

Re-Roof Pennsylvania

Summary:
This initiative mandates standards of thermal resistance for all new roofing projects.

Goals:
Replace 75 percent of commercial building roof areas with more energy-efficient roofing at the time of regular replacement. (See Table 1 for roof types.)

Table 1. Portfolio of Roof Replacements for Commercial Buildings

Types of Roofs	2015	2020
Light colored, super insulated	65%	50%
Green roofs with super insulation	5%	10%
Solar PV roofs with super insulation	2.5%	15%

Implementation:

- Green roofs should be promoted with incentives for benefits to cooling, carbon sequestration, and storm water management.
- Skylights for day-lighting should be encouraged for roof replacements in buildings lower than four stories, with deep sections that result in windowless spaces for occupants.
- Shading or insulation from renewable energy systems as secondary goals should be explored.
- Consider adopting the International Green Construction Code (IgCC) in 2015, which incorporates commercial performance standards consistent with goals and commercial building elements listed above. Support educational and training sessions about the IgCC provided by professional associations and providers.
  - Alternatively, amend the Pennsylvania Uniform Construction Code (UCC) so high reflectivity is mandatory for all commercial buildings to minimize cooling loads.
- In addition, adopt latest version of International Construction Code so thermal resistance standards (R/U factors) minimize both cooling and heating loads.
- Support the financial feasibility of solar roof systems.
- Recycle funding of Renewable Energy Program and extend The Alternative and Clean Energy (ACE) program.

Assumptions:

- Only commercial buildings.
- All public and private.
- 75 percent are less than 4 stories; roof is 25 percent of floor space.
- 20–25-year roof replacement on commercial buildings, but many roofs in PA have not been replaced regularly recently so there is pent-up need for replacement; assume 5 percent roof replacement a year until 2030.
- Replace with light-colored (75 percent dark now, 15 percent cooling energy savings with light colored roofs, no cost delta).

- Replace with light-colored and super-insulated R40 (10 percent heating energy savings and 20 percent cooling energy savings).
- AEPS requirements increase every year and will jump in 2015/2016. SRECs may increase in value at that point, making solar more financially feasible.
- Equip solar photovoltaic (PV) roofs with super insulation (10 percent heating and cooling energy savings, distributed power generation PA GHG savings)

Table 2. Key Data and Assumptions

Key Data and Assumptions, Year 2020		
Incremental Cost of Roof Replacement (relative to regular roof replacement)		
Upgrade from R-11 to R-30 roof insulation[1]	0.08	$/sq. ft. roof ($2010)
Light colored, super insulated[2]	1.07	$/sq. ft. roof ($2010)
Green roofs with super insulation[3]	10.89	$/sq. ft. roof ($2010)
Solar PV roofs with super insulation[4]	82.80	$/sq. ft. roof ($2010)
Energy Savings from Roof Replacement		
Light colored, super insulated		
Heating[5]	0.1	
Cooling[6]	0.113	
Green roofs with super insulation		
Heating[5]	0.1	
Cooling[6]	0.48	
Solar PV roofs with super insulation		
Heating[5]	0.1	
Cooling[7]	0.113	
Electricity capacity	12	W/sq.ft. roof
Capacity factor[5]	0.13	
Electricity generation	13.67	kWh/sq.ft. roof
Avoided Electricity Cost	**130**	**$/MWh**
Avoided Natural Gas Cost	**4.61**	**$/MMBtu**

[1] ACEEE (2009) Table B-10

[2] e-BIDS Guidelines for High Performance Buildings 2005 cites $0.89/sq. ft. for light-colored membrane; no reference to super insulation

[3] Dirksen (email from Vivian Loftness) and ACEEE (2009)

[4] Implied from ACEEE (2009) p. 227

[5] Assumption

[6] e-BIDS Guidelines for High Performance Buildings 2005; not PA-specific

[7] Assume same as light colored

Potential GHG Reduction:

Table 3. Estimated GHG Reductions and Cost-effectiveness

Work Plan Name	Annual Results (2020)			Cumulative Results (2013-2020)		
	GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effective ness ($/$tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($/$tCO_2e$)
Re-Roof Pennsylvania	0.8	$1,110	$1,412	2.4	$2,786	$1,168
Light-colored materials	0.2	$0	-$1	0.7	$25	$36
Green roofs	0.1	$81	$775	0.3	$155	$587
PV roof	0.5	$1,030	$2,068	1.4	$2,259	$1,579

Economic Cost: See Table 3 above.

Potential Overlap: Overlaps with AEPS and High Performance Buildings.

CCAC Member Comments:

One member provided the following comments:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.
- Concerns because consistent methodology is needed among all work plans for treatment of amortizing costs and savings.
- Cost of solar used for this analysis is very outdated (2009), especially given how significantly the price of solar has dropped since 2009.
- This work plan is not cost effective. Other work plans that exhibit cost effective measures should be pursued first.

Re-Light Pennsylvania

Summary:

This initiative is a critical building technology that accelerates replacement of less efficient outdoor and indoor lighting systems, including maximizing use of daylighting in indoor settings. It applies to residential and commercial buildings, as well as parks, streetlights and parking facilities.

This initiative would encourage Active investment in PA manufacturing, sales, green collar jobs and green building infrastructure by relamping, re-fixturing and upgrading lighting systems, windows and control systems. This would also measurably improve the pastoral and remarkable qualities of the state, the quality of light delivered and the health and safety of residents.

Implementation:

Propose establishment of the following goals in Pennsylvania:

Lighting Performance goals

- Lighting power density (LPD) 0.9 watt/sq.ft. connected load as maximum for all workplaces
- New construction effective immediately; existing construction by 2020, with a linear percentage increase in performance each year

Fixture Performance

- LOR (lighting output ratio, an index of fixture effectiveness) 70 percent minimum for all new construction, all building types, and all fixture replacements

Lamp Performance (for all new lamp purchases, for all points of sale by 2015)

- 90 mean lumens/watt lamps
- Mercury not to exceed 80 picograms per lumen-hour, five milligrams of mercury per lamp
- CRI (color rendering index) of 85 minimum
- 92 percent luminance maintenance (lamp depreciation) over rated life

Controls and System Performance (new construction by 2015; existing buildings by 2020)

- Individual lighting controls for 90 percent of occupants
- Occupancy sensors in single-occupancy rooms or short time-of-use rooms
- Commissioning of installed lighting system, including controls

Daylight (all non-residential buildings)

- 25 foot candle (fc) of daylight to 90 percent of occupied spaces (new construction and historic buildings)
- Seated daylight access for 90 percent of occupants (new construction and historic buildings)
- Glazing with visible transmission over 50 percent, solar heat gain coefficient (SHGC) under 50 percent or 1.5 ratio of visible light divided by SHGC in summer (whenever replacements are made)

- Window blinds/shades to ensure daylighting and view without glare and overheating (new construction by 2015; existing buildings by 2020)
- Daylight-responsive controls for all fixtures within 15 feet of window (new construction by 2015; existing buildings by 2020)

Exit Lighting (all new construction by 2015; existing buildings by 2020)

- Maximum 5 watts per fixture or "face"

Site Lighting (all new construction by 2015; existing buildings by 2020)

- LPD 0.15 watt/sq.ft. max
- No night sky pollution (0 percent above 90° cutoff)
- Zone-occupancy controls in large parking lots
- Light-emitting diode (LED) traffic lights
- No LED billboard faces

No- or Low-Cost Education Campaign

- Wash reflectors, lenses to maximize light output
- Install occupancy and daylight sensors
- Promote the Turn It Off campaign
- Delamp where light levels are not needed
- Raise or tilt the blinds and use daylight

Key Assumptions and Calculations:

Assumptions and Calculations	2013	2020	Units
Residential			
Number of housing units	5,520,197	5,570,337	
Single-family	4,228,471	4,266,878	
http://pasdc.hbg.psu.edu/pasdc/whats_new/2008factsfortheweb.pdf			
Multi-family	1,291,726	1,303,459	
Fraction of Residential Electricity Consumption as Lighting		8.8%	
National average based on Residential Energy Consumption Survey data from 2001 survey (http://www.eia.doe.gov/emeu/recs/recs2001/enduse2001/enduse2001.html).			
Residential electricity consumption as lighting	5,010	5,336	GWh
Power demand of existing lamps		60.0	W
Power demand of new lamps		15.0	W
Difference between old lamp and new lamp		45.0	W
Daily hours of operation		6.0	h
Rate of uptake of high-efficiency lamps	66%	95%	
Assumed			
Lifetime		5.0	yr
Existing power intensity of lighting		14.5	lm/W
Assume incandescent bulbs http://www.ccri.edu/physics/keefe/light.htm		0.069	W/lm

New power intensity of lighting		90.0	lm/W
		0.011	W/lm
Energy savings	2,818	4,002	GWh
Number of high-efficiency lamps in use	28,596,115	40,607,603	lamps
Number of lamps replaced annually	11,645,045	8,485,363	lamps
Cost premium		$3.44	one-time
		$0.79	$ / lamp / year
Gross annual cost	$40	$29	$ million
Emissions avoided	1.9	2.8	$MMtCO_2e$
Net annual cost	-$327	-$492	$ million

Commercial

Lighting Performance Goals

Existing lighting power density		2.0	W / sq.ft.
Proposed lighting power density		0.9	W / sq.ft.
Rate of update in existing buildings	30%	100%	
Electricity savings - existing buildings only	1,739	5,338	GWh
Electricity savings - new construction only	325	785	GWh
Electricity savings - total	2,064	6,122	GWh
Residual electricity use - existing buildings only	9,392	5,794	GWh
Residual electricity use - new construction only	266	642	GWh
Residual electricity use - total	9,658	6,435	GWh
Cost premium		$0.36	$/sq ft

US DOE Energy efficiency and renewable energy website, The Business Case for Sustainable Design in Federal Facilities http://www1.eere.energy.gov/femp/sustainable/sustainable_federalfacilities.html www1.eere.energy.gov/femp/pdfs/buscase_appendixb.pdf

Conversion		11	sq ft / m2
Gross cost of changing power density	**$179**	**$179**	**$ million**
Emissions avoided (stand-alone)	1.4	4.2	$MMtCO_2e$
Net cost of changing power density	**-$90**	**-$618**	**$ million**

Fixture Performance Goals

Existing power intensity of lighting		60.0	lm/W
Assume incandescent bulbs http://www.ccri.edu/physics/keefe/light.htm		0.017	W/lm
New power intensity of lighting		90.0	lm/W
		0.011	W/lm
Rate of uptake of high-efficiency lamps in existing buildings	66%	95%	

Assumed

Electricity savings - existing buildings only	2,432	2,098	GWh

Electricity savings - new construction only	71	261	GWh
Electricity savings - total	2,503	2,359	GWh
Residual electricity use - existing buildings only	6,960	3,696	GWh
Residual electricity use - new construction only	195.2	380.5	GWh
Residual electricity use - total	7,155	4,076	GWh
Cost premium (4-ft. 32 W T8)	*one-time*	$2.99	$ / lamp
		$0.69	$ / lamp / year
Lifetime		5.0	yr
Difference between old lamp and new lamp		19	W
Daily hours of operation		10	h / d
Number of days in use annually		261	d / yr
Existing power per lamp	*Assumed*	44	W / lamp
Existing lighting power density	*Assumed*	1.1	W / sq.ft.
Estimate of lamps in PA	125,363,629	125,363,629	lamps
Number of lamps replaced annually	25,072,726	25,072,726	lamps
Gross cost of replacing lamps	**$75**	**$75**	**$ million**
As stand alone			
Electricity savings - existing buildings only	2,980	4,186	GWh
Electricity savings - new construction only	148	475	GWh
Electricity savings - total	3,128	4,661	GWh
Emissions avoided	2	3	$MMtCO_2e$
Net cost of replacing lamps	**-$251**	**-$232**	**$ million**

Daylighting

Reduction in lighting energy consumption		44%	
Percentage of existing buildings that are historic		0.5%	by floor space
Applicable floor space (new construction and historic)	77.2	76.4	million sq.ft. / yr
Cost premium - levelized		$0.22	$ / sq.ft.
Cost premium	$16.92	$16.74	$ million
As stand-alone			
Electricity savings - existing buildings only	119	274	GWh
Electricity savings - new construction only	260	628	GWh

Electricity savings - total	379	901	GWh
Emissions avoided (standalone)	0	1	MMtCO$_2$e
Net cost	-$32.39	-$100.57	

Controls and System Performance

Reduction in lighting energy consumption		19%	
Rate of uptake in existing buildings	25%	100%	
Cost premium for new construction		$0.25	$ / sq.ft.

e-BIDS Guidelines for High Performance Buildings 2005
Estimate in document includes ballasts, lamps, etc. Assume 25% of cost is for controls.

Life of measure (life of building)		50	yrs
Levelized incremental cost		$0.01	$ / sq.ft. / yr.
Cost of retrofit		$0.90	$ / sq.ft.

e-BIDS Guidelines for High Performance Buildings 2005
Estimate in document includes ballasts, lamps, etc. Assume 25% of cost is for controls.

Life of measure (remaining life of building)		25	yrs
Levelized cost of retrofit		$0.06	$ / sq.ft. / yr.
Cost premium	$80.79	$320.96	$ million

As stand alone			
Electricity savings - existing buildings only	529	2,115	GWh
Electricity savings - new construction only	112	271	GWh
Electricity savings - total	641	2,386	GWh
Emissions avoided (stand-alone)	0	2	MMtCO$_2$e
Net cost	-$2.68	$10.34	$ million

Site Lighting

Number of vehicles in Pennsylvania	9,610,595	9,697,888	vehicles

Bureau of Transportation Statistics

Ratio of parking spaces to vehicles		9	spaces / vehicle
Eligible parking lot area	*Assumed*	25%	
Area of parking lots		150	sq.ft. / space
Existing lighting intensity in parking lots	*See Note 3*	0.29	W / sq.ft.
Proposed lighting intensity in parking lots		0.15	W / sq.ft.
Annual hours in operation	*Assumed*	2,920	h / yr
Rate of participation	100%	100%	
Area of parking lot with efficient lighting	3,244	3,273	million sq.ft.

Area of parking lot with efficient lighting (new)	4	4	million sq.ft.
Energy savings	1,307	1,319	GWh / yr
Cost premium - levelized		$0.05	$ / sq.ft.
Gross cost	$0.21	$0.18	$ million
Emissions reduced	1	1	$MMtCO_2e$
Net cost	-$169.92	-$171.49	$ million

Exit sign - 5 W / face

Annual savings per sign		114	kWh / sign / yr
Density of signs		0.00013	signs / sq.ft.
Rate of uptake in existing buildings	100%	100%	
Number of signs	155,089	155,121	signs
Cost of unit retrofit	*Annualized*	$4	$ / sign / yr
Total cost of retrofit	$0.61	$0.61	$ million
Energy savings	17.66	17.67	GWh / yr
Emissions reduced	0.01	0.01	$MMtCO_2e$
Net cost	-$1.69	-$1.69	$ million

GHG Reductions:

Table 1. Estimated GHG Reductions and Cost-effectiveness

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effectiveness ($\$/tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($\$/tCO_2e$)
10.3	-$1,486	-$64	71.1	-$8,153	-$145

Economic Cost:

See Table 1, above.

Potential Overlap:

- High Performance Buildings Work Plans
- Energy Efficient Appliances

CCAC Member Comments:

One member provided the following comments:

- I am very supportive of increasing the energy efficiency of lighting.

- The implementation strategy for this work plan is unclear. The work plan identifies technology penetration goals and timelines, but does not describe the manner in which these goals will be achieved, other than through increased education efforts.
- It is not realistic to assume these levels of high efficiency lighting will be reached without a clear implementation strategy. It is also inappropriate to claim full GHG reductions for achieving these penetration goals if there is not a clear pathway identified for how to achieve benchmarks.
- In absence of a more clear strategy, this type of voluntary initiative should have a sensitivity analysis performed that shows a range of potential GHG reductions based on low, moderate or high penetration.
- It is unclear how this work plan overlaps with federal lighting standards. If there is significant overlap with the federal standard, then these reductions should be incorporated into the GHG projections, not listed as a state-based GHG reduction strategy.

Industrial Electricity Best Management Practices

Summary:
This initiative considers the possible reductions in electricity consumption in the industrial sector via increased efficiency and increased coordination between DEP's Office of Pollution Prevention and Energy Assistance, industrial resource centers at various universities and the U.S. Department of Energy (DOE).

Background:
The DOE, via their Industrial Technology Program (ITP) Best Management Practices (BMPs) has determined that electricity efficiency improvements can result in a 20 percent reduction in consumption from the projected electricity use by the year 2031 are possible. This is consistent with the supply of industrial electricity efficiency opportunities identified in the ACEEE (2009) report through the year 2025. Industrial electricity consumption in Pennsylvania is expected to increase by about 0.4 percent by 2020, according to data from the Energy Information Administration's 2012 Annual Energy Outlook.

The ACEEE et al (2009) report identifies significant energy efficiency opportunities in Pennsylvania's industrial sector.[55] As illustrated in Table 1, industrial electricity supplies are estimated at 16 percent of overall 2025 sales, equal to 9,297 GWh of efficiency improvement potential. This work plan targets approximately 75 percent of this value (6974 GWh) by 2020.

Table 1. Industrial Electricity Measure Savings and Costs

Measures	Fraction of Savings by Measure	Savings Potential in 2025 (GWh)	Savings Potential in 2025 (%)	Levelized Cost of Saved Energy ($/kWh)
Sensors & Controls	3%	237	0.4	$0.014
EIS	1%	67	0.1	$0.061
Duct/Pipe Insulation	17%	1,587	2.8	$0.052
Electric Supply	18%	1,710	3	$0.010
Lighting	6%	550	1	$0.020
Motors	25%	2,240	3.9	$0.027
Compressed Air	11%	1,030	1.8	$0.000
Pumps	16%	1,523	2.7	$0.008
Fans	2%	231	0.4	$0.024
Refrigeration	1%	123	0.2	$0.003
Total	100%	9,298	16.3	$0.22

Source: updated with 2012 projected Pennsylvania costs from ACEEE et al. (2009). Energy Efficiency, Demand Response, and Onsite Solar Energy Potential in Pennsylvania. April. http://www.aceee.org/pubs/e093.htm

Note: Producing energy typically requires making an investment in a technology that produces energy over a number of years. The value of such an investment to a private firm is the present

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[55] ACEEE, et al. (2009) Energy Efficiency, Demand Response and Onsite Solar Energy Potential in Pennsylvania. http//www.aceee.org/pubs/e093.htm

discounted value of revenue from energy sales minus the present discounted value of the costs, where the discount rate represents the opportunity cost of investment funds -- typically the competitive rate of return. The levelized cost of energy is defined as the constant price per unit of energy that causes the investment to just breakeven: earn a present discounted value equal to zero. In other words, present discounted value of energy produced times the levelized cost equals the present discounted value of the fixed and variable costs over the life of the investment.

Quantification Approach and Assumptions:

- Reductions from the work plan are assumed to begin in 2014 and are implemented at a rate of between 1 to 5 percent of energy sales each year through the end of the planning period.
- Reductions take into account the savings already being realized via Act 129 of 2008 and estimated reductions from the industrial sector via Act 129 Phase II such that the reported values only reflect attribution from this work plan initiative.
- Energy efficiency costs are expressed as levelized costs over the life of the energy efficiency options.
- The costs of the work plan are calculated by estimating the annual costs of energy efficiency (capital, O&M, labor) less energy savings.
- These cash flows are then discounted at a real rate of 5 percent.
  - The net present value of cash flows is calculated beginning in 2014 through 2020.
- All prices are in 2010 dollars.
- The levelized cost of electric efficiency measures is $26.03/MWh.[56]
  - This figure includes all utility and participant costs as commonly performed in a total resource cost test.
  - Program fixed costs are assumed to be part of each measure's capital cost, including administrative, marketing, and evaluation costs of 5 percent.[57]
- Avoided electricity prices range from approximately $87/MWh in 2014 to $108/MWh in 2020.
- Electricity transmission and distribution losses are assumed to be 6.6 percent over the analysis period.
- To estimate emission reductions from work plans that are expected to displace conventional grid-supplied electricity (i.e., energy efficiency and conservation) a simple, straightforward approach is used. That these policy recommendations would displace generation from an "average thermal" mix of fuel-based electricity sources. For 2013 through 2020 the assumption made is that this fossil-based thermal mix will be 50 percent coal and 50 percent natural gas. For reference, EIA data from Pennsylvania generation sources reflects an approximate mix of 60% coal and 40% natural gas.
  - The average thermal approach is preferred over alternatives because sources without significant fuel costs would not be displaced—e.g., hydro, nuclear or renewable generation.
  - This approach provides a transparent way to estimate emission reductions and to avoid double counting (by ensuring that the same MWh from a fossil fuel source are not "avoided" more than once). The approach can be considered a "first-order" approach; it does not attempt to capture a number of factors, such as the distinction

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[56] Source: ACEEE et al. (2009).

[57] Source: ACEEE et al. (2009) p. 49.

between peak, intermediate and baseload generation; issues in system dispatch and control; impacts of non-dispatchable and intermittent sources, such as wind and solar; or the dynamics of regional electricity markets. These relationships are complex and could mean that policy recommendations affect generation and emissions (as well as costs) in a manner somewhat different from that estimated here. Nonetheless, this approach provides reasonable first-order approximations of emission impacts and offers the advantages of simplicity and transparency that are important for stakeholder processes.

Work Plan Costs and GHG Reductions:

Table 3. Quantification Results

Annual Results (2020)			Cumulative Results (2014-2020)		
GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effectiveness ($/$tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($/$tCO_2e$)
4.0	-$446	- $101	9.5	-$989	-$94.4

Notes: The cost estimates in Table 3 (columns 3 and 6) are incremental costs of energy efficient measures including capital cost, operating and maintenance, and labor, above baseline measure costs. The cost estimates are calculated as the costs less avoided energy expenditures. Also, the difference between the 2020 cost effectiveness (column 3) and the cumulative cost effectiveness (column 6) is due, in part, to the effects of discounting the net cash flows over the analysis period of 2014 to 2020. Also, the energy savings payback time frames are typically very good.

Implementation Steps:

- Tap the resource expertise of the Industrial Assessment Center (IAC) at Lehigh University and similar resources to map out a plan identifying a prioritized list of opportunities and barriers achieving energy reductions.
- Work with community colleges and trade schools to educate and train students and staff to be able to perform resource assessments.
- Conduct DOE-supported workshops that advance best practice implementation for process heating and steam systems.
- Partner with utilities to develop energy use reduction programs for large energy users.

Potential Overlap:

- Act 129 Phases I, II & III

CCAC Member Comments:

One member provided the following comments:

- Producing energy typically requires making an investment in a technology that produces energy over a number of years. The value of such an investment to a private firm is the present discounted value of revenue from energy sales minus the present discounted value of the costs, where the discount rate represents the opportunity cost of investment funds -- typically the competitive rate of return. The levelized cost of energy is defined as the constant price per unit of energy that causes the investment to just breakeven: earn a present discounted value equal to zero. In other words, present discounted value of energy produced times the levelized cost equals the present discounted value of the fixed and variable costs over the life of the investment.

Heading Oil Conservation and Fuel Switching

Summary:

Demand Side Management (DSM) for Heating Oil

This initiative aims to replace or upgrade inefficient household appliances that use fuel oil with more energy-efficient models. This initiative recognizes potential for additional GHG reductions through fuel switching from heating oil to natural gas but DEP does not have any data with which to estimate the potential for fuel switching because it is largely dependent upon the rate of natural gas distribution line expansion.

Goal:

DSM for Heating Oil

Residential sector: Achieve 37 percent reductions from reference case oil consumption in 2020.
Commercial sector: Achieve 26 percent reductions from reference case oil consumption in 2020.

Natural Gas

Fuel switching to natural gas can also yield significant reductions in GHG emissions. Fuel switching to natural gas has increased dramatically with the significant decrease in natural gas prices and is expected to continue. However, large geographical areas of the state still do not have access to natural gas, including urbanized areas of the southeast. Additionally, there are numerous neighborhoods where natural gas is available on one street but not another. Fuel switching to natural gas was not quantified in this work plan because of:

- The difficulties assessing the extent of the distribution pipeline build out that may be possible through 2020,
- The relative costs associated with the expansion of the distribution pipeline network
- Costs associated with the connection to the gas distribution system and,
- Average cost savings associated with the conversion from heating oil to natural gas.

Fuel switching to natural gas should be encouraged by first ascertaining what may be the barriers to greater deployment and providing incentives to hasten the transition to this cleaner-burning, domestically produced fuel.

According to the U.S. Energy Information Administration (EIA) the average Pennsylvania home fueled by heating oil uses about 540 gallons per year whereas, the average home fueled by natural gas uses about 70,000 thousand cubic feet (MCF) per year.[58] EIA data for 2011 indicates that that average delivered cost of natural gas to the residential sector was $12.46 per MCF.[59] The average price of heating oil in Pennsylvania for the same time period was $3.59 per gallon. At these prices the average family could save about $1,050 per year in heating fuel costs by switching to natural gas.

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[58] http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=consumption#end-use-by-fuel

[59] http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

Implementation Steps for Conservation:

Encourage the following:

1. Air Sealing and Insulation (10 percent–40 percent annual energy savings)
    - Pennsylvanians using oil for heating use about 400 gallons per household.
    - By air sealing & insulation, consumers could probably save 25 percent of this.
2. Increased furnace and boiler efficiency to >95 AFUE
    - Nationwide and in PA, about 50 percent of homes use oil for heating.
    - The minimum allowed annual fuel utilization efficiency (AFUE) rating for a non-condensing, fossil-fueled, warm-air furnace is 78 percent; the minimum rating for a fossil-fueled boiler is 80 percent; and the minimum rating for a gas-fueled steam boiler is 75 percent.
    - Although older furnace and boiler systems had efficiencies in the range of 56 percent-70 percent, modern conventional heating systems can achieve efficiencies as high as 97 percent, converting nearly all the fuel to useful heat for the home. Energy efficiency upgrades and a new high-efficiency heating system can often cut fuel bills and a furnace's pollution output in half. Upgrading a furnace or boiler from 56 percent to 90 percent efficiency in an average cold-climate house will save 1.5 tCO_2 emissions each year if heated with gas, or 2.5 tCO_2 if heated with oil (DOE, Energy Savers).
    - Therefore, consumers could expect to see a 15 percent–50 percent range in energy savings from "heating season" improvements (depending on age and efficiency of equipment being replaced).
3. Solar domestic hot water heaters
    - Heating water accounts for 14 percent–25 percent of total household energy consumption. Solar water heaters can provide 85 percent of DHW needs.
4. Instantaneous hot water heaters with an energy factor >0.80
    - For homes that use 41 gallons or less of hot water daily, demand water heaters can be 24 percent–34 percent more energy efficient than conventional storage tank water heaters.
    - They can be 8 percent–14 percent more energy efficient for homes that use a lot of hot water—around 86 gallons per day. You can achieve even greater energy savings of 27 percent—50 percent if you install a demand water heater at each hot water outlet.

Implementation Steps for Fuel Switching:

Recommend that the Pennsylvania Public Utility Commission hold hearings for input to improve the availability/distribution of natural gas in Pennsylvania.

Encourage the use of on-bill financing and other creative financing options to assist with the payment of new installations and hook-up fees.

Assumptions:

Values from Pennsylvania: Potential for Energy Efficiency, Demand Response, and Onsite Solar Energy (ACEEE 2009). See page 21 for residential and page 27 for commercial. This represents the cost-effective potential. Note that these savings are greater than the amount identified by ACEEE analysis as achievable by the set of policies analyzed. The policy analysis led to savings of 11 percent fuel oil in 2025, for residential and commercial combined (see page 46). The assumptions in this work plan imply stronger policies than those identified by ACEEE (mostly standards and utility programs)

Key Data and Assumptions	**2013**	**2020**	**Units**
First Year Results Accrue		**2013**	
Savings Targets			
Heating Oil			
Achievable cost-effective savings in heating oil use as a fraction of total oil demand:			
Residential		**37%**	
Commercial		**26%**	
Value from Pennsylvania: Energy Efficiency, Demand Response and On-Site Solar Potential. ACEEE 2009. See page 21 for residential and page 27 for commercial. This represents the cost-effective potential. Note that these savings are greater than the amount identified as ACEEE analysis as achievable by the set of policies analyzed. The policy analysis led to savings of 11 percent fuel oil in 2025, for residential and commercial combined (see page 46). This work plan assumptions imply stronger policies than those identified by ACEEE (mostly standards and utility programs)			
Fraction of achievable savings reached under program		**100%**	
Year in which target fraction reached		**2020**	
Year in which programs fully "ramped in"		**2013**	
Fraction of full program savings by year	0%	100%	
Implied fractional new annual oil demand savings, residential	0.0%	4.6%	
Implied fractional new annual oil demand savings, commercial	0.0%	3.3%	
Weighted Levelized Cost of Saved Energy			
Residential		**$0.63**	$/gal
Commercial		**$0.98**	$/gal
Value from Pennsylvania: Energy Efficiency, Demand Response and On-Site Solar Potential. ACEEE 2009. See page 21 for residential and page 27 for commercial. Equipment cost is based on customer equipment and not infrastructure.			
Assumed average measure lifetime		**8**	years
Avoided Delivered Heating Oil Cost		**$22.8**	$/MMBtu
Avoided Delivered Heating Oil Cost		**$3.2**	$/gal
Projected cost of heating oil	$3.35	$3.89	$/gal
Avoided Heating Oil Emissions Rate		0.07	tCO_2e / MMBtu

Additional Data and Analyses	2013	2020	Units
DSM Heating Oil Analyses			
Reduction in Oil Use (Cumulative)	8,943	71,360	Billion Btu
Reduction in Oil Use (Cumulative)	64	513	Million Gal
Reduction as % of overall projected sales in that year	4.28%	34.13%	
Incremental GHG Emission Savings, Heating Oil	**0.6**	**5.2**	$MMtCO_2e$
Net Present Value (2013-2020) (DSM)		**-$142**	$million
Cost effectiveness (DSM)		**-$6**	$/tCO2e
Total Fuel Consumption after DSM	199,949	137,752	Billion Btu
Total Heating Oil Consumption after DSM	1,366	941	Million Gal

Potential GHG Reduction:

Table 1. Estimated GHG Reductions and Cost-effectiveness

Annual Results (2020)			Cumulative Results (2013-2020)		
GHG Reductions ($MMtCO_2e$)	Costs (Million $)	Cost-Effectiveness ($/$tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Costs (NPV, Million $)	Cost-Effectiveness ($/$tCO_2e$)
5.2	-$22	-$37	23.3	-$142	-$6.11

Economic Cost:

See Table 1 above.

Potential Overlap:

- High Performance Buildings

CCAC Member Comments:

One member provided the following comment:

- Equipment cost is based on customer equipment and not infrastructure.

Improved Efficiency at Wastewater Treatment Facilities

Initiative Summary: Improving efficiency at wastewater treatment facilities through outreach programs based on sustainable infrastructure principles.

Goals: Assist 50 percent more treatment plants per year to improve efficiency (a 50 percent improvement over the current six to eight treatment plants)

Implementation Period: three to four additional treatment plants per year from 2013 through 2020

Other Involved Agencies: DEP, Outreach Assistance Provider Program (OAPP), wastewater system owners and operators.

Implementation Steps:

- DEP—Increase personnel assigned to OAPP wastewater treatment plant outreach
- Provide funding for additional training seminars/webinar or other venues (possibly via state energy plan funding)
- Provide grant funding for wastewater plant upgrades.
- Emphasize outreach to larger, > 2 million gallons per day (mgd), operations than those analyzed in this work plan for even more significant benefits
- Encourage entities to utilize EPA's *Energy Management Handbook for Wastewater and Water Utilities and available baseline assessment software* as part of facility outreach program: (http://water.epa.gov/infrastructure/sustain/cut_energy.cfm)
- Provide exemptions from Water Quality Management (Part II) permitting if intent of equipment upgrade is for increasing energy efficiency and does not change the overall functionality of a wastewater treatment operation.
- DEP in collaboration with other professional associations provide accredited energy efficiency training programs to help certified operators meet mandatory continuing education unit requirements and professional development hours.
- Encourage WWTP to work with electric distribution companies for improved efficiencies and to take advantage of Act 129 funding.

Data sources/Assumptions/Methods for GHG:
Based on past program performance, treatment facilities visited by this program tend to treat around 1–2 mgd. Calculations on GHG savings are as follows:

- 2,500 Kilowatt-hours (kWh)/mgal treated x 1.5 mgal/day facility = 3,750 kWh/day[60]

- 3,750 kWh x 365 days = 1,368,750 kWh/yr

Savings at these facilities is estimated at 10 percent, so:

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[60] Electricity usage was determined by surveying twelve wastewater treatment plants in Pennsylvania and plotting electricity usage against the size of facility. This information was provided by Jim Elliott, Gannett Fleming, Inc. to Rachel Anderson, CCS via email, June 2009.

- 1,368,750 kWh/yr x 0.10 = 136,875 kWh/yr savings per facility

Converting to CO_2 emissions:

136,875 kWh/yr x 7.18 x 10^{-4} tCO_2/kWh[61]= 98.3 tCO_2/yr per facility

Table 1 summarizes the GHG savings possible from implementing a 50 percent increase in treatment plant upgrades. By upgrading an average of three to four additional facilities per year, a total of 0.022 $MMtCO_2e$ can be saved.

Table 1. GHG Savings and Costs of Treatment Plant Upgrades

Year	Average Additional Treatment Plants Improved	Savings per Facility (metric tons CO_2e/ year)	Total Savings Above BAU (metric tons CO_2e/year)	Annualized Capital Costs ($)	Cost Savings to Plants ($)	Cost of Additional Personnel	NPV of Net Costs (2007$)	Cost-Effec-tiveness ($/$tCO_2e$)
2013	3.5	98.3	1,376	7,103	($415,399)	44,761	($236,370)	
2014	3.5	98.3	1,720	8,879	($498,479)	44,761	($289,345)	
2015	3.5	98.3	2,064	10,654	($581,559)	44,761	($336,739)	
2016	3.5	98.3	2,408	12,430	($664,638)	44,761	($378,963)	
2017	3.5	98.3	2,752	14,206	($747,718)	44,761	($416,403)	
2018	3.5	98.3	3,096	15,981	($830,798)	44,761	($449,417)	
2019	3.5	98.3	3,441	17,757	($913,878)	44,761	($478,343)	
2020	3.5	98.3	3,785	19,533	($996,958)	44,761	($503,495)	
TOTAL			20,642				($3,089,075)	($149.65)

<u>Data Sources/Assumptions/Methods for Costs:</u>

The cost of implementation of treatment plant upgrades is estimated at $5,000 per plant, and upgrades result in an average cost savings of $25,000 per plant per year.[62] Upgrades were annualized over 15 years at a 5 percent interest rate. The cost to DEP to hire additional personnel necessary to increase outreach efforts is in a range of between $35,000 and $50,000. The total cost savings over the policy period is $3.1 million discounted to 2010 dollars, as summarized above in Table 1.

<u>Notes/Other Considerations:</u>

The DEP Office of Water Management proposes several methods to improve efficiency in order to maintain sustainable infrastructure (SI) within wastewater treatment systems. The efficient use of energy is crucial for sustaining infrastructure and national security. The end of electricity rate caps further exacerbates this issue.

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[61] Kilowatt-hour conversion from http://www.epa.gov/grnpower/pubs/calcmeth.htm,accessed May 2009.

[62] Thomas Brown, PA DEP; communicated via email to Rachel Anderson, CCS, May 2009.

Wastewater treatment plants typically are the largest consumer of electricity on most municipal bills, often consuming more than one-third of the energy consumed for all municipal services. In many instances, opportunities exist to reduce energy consumption at these facilities. To assist treatment plants in improving efficiency, DEP provides outreach to these facilities, teaching system operators how to use the system in the most efficient manner for treatment and suggesting ways to reduce the amount of energy required to operate the facility while maintaining compliance with permit limits and conditions.

Three basic types of municipal treatment plants are primarily in use today: activated sludge, fixed film and lagoon systems. Of the many treatment facilities in Pennsylvania, approximately 70 percent are activated sludge facilities. Activated sludge facilities inject diffused air into an aeration basin to sustain a biological growth in order to treat the wastewater. The aeration basins that these facilities require are the largest consumer of electricity in wastewater treatment systems. Opportunities exist to improve efficiency in many of these facilities throughout the state.

OAPP uses part-time wage payroll instructors who are certified operators or specialists in a given field. These instructors provide on-site technical, managerial and financial assistance to wastewater system owners and operators. The program responds to system needs identified by DEP regional staff, local government associations, or system personnel. On-site assistance and training are provided through a combination of video, classroom, and web-based training and one-on-one assistance to address specific system problems. Notwithstanding the uncertainties associated with funding and staffing levels, the OAPP plans to accomplish the following:

- Continue on-site technical assistance for facilities requesting assistance with energy efficiency. The average activated sludge wastewater treatment plant consumes 6,000 kWh/million gallons of wastewater treated. At approximately $0.08/kWh, the energy consumption is estimated at $500/million gallons treated. Using energy audits under the auspices of OAPP, DEP proposes to assist approximately six wastewater systems in reducing energy consumption per year, with a focus on assisting at least one in each DEP region. On average, these audits will result in an estimated annual energy savings of 10 to 15 percent per treatment plant. Due to the relatively low cost of electricity in the past, the preference for wastewater treatment has been aerobic treatment processes. With the expiration of electricity rate caps this may no longer be the most cost-effective solution. Therefore, based on the costs per kWh and available funding, a further focus of this outreach effort will be to encourage and re-educate the owners and operators of wastewater treatment systems on the benefits of more energy-efficient and effective wastewater treatment processes related to anaerobic treatment.
- Continue collaboration with DEP central and regional staff in providing training opportunities for operators in conjunction with various associations.
- Integrate the principles of SI in all technical assistance provided by OAPP. This would include providing training with regard to all aspects of SI.
- Distribute a DVD on energy efficiency and other tools for SI.
- Enhance the operator information center web site "Technical Corner" as it relates to SI, energy efficiency and other operational issues.

- Include SI principals as part of wastewater operator certification program

The DEP Wastewater Outreach Program has provided assistance in energy efficiency since 1993. Unfortunately, in the 1990s energy costs were not high enough to cause a significant amount of interest. While the program had several success stories in the past, many people simply were not tuned into the idea of energy efficiency. In one case, the program saved a municipality over $100,000 annually (in an approximately 6 mgd system). By today's standards, this type of savings would be greatly magnified. With the expiration of electricity rate caps and the increasing volatility of oil prices, people are now starting to pay attention and ask questions.

Below are examples of DEP’s past accomplishments:

- On-site technical assistance to Ridgeway Borough on energy efficiency and process control utilized the process of denitrification to save energy and chemical costs. This process utilizes the nitrate that is produced in the process of nitrification for facultative organism respiration. This results in improved water quality by reducing total nitrogen released to the receiving stream and saves money. With an investment of $500, Ridgeway was able to document savings of $31,000 annually in energy and chemical costs, in addition to improving the quality of its effluent.
- On-site energy efficiency technical assistance was provided to the City of Warren. In this system older sparge ring diffusers were used for mixing and aeration. By changing the cycles of mixing and aeration, the system could realize a savings of several thousand dollars per month. This project is still underway.
- DEP central and regional office staff collaborated to produce a continuing education training program titled "Flush Away High Energy Costs." In conjunction with PA Rural Water, this training session was piloted in the northwestern region and was well received by operators throughout the region. This session provides operators with the tools they need to reduce energy costs within their systems, while maintaining or improving water quality.
- In 1996, an energy efficiency in wastewater treatment systems video was produced jointly by DEP and the Maryland Center for Environmental Training. In the past year, this video was upgraded and digitized to a DVD format so it can be widely distributed.
- A training session was held in the State College area for DEP central and regional office staff on energy efficiency in water/wastewater systems. This session followed a format similar to the "Flush Away High Energy Costs" operator training session. This session will help regional staff to further spread the word about energy efficiency.
- A special conference on total nutrient reduction was held in the Lancaster area last fall. This sold-out event provided operators and managers with tools needed to improve reduction of nutrients and increase efficiency.
- Assistance was provided to program staff involved in a pilot project with Montgomery County Community College to create a certificate program focusing on water and wastewater treatment. Based on the input provided, the pilot program will be modified to include basics of SI with an emphasis on energy efficiency, as well as effective process control.
- The DEP’s Southeast Regional Office held a joint meeting for wastewater treatment plant officials. The meeting was held in conjunction with the U.S. EPA, PECO and the Delaware

Valley Regional Planning Commission. Continuing education credits were provided and the program is viewed as a successful model to be replicated.

All treatments plants produce excess solids, often referred to as sludge or biosolids. These excess solids have to be treated before their ultimate disposal. There are two basic types of treatment for these solids: aerobic digestion and anaerobic digestion. Anaerobic treatment tends to be more energy neutral or even produces energy, as the methane produced through this process can be used as a fuel. Unfortunately, this technology is not used in many instances in Pennsylvania, due to past problems with the operation, mostly due to problems in handling the gases produced in the treatment process. Technology in this arena has improved in recent years, making the management of these systems safer and more efficient. DEP currently has a pilot project in the works that will use anaerobic treatment and, depending on the outcome of this project, expects that other facilities may consider this option moving forward.

In a recent fiscal year, DEP had several projects in this arena. These projects are closely tied into the overall goal of SI. In many cases, treatment systems have operated in a fashion set forth by previous generations, where energy consumption was not a large concern. Taking a moment and asking why we operate in this fashion can lead to significant opportunities for reduced energy costs and improved water quality. By today's standard, any treatment facility that is required to nitrify should also consider denitrification, as it can lead to reduced operating costs, lower sludge production, and improved water quality.

The savings realized by energy-efficient measures could easily be used to fund improved water quality. In fact, in cases where a facility starts using denitrification for the beneficial uptake of nitric acid, there would be a recovery of 60 percent of the cost of nitrification and improved water quality at the same time. Cost savings are certain, and the savings could escalate as energy costs continue to rise.

It is a goal for systems to be self-sustaining in the water/wastewater industry. The single largest cost for a wastewater system is the cost of aeration. Fine bubble aeration could reduce those costs by 50 percent. This money could be incorporated into sustainable infrastructure.

Potential Overlap:
None

Increased Recycling Initiative

Summary:
Support the increased recycling of municipal solid waste (MSW) sufficient to achieve an additional, cumulative reduction (i.e. 2013 through 2020) in GHG emissions of 5.0 million metric tons of carbon dioxide equivalent ($MMtCO_2e$) by improving the efficiency of existing programs and maximizing collections within mandated communities including expansion of single-stream recycling, focusing on increasing collection of those materials with the greatest GHG emission reductions per ton recycled and then consideration of expanding mandatory recycling requirements to currently non-mandated communities.

Goal:
Increase recycling in Pennsylvania to achieve a cumulative 5.0 $MMtCO_2e$ reduction, which equates to increased tonnage recycled of approximately 2.1 million tons above projected "Business as Usual" recycling volumes.

Background Discussion:
Act 101, the Municipal Waste, Planning Recycling and Waste Act Reduction of 1988, provides the foundation for recycling that has resulted in comprehensive environmental and economic benefits for Pennsylvania. The act provides for a $2/ton recycling fee on waste disposed of or processed at municipal waste landfills and resource recovery facilities in the state. In 2007, the recycling fee generated approximately $47 million to the Recycling Fund administered by DEP. Since adoption of the $4/ton Growing Greener Fee established by Act 90 of 2002, the amount of out-of-state waste disposed of or processed in Pennsylvania has declined, resulting in significantly lower annual revenue for the Recycling Fund. In 2011, the recycling fee generated approximately $37.7 million to the Recycling Fund.

The Recycling Fund provides support to local governments for implementation of recycling programs. The recycling fee also supports the stimulation of markets for recyclable materials. DEP is focusing Act 101 funds on programs geared toward financial sustainability, including those programs that are targeting new materials for recycling that have historically been disposed. Increasing the amount of materials recycled will provide direct reductions in GHG emissions.

In 2000, 2005 and 2010, Pennsylvania's recycling efforts provided GHG reductions equal to about 9.2, 9.7 and 10.8 $MMtCO_2e$, respectively. During these years the approximate tonnage of MSW recycled was 3.4, 3.6 and 4.3 million tons. According to EPA, the energy conserved from manufacturing products from the 4.3 million tons of recycled feedstock, rather than using virgin raw materials or non-renewable resources, is equivalent to 1.2 billion gallons of gasoline or enough electricity to power 1.6 million homes.

When considering the impact of population growth, the per capita rate of recycling has been 27.6 percent in 2000, 28.8 percent in 2005 and 33.6 percent in 2010. While there has been an annual rate of increase in recycling, it is not valid to assume that annual increases in the mass of materials recycled can or will continue for several reasons, including consumer-driven issues such as:

- Reduced product and packaging weights (light-weighting), which can decrease gross tonnages of materials recycled despite constant/increasing recycling rates (for example, decreases in the mass of plastic used in water bottles).
- Greater use of e-commerce and electronic media, which is reducing production/distribution of certain types of printed media, including newspapers, magazines, novels and phone books.

And municipal governmental issues such as:

- The fiscal ability of municipalities to offer single-stream recycling
- The continued fiscal ability of municipalities currently offering recycling services that are not currently required to do so under Act 101.

In some cases, when secondary effects are considered, an overall reduction in GHG emissions will occur even though the reductions cannot be attributed directly to recycling activities. For example, light-weighting will result in GHG emission reductions from reduced production of packaging, as well as GHG emission reductions related to decreased fuel costs from transporting products that have lower weights due to decreased packaging.

Since 2005, a significant increase in recycling in the commonwealth has come from the growth of single-stream recycling. Single-stream recycling, providing convenience, cost effectiveness and immediate increases in the amount of recycled materials, accounted for over 43 percent of recycled residential materials in 2009, up from only 6 percent in 2005. Pennsylvania now hosts six privately owned and funded, single-stream recycling facilities, and at least two more are scheduled to come on-line in the near future. When single-stream recycling service is provided to a curbside collection community, the amount of material recycled increases by approximately 45 percent.

Clearly, the single biggest boon to recycling rates is making curbside, single-stream recycling widely available. As published on DEP's website, while at least 94 percent of the state's population has access to recycling, only 79 percent have convenient access to recycling through curb-side pickup programs (although not discussed on the website, a significant portion of that 79 percent does not have access to single-stream recycling). The City of Philadelphia's recent initiative to increase its recycling rate was very successfully; with single-stream recycling at the core of the initiative, the recycling rate quadrupled.

The typical single-stream facility can handle more material in one day than most of the other 89 recycling facilities located in the commonwealth can handle in a year, and this increase in recycling capacity provides the critical foundation necessary for success of this work plan's GHG emission reduction goals.

Calculations and Methodology:

The EPA's Waste Reduction Model (WARM) was used to calculate the estimated reductions in GHG emissions. WARM provides lifecycle-based emission reductions for each of numerous types of materials being recycled or composted. Table 1 provides the WARM values with tonnage of materials recycled in PA in 2000, 2005 and 2010 and the associated GHG emissions reduced, expressed in metric tons of carbon dioxide equivalent (MTCO$_2$e).

The EPA-WARM data presented in Table 1 represents recyclables generated from the municipal waste stream (46 materials) in PA. County recycling data reported to the DEP included material numbers from both the municipal and residual waste streams (62 materials). For this reason much higher recycling figures and GHG reductions for 2011 are found on the DEP's website.

Table 1. WARM GHG Values and PA Recycling Tonnages

Material	**GHG Emissions per Ton of Material Recycled (MTCO$_2$E)**	**GHG Emissions per Ton of Material Composted (MTCO$_2$E)**	**2000 Recycled (Tons)**	**2000 GHG Reduced (MTCO2e)**	**2005 Recycled (Tons)**	**2005 GHG Reduced (MTCO2e)**	**2010 Recycled (Tons)**	**2010 GHG Reduced (MTCO2e)**
Aluminum Cans	(8.89)	NA	17,590	156,384	47,603	423,218	39,037	347,058
Aluminum Ingot	(6.97)	NA		0				
Steel Cans	(1.80)	NA	13,936	25,114	19,074	34,373	912,956	1,645,269
Copper Wire	(4.89)	NA		0			10,658	52,136
Glass	(0.28)	NA	28,571	7,947	57,447	15,978	58,888	16,379
HDPE	(0.86)	NA	12,341	10,578	6,629	5,682	4,901	4,201
LDPE	NA	NA	37,267	0			4,894	0
PET	(1.11)	NA	6,755	7,487	6,644	7,364	5,446	6,036
LLDPE	NA	NA						
PP	NA	NA					1,542	0
PS	NA	NA	1,850	0			327	0
PVC	NA	NA					578	0
PLA	NA	(0.20)					5,789	0
Corrugated Containers	(3.11)	NA	713,552	2,219,177	660,244	2,053,386	751,248	2,336,412
Magazines/third-class mail	(3.07)	NA	24,683	75,784			30,182	92,668
Newspaper	(2.78)	NA	244,252	679,393	234,406	652,006	96,353	268,007
Office Paper	(2.85)	NA	76,304	217,815	73,939	211,063	110,572	315,636
Phonebooks	(2.65)	NA					784	2,078
Textbooks	(3.11)	NA						
Dimensional Lumber	(2.46)	NA	213,285	524,070	191,032	469,392	220,224	541,119
Medium-density Fiberboard	(2.47)	NA						
Food Scraps	NA	(0.20)	66,482	13,141	63,573	12,566	73,603	14,549
Leaves/Grass/Yard Trimmings	NA	(0.20)	585,682	115,769	557,691	110,236	484,920	95,852
Branches	NA	(0.20)						
Mixed Paper (general)	(3.52)	NA	239,283	841,762	249,233	876,762	192,736	678,017
Mixed Paper (primarily residential)	(3.52)	NA						
Mixed Paper	(3.59)	NA						

(primarily from offices)								
Mixed Metals	(3.97)	NA	1,074,263	4,268,428	1,084,607	4,309,527	963,236	3,827,276
Mixed Plastics	(0.98)	NA			43,352	42,556	24,290	23,844
Mixed Recyclables	(2.80)	NA			178,576	499,724	172,558	482,884
Mixed Organics	NA	(0.20)	25,183	0	24,029		15,355	0
Mixed MSW	NA	NA					18,606	0
Carpet	(2.37)	NA						
Personal Computers	(2.35)	NA	2,962	6,950	2,835	6,652	7,717	18,110
Tires	(0.39)	NA			49,730	19,430	63,975	24,996

This work plan establishes a goal of reducing an additional cumulative 5.0 million metric tons of carbon dioxide equivalent (MMTCO$_2$e) beyond the GHG emission reductions of 9.2 MMTCO2e that occurred in 2000. This is consistent with the outcome from the original work plan from the 2009 Pennsylvania Climate Change Action Plan. The total GHG reductions therefore, would be 14.6 MMTCO2e in 2020 corresponding to approximately 5.5 million tons of recycled materials. Because GHG reductions per ton of recycled materials vary, it is expected that the final gross tonnage recycled necessary to achieve this goal will also vary. Average annual rates of GHG reduction per ton of gross recycled material were used in helping to project future recycled tonnages to meet the goal. For purposes of this work plan, future changes in recycling rates are assumed to be uniform across all types of materials.

In performing the analysis three sets of calculations were made to examine a possible business-as-usual (BAU) scenario, the policy implementation scenario and an examination of the incremental growth between these two scenarios. The BAU scenario assumes an annual increase of roughly 0.44 percent in total tons of materials recycled each year in 2014 and 2015 (as compared to the previous year), and an annual increase of roughly 1.44 percent in total tons of materials recycled each year in subsequent years. As noted previously, whether recycling rate growth can or will continue is uncertain. Using this estimated BAU recycling rate growth and the increase of 5.0 MMTCO2e above baseline levels from 2000, the incremental GHG reduction in 2020 will be 2.19 MMTCO2e , indicating that additional measures and efforts (such as set forth in this work plan) are required to achieve the 5.0 MMTCO2e GHG emission reduction goal. These values are displayed in Table 2.

Economic data for this analysis was taken from *Increased Recycling Economic Information Study Update: Delaware, Maine, Massachusetts, New York and Pennsylvania Final Report 2009*. This report provides for residential and commercial costs of collection and revenues as well as, tonnages of material recycled. This data reflects collected survey data from numerous establishments in Pennsylvania representing urban and rural communities with widely divergent populations and should not therefore be used to estimate costs for any specific location or facility. This data served as the basis for the costs and cost-effectiveness data displayed in Table 2. Annual rate of discounting of 5 percent was applied to the net costs. The net present value for the policy scenario is a savings of approximately $119 per ton of CO$_2$e reduced, and the difference between BAU and the policy scenario is a net present value of $82. The cost-effectiveness of this initiative is a savings of $6.22 per ton of CO$_2$e.

This analysis does not include an assessment of the indirect and induced economic benefits realized by recycling, but these are significant. A 2009 study, "Recycling Economic Information Study Update," prepared for the Northeast Recycling Council, Incorporated indicates that as of 2007, PA had 3,800 establishments involved in some aspect of recycling, employing a work force of more than 52,000 with an annual payroll of approximately $2.2 billion and revenues of nearly $21billion. In Pennsylvania, private sector employment in the recycling industry is significant and growing. Much of this growth is being driven by the expansion of single-stream recycling capacity, as well as expansion of recycling pick-up services by private industry.

Table 2. Costs and Cost-effectiveness

	2013	2014	2015	2016	2017	2018	2019	2020
BAU Tons Recycled	4,328,724	4,347,840	4,366,957	4,428,026	4,489,095	4,550,164	4,611,233	4,672,302
Policy Tons Recycled	4,576,489	4,678,194	4,779,899	4,923,557	5,067,214	5,210,872	5,354,529	5,498,187
Incremental Tons Recycled	247,765	330,354	412,942	495,531	578,119	660,708	743,296	825,885
BAU GHG Reduced (MMtCO2e)	11.28	11.44	11.60	11.77	11.93	12.09	12.25	12.42
Policy GHG Reduced (MMtCO2e)	11.94	12.32	12.70	13.08	13.46	13.85	14.23	14.61
Incremental GHG Reduction (MMtCO2e)	0.66	0.88	1.10	1.32	1.54	1.76	1.98	2.19
BAU Collection Cost ($ million)	219.83	220.81	221.78	224.88	227.98	231.08	234.18	237.28
Policy Collection Cost ($ million)	232.42	237.58	242.75	250.04	257.34	264.63	271.93	279.23
Incremental Collection Cost ($ million)	12.58	16.78	20.97	25.17	29.36	33.55	37.75	41.94
BAU Recycling Revenue($ million)	339.42	340.91	342.41	347.20	351.99	356.78	361.57	366.36
Policy Recycling Revenue ($ million)	358.84	366.82	374.79	386.06	397.32	408.58	419.85	431.11
Incremental Recycling Revenue ($ million)	19.43	25.90	32.38	38.85	45.33	51.81	58.28	64.76
BAU Net Cost ($ million)	(119.58)	(120.11)	(120.64)	(122.32)	(124.01)	(125.70)	(127.39)	(129.07)
Policy Net Cost ($ million)	(126.43)	(129.24)	(132.04)	(136.01)	(139.98)	(143.95)	(147.92)	(151.89)
Incremental Net Cost ($ million)	(6.84)	(9.13)	(11.41)	(13.69)	(15.97)	(18.25)	(20.53)	(22.82)
BAU Discounted Net Cost ($ million)	(102.53)	(97.83)	(93.35)	(89.92)	(86.60)	(83.39)	(80.28)	(77.28)
Policy Discounted Net Cost ($ million)	(108.39)	(105.26)	(102.17)	(99.98)	(97.75)	(95.50)	(93.23)	(90.94)
Incremental Discounted Net Cost ($ million)	(5.87)	(7.43)	(8.83)	(10.06)	(11.15)	(12.11)	(12.94)	(13.66)

Implementation Steps:

To achieve the goal of this initiative, a two-pronged approach is suggested. The single most effective strategy for improving recycling rates and thereby reducing GHG emissions, is to increase the availability of curbside, single-stream recycling. Similarly, efforts targeting those specific materials that provide the maximum GHG reductions, as set forth in the "GHG Emissions per Ton of Material Recycled (MTCO2E)" column in Table 1, are also highly recommended.

Additional specific recommendations include:

1. *Commonwealth Management Directive:* Ensure that the state government is taking a leadership role and maximizing recycling efforts. These efforts will include ensuring

compliance with the comprehensive management directive that all commonwealth agencies, boards and commissions implement recycling and waste reduction programs, as well as purchase environmentally preferable products. DEP will promptly review the annual reports from GSA regarding the status of compliance with the directive, and will take appropriate measures to ensure future compliance.

2. *Recycling Reporting Improvements:* Encourage county governments to report recycling activities within their jurisdiction, as required by Act 101. To facilitate more timely and improved reporting, DEP has procured a new reporting system to capture much of the recycling data that currently goes unreported. DEP should conduct regular and comprehensive audits of the data to ensure accuracy and consistency, and then promptly make the information available for review on DEP's website. It is important that the website-posted data distinguish between recycled material quantities from residential and non-residential sources, as well as the amounts of materials managed by single-stream processing.

3. *Municipal Government Recycling Programs*

    a. Assist in working to amend Act 101 to either require recycling programs for municipalities with a lesser population density or smaller populations than currently stated in the act, and/or (current population threshold is 5,000 in the act).
    b. In addition to considering proposing the new density/population limits, DEP should consider adding "high concentration" facilities to the mandatory recycling requirements under Act 101. High concentration facilities could include gathering places located in non-mandated communities such as larger airports, shopping malls, rest stops, arenas, stadiums concert halls, etc. seating 3,000 or more people that offer food or drink service.
    c. Seek ways to encourage all municipal recycling programs to include all plastic and paper types in a list that should be developed by DEP. This would logically include all types of plastic and paper that have a market potential and/or sorting convenience to home owners—e.g., generally co-mingled materials that do not required confusing requirements for acceptable versus unacceptable materials.
    d. DEP should evaluate existing recycling programs and assist municipalities to identify steps to improve recycling services, such as endorsement of more encompassing or efficient collection processes and consolidation or elimination of redundant, outdated or non-sustainable recycling facilities.

4. *Public Recycling Availability*: DEP should consider establishing rules on density and availability of recycling containers for all public areas in which waste disposal receptacles are placed, including high concentration facilities, such as airports, shopping malls, arenas, stadiums and concert halls seating 3,000 or more people and offering food or drink service. This should be in the form of guidelines for municipal recycling programs and state governmental agencies. Appropriate language can be incorporated into the Act 101 amendments.

5. *Funding through Act 101:* In light of the reduction in fees generated for the Recycling Fund, DEP should become more discerning in how those funds are utilized. The department should encourage more encompassing and efficient collection processes, provide greater incentive to those programs and processes that demonstrate improved recycling performance, provide expansion of recycling to high concentration events and facilities, and consolidation or elimination of redundant, outdated or non-sustainable recycling operations.

6. *Review Legislation to Remove Impediments:* Conduct a comprehensive review of all the current legislation to identify areas where legislation creates obstacles or impediments to the management and beneficial use of waste material.

7. *Assist in Expanding Recycling Programs:* Develop a strategy to focus on expanding recycling programs to:
    a. Support and grow recycling industries
    b. Eliminate barriers that impede the use of waste for energy production
    c. Support the growth of private-sector recycling programs by leveling the playing field between government-supported and private-sector programs
    d. Ensure financial support to protect past investments in recycling programs
    e. Promote new private-sector investments and protect past private-sector investments in LFGTE projects and similar programs
    f. Ensure adequate funding to facilitate a sophisticated and robust statewide recycling program for all commonwealth citizens

8. *Comprehensive Legislative Package:* Assist in developing a single legislative package for consideration that folds all previously enacted legislation under one comprehensive package. The resulting package should include assisting in recycling at the source of generation, encouraging market development, and limiting disposal of recyclable materials at the end.

Potential Overlap:

- Waste-to-Energy MSW Work Plan. An overlap may exist between the Waste-to-Energy MSW Work Plan and this Statewide Recycling Initiative Work Plan, but it is not quantifiable based on the data available at this time. The overlap would only exist to the extent that the same waste would be subject to both work plans.

CCAC Member Comments:

One member commented:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013 and therefore cannot be implemented in a timeframe to deliver reductions throughout the year 2013.
- Per ton cost effectiveness numbers could not be identified.
- It is unclear how fuel costs and related emissions are being considered in this work plan.

C. 3 Land Use and Transportation Sectors Work Plans

The following work plans were discussed with CCAC Land Use and Transportation Subcommittee. Members of this subcommittee include the following:

Subcommittee Chair Laureen Boles, City of Philadelphia

Robert Graff, Delaware Valley Regional Planning Commission

Paul Opiyo, Pennsylvania Department of Community and Economic Development

Alternative Fueled Transit Bus Fleets

Summary:

Transition 25 percent of Pennsylvania's existing transit buses to alternative fuels/hybrid technology by the year 2020 through an initiative that facilitates the replacement and/or conversion of the existing bus fleet to cleaner burning compressed natural gas (CNG) and/or more fuel-efficient hybrid electric vehicle (HEV) technology for diesel-hybrid buses.

Discussion of Analysis:

The 2009-2010 fleet inventory lists 3,201 buses in fixed-route service. The inventory is split between 36 separate transit authorities. There are 22 urban transit systems accounting for 93 percent of the vehicles and 14 rural systems that comprise the remaining 7 percent of the vehicles. In 2009, the 2,979 urban buses traveled over 100 million miles with the urban systems accounting for 95 percent of the miles traveled, of which, 76 percent of these miles were traveled by the Southeast Pennsylvania Transit Authority (SEPTA) and Port Authority of Allegheny County (PAAC). The rural systems accounted for 5 percent of the total miles traveled, of which 42 percent of these miles were traveled by Area Transportation Authority (ATA) and New Castle Area Transit Authority (NCATA).

Table 1: Breakdown of PA Fleet's and Average Bus Miles Traveled:

TRANSIT SYSTEMS	FY 2009-10		
	Fixed Route Total Vehicle Miles	Total Fixed Route Fleet Size	Average Annual Bus Miles
SEPTA	45,027,501	1,392	32,347
PAAC	31,191,980	847	36,826
AMTRAN (Altoona)	536,238	30	17,875
BARTA (Berks)	1,726,679	53	32,579
BCTA (Beaver)	1,042,170	25	41,687
CAT (Dauphin/Cumberland)	1,951,040	78	25,013
CATA (Centre)	1,722,580	61	28,239
CCTA (Cambria)	1,163,744	47	24,761
COLT (Lebanon)	532,088	13	40,924
COLTS (Lackawanna)	1,172,356	33	35,526
EMTA (Erie)	2,037,199	73	27,907
FACT (Fayette)	544,895	10	54,490
LCTA-HPT (Hazleton)	1,463,906	50	59,175
LANTA (Lehigh/Northampton)	3,775,319	78	48,402
LCTA (Luzerne-Hazleton)	1,463,906	50	29,278
MMVTA (Mid Mon Valley)	889,897	25	35,596
POTTSTOWN	304,833	8	38,104
RRTA (Lancaster)	1,681,979	43	39,116

SVSS (Mercer)	151,387	6	25,231
WASHINGTON	192,643	5	38,529
WBT (Williamsport)	846,409	33	25,649
WCTA (Westmoreland)	939,810	33	28,479
YCTA (York)	1,566,498	36	43,514
ATA (North Central)	1,234,673	87	14,192
BTA (Butler)	231,966	6	38,661
CATA (Crawford)	232,346	7	33,192
CARBON	56,950	1	56,950
DUFAST (Clearfield)	119,819	6	23,964
EMTA (Endless Mtns)	719,095	19	34,847
ICTA (Indiana)	420,784	21	20,037
MCTA (Monroe)	508,231	15	33,882
MID-CO (Armstrong)	129,190	6	21,532
BMC (Mount Carmel)	52,275	3	17,425
NCATA (New Castle)	1,098,093	30	36,603
STS (Schuylkill)	371,415	14	26,530
TAWC (Warren)	204,656	5	40,931
VCTO (Venango)	162,888	3	54,296
TOTAL	**106,003,848**	**3,201**	**33,505**

The fleet inventory is further delineated by fuel type. For the purpose of this analysis however, the focus will be on gasoline, CNG, diesel-hybrid and diesel/biodiesel powered buses. The other fuel bus types, such as electric trackless-trolley employed by SEPTA, only account for 2.7 percent of SEPTA's transit fleet and are not considered in the transition scheme.

The urban transit systems make up 95 percent of the total transit vehicles in PA and a transition of their fleet will statistically have the largest impact. Currently, 33.9 percent of SEPTA's fleet is already made up of diesel-electric hybrid vehicles. SEPTA's replacement plan projects an 88.7 percent diesel-electric hybrid fleet by 2020. PAAC's fleet is made up of 32 diesel-electric hybrid vehicles, which is 4 percent of their current fleet. PAAC's replacement plan does not currently project the use of diesel-electric hybrids but rather clean diesel buses. PAAC is currently working on a CNG feasibility study that may impact future vehicle replacement decisions.

In addition to SEPTA and PAAC, other PA transit systems also have incorporated and plan to continue incorporating alternative fueled transit buses within their system. Specifically, Centre Area Transit Authority's entire fleet is operated on CNG. Some transit authorities, such as River Valley Transit of Williamsport, are progressing with plans to install CNG fueling infrastructure and to transition their bus fleet to operate on this alternative, domestically-produced fuel while some others are in the process of evaluating the costs of such a transition.

The current analysis indicates that the statewide fleet is responsible for 0.39 MMtCO2e emissions annually. Projected over 8 years (2013 through 2020), the current fleet composition would result in 3.05 MMTCO2e by 2020. These emissions were calculated using the emissions factors in Table 2, as provided by the U.S. Department of Energy's Energy Information Administration (EIA) database and the Argonne National Laboratory's Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) model and the fuel economy factors presented in Table 3. The data in Tables 1, 2 and 3 were used to calculate the annual CO2e emissions for each fleet.

Table 2: Pounds of CO2 Emitted for Each Fleet Mode (GREET Model)

Bus Engine Type	Pounds CO2/Gallon
CNG	19.74
Diesel	25.02
Diesel-Hybrid	25.02
Gasoline	24.95

Table 3: Fuel Economy, MPG for Each Fleet Mode:

Data Source	MPG			
	Gasoline	CNG	Diesel	Diesel - Hybrid
U.S. Department of Transportation Federal Transit Administration	5.5	3.27	3.86	4.58
U.S. Department of Energy's National Renewable Energy Laboratory New York City Transit Hybrid & Diesel Transit Buses	n/a	1.7	2.33	3.19
Environmental &Energy Study Institute	n/a	1.7	2.33	3.18
Argonne National Laboratory*	2.5	2.5	3	3.8
Centre Area Transit Authority (CATA)**	-	3.0	-	-
Southeaster PA Transit Authority (SEPTA)**	-	-	2.72	3.92

***Data selected for analysis**
****Date received from CATA and SEPTA**

Table 4 illustrates a simplified schedule for the transition of the statewide bus fleet to make a 25 percent transition to either CNG or HEV diesel (diesel-hybrid). Collectively, the data from each of the preceding tables was then used to estimate the projected annual CO2e emissions, through 2020, resulting from this transition, as illustrated in Tables 5A through 5C. In doing so the number of buses in the fleet was multiplied by the average annual bus miles, divided by the fuel economy (MPG) and then multiplied by the specific emissions factor for the specific fuel. The emissions reported in Tables 5A through 5C are in metric tons. The analysis shows the potential GHG emissions for different scenarios that would result if 25 percent of the 2010 bus fleet was operated on CNG (Scenario #1) or if 25 percent of the fleet was operated with diesel-hybrid technology (Scenario #2).

Table 4: 25 percent Fleet Transition Schedule:

	2013	2014	2015	2016	2017	2018	2019	2020	Total Additional Buses by Type
CNG	77	77	77	78	78	78	78	78	621
Diesel-Hybrid	45	45	45	45	45	46	46	46	363

Table 5A: Baseline Annual Emissions Summary

Year	Fixed Route Total Vehicle Miles	Total Fixed Route Fleet Size	Average Annual Bus Miles	Bus Type				Emissions (MMtCO2e)				
				Gasoline	CNG	Diesel - Hybrid	Diesel	Gasoline	CNG	Diesel - Hybrid	Diesel	Total MMtCO2e
2010	106,003,848	3,201	33,116	57	90	542	2467	0.009	0.011	0.054	0.309	0.382
2011	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2012	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2013	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2014	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2015	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2016	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2017	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2018	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2019	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
2020	106,003,848	3,201	33,116	57	90	542	2,467	0.009	0.011	0.054	0.309	0.382
TOTALS	**106,003,848**	**3,201**	**33,116**	**57**	**90**	**542**	**2,467**	**0.068**	**0.085**	**0.429**	**2.472**	**3.054**

Note: Total bus type will not add "Total Fixed Route Fleet Size" because of other types of fleet vehicles, such as trackless trolley.

Table 5B: Estimated Annual Emissions Summary for Fleet Transitioning Under Scenario #1 (CNG)

Year	Fixed Route Total Vehicle Miles	Total Fixed Route Fleet Size	Average Annual Bus Miles	Bus Type				Emission (MMtCO2e)				
				Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline	CNG	Diesel-Hybrid	Diesel	Total MMtCO2e
2013	106,003,848	3,201	33,116	57	314	542	2252	0.009	0.037	0.054	0.282	0.38
2014	106,003,848	3,201	33,116	57	370	542	2196	0.009	0.044	0.054	0.275	0.38
2015	106,003,848	3,201	33,116	57	426	542	2140	0.009	0.051	0.054	0.268	0.38
2016	106,003,848	3,201	33,116	57	483	542	2083	0.009	0.057	0.054	0.261	0.38
2017	106,003,848	3,201	33,116	57	540	542	2026	0.009	0.064	0.054	0.254	0.38
2018	106,003,848	3,201	33,116	57	597	542	1969	0.009	0.071	0.054	0.247	0.38
2019	106,003,848	3,201	33,116	57	654	542	1912	0.009	0.078	0.054	0.240	0.38
2020	106,003,848	3,201	33,116	57	711	542	1855	0.009	0.084	0.054	0.232	0.38
TOTALS	**106,003,848**	**3,201**	**33,116**	**57**	**711**	**542**	**1855**	**0.068**	**0.486**	**0.429**	**2.058**	**3.04**

Table 5C: Estimated Annual Emissions Summary for Fleet Transitioning Under Scenario #2 (Diesel-Hybrid)

Year	Fixed Route Total Vehicle Miles	Total Fixed Route Fleet Size	Average Annual Bus Miles	Bus Type				Emissions (MMtCO2e)				
				Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline	CNG	Diesel-Hybrid	Diesel	Total MMtCO2e
2013	106,003,848	3,201	33,116	57	90	674	2288	0.009	0.011	0.067	0.287	0.372
2014	106,003,848	3,201	33,116	57	90	707	2255	0.009	0.011	0.070	0.282	0.372
2015	106,003,848	3,201	33,116	57	90	740	2189	0.009	0.011	0.073	0.274	0.367
2016	106,003,848	3,201	33,116	57	90	773	2156	0.009	0.011	0.076	0.270	0.366
2017	106,003,848	3,201	33,116	57	90	806	2123	0.009	0.011	0.080	0.266	0.365
2018	106,003,848	3,201	33,116	57	90	839	2090	0.009	0.011	0.083	0.262	0.364
2019	106,003,848	3,201	33,116	57	90	872	2057	0.009	0.011	0.086	0.258	0.363
2020	106,003,848	3,201	33,116	57	90	905	2024	0.009	0.011	0.090	0.254	0.362
TOTALS	**106,003,848**	**3,201**	**33,116**	**57**	**90**	**905**	**2024**	**0.068**	**0.085**	**0.625**	**2.152**	**2.930**

CNG and Methane Losses:

The climate effect that results from replacing other fossil fuels with natural gas depends largely on the sector and the type of fuel being replaced. When estimating the net climate change implications of fuel-switching strategies, outcomes must be based on the complete fuel cycle, a Life Cycle Analysis (LCA), and account for changes in the radiative forcing effects (warming) of the relevant GHGs.

Methane, the major constituent of natural gas, when considered on a 100-year time horizon, is 21 to 25 times more potent of a GHG than CO_2 however, over a shorter, 20-year time horizon it is 72 times more potent than CO_2[63]. The shorter time frame is particularly relevant since many policy decisions are analyzed within such a window. With the addition of more wells and increased Marcellus Shale play activity, left unchecked, the amount of fugitive and vented CH_4 emissions will only increase, compounding any efforts to decrease emissions of GHGs.

Given an estimated 2.4 percent leakage and loss rate for natural gas, along with the associated CH_4 emissions from the transportation sector itself, CNG vehicles do not currently represent a viable mitigation strategy for climate change.[64] However, if the natural gas system leakage rate was reduced from the current estimate of down to below 1 percent, CNG-powered heavy-duty vehicles would provide immediate GHG reductions[65]. In this analysis, it is assumed that the leakage rate will be reduced to 1 percent or less by 2016. This work plan makes the assumption that the leakage rate will be reduced such that additional GHG benefits can be realized, as estimated in this document. (Refer to the Transportation Chapter for further information on methane leakage reduction)

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[63] Argonne National Laboratory, 2011, November 2011, *Life-Cycle Analysis of Shale Gas and Natural Gas*

[64] IBID

[65] IBID

Emissions Reductions:

As noted in Table 5B, the 25 percent fleet transition to CNG buses (Scenario 1), coupled with a leak reduction rate below 1 percent, is estimated to result in total emissions of 0.38 MMTCO2e in 2020. The 25 percent increase in fleet CNG buses is the result of the addition of 621 CNG buses to the existing fleet, as suggested in Table 4. Commensurately, the number of diesel buses in the fleet is reduced by 621 units. This difference leads to an overall calculated GHG reduction of 0.003 MMtCO2e in 2020 (Table 6A) and a cumulative reduction from 2013 through 2020 of 0.01 MMtCO2e (Table 6B).

As noted in Table 5C, the 25 percent fleet transition to diesel-hybrid buses (Scenario 2) results in total emissions of 0.362 MMTCO2e in 2020. This fleet transition is accomplished by the addition of 363 diesel-hybrid buses to the existing fleet, as suggested in Table 4. Commensurately, the number of diesel buses in the fleet is reduced by 363 units. The net effect leads to an overall calculated GHG reduction of 0.02 MMtCO2e in 2020 (Table 6A) and a cumulative reduction from 2013 through 2020 of 0.12 MMtCO2e (Table 6B).

As noted in Tables 6A and 6B, both scenarios (CNG and diesel-hybrid) provide GHG emissions reductions; however, the difference is significant, with 92 percent greater GHG reductions by utilizing diesel-hybrid technology. This difference is, in part, due to the differences in energy density (Btu per unit of fuel) and increased fuel efficiency of diesel (includes diesel-hybrid) buses. Based on Btu values and the fuel economy data, a CNG-powered bus requires more fuel to travel an equal distance as compared to a diesel or diesel-hybrid powered bus. Diesel-hybrid buses are capable of reducing GHG emissions by as much as 75 percent when compared to conventional diesel buses. These reductions are a function of the electric drive system, which facilitates utilization of a smaller-than-normal conventional internal combustion engine.

Table 6A: 2020 Annual Emissions Summary (MMtCO2e) Comparison of Baseline, CNG and HEV Scenarios

	Gasoline	CNG	Diesel-Hybrid	Diesel	Total	Reduction*
2010 Baseline	0.009	0.011	0.054	0.309	0.382	0
25% transition to CNG	0.009	0.084	0.054	0.232	0.379	0.003
25% transition to HEV	0.009	0.011	0.089	0.254	0.362	0.020

**CNG emissions reduction possible only if upstream CH4 leakage rate dips below 1 percent*

Table 6B: Cumulative (2013 -2020) Emissions Summary (MMtCO2e) Comparison of Baseline, CNG and HEV Scenarios

	Gasoline	CNG	Diesel-Hybrid	Diesel	Total	Reduction*
2010 Baseline	0.068	0.085	0.429	2.472	3.054	0
25% transition to CNG	0.068	0.486	0.429	2.058	3.041	0.01
25% transition to HEV	0.068	0.085	0.625	2.152	2.930	0.12

**CNG emissions reduction possible only if upstream CH4 leakage rate dips below 1 percent*

Table 7: Estimated Economic Costs 2013-2020

Net present value (2013-2020) at 25% transition CNG*	525.3	$million
Net present value (2013-2020) at 25% transition HEV	590.5	$million
Cost-effectiveness CNG (2013-2020)*	52,532	$/tCO$_2$e
Cost-effectiveness HEV (2013-2020)	4,921	$/tCO$_2$e

$/MtCO$_2$e = dollars per metric ton of carbon dioxide equivalent.

*CNG emissions reduction possible only if upstream CH4 leakage rate dips below 1 percent

<u>Economic Cost:</u>

The primary cost of the transition to a CNG or diesel-hybrid fleet is the incremental purchase cost of the vehicles or the costs to retrofit or convert the few existing gasoline-powered buses to operate on CNG. CNG vehicles require a spark-ignited engine but as diesel buses are compression-ignition engines, lacking spark plugs, it is not feasible to convert a diesel bus to operate on CNG. In 2011 the MSRP of a diesel-powered, standard options Orion VII 40' low-floor transit bus was $380,000. The MSRP for the same model and optioned bus powered by CNG was $425,000 (incremental cost of $45,000), while the same bus powered by hybrid electric diesel technology was $545,000 (incremental cost of $165,000). In addition to the incremental purchase price of the vehicles other factors must be taken into consideration to determine the cost effectiveness of a transition to either CNG or diesel-hybrid transit buses. In this analysis the cost of the bus, the annual cost of fuel, the cost of compression electricity for CNG, the cost of operation and maintenance (O&M), the cost of HEV battery replacement and the cost of additional infrastructure for CNG buses (not required for diesel-hybrids) was considered. Fuel costs were based on the price at the pump at the end of March 2012 (diesel fuel at $4.17 per gallon and CNG at $2.40 per diesel gallon equivalent (DGE)). Compression electricity costs of $3,000 per month were based on publicly available data from WAVE Transit in Wilmington, Delaware. Operation and Maintenance (O&M) costs of $1.04 for both CNG and diesel-hybrid buses were calculated using a formula provided in the NYCT study and the available data provided for the current PA transit bus fleet. CNG fueling station costs of $1.7 million per station are from WAVE Transit. Battery replacement costs were based on an average HEV bus traction battery replacement ranging from $35,000 - $45,000 per unit. The analysis for this initiative assumes an average battery cost of $40,000. Recent information provided by SEPTA indicated that they experience lower diesel fuel costs ($2.41/gal.), lower O&M costs ($0.46/mile, depot maintenance not included) and lower battery replacement costs ($31,450/battery) for their diesel-hybrid fleet than the formulated and national laboratory data utilized in this work plan.

Along with the option to purchase original equipment manufacturer (OEM) CNG buses is the option to retrofit/convert existing fleet vehicles to CNG. CNG retrofit kits also present a sizable investment of $20,000 and more depending on size. These kits are not always the best economical route to take. A comprehensive evaluation of the existing fleet must be conducted to ascertain the merit of converting existing transit buses. In the case of older buses the age and condition of the unit must be taken into consideration in order to determine if this type of investment is warranted. A retrofit to an existing vehicle that is near the end of its useful life may experience a catastrophic failure before the investment payback period has been reached. For this reason, replacement of the bus with a new CNG bus may be the best option.

The infrastructure costs associated with the transition to a CNG-powered fleet are significant. An engineering analysis should be conducted to determine if a fleet depot has access to CNG and also has the physical capability to house CNG-related infrastructure. Major facility reconfiguration and/or the purchase of additional real estate could be required to house and maintain a CNG fleet which would result in increased capital costs over and beyond the incremental cost of the vehicles. In a report to the DEP, SEPTA conducted an evaluation of converting its fleet to CNG. They conducted an engineering study involving eight SEPTA depots and found that only two of their eight depots, (Midvale and Frontier) had the physical capability to accommodate new CNG related infrastructure. Construction costs to retrofit these two facilities would have to include a new fueling station and existing building modifications to satisfy minimum code requirements. The cost of the retrofit to these two depots was estimated to be $34.4 M and $12.2 M respectively. Replacement costs of the other six depots ran from $35 M to $53 M.

With such a significant capital investment, SEPTA chose to transition a large portion of their fleet to diesel-hybrid buses and utilize existing infrastructure, even though the incremental cost of the new buses was higher than that of a comparable CNG unit. The use of HEV transit buses does present advantages over CNG units in that the technology does not require any reconfiguration of an existing depot as with the addition of CNG infrastructure.

Along with the cost of CNG fueling stations there is another major consideration with CNG fueling infrastructure is the operational reliability of the CNG station. A transit agency transitioning to CNG buses in areas where CNG refueling infrastructure is limited or non-existent must rely entirely on their own depot fueling infrastructure. Unlike an event where one or two buses have mechanical problems that impacts only those vehicles, a CNG compressor failure or other serious problem with the CNG fueling station could ground the entire fleet. Because of this, redundancy of station components is a necessity for some locations adding to fleet conversion costs. Redundancy, over sizing and a back-up station provide operational reliability.

HEV technology, on the other hand, can be introduced into a transit fleet and use the existing conventional refueling infrastructure at the depot or at readily available public or private diesel fueling stations. HEV buses are also expected to have lower maintenance costs due to reduced stress and maintenance on mechanical components such as brake linings. In addition the electric drive has fewer moving parts than conventional drive units, thus requiring less maintenance than a traditional transmission. More efficient operation and higher average fuel economy of the HEV technology significantly reduce annual fuel costs over both conventional fuel and CNG transit buses. Studies indicate that on average HEV buses experience a 37 percent improvement in fuel economy compared to a standard diesel bus. In comparison with CNG buses, the improved fuel economy of HEV technology increased by an average of 88 percent with expected decreases in the summer months due to increased energy demand by vehicle accessories.[66] Maintenance costs are reported to be slightly lower for CNG buses when compared to the maintenance costs of a

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[66] *NREL, 2006: New York City Transit (NYCT) Hybrid (125 Order) and CNG transit Buses, Final Evaluation Results, November, 2006.*

diesel unit. Diesel-hybrid bus maintenance costs are reported to be lower than both CNG and non-HEV diesel powered buses,[67] however this analysis indicates that they are the same.

Table 7 and the following tables within this work plan's Appendix AFB1 provide additional details on costs and cost-effectiveness. The cost effectiveness dollar amounts were derived by taking the numbers of CNG and diesel-hybrid buses needed to complete a 25 percent fleet transition of each fuel mode. For CNG buses this amounted to 621 buses and for the transition to diesel-hybrid, 363 additional buses are needed. The total cost for each scenario ($656.1 M for CNG, $776.2 M for diesel-hybrid) is divided by the total emissions reduction to determine the cost-effectiveness of each scenario, expressed as dollars per metric ton of CO2e reduced. A more detailed analysis of the data and calculations can be found in the appendix at the end of this work plan.

Key Assertions:

- HEV diesel transit buses are superior in fuel economy, emissions and have lower maintenance costs.
- GHG emissions could be further reduced if a more comprehensive public transit system were in place throughout Pennsylvania.
- The use of mandated percentages of biodiesel in the Commonwealth will further add to GHG reductions associated with the operation of HEV diesel buses. The associated incremental reductions have not been accounted for in this work plan but will be addressed separately in the Biofuel Development and In-state Production Incentive Act work plan.

Key Uncertainties:

- The largest uncertainty with this assessment involves the life cycle GHG impacts of unconventional natural gas. A number of studies have been published on the subject of GHG emissions from natural gas, e.g., the impacts of using natural gas for electricity generation and of natural gas substituted as transportation fuel.[68] While these studies are comprehensive in scope they do not present a rigorous treatment of the uncertainty and variability in estimating life cycle environmental impacts. The lifecycle GHG emissions factors applied in this assessment do not take into account unconventional natural gas which many have reported to have a greater impact on GHG emissions.
- Availability of state and federal grant dollars for AFV and infrastructure
- Cost of alternative fuels and AF technology
- With increased manufacturing, incremental costs of AFV technology are reasonably expected to decline over time
- Increased utilization of public transit

Additional Benefits and Costs:

- Direct reduction of diesel fuel and therefore imported petroleum
- Criteria pollutants are reduced. A northeast advanced vehicle study, conducted by the U.S. Department of Energy, demonstrated that nitrogen oxide (NOx) emissions from

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[67] *Environmental and Energy Study Institute (EESI) "Hybrid Buses Costs and Benefits" March, 2007*

68 Advanced Resources International Inc. Life-Cycle Emissions Study: Fuel Life-Cycle of U.S. Natural Gas Supplies and International LNG; 2008 diesel-hybrid buses were 30 percent to 40 percent lower than conventional diesel vehicles.[69] In addition diesel-hybrid buses exhibited the lowest carbon monoxide (CO) emissions of any of the buses tested including CNG powered units.

- Criteria pollutants are reduced. A DOE study indicated that nitrogen oxide (NOx) emissions from CNG buses were up to 59 percent lower than conventional diesel buses.
- Utilization of CNG is expected to result in increased job opportunities, at least for short-term jobs

Implementation Steps:

- Encourage transit authorities to utilize AF vehicles and AF technology buses especially HEV diesel buses when replacing transit buses that are scheduled for normal replacement.
- Keep transit authorities updated on available financial state and federal alternative fuel vehicle incentives.
- Offer special state grant solicitations for transit authorities to install AF infrastructure.
- Offer special state grant solicitations to assist transit authorities with the incremental cost associated with the purchase of HEV diesel and dedicated CNG buses.

Potential Overlap:

- The use of mandated percentages of biodiesel in Pennsylvania will further add to GHG reductions associated with the operation of HEV diesel buses. The associated incremental reductions have not been accounted for in this work plan but will be addressed separately in the Biofuel Development and In-state Production Incentive Act work plan.

Committee Comments

One member provided the following comments:

- In general, I am supportive of the greenhouse gas and environmental benefits of fuel switching from oil-based transportation fuels towards electric or natural gas powered vehicles. However, the greenhouse gas benefits of natural gas powered vehicles depend on the lifecycle of natural gas emissions.
- A scientific paper from the Proceedings of the National Academy of Sciences[70] found that:
    - Assuming EPA's 2009 estimates of 2.4% (from well to city) for leak rates, compressed natural gas (CNG)-fueled vehicles are not a viable mitigation strategy for climate change because of methane leakage from natural gas production, delivery infrastructure and from the vehicles themselves. For light-duty CNG cars to become a viable short-term climate strategy, methane leakage would need to be

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[69] *Department of Energy "Early results from National Renewable Energy Laboratory Transit Bus Evaluations" May, 2005*

[8] *Department of Energy "Heavy Duty Vehilce Emissions Testing" June, 2003*

[70] Ramon A. Alvarez, Proceedings of the National Academy of Sciences of the United States of America, "Greater focus needed on methance leakage from natural gas infrastructure", Vol. 109, no. 17, 6435-6440, http://www.pnas.org/content/109/17/6435

kept below 1.6% of total natural gas produced (approximately half the current amount for well to wheels – note difference from well to city).
    - Methane emissions would need to be cut by more than two-thirds to immediately produce climate benefits in heavy duty natural gas-powered trucks.
    - At current leakage rate estimates, converting a fleet of heavy duty diesel vehicles to natural gas would result in nearly 300 years of climate damage before any benefits were achieved.
- This work plan analysis assumes methane leakage will be at 1%, which may or may not be a realistic assumption.

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The Connecticut Academy of Science and Engineering *Demonstration and Evaluation of Hybrid Diesel-Electric Transit Buses*, October 2005

Appendix AFB1

Fleet Base Year	FY 2009-10		Number of Buses by Type				Emissions Tons CO2e				
	Total Fixed Route Fleet Size	Average Annual Bus Miles	Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline	CNG	Diesel / Hybrid	Diesel	Total Tons CO2e
2013-2020	3,201	33,116	57	90	542	2467	9,419.2	11,766.8	59,089.6	340,677.2	420,952.7

CNG Scenario: Fleet Stats

Year			Number of Buses by Type			
	Total Fixed Route Fleet Size	Average Annual Bus Miles	Gasoline	CNG	Diesel-Hybrid	Diesel
2013	3,201	33,116	57	314	542	2243
2014	3,201	33,116	57	370	542	2187
2015	3,201	33,116	57	426	542	2131
2016	3,201	33,116	57	483	542	2075
2017	3,201	33,116	57	540	542	2018
2018	3,201	33,116	57	597	542	1961
2019	3,201	33,116	57	654	542	1904
2020	3,201	33,116	57	711	542	1847
TOTAL	**3,201**	**33,116**	**57**	**711**	**542**	**1847**

CNG Scenario: Vehicle and Fuel Costs

Year	Vehicle Cost $				Fuel Cost $			
	Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline @ $3.85	CNG @ $2.71	Diesel Hybrid @ $4.09	Diesel @ $4.09
2013	0.0	$23,800,000	0.0	0.0	$2,906,922	$11,271,892	$19,318,654	$101,267,293
2014	0.0	$23,800,000	0.0	0.0	$2,906,922	$13,282,165	$19,318,654	$98,738,997
2015	0.0	$23,800,000	0.0	0.0	$2,906,922	$15,292,439	$19,318,654	$96,210,701
2016	0.0	$24,225,000	0.0	0.0	$2,906,922	$17,338,610	$19,318,654	$93,682,404
2017	0.0	$24,225,000	0.0	0.0	$2,906,922	$19,384,782	$19,318,654	$91,108,960
2018	0.0	$24,225,000	0.0	0.0	$2,906,922	$21,430,953	$19,318,654	$88,535,516
2019	0.0	$24,225,000	0.0	0.0	$2,906,922	$23,477,125	$19,318,654	$85,962,071
2020	0.0	$24,225,000	0.0	0.0	$2,906,922	$25,523,296	$19,318,654	$83,388,627
TOTAL	**0.0**	**$192,525,000**	**0.0**	**0.0**	**$31,976,147**	**$168,755,295**	**$212,505,198**	**$1,057,866,225**

CNG Scenario: O&M Costs

Year	O&M Cost $ (Facility & Propulsion Maintenance)				O&M Cost $ (Compression Electricity)				O&M Cost $ (Battery Replacement)			
	Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline	CNG	Diesel Hybrid	Diesel	Gasoline	CNG	Diesel Hybrid	Diesel
2013	0	$10,814,361	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2014	0	$12,743,037	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2015	0	$14,671,713	$18,666,827	0	0	$36,000	0	0	0	0	$21,680,000	0
2016	0	$16,634,829	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2017	0	$18,597,946	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2018	0	$20,561,062	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2019	0	$22,524,179	$18,666,827	0	0	$36,000	0	0	0	0	0	0
2020	0	$24,487,295	$18,666,827	0	0	$36,000	0	0	0	0	0	0
TOTAL	**0**	**$161,905,449**	**$205,335,096**	**0**	**0**	**$396,000**	**0**	**0**	**0**	**0**	**$21,680,000**	**0**

CNG Scenario: Costs Associated with Refueling Infrastructure

Year	Total Fixed Route Fleet Size	Average Annual Bus Miles	Number of Buses by Type				Additional Infrastructure (CNG Stations)			
			Gasoline	CNG	Diesel-Hybrid	Diesel	Gasoline	CNG	Diesel Hybrid	Diesel
2013	3,201	33,116	57	314	542	2243	0	$5,559,000	0	0
2014	3,201	33,116	57	370	542	2187	0	$5,559,000	0	0
2015	3,201	33,116	57	426	542	2131	0	$5,559,000	0	0
2016	3,201	33,116	57	483	542	2075	0	$5,559,000	0	0
2017	3,201	33,116	57	540	542	2018	0	$5,559,000	0	0
2018	3,201	33,116	57	597	542	1961	0	$5,559,000	0	0
2019	3,201	33,116	57	654	542	1904	0	$5,559,000	0	0
2020	3,201	33,116	57	711	542	1847	0	$5,559,000	0	0
TOTAL	**3,201**	**33,116**	**57**	**711**	**542**	**1847**	**0**	**$61,149,000**	**0**	**0**

Diesel – Hybrid Scenario: Fleet Stats

Year			**Number of Buses by Type**			
	Total Fixed Route Fleet Size	**Average Annual Bus Miles**	**Gasoline**	**CNG**	**Diesel-Hybrid**	**Diesel**
2013	3,201	33,116	57	90	674	2335
2014	3,201	33,116	57	90	707	2302
2015	3,201	33,116	57	90	740	2269
2016	3,201	33,116	57	90	773	2236
2017	3,201	33,116	57	90	806	2203
2018	3,201	33,116	57	90	839	2170
2019	3,201	33,116	57	90	872	2137
2020	3,201	33,116	57	90	905	2104
TOTAL			**57**	**90**	**905**	**2104**

Diesel – Hybrid Scenario: Vehicle and Fuel Costs

Year	**Vehicle Cost $**				**Fuel Cost $**			
	Gasoline	**CNG**	**Diesel-Hybrid**	**Diesel**	**Gasoline @ $3.85**	**CNG @ $2.71**	**Diesel Hybrid @ $4.09**	**Diesel @ $4.09**
2013	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$24,023,566	$105,420,922
2014	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$25,199,794	$103,931,034
2015	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$26,376,023	$102,441,145
2016	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$27,552,251	$100,951,256
2017	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$28,728,479	$99,461,367
2018	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$29,904,707	$97,971,478
2019	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$31,080,935	$96,481,589
2020	$0	$0	$17,985,000.0	$0	$2,906,922	$3,230,797	$32,257,163	$94,991,701
TOTAL	$0	$0	**$197,835,000.0**	$0	**$31,976,147**	**$35,538,767**	**$290,136,248**	**$1,126,852,593**

Diesel – Hybrid Scenario: O&M Costs

Year	O&M Cost $ (Facility & Propulsion Maintenance)				O&M Cost $ (Compression Electricity)				O&M Cost $ (Battery Replacement)			
	Gasoline	**CNG**	**Diesel-Hybrid**	**Diesel**	**Gasoline**	**CNG**	**Diesel-Hybrid**	**Diesel**	**Gasoline**	**CNG**	**Diesel Hybrid**	**Diesel**
2013	0	3,099,658	23,212,991	0	0	$36,000	0	0	0	0	0	0
2014	0	3,099,658	24,349,532	0	0	$36,000	0	0	0	0	0	0
2015	0	3,099,658	25,486,074	0	0	$36,000	0	0	0	0	$1,320,000	0
2016	0	3,099,658	26,622,615	0	0	$36,000	0	0	0	0	$1,320,000	0
2017	0	3,099,658	27,759,156	0	0	$36,000	0	0	0	0	$1,320,000	0
2018	0	3,099,658	28,895,697	0	0	$36,000	0	0	0	0	$1,320,000	0
2019	0	3,099,658	30,032,238	0	0	$36,000	0	0	0	0	$1,320,000	0
2020	0	3,099,658	31,168,779	0	0	$36,000	0	0	0	0	$1,320,000	0
TOTAL	**0**	**34,096,234**	**280,346,810**	**0**	**0**	**$396,000**	**0**	**0**	**0**	**0**	**$7,920,000**	**0**

Alternative Fueled Taxicab Fleets

Summary:
Transition 25 percent of Pennsylvania's existing taxi cab fleet to compressed natural gas (CNG), hybrid electric vehicle (HEV) technology or a combination of the two by the year 2020.

Background Discussion:
Data compiled from the Pennsylvania Department of Transportation indicates that there were 3,150 taxi cabs in service in the Commonwealth of Pennsylvania in 2010[71]. The data is broken down by county, number of taxis and average annual miles traveled.

Table 1: 2010 Pennsylvania Taxicab Registrations by County[1]

COUNTY OF REGISTRATION	NUMBER OF TAXIS	AVERAGE ANNUAL MILES*	COUNTY OF REGISTRATION	NUMBER OF TAXIS	AVERAGE ANNUAL MILES*
Allegheny	340	15,300,000	Lancaster	24	1,080,000
Armstrong	1	45,000	Lawrence	1	45,000
Beaver	10	450,000	Lebanon	7	315,000
Berks	51	2,295,000	Lehigh	22	990,000
Blair	14	630,000	Luzerne	38	1,710,000
Bradford	6	270,000	Lycoming	13	585,000
Bucks	167	7,515,000	Mercer	1	45,000
Butler	19	855,000	Mifflin	3	135,000
Cambria	4	180,000	Monroe	31	1,395,000
Carbon	1	45,000	Montgomery	322	14,490,000
Centre	49	2,205,000	Northampton	16	720,000
Chester	35	1,575,000	Northumberland	16	720,000
Clarion	6	270,000	Philadelphia	960	43,200,000
Clinton	6	270,000	Pike	6	270,000
Columbia	5	225,000	Somerset	2	90,000
Cumberland	5	225,000	Union	1	45,000
Dauphin	292	13,140,000	Venango	2	90,000
Delaware	414	18,630,000	Warren	2	90,000
Erie	36	1,620,000	Washington	6	270,000
Fayette	4	180,000	Wayne	5	225,000
Franklin	2	90,000	Westmoreland	16	720,000
Huntingdon	1	45,000	Wyoming	4	180,000
Indiana	3	135,000	York	16	720,000
Lackawanna	21	945,000	Out of State	144	6,480,000

*Average mileage based on the IRS mileage estimate of 45,000 miles annually

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[71] PennDOT, 2011: *Report of Registrations for Calendar Year 2010*

The current analysis of the 2010 registration data indicates that the statewide fleet consists of 3,150 taxis distributed across 47 counties with 144 being registered outside of the state. The largest numbers of taxi registrations are seen in the urban counties of Philadelphia, Delaware, Allegheny, Montgomery and Dauphin. These five counties account for 74 percent of the taxis in Pennsylvania. Using the IRS taxicab audit estimate of 45,000 miles per year per taxi, we assume the annual miles traveled by the Pennsylvania fleet to be 141,750,000 miles. The GHG emissions numbers presented in this analysis were calculated using the emissions factors for pounds of CO2/gallon, found in Table 2, as provided by the U.S. Department of Energy (DOE) and the National Renewable Energy Laboratory's (NREL) Barwood Cab Fleet Study.

By using the factors in Tables 1, 2 and 3, the annual CO2e emissions were able to be calculated. First the number of taxis in the PA fleets was multiplied by the average annual travel miles. This number was then divided by the fuel economy miles per gallon (MPG) for fuel mode and then multiplied by the specific emissions factor for a particular fuel. Lastly by dividing by 2000 we were able to calculate the tons of CO2e emissions for each fuel mode, which in turn was converted to million metric tons of carbon dioxide equivalents (MMtCO2e). The results of these calculations can be found in Table 5.

The analysis shows the potential GHG emissions that would result if the 2010 fleet was comprised of 25 percent CNG vehicles (Scenario #1), or 25 percent HEV (Scenario #2).

CNG and Methane Losses:

The climate effect that results from replacing other fossil fuels with natural gas depends largely on the sector and the type of fuel being replaced. These distinctions have been for the most part absent in policy discussions. When estimating the net climate change implications of fuel-switching strategies, outcomes must be based on the complete fuel cycle, a Life Cycle Analysis (LCA), and account for changes in the radiative forcing effects (warming) of the relevant GHGs.

Methane, the major constituent of natural gas, when considered on a 100-year time horizon, is 21 times more potent of a GHG than CO_2 but over a shorter, 20-year time horizon it is 72 times more potent than CO_2[72]. The shorter time frame is particularly relevant since many policy decisions are analyzed within such a window. With the addition of more wells and increased Marcellus Shale play activity, left unchecked, the amount of fugitive and vented CH_4 emissions will only increase, compounding any efforts to decrease emissions of GHGs.

Given an estimated 2.4 percent leakage and loss rate for natural gas, along with the associated CH_4 emissions from the transportation sector itself, CNG vehicles do not currently represent a viable mitigation strategy for climate change.[73] However, if the natural gas system leakage rate was reduced from the current estimate of down to below 1.6 percent, CNG-powered heavy-duty vehicles would provide immediate GHG reductions[74]. In this analysis, it is assumed that the leakage rate will be reduced to 1.6 percent or less by 2016. This work plan makes the assumption that the leakage rate will be reduced such that additional GHG benefits can be realized, as estimated in this document.

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[72] Argonne National Laboratory, 2011, November 2011, *Life-Cycle Analysis of Shale Gas and Natural Gas*

[73] IBID

[74] Argonne National Laboratory, 2011, November 2011, *Life-Cycle Analysis of Shale Gas and Natural Gas*

Emissions Reductions:

In Scenario #1, a 25 percent increase in the number of CNG taxis in the PA fleet is represented and a 25 percent decrease in gasoline powered taxis is also seen. Under this scenario, 748 CNG cabs are added. Subsequently the 2,993 gasoline taxis is reduced to 2,245 taxis. In this scenario the 25 percent increase of CNG taxis, along with an upstream CNG leak reduction rate below 1.6 percent, could result in a net calculated decrease of 5,158 tons of CO2e in the annual fleet emissions.

In Scenario #2, a 25 percent increase in the number of HEV taxis is shown, commensurate with a corresponding decrease in gasoline powered taxis. Under this scenario, 748 HEV cabs are added. As in Scenario #1 the 2,993 gasoline taxis is reduced to 2,245 taxis however, in this scenario the 25 percent increase of HEV taxis results in a net decrease of 11,976 tons of CO2e in annual fleet emissions.

The disparity between emissions from the CNG powered vehicles and the HEV technology vehicles is due to the amount of fuel used by each fuel mode fleet vehicle. Based on BTU value and the fuel economy (MPG) data, a CNG powered taxi requires more fuel to travel an equal distance as the HEV taxi.

Table 2: Pounds of Life Cycle CO2 Emitted for Each Fleet Mode (Greet Model)

Fuel Type	Pounds CO2e/Gallon
CNG	19.74
HEV	24.95
Gasoline	24.95

Table 3: Fuel Economy, MPG for Taxi Fleet

Data Source	MPG		
	Gasoline	CNG	Hybrid
U.S. Dept of Energy, NREL	16	n/a	33-48
NREL, Barwood Cab Fleet Study	17	17	n/a

Table 4: Baseline Scenario Fleet Characteristics and Emissions

Base Year	Total Fleet Miles	Fleet Size	Average Annual Taxi Miles	Taxis by Fuel Mode			Annual CO2e Emissions (Short Tons)			Total Emissions (MMtCO2e)
				Gasoline	CNG	HEV	Gasoline	CNG	HEV	
2010	141,750,000	3,150	45,000	2,993	79	79	98,819	2,058	1,105	0.09

Assumes 5% of current fleet is AFV

Table 5a: Scenario #1 (CNG) 2013-2020 Emissions

Year	Annual Total Miles	Fleet Size	Ave. Vehicle Miles	Taxi Type			Emissions Reductions (MMtCO2e)			
				Gasoline	CNG	HEV	Gasoline	CNG*	HEV	Total
2013	141,750,000	3,150	45,000	2,899	94	79	0.09	0.00	0.00	0.09
2014	141,750,000	3,150	45,000	2,805	187	79	0.08	0.00	0.00	0.09
2015	141,750,000	3,150	45,000	2,711	281	79	0.08	0.01	0.00	0.09
2016	141,750,000	3,150	45,000	2,617	374	79	0.08	0.01	0.00	0.09
2017	141,750,000	3,150	45,000	2,523	468	79	0.08	0.01	0.00	0.09
2018	141,750,000	3,150	45,000	2,429	561	79	0.07	0.01	0.00	0.09
2019	141,750,000	3,150	45,000	2,335	655	79	0.07	0.02	0.00	0.09
2020	141,750,000	3,150	45,000	2,241	748	79	0.07	0.02	0.00	0.09
TOTAL				**2,241**	**748**	**79**	**0.62**	**0.08**	**0.01**	**0.70**

Table 5b: Scenario #2 (HEV) 2013-2020 Emissions

				Taxi Type			Emissions (MMtCO2e)			
Year	Annual Total Miles	Fleet Size	Ave. Annual Miles	Gasoline	CNG	HEV	Gasoline	CNG	HEV	Total
2013	141,750,000	3,150	45,000	2,899	79	94	0.09	0.00	0.00	0.09
2014	141,750,000	3,150	45,000	2,805	79	187	0.08	0.00	0.00	0.09
2015	141,750,000	3,150	45,000	2,711	79	281	0.08	0.00	0.00	0.09
2016	141,750,000	3,150	45,000	2,617	79	374	0.08	0.00	0.00	0.09
2017	141,750,000	3,150	45,000	2,523	79	468	0.08	0.00	0.01	0.08
2018	141,750,000	3,150	45,000	2,429	79	561	0.07	0.00	0.01	0.08
2019	141,750,000	3,150	45,000	2,335	79	655	0.07	0.00	0.01	0.08
2020	141,750,000	3,150	45,000	2,241	79	748	0.07	0.00	0.01	0.08
TOTAL				**2,241**	**79**	**748**	**0.62**	**0.01**	**0.04**	**0.67**

Tables 5a and 5b provide estimated GHG emissions, for each fuel type in the CNG scenario and HEV scenario. Hybrid automobiles and CNG automobiles are capable of reducing CO_2 emissions by as much as 25 percent when compared to conventional gasoline powered automobiles. A DOE, NREL Taxicab study comparison of 10 conventional gasoline powered Ford Crown Victoria taxis and 10 CNG powered Ford Crown Victoria taxis demonstrated that CNG exhaust emissions were significantly lower than their gasoline counterparts.[75] In addition, the testing demonstrated that although both the gasoline and CNG vehicle emissions fell within the EPA's applicable standards the CNG vehicles had significantly lower levels of non-methane hydrocarbons (NMHC), carbon monoxide (CO) and oxides of nitrogen (NOx).

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[75] *NREL, 1999: Barwood Cab Fleet Study Summary, May, 1999.*

In general, HEVs produce lower emissions than conventional gasoline powered vehicles. These lower emissions are the result of the combination of a conventional internal combustion engine (ICE) propulsion system with an electric propulsion system. The presence of the electric powertrain is intended to achieve either better fuel economy than a conventional vehicle, or better performance. A hybrid-electric produce less emissions from its ICE than a comparably-sized gasoline car, since an HEV's gasoline engine is usually smaller than a comparably-sized pure gasoline-burning vehicle.

The results of this analysis are presented in Table 6. Annual emissions are presented in MMtCO2e for each of the three fuel types along with an annual CO2e emissions total and a final total GHG reduction by the year 2020 for each fuel scenario. As indicated in the table the cumulative GHG reductions are 0.07 MMtCO2e for the HEV scenario and 0.04 MMtCO2e for the CNG scenario.

Table 6: Summary of Annual (2020) and Cumulative (2013 - 2020) GHG Emissions and Emissions Reductions by Scenario*

	Taxis by Fuel Mode			Annual Emissions CO2e/tons			2020 Annual Emissions (MMtCO2e)	Cumulative Emissions (MMtCO2e)	2020 Emissions Reductions (MMtCO2e)	Cumulative Emissions Reductions (MMtCO2e)
Scenario	Gasoline	CNG	HEV	Gasoline	CNG	HEV				
BAU	2,993	79	79	98,819	2,057	1,105	0.09	0.74	0.00	0.00
CNG	2,241	748	79	73,986	19,546	1,105	0.09	0.70	0.01	0.04
HEV	2,241	79	748	73,986	2,064	10,499	0.08	0.67	0.01	0.07

***** *Possible emissions reduction with CNG upstream leakage rate below 1.6%*

Economic Cost:

When doing an analysis of the cost-effectiveness of the transition represented in Scenario #1, additional factors, besides the incremental cost of the CNG automobiles, must be taken into consideration. A significant drawback to the transition of fleet taxis to CNG is the cost of a new CNG vehicle or the cost of a retro-fit kit to convert an existing gasoline powered vehicle to a CNG powered unit.

Currently, retro-fit/ repowering is the only available option because only one original equipment manufacturer (OEM) CNG passenger automobile is available in the US. In today’s market, the cost of a retro-fit kit, depending on vehicle size, can range from $10,000 to $14,000. With this kind of re-fit cost per unit, in addition to the cost of the platform vehicle, the cost per unit can easily approach $35,000 to $40,000 per unit. CNG retro-fit kits present a sizable investment and are not always the best economical route to take especially when considering the CNG conversion of a used vehicle. The age and condition of the automobile/cab must be taken into consideration in order to determine if this type of investment is warranted. A retrofit to an existing vehicle that is near its useful life period may experience a catastrophic failure before the investment pay-back period has been reached. For this reason, total replacement of the unit with an OEM model, when available, or new vehicle conversion may be the best option.

One of the most popular hybrid taxis found on the streets of the U.S. today is the Toyota Camry Hybrid. The 2012 MSRP for the Camry Hybrid LE (base model) is $25,900. With the unavailability of a Toyota Camry in a CNG fuel mode for a direct comparison, based on vehicle size and retro-fit kit availability a Chevrolet Malibu was chosen as the comparison vehicle. The 2012 MSRP for the Chevrolet Malibu (base model) is $22,110. Add to this the incremental cost of $10,000 -$14,000 for a CNG retro-fit conversion kit and the investment for a new CNG taxicab can approach $35,000 per unit. The cost to compare for a used Ford Crown Victoria was estimated at $8,000 for the business as usual scenario.

Tables 7a and 7b illustrate the net costs and cost effectiveness of each scenario. The net costs are negative indicating that the costs to implement the initiatives provides a significant savings, as compared to maintaining the current fleet of conventional (gasoline) taxis with poor fuel economy. It is estimated that the gross costs associated with implementing this initiative in 2020 are $45 million and $41 million, respectively, for the CNG and HEV scenarios. These gross-level costs are offset by savings from the estimated cost of maintaining the current taxi fleet at $74 million.

Along with a switch from conventional gasoline to the alternative fuel CNG, comes a change to the fueling infrastructure of the fleet depot or the local fueling stations. Currently the majority of the Pennsylvania taxicab fleets consists of gasoline powered vehicles either utilizing public gasoline stations or fleet fueling infrastructure. With the transition of a taxi fleet to CNG powered vehicles the logistics and cost of a CNG fueling station must also be taken into consideration. An engineering analysis should be conducted to determine if a fleet depot has access to CNG and also has the physical capability to house CNG-related infrastructure. Major facility reconfiguration and/or the purchase of additional real estate could be required to house and maintain a CNG fleet which would result in additional capital costs over and beyond the incremental cost of the vehicles. In comparison, HEV taxis can utilize existing fueling and maintenance infrastructure.

Another aspect to consider with the transition of a fleet to AFVs is vehicle maintenance costs. In this respect maintenance costs are reported to be slightly lower, about 25 percent on a per-mile basis, for CNG taxis when compared to the maintenance costs of a gasoline unit.[76]

Table 7a: Estimated GHG Reductions* and Cost-effectiveness CNG

Annual Results (2020)			**Cumulative Results (2013 - 2020)**		
GHG Reductions (MMtCO$_2$e)	**Net Costs (Million $)**	**Cost-Effectiveness ($/tCO$_2$e)**	**GHG Reductions (MMtCO$_2$e)**	**Net Costs (NPV, Million $)**	**Cost-Effectiveness ($/tCO$_2$e)**
0.007	$-29	$-4,392	0.037	$-23	$-619

**** Possible emissions reduction with GNG upstream leakage rate below 1.6%***

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[76] Taxicab, Limousine & Paratransit Association: 2009, July 2009, *Analysis of Alternative Fuels & Vehicles for Taxicab Fleets.*

Table 7b: Estimated GHG Reductions and Cost-effectiveness HEV

Annual Results (2020)			Cumulative Results (2013 - 2020)		
GHG Reductions ($MMtCO_2e$)	Net Costs (Million $)	Cost-Effectiveness ($/$tCO_2e$)	GHG Reductions ($MMtCO_2e$)	Net Costs (NPV, Million $)	Cost-Effectiveness ($/$tCO_2e$)
0.014	$-33	$-2,373	0.067	$-42	$-634

Conclusion:

The use of HEV taxicabs does present certain advantages over CNG units in that the technology does not require any reconfiguration of an existing depot as with the addition of CNG infrastructure. HEV technology can be introduced into a taxi fleet and use the existing conventional refueling infrastructure. HEV vehicles are also expected to have lower maintenance costs due to reduced stress and maintenance on mechanical components such as brake linings. In addition the electric drive has fewer moving parts than conventional drive units, thus requiring less maintenance than a traditional transmission. More efficient operation and higher average fuel economy of the HEV technology significantly reduce annual fuel costs over both conventional fuel and CNG vehicles. However, typical fuel economy is expected to decrease when a HEV vehicle is operated in the summer months due to increased energy demand by vehicle accessories.

The data in this analysis supports that there could be significant reductions in GHG emissions realized with the adoption of either CNG taxis or HEV taxis to replace existing gasoline powered units. Cost effectiveness of the fuel mode selected along with availability of the technologies at the present will dictate the early choice for pioneer taxi fleets. Looking toward the future when CNG and HEV/EV OEM vehicle and public and private fueling infrastructure are more readily available taxi fleets will be able to select from multiple alternative fuel modes to fit their individual needs and goals.

Implementation Steps:

- Encourage taxi fleet owners to utilize AF vehicles and AF technology when replacing taxicabs that are scheduled for normal replacement.
- Keep taxi fleet owners updated on available state and federal alternative fuel vehicle incentives.
- Special state grants solicitations for taxi companies to install AF infrastructure.
- Special state grants solicitations to assist taxi companies with the incremental cost associated with the purchase of dedicated AF vehicles.

Key Assumptions:

- HEV and CNG taxicabs are superior to conventional gasoline powered taxis in reducing GHG emission.
- GHG emissions could be further reduced with the transition of gas powered taxis to AFV and AF technology taxis.
- The electric drive components and systems market will continue to progress and provide more products at lower prices to the taxicab market.
- CNG infrastructure and OEM vehicles will become readily available within the next few years.

- Methane leakage rate for CNG.

Key Uncertainties:

- Availability of State and Federal Grant dollars for AF vehicles and infrastructure
- Cost or alternative fuels and AF technology
- Availability of CNG infrastructure in all areas throughout the state.
- Availability of OEM vehicles in near future.

Additional Benefits and Costs:

- Direct reduction of gasoline fuel usage through the utilization of CNG and Hybrid (gasoline) technology without the added cost of new infrastructure.
- Criteria Pollutants reduction

CCAC Member Comments:

One member provided the following comments:

- In general, I am supportive of the greenhouse gas and environmental benefits of fuel switching from oil-based transportation fuels towards electric or natural gas powered vehicles. However, the greenhouse gas benefits of natural gas powered vehicles depend on the lifecycle of natural gas emissions.
- A scientific paper from the Proceedings of the National Academy of Sciences[77] found that:
    - Assuming EPA's 2009 estimates of 2.4% (from well to city) for leak rates, compressed natural gas (CNG)-fueled vehicles are not a viable mitigation strategy for climate change because of methane leakage from natural gas production, delivery infrastructure and from the vehicles themselves. For light-duty CNG cars to become a viable short-term climate strategy, methane leakage would need to be kept below 1.6% of total natural gas produced (approximately half the current amount for well to wheels – note difference from well to city).
    - Methane emissions would need to be cut by more than two-thirds to immediately produce climate benefits in heavy duty natural gas-powered trucks.
    - At current leakage rate estimates, converting a fleet of heavy duty diesel vehicles to natural gas would result in nearly 300 years of climate damage before any benefits were achieved.
- This work plan analysis assumes methane leakage will be at 1%, which may or may not be a realistic assumption.
- This work plan calculations indicate the initiative is highly cost effective. However, it is unclear if and what costs of implementation are incorporated.
- The assumption that CNG infrastructure will be readily available throughout the Commonwealth within five years may not be realistic.

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[77] Ramon A. Alvarez, Proceedings of the National Academy of Sciences of the United States of America, "Greater focus needed on methance leakage from natural gas infrastructure", Vol. 109, no. 17, 6435-6440, http://www.pnas.org/content/109/17/6435

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Cutting Emissions from Freight Transportation

Summary:

This initiative presents an array of specific measures that can be adopted to decrease GHG emissions from the state's freight transportation sector, which is forecast for continued growth, despite the economic downturn and decreased transportation funding. Primarily, these measures aim to (1) improve the efficiency of vehicle trips; (2) reduce large diesel engine idling and emissions; and (3) shift freight from trucks to other modes.

Other Agencies Involved:

The Pennsylvania Department of Transportation , American Trucking Association (ATA)/PA Motor Truck Association (PMTA), Keystone State Railroad Association/members, PennPORTS (Department of Community and Economic Development [DCED]), MPO/RPOs and local governments.

Possible New Measures:

I. Improve Trucking Efficiency

A. **Expand EPA SmartWay Truck Transport:** This option entails development of a technology option package modeled after the EPA's SmartWay Transport Partnership (EPA, 2009a). This voluntary partnership is designed to encourage shippers and fleets to reduce air pollution and GHG emissions through lower fuel consumption. By identifying and promoting fuel-saving retrofit technologies, the partnership enables truck fleets to better understand how to reduce fuel consumption via the most economical means available. In many cases, fuel-saving retrofits can result in net cost savings over the long run. The two technology options analyzed are listed below:

- **Aluminum Wheels With Single-Wide Tires:** Replacing the typical configuration of two wheels and tires at the end of each axle on heavy-duty trucks and commercial trailers with an aluminum wheel and a single-wide tire improves fuel economy by 4 percent by decreasing rolling resistance and weight (EPA, 2009b).
- **Trailer Fairings:** Adding front and side fairings (e.g., skirts) to trailers reduces aerodynamic drag and improves fuel economy by 5 percent (EPA, 2009b).

While the combined costs associated with installing both technology options (<$10,000) is modest compared to the cost of a tractor-trailer, such up-front costs may be prohibitive for some truck owners. While grants may help, a revolving loan program is a better financial assistance option (Bynum, 2009). With a payback of roughly three years, the money loaned from the initial fund is quickly returned and used for new loans. The SmartWay Transport Partnership is currently working with iBank, a company that provides businesses with access to its network of loan lenders (Bynum, 2009; iBank, 2009). The advantage is that these lenders will bid on the loan request, lowering the interest rate and simplifying the process of acquiring a loan. The process is similar to what LendingTree is doing for consumer loans (Bynum, 2009).

The following ATA recommendations target reduced fuel consumption by 86 billion gallons and the carbon footprint of commercial vehicles by nearly 1 billion tons over the next 10 years nationwide:

- **Increase Fuel Efficiency**: Under SmartWay, CO_2 reductions of 119 million tons expected nationwide by 2018 (24.95 and 25.02 lbs/gal gasoline and diesel, respectively).
- **Install Heavy Truck On-Board Emission Sensors*:*** Devices alert a driver when the emissions system is malfunctioning. An EPA rule phased in beginning in 2010, with a universal engine mandate by 2013. The rule is modeled after passenger vehicle systems and CARB. Emissions are reduced by up to 90 percent. However, current costs are high.
- **Outfit Trucks With Speed Governors:** Use the EPA calculator to estimate fuel savings. Obtain cost information on and set a goal for what percentage of PA trucks might have this technology installed within 10, 15 and 20 years, and the type of state policy/program needed to achieve these goals.
- **Install Idling Reduction Technologies:** Anti-idling technology is addressed in the Diesel Powered Motor Vehicle Idling Act, Act 124 of 2008.

Approximately 30 (2 percent) of more than 1,600 PMTA members are enrolled in SmartWay. EPA and ATA could work more closely with state trucking associations (including possible customization and state-run SmartWay plans) to facilitate greater participation.

B. **More Productive Truck Combinations:** Advocated by the ATA, this option expands (geographic) operation of higher-productivity vehicles, including single tractor trailer maximum gross vehicle weight of 97,000 lbs, heavier double 33-foot trailers and triples. Determine the relationships between truck weight, fuel consumption and increased ability to move freight. Establish goals for how this initiative would lead to changes and improvements in PA at the same 10, 15 and 20 year intervals listed previously.

C. **Future Federal Requirements*:*** Current federal/EPA requirements mandate reductions in NO_x and PM, but not CO_2. Regulations are under congressional consideration and development, and the plan will be updated should legislation including significant emission reductions be passed.

II. Expand Rail Freight and Improve Efficiency

A. Switchyard Initiatives

Low-Emission Locomotive: This is Norfolk Southern's (NS's) preferred/approved terminology to allow flexibility regarding current and future technologies. The current focus on the new General Electric (GE) engine is due to a favorable cost-benefit ratio and a long history with GE;

"GenSet Switcher" Locomotive: GenSets use two small diesel engines instead of one large one, with one switched off during idle (see Section B) or when not hauling a heavy load or climbing grade. This is a good option for smaller class II/III railroads operating locomotives individually or not transporting a lot of freight cars at once; Class I (e.g., NS) can't cover costs with fuel savings to date. Over 60 PA railroads use hundreds of locomotives that would be candidates for GenSet conversion. This reduces emissions by 80 to 90 percent, and uses up to 37 percent **less** fuel versus older models.

Electric Wide-Span Cranes: Operating from electric power, these cranes produce zero emissions on site. The wide-stance design eliminates up to six diesel trucks (hostlers) for shuttling containers. A hybrid model is also under development.

Battery Powered Locomotives: NS has received grants from the Federal Railroad Association and the U.S. Department of Energy to support research of electric locomotives powered by lead acid batteries. Successful project completion will enable diesel locomotive regenerative braking and reduce fuel consumption.

Mother/Slug Engine Re-Powers: Switcher/yard locomotives often operate in pairs to move large numbers of cars to other locations after long-haul delivery. A mother/slug is a locomotive pair configuration that consists of one four-axle locomotive (mother) powered by an engine approaching current EPA standards for controlling emissions of criteria pollutants, and one four-axle platform of four traction motors without an engine (slug). Typically, switchers are powered by pre-1973 engines not mandated to be rebuilt by existing federal law/regulations. A mother/slug realizes fuel benefits over existing pairs due to one engine instead of two, and the new replacement engine is more fuel efficient. Fuel savings for converting a switcher pair from traditional configuration to mother/slug are estimated at 25 to 38 percent, with corresponding GHG emission reduction.

Because these projects reduce criteria pollutants in many cases, re-powering the mother/slug could be partly funded by CMAQ funding, with a match provided by the railroad. This yard locomotive configuration can be built at NS's Juniata Locomotive Shop, and the new engine can be built at the GE plants in Erie and Grove City. Currently, NS operates about 27 pair (54) of switcher locomotives in PA, and each locomotive uses approximately 82,000 gallons of fuel per year.[78]CSX also operates about 38 yard locomotives statewide.

B. *Reduce Locomotive Engine Idling (not included in PA Act 124)*

Auxiliary Power Units: Railroads use APUs to warm engines, allowing them to shut down in cold weather. CSX pioneered APUs, and hundreds are currently in use in PA. NS plans to ultimately phase out APUs, which still produce emissions, and future engine requirements will result in much greater idling reductions.

Automatic Engine Stop-Start Idling Reduction: This technology allows the main engines to shut down when ambient conditions are favorable. It is currently built and installed in Altoona (e.g., NS). Railroads are establishing and reinforcing shutdown requirements, including driver training/rewards.

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[78] Procedures for Emission Inventory Preparation Volume IV: Mobile Sources, Chapter 6, United States Environmental Protection Agency, 1992.

"GenSet Switcher" Locomotives (see also Section A): Their smaller engines are the only ones that use antifreeze, allowing them to shut down in cold weather.

C. Long-Haul Initiatives

Expand/Upgrade Existing Rail: Each ton-mile of freight moved by rail versus road reduces GHG emissions by two-thirds or more. If 10 percent of nationwide long-haul truck freight converted to rail, annual GHG emissions would fall by more than 12 million tons (equivalent to taking 2 million cars off the road), and cumulative reductions through 2020 could be 200 million tons. Upgrading existing rail capacity to facilitate double-stacked trailers significantly enhances freight delivery, reduces fuel use, and minimizes freight reconfiguration during delivery. NS's impending Crescent Corridor expansion consists primarily of upgrading track to accommodate double-stacked containers the 6-state length of I-81 (Tennessee to upstate New York), as well as upgrading/installing some double track. (The Heartland Corridor will reduce 200 route miles from each shipment and transit time by one day.) However, the large majority of rail expansion is intermodal, which still involves truck transport to/from the facility. Finally, significant improvement in the NS-Amtrak relationship could expand rail capacity.

Expand EPA SmartWay Rail Transport*:* SmartWay members agree to improve their fuel efficiency, reduce their environmental footprint, reduce their energy consumption, and engage in corporate citizenship. Freight trains are three or more times more fuel-efficient than trucks. (See I, Trucking, for additional guidance).

Policy Issues: Class I rail expansion is contingent on significant public-sector cost sharing at the federal and state levels.

III. Expand Marine Freight and Improve Efficiency

There are two recommended PA initiatives for the commercial marine sector. One is to make the infrastructure improvements needed to allow the amount of freight shipped by vessel in PA to increase in situations where marine vessel transport is more energy efficient than truck or rail transport. Growth possibilities and issues differ for each of the three major PA port areas: the Philadelphia area, the Pittsburgh area and the Erie area. The second initiative is to provide the financing and incentives (and regulations) needed to improve the energy efficiency and associated GHG emissions of the vessels and cargo handling equipment in use at the major PA port facilities. This second initiative is designed to make the PA port operations as GHG efficient as possible.

Superior Efficiency: Water transport is generally 40 percent more efficient than rail; rail is already three times more fuel efficient than trucks. For example, in the Port of Pittsburgh, one 15-barge tow replaces 1,000 trucks.

Philadelphia/South Jersey/Delaware River Ports: These ports have signed a Memorandum of Understanding (MOU, 2008) to reduce or neutralize the impacts of operations and expansion by reducing energy consumption, employing cleaner energy sources, and replacing and modernizing vehicles and equipment.

Marine Diesel Engine Retrofits: The Port of Pittsburgh's "gap financing" plan contains $20 million (including CMAQ funds) to repair and upgrade engines per EPA **r**equirements.

Diesel Engine Containerized Cranes: The Port of Philadelphians developed a plan to electrify all (20+) current cranes by the fall of 2009.

Intermodal Port/Rail*:* PennDOT Rail Freight Assistance Program has awarded $1million to the Port of Erie/Industrial Development Corporation to restore rail service to industrial parks, replace 12,000 trucks, and serve biodiesel manufacturers. GE Locomotive is seeking to partner on hybrid locomotive and tugboat prototypes.

America's Marine Corridor/Ben Franklin Corridor*:* The Port of Philadelphia is applying for federal funds to glean business from Panama Canal widening (2014), which is expected to reroute significant volumes from the West Coast. The conversion of cross-country truck/rail freight to ships/barges will reduce regional emissions.

Policy Issues: Federal regulations (e.g., Jones Act) present roadblocks to short sea shipping and other marine conversion opportunities. Environmental concerns regarding waterway dredging (water quality, wildlife, etc.) must also be resolved/balanced.

Potential GHG Reductions and Economic Costs:

Table 1 below summarizes the emission benefits and costs of the measures applied to truck freight and locomotives. Marine freight measures are not yet included in this table.

Table 1. Estimated GHG Emissions Reductions and Cost-Effectiveness

GHG emission savings (2020)	1.15	$MMtCO_2e$
Net Present Value (2013-2020)	-1370.38	$million
Cumulative Emissions Reductions (2013-2020)	5.89	$MMtCO_2e$
Cost-effectiveness (2013-2020)	-211	$\$/tCO_2e$

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent; $\$/tCO_2e$ = dollars per metric ton of carbon dioxide equivalent. Negative numbers indicate cost savings.

Heavy-Duty Trucks

The two technology options considered in the heavy-duty truck analysis are based on EPA's SmartWay Transport Partnership (EPA, 2009b). The first option is the installation of aluminum wheels for single-wide tires to reduce vehicle weight and rolling resistance. The second option is the installation of fairings (e.g., front and side skirts) to improve vehicle aerodynamics. The improved fuel economy and associated GHG emission reductions for each option are additive (Bynum, 2009).

GHG Reduction from Installing Aluminum Wheels

Replacing the typical heavy-duty truck configuration of two wheels and tires at the end of each axle with an aluminum wheel and a single-wide tire decreases rolling resistance and weight. This technology can be applied to all tractor and trailer tire positions, except for the steer tires. When applied to these tire positions, it can reduce fuel consumption by 4 percent (EPA, 2009b). Since half of the tires suitable for retrofitting are located on the tractor, and half are located on the trailer, the fuel savings is allocated equally between the tractor and the trailer (i.e., the fuel savings from retrofitting a tractor-truck is assumed to be 2 percent, and the fuel savings from retrofitting a trailer is assumed to be 2 percent). DOT reports the number of tractor-trucks registered in Pennsylvania in 2007 as 74,404 (DOT, 2008b) and the number of commercial trailers as 152,489 (DOT, 2008c). Table 2 shows the assigned penetration rate for retrofits and the total tractor-trucks and trailers retrofitted through 2020 under this policy option.

Table 2. Total Tractor-Trucks and Trailers Retrofitted With Aluminum Wheels

Year	Heavy-Duty Trucks Registered in PA	Penetration Rate for Tractor-Trucks	Trucks Retrofitted	Commercial Trailers Registered in PA	Penetration Rate for Trailers	Trailers Retrofitted
2013	74,404	12.5	9,301	152,489	6.9	10,522
2014	74,404	25	18,601	152,489	13.8	21,043
2015	74,404	37.5	27,566	152,489	20.7	34,565
2016	74,404	50	37,202	152,489	27.6	42,087
2017	74,404	62.5	46,502	152,489	34.5	52,609
2018	74,404	75	55,803	152,489	41.4	63,130
2019	74,404	87.5	65,103	152,489	48.3	73,652
2020	74,404	100	74,404	152,489	55.2	84,174

The estimated GHG emission reductions from replacing existing two-wheel, two-tire configurations with a single aluminum wheel are based on diesel fuel savings. To calculate these emissions, the total VMT in the state (108,699 million miles; DOT, 2008a) are multiplied by the fraction of miles traveled by heavy-duty trucks (0.07; PA DEP, 2007) to obtain total annual VMT by heavy-duty trucks in Pennsylvania in 2007. Total annual VMT is then divided by the average fuel economy of heavy-duty trucks (6.0 mpg; Bynum, 2009) to obtain total diesel fuel consumed (1,268 million gallons). Fuel savings are based on the total diesel fuel consumed, the percentage of fuel savings associated with the retrofits, and the penetration rate for tractor-trucks and trailers:

Total fuel savings = (1,268 million gallons)*(0.02)*((penetration rate for tractor trucks + penetration rate for trailers)/100)

Total fuel savings is multiplied by GHG emissions per million gallons of diesel fuel consumed (0.01125 MMt; DOE, 2008) to obtain the total annual GHG emission reduction.

Table 3. GHG Emission Reduction From Installing Aluminum Wheels

Year	Vehicle Miles Traveled by Heavy Trucks in PA (million miles)	Average Fuel Economy of Long-Haul Heavy Trucks (miles per gallon)	Diesel Fuel Savings (million gallons)	GHG Reduction ($MMtCO_2e$)
2013	7,609	6.00	4.92	0.06
2014	7,609	6.00	9.84	0.11
2015	7,609	6.00	14.76	0.17
2016	7,609	6.00	19.68	0.22
2017	7,609	6.00	24.60	0..28
2018	7,609	6.00	29.52	0.33
2019	7,609	6.00	34.44	0.39
2020	7,609	6.00	39.36	0.45
Total				**2.01**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Heavy-Duty Trucks: Costs Associated With Installing Aluminum Wheels

The cost of retrofitting a tractor-truck and trailer with aluminum wheels is approximately $5,600 (2007$; EPA, 2009b). Since half of the wheels suitable for retrofit are located on the tractor-truck and half are located on the trailer, the cost is assumed to be $2,800 for each. The total cost of retrofitting is calculated by multiplying the number of trucks and trailers being retrofitted in a given year by $2,800. The cost savings, shown in Table 4, are realized in the fuel savings from reduced vehicle weight and lower rolling resistance. Fuel cost savings are simply the diesel fuel saved multiplied by the price per gallon of diesel fuel. Net costs are the installation costs minus the fuel cost savings. Since two standard tires cost roughly the same as one single-wide tire and wear at a comparable rate, there is no additional tire cost imposed by retrofitting (EPA, 2004a). Trucks retrofitted with aluminum wheels and new-generation wide tires cause no more damage to roads than trucks with conventional tire configurations (EPA, 2004a).

Table 4. Costs of and Cost Savings From Installing Aluminum Wheels for Single-Wide Tires

Year	Installation Costs ($MM)	Diesel Fuel Saved (million gallons)	Fuel Cost Savings ($MM)	Net Costs ($MM)
2013	42.70	4.92	16.97	25.72
2014	42.70	9.84	36.01	6.68
2015	42.70	14.76	55.79	-13.09
2016	42.70	19.68	75.38	-32.68
2017	42.70	24.60	95.45	-52.75
2018	42.70	29.52	115.72	.73.03
2019	42.70	34.44	135.70	-93.01
2020	21.35	39.36	156.273	-134.92
Total				**-294.05**

$MM = million dollars. Negative net costs indicate costs savings.

Heavy-Duty Trucks: GHG Reduction From Installing Fairings

At highway speeds, aerodynamic drag accounts for the majority of truck energy losses (EPA, 2004b). Reducing drag improves fuel efficiency. Since the majority of long-haul tractor trucks on the road in 2009 (>75 percent) already contain aerodynamic features, such as air deflectors mounted on the top of the cab, drag-reduction options should focus on trailer aerodynamics (Bynum, 2009). The addition of front and side fairings (e.g., skirts) to a trailer can reduce fuel consumption by 5 percent (EPA, 2009b). These panels are attached to the side or bottom of the trailer and hang down to enclose the open space between the rear wheels of the tractor and the rear wheels of the trailer. Such enclosure reduces wind resistance.

The estimated GHG emissions reductions from installing front and side fairings on trailers are based on diesel fuel savings. To calculate these emissions, the total VMT in the state (108,699 million miles; DOT, 2008a) are multiplied by the fraction of miles traveled by heavy-duty trucks (0.07; PA DEP, 2007) to obtain total annual VMT by heavy-duty trucks in Pennsylvania in 2007. Total annual VMT is then divided by the average fuel economy of heavy-duty trucks (6.0 miles per gallon; Bynum, 2009) to obtain total diesel fuel consumed (1,268 million gallons). Fuel savings are based on the total diesel fuel consumed, the percent fuel savings associated with the retrofits, and the penetration rate for trailers. DOT reports the number of commercial trailers registered in Pennsylvania in 2007 as 152,489 (DOT, 2008c). Since there are more trailers than tractor-trucks, the probability of realizing the fuel savings associated with a trailer retrofit is the ratio of tractor-trucks to trailers.

Total fuel savings = (1,268 million gallons)*(0.05)*(penetration rate for trailers/100)*(# of heavy-duty trucks/# of commercial trailers)

Total fuel savings is multiplied by GHG emissions per million gallons of diesel fuel consumed (0.01125 MMt; DOE, 2008) to obtain the total annual GHG emissions reduction.

Table 5. GHG Emission Reductions From Installing Fairings

Year	Commercial Trailers Registered in PA	Penetration Rate	Trailers Retrofitted	Diesel Fuel Savings (million gallons)	GHG Reduction ($MMtCO_2e$)
2013	152,489	6.9	10,522	3.87	0.04
2014	152,489	13.8	21,044	7.73	0.09
2015	152,489	20.7	31,565	11.60	0.13
2016	152,489	27.6	42,087	15.47	0.18
2017	152,489	34.5	52,609	19.34	0.22
2018	152,489	41.4	63,130	23.20	0.26
2019	152,489	48.3	73,652	27.07	0.31
2020	152,489	55.2	84,174	30.94	0.35
Total					**1.58**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Heavy-Duty Trucks: Costs Associated with Installing Fairings

The cost of retrofitting a trailer with front and side fairings is approximately $2,400 (2007$; EPA, 2009b). The total cost of retrofitting is calculated by multiplying the number of trailers being retrofitted in a given year by $2,400. The cost savings, shown in Table 6, are realized in the fuel savings from reduced vehicle drag. Fuel cost savings are simply the diesel fuel saved multiplied by the price per gallon of diesel fuel. Net costs are the installation costs minus the fuel cost savings.

Table 6. Costs of and Cost Savings From Installing Fairings

Year	Installation Costs ($MM)	Diesel Fuel Saved (million gallons)	Fuel Cost Savings ($MM)	Net Costs ($MM)
2013	25.3	3.9	13.3	12.0
2014	25.3	7.7	28.3	-3.0
2015	25.3	11.6	43.9	-18.6
2016	25.3	15.4	59.2	-33.9
2017	25.3	19.3	75.0	-49.7
2018	25.3	23.2	91.0	-65.7
2019	25.3	27.0	106.7	-81.4
2020	25.3	30.9	122.8	-97.5
Total				**-338**

$MM = million dollars. Negative net costs indicate cost savings.

Locomotives

The two technology options considered in the locomotive analysis are based on EPA's SmartWay Transport Partnership (EPA, 2009c). The first option is the retrofitting of switchers and line-haul locomotives with APUs to reduce idling. The second option is the installation of a wheel flange lubrication system on line-haul locomotives to reduce friction. The improved fuel economy and associated GHG emissions reduction for each option are additive.

Locomotives: GHG Reduction from Anti-Idling Technologies

There are two types of locomotives commonly used by railroad companies—switcher and line-haul. Switcher locomotives are used to move materials within a rail yard, while line-haul locomotives are used to move freight across long distances (EPA, 2005). Switchers idle approximately 12 hours a day to avoid difficult startups and possible freezing inside the engine in cold weather (locomotive engines do not use antifreeze). Installing auxiliary engines in these locomotives can decrease fuel consumption, which helps reduce GHG emissions as well as local air pollutants and noise. This reduction is achieved by reducing fuel consumption while idling. Installing an APU is highly cost-effective, with a payback period of 2–2.5 years without taking any environmental benefits into account (EPA, 2005).

Approximately 27 percent of a switcher's annual fuel consumption is attributed to idling (DOE, 2002). While idling, the locomotive's main engine burns about three gallons of diesel fuel per hour in warm weather and 11 gallons per hour in cold weather (a higher idle setting is required to keep the engine from freezing). Assuming four months of cold weather a year, the average switcher would consume over 24,000 gallons of diesel fuel annually just idling. An APU can reduce fuel consumption to 0.8 gallons per hour, saving 20,500 gallons of fuel (EPA, 2005).

The number of switchers operating in Pennsylvania was estimated using the total fuel consumed for rail transport in Pennsylvania (provided by Michael Baker Consulting, 2009). Since switchers account for roughly 7.5 percent of the total diesel fuel burned by locomotives and an average switcher consumes 89,000 gallons of fuel per year, the number of switchers is calculated by dividing the total fuel consumed by switchers by 89,000 gallons (EPA, 1998). The number of line-haul locomotives operating in Pennsylvania was estimated by multiplying the total number of Class I locomotives operating in the United States (24,143; AAR, 2009a) by the fraction of U.S. rail tons carried in Pennsylvania (0.0237; AAR, 2009b). The number of locomotives in 2009 is grown through 2020 using the annual growth rate of fuel consumption.

The estimated GHG emission reductions from retrofitting locomotives with auxiliary power units are based on the total diesel fuel consumed, the percentage of fuel savings associated with the retrofits, and the penetration rate:

Total fuel savings = (total fuel consumed by switchers)*(0.23)*(penetration rate for switchers)/100) + (total fuel consumed by line-haul)*(0.10)*(penetration rate for line-haul/100)

Table 7. Estimated Number of Switchers and Line-Haul Locomotives in Pennsylvania

Year	Total Fuel Consumed by All Locomotives (thousand gallons)	Total Fuel Consumed by Switchers (thousand gallons)	Total Fuel Consumed by Line-Haul Locomotives (thousand gallons)	Estimated Number of Switchers	Estimated Number of Line-Haul Locomotives
2013	129,093	9,682	119,411	109	652
2014	133,084	9,981	123,103	112	672
2015	137,075	10,281	126,795	116	692
2016	141,066	10,580	130,486	119	712
2017	145,058	10,879	134,178	122	732
2018	149,049	11,179	137,870	126	752
2019	153,040	11,478	141,562	129	773
2020	157,032	11,777	145,254	132	793

Total fuel savings is multiplied by GHG emissions per thousand gallons of diesel fuel consumed (0.00001125 MMt; DOE, 2008) to obtain the total annual GHG emissions reduction. This calculation likely overestimates the incremental benefit of the policy option, since some locomotives are already equipped with APUs.

Table 8. GHG Emissions Reduction From Retrofitting Locomotives With APUs

Year	Penetration Rate of Switcher Retrofits (percent)	Number of Switchers Retrofitted	Penetration Rate of Line-Haul Locomotive Retrofits (percent)	Number of Line-Haul Locomotives Retrofitted	Diesel Fuel Savings (thousand gallons)	GHG Emissions Reduction ($MMtCO_2e$)
2013	80	87	40	261	6,554	0.07
2014	100	112	50	336	8,446	0.10
2015	100	116	60	415	9,967	0.11
2016	100	119	70	499	11,562	0.13
2017	100	122	80	586	13,231	0.15
2018	100	126	90	677	14,974	0.17
2019	100	129	100	773	16,790	0.19
2020	100	132	100	793	17,228	0.19
Total						**1.11**

APUs = auxiliary power units; GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Locomotives: Costs Associated With Anti-Idling Technologies

The cost of retrofitting a locomotive with an APU is approximately $27,250 (2007$; EPA, 2009c). The total cost of retrofitting is calculated by multiplying the number of locomotives being retrofitted in a given year by $27,250. The cost savings, shown in Table 9, are realized in the fuel savings from reduced idling. Fuel cost savings are simply the diesel fuel saved multiplied by the price per gallon of diesel fuel (DOE, 2009). Net costs are the installation costs minus the fuel cost savings.

Table 9. Costs of and Cost Savings From Retrofitting Locomotives With APUs

Year	Installation Costs ($MM)	Diesel Fuel Saved (thousand gallons)	Fuel Cost Savings ($MM)	Net Costs ($MM)
2013	2.59	6,554	22.99	-20.40
2014	2.74	8,446	30.86	-28.12
2015	2.25	9,967	37.31	-35.06
2016	2.36	11,562	43.38	-41.02
2017	2.47	13,231	49.67	-47.20
2018	2.58	14,974	56.42	-53.84
2019	2.69	16,790	63.44	-60.75
2020	0.64	17,228	65.27	-64.63
Total				**-351.02**

$MM = million dollars; APUs = auxiliary power units. Negative net costs indicate cost savings.

Locomotives: GHG Reduction From Wheel Flange Lubrication System

Ineffective lubrication at the wheel/rail interface of trains results in wear and friction that costs the country's railroads more than $2 billion each year (DOE, 2006). Installing a wheel flange lubrication system significantly reduces track degradation and noise, and decreases line-haul locomotive fuel consumption by 5 percent (Mitrovitch, 2009).

The estimated GHG emission reductions from retrofitting locomotives with wheel flange lubrication systems are based on the total diesel fuel consumed, the percentage of fuel savings associated with the retrofits, and the penetration rate:

Total fuel savings = (total fuel consumed by line-haul)*(0.05)*(penetration rate for line-haul)/100)

Total fuel savings is multiplied by GHG emissions per thousand gallons of diesel fuel consumed (0.00001125 MMt; DOE, 2008) to obtain the total annual GHG emissions reduction. Note that a limited number of PA locomotives may already be equipped with lubrication systems.

Locomotives: Costs Associated With Wheel Flange Lubrication System

The cost of retrofitting a locomotive with an auxiliary power unit is approximately $650 (2007$; Mitrovitch, 2009). The operation and maintenance (O&M) cost of replacing springs and lubrication sticks is approximately $1,110 per year (Mitrovitch, 2009). The total cost of retrofitting is calculated by multiplying the number of locomotives being retrofitted in a given year by $650 and adding the O&M costs for all locomotives with wheel flange retrofits. The cost savings, shown in Table 11, are realized in the fuel savings from reduced friction. Fuel cost savings are simply the diesel fuel saved multiplied by the price per gallon of diesel fuel (DOE, 2009). Net costs are the installation costs minus the fuel cost savings.

Table 10. GHG Emissions Reduction From Retrofitting Line-Haul Locomotives with Wheel Flange Lubrication Systems

Year	Penetration Rate of Line-Haul Locomotive Retrofits (percent)	Number of Line-Haul Locomotives Retrofitted	Diesel Fuel Savings (thousand gallons)	GHG Reduction ($MMtCO_2e$)
2013	100	652	11,941	0.13
2014	100	672	12,310	0.14
2015	100	692	12,679	0.14
2016	100	712	13,049	0.15
2017	100	732	13,418	0.15
2018	100	752	13,787	0.16
2019	100	773	14,156	0.16
2020	100	793	14,525	0.16
Total				**1.19**

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Table 11. Costs of and Cost Savings From Retrofitting Line Haul Locomotives With Wheel Flange Lubrication Systems

Year	Installation Costs ($MM)	Diesel Fuel Saved (thousand gallons)	Fuel Cost Savings ($MM)	Net Costs ($MM)
2013	0.74	11,941	41.88	-41.15
2014	0.76	12,310	44.98	-44.22
2015	0.78	12,679	47.47	-46.68
2016	0.80	13,049	48.96	-48.15
2017	0.83	13,418	50.37	-49.55
2018	0.85	13,787	51.95	-51.10
2019	0.87	14,156	53.49	-52.62
2020	0.89	14,525	55.03	-54.14
Total				**-387.61**

$MM = million dollars. Negative net costs indicate cost savings.

Marine Vessels and Port Machinery

One of the possibilities for evaluating potential GHG emission reductions from marine vessels and port machinery is to examine information available from other states. For example, through the Global Warming Solutions Act of 2006 (AB 32), California has committed to reducing GHG emissions to 1990 levels by 2020. Measure T-6 in the AB32 scoping plan—freight transport efficiency measures—is a broad initiative designed to achieve at least a 3.5-MMtCO$_2$e reduction in GHG emissions from the freight transport sector by 2020 (CARB, 2008). This represents about a 20 percent reduction in the projected 2020 GHG emissions from this sector. Due to the complexity of this sector and the need for a thorough investigation of a variety of approaches to determine how best to improve freight transport efficiency, an overall emission reduction goal was established for California measure T-6, rather than assigning emission reduction targets to individual measures.

The current components of California's freight efficiency measure are:

1. Port Drayage Trucks (replacement/retirement)
2. Transport Refrigeration Units Cold Storage Prohibition and Energy Efficiency
3. Cargo-Handling Equipment—Anti-Idling, Hybrid, Electrification
4. Goods Movement System-Wide Efficiency Improvements
5. Commercial Harbor Craft—Maintenance and Design Efficiency
6. Clean Ships
7. Vessel Speed Reduction
8. Long-Haul Trucks
9. Locomotives

Since GHG reduction options for trucks and locomotives in Pennsylvania have already been discussed, only items two through seven are considered for the marine emissions reduction strategy. Similar to California, individual reduction targets are not assigned due to the complexity of the sector. Instead, an overall emission reduction goal of 18 percent is evaluated. The reduction target is lower than California's, since some options are simply moving the emissions from ports to power plants. With the electricity generation mix in PA (Reliability First

Corporation [RFC] East subregion), GHG reductions are currently about 50 percent less than in California by switching from diesel fuel to shore power.

The overall GHG savings is calculated by multiplying the projected 2020 GHG emissions from ships (2.71 $MMtCO_2e$; Baker, 2009) and port machinery (0.29 $MMtCO_2e$; assumed to be 10 percent of "other" non-highway emissions; Baker, 2009) in PA by 0.18. Some strategies, such as vessel design improvements, will also achieve GHG emission reductions beyond PA. The costs and costs savings associated with marine reduction strategies are difficult to estimate due to the variety of control options and limited data availability. Thus, GHG reductions and costs associated with the marine sector are not included in Table 12.

Table 12. Potential GHG Emission Reductions for Marine Transport

Reduction Measures and Targeted Vehicles	Potential 2020 GHG Reduction ($MMtCO_2e$)	Net Costs ($MM)
All Measures Combined	0.54	Not Quantified
Ocean-Going Vessels		
Commercial Harbor Craft		
Cargo Handling Equipment		
Transportation Refrigeration Units		
Goods Movement System-Wide Efficiency Improvements		

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Marine: Ocean-Going Vessels

Options to improve the fuel efficiency of ocean-going vessels (OGVs) include advanced hull and propeller coatings, advanced engine design, heat recovery, wind power assistive devices, shore power and vessel speed reduction. The last two options are discussed below.

Providing shore power at port facilities typically requires an up-front capital investment to purchase a more efficient engine, and the cost savings result from reduced fuel usage compared to the original equipment. The length of the payback period for this capital investment is often the most important question when considering the feasibility of an option such as this. While CARB anticipates that the overall savings due to reduced fuel consumption will offset the costs associated with retooling ships and ports in California, the costs may be substantially higher for Pennsylvania, with only modest GHG emissions reduction (CARB, 2008).

Shore power is becoming a major part of the green port strategies being implemented at ports on the U.S. West Coast. For example, the Port of Long Beach has adopted a green port policy that is intended to guide the port's operations in a green manner (CARB, 2006). The port has committed to providing shore power to all new and reconstructed container terminal berths and other berths, as appropriate. Through lease language, the port will require selected vessels to use shore power and all other vessels to use low-sulfur diesel in their auxiliary generators. The primary method for providing shore power at California ports is cold ironing, a strategy whereby ships shut down onboard auxiliary engines while in port and connect to electrical power supplied at the dock. Without cold ironing, auxiliary engines run continuously while a ship is docked, or "hotelled" at a berth, to power lighting, ventilation, pumps, communication and other onboard equipment. Ships can hotel for several hours or several days.

In an example of cold ironing, an analysis was done on the cost-effectiveness of three ships that each visited the port 17 times during the year. On every trip, the ships were electrified for 60 hours in port, saving a total of 1,478 metric tons of fuel and reducing GHG emissions by 4,741 tCO_2e annually. Given the estimated annual cost of \$1,583,000, this means that \$334/tCO_2e can be avoided through fuel consumption. However, the production of electricity for use in the ship will reduce the GHG savings with this approach. Using Pennsylvania emission factors, the annual GHG benefits of this program would be reduced to only 1,297 tCO_2e. This would mean a cost of \$1,221/tCO_2e reduction from the cold ironing method.

There are several other important factors to consider on the issue of cold ironing. This process has significant up-front costs. While the analysis above considers the annual costs of the program over a 10-year period, the initial costs are considerable. In this example, the port requires an initial investment of \$4.5 million to provide electrification, and each of the three ships must undergo a \$1.5 million modification to accept electricity from the ports. If very few ships make this modification, then the costs per tCO_2e would increase dramatically. Labor and electricity are also part of the cost estimate, though these are less of a problem in terms of up-front capital. Finally, the example is of ships that use the port 17 times a year. If a ship does not frequent a particular port more than a few times a year, it is unlikely that the owner would want to undertake the modification. And even if the ship were equipped to engage in cold ironing, the benefits of such a case would be far reduced.

Establishing vehicle speed reduction (VSR) zones around ports can reduce GHG emissions by reducing fuel consumption. A California study indicates that reducing the speed of a cargo ship from 22 knots to 12 knots from 6 to 24 miles offshore (outside the 6-mile precautionary zone) saves 1,249 gallons of fuel (CARB, 2008b). This translates into fuel cost savings of approximately \$3,600. However, the costs associated with increased transit time must be considered. In the California study, the inbound time spent in the VSR zone was one hour longer for a trip traveling at 12 knots. Terminals may incur costs of \$10,000–\$20,000/hour for vessel delays. Ships may incur costs of up to \$5,000/hour for delays if the vessel does not make up time during other segments of the voyage. If ships increase speed outside the VSR zone to make up time, total GHG emissions may increase.

Marine: Commercial Harbor Craft

Reducing GHG emissions from harbor crafts depends upon maintenance and operational improvements. Recommended options to evaluate are optimization of scheduling and vessel speed, improved hull surface finish and reduced hull fouling to reduce friction, and improved propeller design and maintenance.

Marine: Cargo-Handling Equipment

Cargo-handling equipment includes diesel-powered vehicles and cranes operating at ports. Recommended options to evaluate are reduced idling, hybrid propulsion technologies and electrification of cranes (IAPH, 2009).

Marine: Transport Refrigeration Units

To transport temperature-sensitive products, shipping containers employ refrigeration systems powered by internal combustion engines. To reduce GHG emissions from these transportation refrigeration units, energy efficiency guidelines should be implemented and a best practices guidance document should be prepared to help educate the industry about potential costs and GHG savings.

Marine: Goods Movement System-Wide Efficiency Improvements

Intermodal transport in PA should be evaluated, with emphasis on improving marine, truck and rail freight movement. All stakeholders, such as railroad operators, shipping companies, terminal operators, trucking companies, government agencies and the public, should contribute to developing a program to achieve system-wide GHG emission reductions beyond existing individual measures. Such collaboration is likely to present opportunities to reduce GHG emissions from the overall freight movement supply chain.

Table 13 provides CO_2 emission factors from the recent Winebrake et al. *Journal of the Air and Waste Management Association* paper for the three primary freight transport modes. These factors can be used to estimate how shifting 100,000 20-foot equivalent units (TEUs) from rail and truck to ships in Pennsylvania might affect GHG emissions.

Table 13. Data for Transport Modes for Case Studies

Mode of Transport	Cost ($/TEU-mile)	Energy (Btu/TEU-mile)	CO_2 (g/TEU-mile)	PM-10 (g/TEU-mile)	SO_X (g/TEU-mile)
Truck	0.87	10,704	1,001	0.12	0.22
Rail	0.55	2,590	201	0.09	0.04
Ship	0.50	13,040	1,094	0.98	3.33

$/TEU-mile = dollars per 20-ft equivalent units-mile; Btu = British thermal unit; CO_2 = carbon dioxide; g/TEU-mile = grams per 20-ft equivalent units-mile; PM10 = particulate matter 10 microns in diameter or smaller; SOx = sulfur oxides.

Ships vary significantly in their sizes, speeds and installed power, which means that their energy and emission characteristics vary. The information in Table 13 is based on ship characteristics that have been highlighted favorably in recent short sea shipping reports, because this policy option was intended to represent a short movement of freight. The ship used in this analysis a roll-on/roll-off vessel capable of speeds of up to about 25 knots with about 11,000 kilowatts (kW) of power, which carries about 200 TEUs. Using the characteristics of other vessel groups would produce different results than the comparison shown in Table 13.

Trucking, Rail and Marine Freight Transport: The GHG reduction analysis still needs to account for the different commodities, infrastructures, and expected near-term changes occurring in each of the major port areas in PA. This information is briefly summarized below:

Port of Philadelphia—The expectation is that trade will pick up after the recession. A major port expansion is occurring as this port expands south into the Navy Yard. This may bring as much as

1 million additional TEUs of freight into this port. The current freight volume via the Port of Philadelphia is 250,000 TEUs. Part of this expansion involves a deepening of the Delaware River channel from 40 to 45 feet. This will allow larger vessels (carrying 1,000 TEUs per vessel) to access this port. With this port expansion comes the need to make infrastructure improvements—mainly to nearby highways. Local truck and rail traffic is expected to increase. Pennsylvania's "America's First Marine Highway Enterprise" would extend the Ben Franklin Corridor (a surface transportation corridor linking the Columbus Regional Airport Authority intermodal terminal in Columbus, Ohio, as well as military depots and commercial distribution hubs in New York, New Jersey, Ohio and Pennsylvania) to a new marine highway corridor connecting the Port of Philadelphia to other U.S seaports. The project includes highway, rail seaport, and intelligent transportation system solutions consistent with federal policy, as well as a proposed shipbuilding strategy for the U.S. domestic trade. Furthermore, the project supports and leverages considerable investments that the commonwealth of Pennsylvania has already made in upgrading and expanding Philadelphia marine terminals.

- *Port of Pittsburgh*—This is really 200 miles of a series of privately owned ports along the three rivers. It is expected that the freight volumes will increase with trade. Note that 75 percent of the current freight volume in southwestern Pennsylvania ports is coal transport. Impending EPA and federal legislative requirements for GHG reductions in the energy supply sector would be expected to change historical coal production, transport and use patterns in this corridor.

- *Port of Erie*—This is a Great Lakes port with the possibility of rapid growth in the 2009-2020 time horizon. Expected growth is a doubling or tripling in cargo handled. Erie is within the bi-national Great Lakes St. Lawrence Seaway system. Therefore, new policies that affect the Port of Erie need to consider their compatibility with the established policies affecting ports within this system.

A December 2007 study by the Texas Transportation Institute found that efficient short sea shipping is more fuel efficient per ton-mile than goods movement by trucks and even railroads. For example, an inland barge enjoys 576 ton miles to the gallon, compared to 155 on a truck and 413 on a train. From a GHG emissions perspective, short sea shipping can offer substantial reductions.

Numerous industry stakeholders agree that the Harbor Maintenance Tax is an onerous roadblock to the energy bill's short sea transportation provisions. This imposes an additional tax on trucking companies that move their cargo from roads and rails to water vessels. Efforts are underway to urge Congress to waive the Harbor Maintenance Tax for short sea transponders. The legislation would not impose the tax to cargo in intermodal cargo containers and loaded by crane on a vessel, or cargo loaded on a vessel by means of wheeled technology. If this is passed by Congress, it would remove a large barrier to implementing the short sea shipping program.

Cost to Regulated Entities: The options that have been evaluated and included in the summary quantification table for trucking and railroads involve some upfront cost to the regulated entities (and in one case some operating and maintenance expenses); however, the fuel savings will be expected to offset the investment costs in a relatively short period of time (one to three years) such that the entities that install these controls will save money.

Ease of Implementation:

Will vary depending on the specific measure.

Implementation Steps:

- Encourage membership in The **SmartWay Transport Partnership.** This program is a market-driven partnership to help businesses move goods in the cleanest, most efficient way possible. SmartWay provides a consistent set of tools and information needed to make informed transportation choices, SmartWay enables companies across the supply chain to exchange performance data in ways that protect the environment, enhance our nation's energy security and foster economic vitality. The program is administered by the United States Environmental Protection Agency (USEPA) and is housed with the USEPA's Office of Transportation and Air Quality (OTAQ) - Transportation and Climate Division (TCD). Initiated in 2004, SmartWay aims to voluntarily achieve improved fuel efficiency and reduce environmental impacts from freight transport. SmartWay consists of partnerships, policy and technical solutions, and research and evaluation to optimize the transportation networks in a company's supply chain.
- Provide incentives to freight companies for participating in the SmartWay Partnership
- Educate independent transporters about the fuel saving and environmental benefits of upgrading their vehicles with advanced fuel saving and anti-idling technologies
- PennDOT sponsored grant and low interest loan program for vehicle upgrades.

Key Assumptions:

The trucking analysis assumes that the penetration rates for the aluminum wheel and fairing retrofits are feasible by 2020. The ability to meet these penetration rates depends on the availability of vehicle body shops that can perform the retrofitting.

Since the technology options analyzed for trucks are retrofit options, new trucks entering the fleet are not considered. Under business as usual, the fuel economy of the existing truck fleet is assumed to remain constant through 2020.

Truck and trailer registrations are assumed to be accurate surrogates for the number of trucks operating in Pennsylvania. In reality, interstate transport may add significantly to the number of trucks and trailers operating in Pennsylvania.

The locomotive analysis assumes that no locomotives are currently retrofitted with the technologies evaluated. Since some locomotives are likely to already be retrofitted, the analysis likely overestimates the incremental GHG benefits.

The cold-ironing project estimate makes assumptions regarding the level of use of cold-ironing facilities, and the amount of emissions from OGVs while at sea and in the harbor. These estimates were based on previous analyses of emission reduction projects in New York and Long

Beach. If the factors involved in Pennsylvania harbors are significantly different, then the costs and emissions savings would likely change.

Key Uncertainties:

The fuel efficiency gains for truck and trailer retrofits are based on test track conditions. The actual on-road fuel efficiency improvement may be less.

The diesel fuel consumed by heavy-duty trucks in Pennsylvania is approximated based on an estimate of heavy-duty truck VMT in the state. The actual diesel fuel consumed may be different.

Establishing VSR zones may increase overall emissions (outside VSR zones) if ships speed up during other segments of voyage.

Other Potential Benefits and Drawbacks:

Additional potential benefits of changing behaviors to decrease GHG emissions from freight transportation include:

- Decreased emissions of ozone precursors (VOC and NO_x), CO, and PM.
- Decreased motor fuel use.
- Direct support of Smart Transportation initiatives, projects and programs.
- Reduced congestion.

Potential Interrelationships With Other GHG Reduction Measures:

These measures aimed at changing behavior need to be implemented in coordination with system changes within the transportation sector, and with transportation-focused land-use measures.

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C. 4 Agriculture and Forestry Sectors Work Plans

The following work plans were discussed with the CCAC Agriculture and Forestry Subcommittee. Members of this subcommittee include the following:

Paul Roth; Sara Nicholas; Seth Cassell; Rebecca Oyler, Pennsylvania Department of Conservation and Natural Resources

Luke Brubaker, Brubaker Farms

Afforestation

Initiative Summary:
Establishing new forests ("afforestation") increases the amount of carbon in biomass and soils compared to pre-existing conditions. Planting and afforestation can take place on land not currently experiencing other uses, such as abandoned mine lands (AMLs), oil and gas well sites, marginal agricultural land, and riparian areas.

This analysis focuses on the carbon sequestration benefit of afforestation only, and does not address the multiple co-benefits (water, habitat, etc.).

Goals:
Increase carbon sequestration on land not being utilized (i.e., AMLs, oil and gas well sites, marginal agricultural land, and riparian areas). Scenarios were designed for practicality to include a scaled usage (25 percent, 50 percent, and 100 percent) of available land in each of the previously referenced land-use categories.

Implementation Period: 2013–2020

Potential GHG Reduction (MMtCO$_2$e): Varies by scenario. See analysis, below.
Scenarios were designed for practicality, and to illustrate the potential benefits and costs under various levels of implementation (Table 1).

Table 1. Summary of Scenarios Used for Quantification of Afforestation

Land-Use Category	**Total Acreage Available for Planting (2013–2020)**	**Acreage Available by Scenario**		
		Planting Scenario	**Total Acreage Available**	**Annual Acreage Available**
Abandoned Mine Lands	250,000	25%	62,500	7,813
		50%	125,000	15,625
		100%	250,000	31,250
Oil and Gas Well Sites	3,250	25%	2,093	262
		50%	4,185	523
		100%	8,370	1,046
Marginal Agricultural Land	2,915,843	25%	728,961	91,120
		50%	1,457,922	182,240
		100%	2,915,843	364,480
Riparian Areas	30,000	2013 and 2014 TreeVitalize + CREP		4,500
		2015 – 2020 CREP		3,500

N/A = not available.

The sections below detail the methods and assumptions used for each of the vegetation types planted and the variety of land-use types considered in this option.

A. GHG Benefits

Forests planted on land not currently in forest cover will likely accumulate carbon at a rate consistent with the accumulation rates of average forest in the region. Therefore, carbon sequestered by afforestation activities was assumed to occur at the same rate as carbon sequestration in average PA forest. Average carbon storage was found based on USFS GTR-NE-343 assuming afforestation activity with a forest type distribution of 50 percent maple-beech-birch and 50 percent oak-hickory. For most afforestation, a 25-year project period was assumed, such that the average rate of forest carbon sequestration (in all forest carbon compartments, including soil, live and dead biomass, forest floor, understory, and downed wood) was estimated at 5.02 tCO_2e/ac/yr (Table 2). In riparian buffers, the amount of carbon sequestration achieved over time was quantified using a carbon sequestration rate of 4.38 tCO_2e/ac/year. To calculate this rate, average carbon densities for elm-ash-cottonwood forests (obtained from USFS data within the EPA's GHG State Inventory Tool, 2012) were divided by 35, based on the assumption of an average stand age of 35 years obtained from FIA data and averaged with the maple-beech-birch rate. Forests planted in one year continue to sequester carbon in subsequent years. Thus carbon storage in a given year is calculated as the sum of annual carbon sequestration on cumulative planted acreage.

Table 2. Forest Carbon Sequestration Rates for Afforestation Activity

Forest Types	**tCO_2e/ac/yr (average)**
Oak-Hickory	5.2
Maple-Beech-Birch	4.9
Elm-Ash-Cottonwood	4.4

tCO_2e/ac/yr = metric tons of carbon dioxide equivalent per acre per year.
Source: J.E. Smith et al. 2006, GTR-NE-343.

B. Land Areas Available for Afforestation

For each of the vegetation types analyzed, a scaled implementation of planting on 25 percent, 50 percent, and 100 percent of the land-use category was considered. A gradual ramp-up was assumed, such that full implementation of each scenario would be achieved in 2020.

B.1. Abandoned Minelands

With 250,000 acres of AMLs statewide, these sites provide a potential opportunity for carbon sequestration. Restoring AMLs, however, can be challenging and very costly due to the need for site preparation because of uneven terrain and the legacy of their prior use.

B.2. Oil and Gas Well Sites

With advent of drilling in the Marcellus shale the number of well pads and wells drilled per year has significantly increased. In the calculations we use an average well pad size of 5 acres. We assume four wells per pad and an average (2007 – 2011) of 977 wells drilled per year for a total available acreage of 1,221.

B.3. Marginal Agricultural Land

Marginal agricultural land is restricted by various soil physical/chemical properties, or environmental factors, for crop production. Based on an analysis of the 1992 U.S. Geological Survey National Land Cover Dataset, together with soil characteristics obtained from the NRCS STATSGO (State Soil Geographic) dataset, Niu and Duiker (2006) reported that marginal agricultural land area in PA totaled 1.18 million hectares (MMha) (approximately 36 percent of all land area in the state). This land was placed in the "marginal agricultural land" category because of its combination of soil and land cover characteristics, and includes land with high water table, steep slopes (high erodibility), shallow soils, stoniness, and low fertility.

B.4 Riparian Areas/Buffers

This analysis combines projected acreage from the Tree Vitalize and Conservation Reserve Enhancement Program (CREP) forest riparian establishment programs. It builds on successes of highly successful programs such as Tree Vitalize[79] to target that establishment of 1,000 acres/year in riparian areas for years 2013 and 2014. It also targets the annual establishment of 3,500 acres from 2013 through 2020. Annual carbon sequestration is based on cumulative acreage planted under this scenario.

C. Economic Cost

Economic analyses typically employ four categories: opportunity cost (of planting forest rather than another, potentially more lucrative land use), conversion cost, maintenance cost, and measuring/monitoring costs (Walker et al. 2007). For this analysis, opportunity cost was assumed to be zero because the land considered in each of the scenarios is currently underutilized.

One-time costs of afforestation include site preparation and planting. These costs are incurred in the year of planting. Ongoing costs of maintenance and monitoring are incurred annually on all acreage planted in all years of policy implementation. The assumed costs of site preparation, planting, and ongoing maintenance for each land use type appear in Table 3.

Table 3. Economic Costs of Site Preparation, Establishment, Maintenance, and Monitoring

Land Use Type	**One-Time Costs**		**Annual Costs**
	Site preparation	Planting	Monitoring
Abandoned Mine Lands	$2,500.00	$680.00	$29.00
Oil & Gas Well Sites	$0.00	$680.00	$29.00
Marginal Agricultural Land	$0.00	$680.00	$29.00
Riparian Areas	$0.00	$680.00	$29.00

D. Summary

Tables 4 and 5 summarize the cumulative and annual (2020) results, respectively, of GHG reductions, NPV and levelized cost effectiveness for each scenario of each land use type. NPV is the sum of the discounted costs—in other words, the economic cost or benefit of implementing the option, calculated in 2010 dollars. Levelized cost-effectiveness is the NPV of a scenario divided by the GHG benefit of that scenario. This is expressed in $/tCO$_2$e sequestered or avoided, and is intended to give a sense of the cost of each scenario standardized for its actual GHG benefit.

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[79] See: http://www.treevitalize.net/

Table 4. Cumulative Results (2013-2020) of Afforestation for Various Land-Use Types in PA

Land-Use Category	Total Acreage Available for Policy Implementation			Cumulative GHG Benefit 2013–2020 (MMtCO$_2$e)			Net Present Value 2013–2020 ($ million (in $2010))			Levelized Cost-Effectiveness ($/tCO$_2$e)
	25%	50%	100%	25%	50%	100%	25%	50%	100%	
Abandoned Minelands	62,500	125,000	250,000	1.41	2.83	5.65	$151.1	$302.2	$604.3	$106.94
Oil and Gas Well Sites	2,443	4,885	9,770	0.06	0.11	0.22	$1.4	$2.9	$5.7	$25.90
Marginal Agricultural Land	728,961	1,457,922	2,915,844	16.48	32.96	65.91	$426.7	$853.4	$1,706.8	$25.90
Riparian Areas	30,000			0.62			$13.0			$21.11

$/tCO$_2$e = dollars per metric ton of carbon dioxide equivalent; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table 5. Annual (2020) Results Per Afforestation for Various Land-Use Types in PA

Land-Use Category	Total Acreage Available for Policy Implementation			2020 GHG Benefit per (MMtCO$_2$e)			2020 Net Present Value ($ million (in $2010))			Levelized Cost-Effectiveness ($/tCO$_2$e)
	25%	50%	100%	25%	50%	100%	25%	50%	100%	
Abandoned Minelands	7,813	15,625	31,250	0.31	0.63	1.26	$16.4	$32.7	$65.5	$52.12
Oil and Gas Well Sites	305	611	1,221	0.01	0.03	0.05	$0.17	$0.34	$0.68	$13.93
Marginal Agricultural Land	91,120	182,240	364,480	3.66	7.32	14.65	$51.0	$102.0	$204.1	$13.93
Riparian Areas	30,000			0.13			$1.3			$9.60

Implementation Steps: ***Target Programs, Goals Support Full Implementation of These Programs***

- The Tree Vitalize initially sought an $8 million investment in tree planting and care in southeastern Pennsylvania over a 4-year period. The goals of the program included planting 20,000 shade trees, restoring 1,000 acres of forests along streams and water-protection areas, and training 2,000 citizens to plant and care for trees. The Pennsylvania Department of Conservation and Natural Resources (DCNR) initiated preliminary discussions with regional stakeholders in the summer of 2003, and appointed a Project Director in January 2004. Planning, assessment, and resource development continued through 2004. Tree-planting activities began in the fall of 2004 and have continued. Subsequently, the regional Tree Tenders program was launched in 2005. Although TreeVitalize is not a permanent entity, the collaborations created and capacity built will continue to increase tree cover and promote stewardship through expansion across other regions of the state. See: http://www.treevitalize.net/aboutus.aspx.

- Numerous programs are in place Statewide— The U. S. Department of Agriculture, CREP (where USDA subsidized farmers to keep highly erodible acres in warm-season grass) may be a significant source of biofuel in switchgrass. In addition to warm-season grasses, CREP subsidizes riparian forest buffer practices. One cost-shared practice is the installation of streambank fencing to exclude livestock and allow for natural forest regeneration. Another practice was riparian forest plantings. CREP has proven to be highly successful in the expansion of forested riparian buffers throughout the Ohio and Chesapeake Bay drainages, including the installation of well over 3,400 acres of forested riparian buffers and planting more than 4,800 acres of native grasses.

- Other buffer initiatives include TreeVitalize, Stream ReLeaf[80], the Chesapeake Bay Urban Tree Canopy Expansion Initiative, and a suite of initiatives offered under the guidance of cooperators, including the Alliance for the Chesapeake Bay, The Chesapeake Bay Foundation, The Western Pennsylvania Conservancy, and DEP lists. A watershed forester working in the Rural and Community Forestry (CFM) section coordinates BOF efforts in riparian projects. Bureau of Forestry (BOF) Service Foresters throughout the state work with landowners to implement watershed programs on private lands.

- Since 2000, this cooperative effort among state, federal, and nonprofit organizations has resulted in the restoration of more than 2,100 miles of forested buffers in the Chesapeake Bay drainage alone.

- A Keystone Opportunity Zone model program could be created to package incentives for private investment in establishing forests on marginal lands.

Enabling Programs, Programs May Provide Relevant Information in Support of Implementation

DEP's Bureau of Abandoned Mine Reclamation develops plans for handling Abandoned Mine Lands in Pennsylvania. In the era of the Department of Environmental Resources, the Bureau of Forestry had a program called Project 20 for mine land reclamation.[81]

Potential Overlap: None.

CCAC Member Comments:

- One committee member commented that accounting for GHG reductions beginning in 2013 was inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a time frame do deliver reductions throughout the year 2013.
- Cost information seems to be outdated
- The potential overlap section should perhaps include several of the other forest protection initiatives.

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[80] http://www.dep.state.pa.us/dep/deputate/watermgt/WC/Subjects/StreamReLeaf/default.htm

[81] See: http://www.depweb.state.pa.us/abandonedminerec/site/default.asp?abandonedminerec.

References:

- J.E. Smith et al. 2006. *Methods for Calculating Forest Ecosystem and Harvested Carbon With Standards Estimates for Forest Types of the United States*, GTR NE-343. USFS Northern Research Station. (Also published as part of the DOE Voluntary GHG Reporting Program).
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Durable Wood Products

Initiative Summary:

This option seeks to enhance the use and lifetime of durable wood products. Durable products made from wood prolong the length of time forest carbon is stored and not emitted to the atmosphere. Wood products disposed of in landfills may store carbon for long periods under conditions that minimize decomposition, especially when methane gas is captured from landfills (carbon originally stored in wood products becomes methane during decomposition). Substituting building products made from wood for building products made from materials with higher embodied energy can reduce life-cycle GHG emissions. This can be achieved through improvements in production efficiency, product substitution, expanded product lifetimes, and other practices. Increasing the efficiency of the manufacturing life cycle for wood products will enhance GHG benefits. To quantify the categories for disposition of carbon in harvested wood, the analysis relied on USDA USFS Northern Research Station GTR-NE-343, *Methods for Calculating Forest Ecosystem and Harvested Carbon with Standard Estimates for Forest Types of the United States.*[82] This methodology demonstrates the eventual destination of carbon from harvested wood in five broad categories: products in use, in landfills, emitted with energy capture, emitted without energy capture, and emitted at harvest.

Goal:

Enhance management activities and timber sales to provide a reliable supply of timber for durable wood products through one of three scenarios:

- Scenario 1: Maintain a 2006 era harvest level of 1.12 Bbf/yr through 2020
- Scenario 2: Increase and maintain a statewide harvest level of 1.5 Bbf/yr through 2020
- Scenario 3: Maintain a harvest level on PA state forest land of 80 MMbf/yr through 2020

Implementation Period: 2013–2020

Quantification Methods:

Carbon sequestration in harvested wood products was calculated following guidelines published by USFS in GTR-NE-343 (Smith et al., 2006). Details on each step of the analysis can be found in the guidelines, following the methodology referred to as "Product-based estimates."

To quantify carbon stored in long-term products, forest harvest is used as a starting point. The methodology calculates the proportion of harvested wood that is diverted to each of four pools after 100 years: wood in use (i.e., building materials, furniture), wood in landfills (i.e., products that were previously in use and have been discarded), wood burned for energy capture, and wood that has decayed or burned without energy capture. The wood that has not been burned or decayed (i.e., the wood in the "in use" or "landfill" pools) is assumed to remain stored 100 years

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[82] J.E. Smith et al. 2006. *Methods for Calculating Forest Ecosystem and Harvested Carbon with Standards Estimates for Forest Types of the United States*. GTR-NE-343. USFS Northern Research Station. (Also published as part of the DOE Voluntary GHG Reporting Program.)

after harvest. Most of the carbon stored in harvested wood products is emitted to the atmosphere over time. Because this method quantifies the amount of carbon in the current year's harvest that is expected to remain stored (or "in use") for a defined period of time, rather than accounting instantaneously for the carbon stored in various products each year, this 100-year approach likely underestimates the carbon stored over the implementation period of this analysis. Despite its conservatism, the 100-year method has the advantage of being simple and consistent, and has compared well with other accounting methods (Miner, 2006).

The general methodology for all scenarios in this option followed these steps:

1. Find the proportion of harvested volume that is in softwood or hardwood logs.
2. For each of the species types (hardwood and softwood), find the proportion of harvested volume in sawtimber and pulpwood.
3. Calculate tons of carbon in harvested volume.
4. Project carbon stored in long-term storage pools 100 years after harvest for each scenario.

The approach for each of the above steps is described below.

1. The U.S. Census estimates that 1,121 MMbf were harvested from PA forests in 2006,[83] of which 1,055 MMbf (94 percent) was hardwood and 66 MMbf (6 percent) was softwood. These values were used directly for Scenario 1, and the total volume of hardwood and softwood harvested for Scenarios 2 and 3 was calculated assuming the same proportions.
2. The fraction of growing-stock volume in hardwood and softwood that occurs in each of the size classes (sawtimber and pulpwood) is given by GTR-NE-343. The distribution of harvest volume was assumed to follow the distribution of growing-stock volume presented in the guidelines. An average mix of 50 percent maple-beech-birch and 50 percent oak-hickory forest was assumed (Table 1).

Table 1. Factors Used to Apportion Harvest Volume into Saw-timber and Pulpwood Classes for PA Forests

Forest Type	Fraction of Softwood Volume That Is Sawtimber	Pulpwood (1 – Sawtimber)	Fraction of Hardwood Volume That Is Sawtimber	Pulpwood (1 – Sawtimber)
Maple-Beech-Birch	0.604	0.396	0.526	0.474
Oak-Hickory	0.706	0.294	0.667	0.333
Average	**0.655**	**0.345**	**0.597**	**0.403**

Source: Table 4, USDA, GTR-NE-343.

3. The fractions above were used to determine the total harvest (MMbf) in each of the four categories (hardwood sawtimber, hardwood pulpwood, softwood sawtimber, softwood pulpwood) under each scenario. These values were converted to m^3, and then multiplied by average specific gravity (from Table 4, GTR-NE-343) to find total carbon in harvested volume (Table 2).

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[83] From U.S. Census: http://www.census.gov/industry/1/ma321t06.pdf.

Table 2. Carbon in Harvested Volume Under Three Scenarios in PA

Wood Categories	tC in Harvested Volume (tC/year)		
	Scenario 1: Current Statewide Harvest (1.12 Bbfyr)	**Scenario 2: 1.5 Bbf/yr**	**Scenario 3: 80 MMbf/yr on State Forest Land**
Softwoods			
Sawtimber	19,306	25,833	1,378
Pulpwood	10,169	13,607	726
Hardwoods			
Sawtimber	390,555	522,598	20,056
Pulpwood	264,189	353,509	13,567
Total (MMt/year)	**0.684**	**0.916**	**0.036**

Bbf/yr = billion board feet per year; MMbf/yr = million board feet per year; MMt = million metric tons.

4. Methods described in GTR-NE-343 were used to calculate the proportions of harvested carbon that were stored in each of the four disposition categories after 100 years (Table 3). These proportions were used to calculate the proportion of harvested carbon remaining in use or in landfills after 100 years.

Table 3. Proportion of Harvested Carbon Remaining in Various Pools 100 Years After Harvest

Disposition Categories	Disposition Factor
Softwoods–Sawlogs	
In use	0.095
Landfill	0.223
Energy	0.338
Emitted w/o energy	0.344
Softwoods–Pulpwood	
In use	0.006
Landfill	0.084
Energy	0.51
Emitted w/o energy	0.4
Hardwoods–Sawlogs	
In use	0.035
Landfill	0.281
Energy	0.387
Emitted w/o energy	0.296
Hardwoods–Pulpwood	
In use	0.103
Landfill	0.158
Energy	0.336
Emitted w/o energy	0.403

Source: USDA, GTR-NE-343, Table 6.

Summary results for all three scenarios, describing the total carbon stored in each long-term pool 100 years after harvest, are listed in Table 4.

The cumulative results of the GHG savings from implementing these three scenarios over the full policy implementation period (2013–2020) are summarized in Table 5.

Table 4. Total Carbon Stored in Harvested Wood Products After 100 Years for Three Scenarios

Disposition Categories	Scenario 1: Current Statewide Harvest (tC/year)	Scenario 2: Increase Harvest to 1.5 Bbf (tC/year)	Scenario 3: Maintain Current State Forest Land Harvest (tC/year)
Softwoods-Sawlog			
In use	1,834.03	2,454.10	130.88
Landfill	4,305.16	5,760.69	307.23
Softwoods-Pulpwood			
In use	61.01	81.63	4.35
Landfill	854.16	1,142.95	60.95
Hardwoods-Sawlog			
In use	13,669.42	18,290.93	701.96
Landfill	109,745.96	146,850.09	5,635.76
Hardwoods-Pulpwood			
In use	27,211.50	36,411.47	1,397.38
Landfill	41,741.92	55,854.48	2,143.56
Total carbon stored in each disposition category 100 years after harvest (tC/year)	**199,423.20**	**266,846.38**	**10,382.12**
Total carbon stored in each disposition category 100 years after harvest (MMtCO$_2$e/year)	**0.731**	**0.978**	**0.038**

Bbf = billion board feet; tCe = metric tons of carbon; tCO$_2$e = million metric tons of carbon dioxide equivalent; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table 5. Cumulative Carbon Stored by Durable Wood Products Under Three Scenarios for Option F-5, 2013–2020

Scenarios	Annual GHG Savings ($MMtCO_2e$/year)	2013–2020 GHG Savings ($MMtCO_2e$)
Scenario 1: 2006 statewide harvest held constant (1.1 Bbf/yr)	0.73	5.85
Scenario 2: Statewide harvest increased to 1.5 billion board feet/year in 2013, maintained through 2020	0.98	7.83
Scenario 3: PA state forest harvest held constant (80 MMbf/yr)	0.04	0.30

Bbf/yr = billion board feet per year; MMbf/yr = million board feet per year; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Economic Cost:

The cost of durable wood products production is dependent upon various factors, which make a cost analysis difficult and uncertain. An increase in carbon sequestration in durable wood products can be approached from various angles, including production efficiency, product substitution, expanded product lifetimes, and other practices. However, in this analysis, only an estimate of GHG savings was provided for scenarios that increase supply of high-quality wood for the manufacture of durable wood products.

The cost analysis for all three scenarios under this initiative is based on reforestation costs, inclusive of planting, tree and herbicide costs and the costs for fencing. The total estimated cost, based on PA Department of Conservation and Natural Resources (DCNR) data, is $716 per acre, after adjusting to 2010 dollars.

Additional costs might include development of marketing materials and program administration meant to promote the use of durable wood products. These costs are not currently included in the analysis. Table 6 shows the costs and cost-effectiveness for the three scenarios in 2020 and cumulatively (2013 through 2020).

Table 6. GHG Reductions, Costs and Cost-effectiveness 2020 and Cumulative

	2020			2013 - 2020		
	GHG Reductions (MMtCO2e)	Costs ($ Million)	Cost-effectiveness ($/tCO2e)	GHG Reductions (MMtCO2e)	Net Present Value ($ Million)	Cost-Effectiveness ($/tCO2e)
Scenario 1	0.73	-41.65	-56.96	5.85	-244.18	-41.74
Scenario 2	0.98	-55.78	-57.01	7.83	-327.03	-41.78
Scenario 3	0.04	-2.97	-78.15	0.30	-17.44	-57.27

Implementation Steps:
Increase use of locally-sourced and sustainably produced wood products and raise awareness of the associated value of carbon sequestration benefits. An example would include structural wood within certified green building efforts that serves as a lower-carbon alternative to steel and concrete. This can be facilitated by expanding the state's current green building efforts beyond the current LEED (Leadership in Energy and Environmental Design) standards to include a greater utilization of locally-sourced wood products and by encouraging local and state government procurement processes to utilize locally-sourced or PA-sourced wood as a substitute material.

The Commonwealth would do well to:

- Work with LEED to ensure that the standards fully recognize the carbon value of using wood building materials
- Support revising green building standards to give more credit for the utilization of wood products (including revising state building standards)
- Promote state lead-by-example programs and promotions for greater utilization of locally and sustainably produced wood products in DCNR and other state construction projects
- Continue and enhance management activities and timber sales on state forestlands that provide a reliable supply of timber for production of wood products.

References:

- Sampson and Kamp. 2007. *The Nature Conservancy Conservation Partnership Agreement*. Part 2: "Recent Trends in Sinks and Sources of Carbon."
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- Miner, Reid. 2006. The 100-year Method for Forecasting Carbon Sequestration in Forest Products in Use. Mitigation and Adaptation Strategies for Global Change.
- USDA Northeastern FIA tables at: http://www.fs.fed.us/ne/fia//pa/.
- Lumber Production and Mill Stocks data from U.S. Census at: http://www.census.gov// /ma321t06.pdf.

CCAC Member Comments:

One member provided the following comments:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.
- No details on implementation are provided with this work plan
- Work plan GHG savings are dependent on increasing consumer demand for PA durable wood products, but no strategy for achieving this is provided.
- Concerns about the term assumptions surrounding durable wood products ability to sequester carbon.
- This work plan is not cost effective. Other work plans that exhibit cost effective measures should be pursued first.

Forest Protection Easements

Initiative Summary:
Increase the carbon sequestration benefits of Pennsylvania's forestland by preserving the existing forest base and conserving additional forestland.

Goal:
Protect 2,000 acres of forestland each year from 2013 to 2020.

Implementation Period: 2013–2020

Possible New Measure(s):
The goal of the Forest Growth & Protection Initiative is to augment the carbon-sequestering benefits of Pennsylvania's forests by preserving the existing forest base and conserving additional forestland. This will be accomplished in two ways:

- Assisting local partners in acquiring open space, such as parks, greenways, river and stream corridors, trails and natural areas; and
- Acquisition of voluntary conservation easements with private landowners.

Data Sources/ Assumptions/ Methods:
Carbon savings from this option were estimated from two sources: (1) the amount of carbon that would be lost as a result of forest conversion to developed uses (i.e., "avoided emissions"); and (2) the amount of annual carbon sequestration potential that is maintained by protecting the forest area.

This initiative assumes that 50 percent of preserved forests are Oak-Hickory and 50 percent are Maple-Beech-Birch. These forest types were chosen because they are most predominant, each making up about 44 percent of total forest cover in Pennsylvania (Forestry Inventory and Analysis [FIA]). The carbon sequestration rates for those types of forests were applied in deriving estimated sequestration totals.

(1) Avoided Emissions

Carbon savings, shown in Table 1, from avoided emissions were calculated using estimates of total standing forest carbon stocks in PA, provided by the USFS as part of the EPA's GHG State Inventory Tool 2012.

Table 1. Carbon Pools in Predominant PA Forests

Forest Carbon Pool	**Oak-Hickory**	**Maple-Beech-Birch**
	tC/acre	**tC/acre**
Live tree	35.8	36.7
Standing dead tree	1.6	2.6
Understory	0.7	0.7
Down dead wood	2.4	2.6
Forest floor	3.3	10.8
Soils	21.5	28.1
Total	**65.3**	**81.5**

tC = metric tons of carbon.

Loss of forests to development results in a large one-time surge of carbon emissions. In this case, it was assumed that 100 percent of the vegetation carbon stocks would be lost in the event of forest conversion to developed uses, with no appreciable carbon sequestration in soils or biomass following development. The soil carbon loss assumption is based on a study that shows about a 35 percent loss of soil carbon when woodlots are converted to developed uses (Austin, 2007). A comparison of data from the American Housing Survey[84] with land-use conversion data from the Natural Resources Inventory (NRI) suggests that, on average, two-thirds of the land area in a given residential lot is cleared during land conversion. Thus, it was assumed that, during forest conversion to developed use, 100 percent of the forest vegetation carbon and 35 percent of the soil carbon would be lost on 67 percent of the converted acreage.

To estimate avoided emissions, the total number of acres protected in a year was multiplied by the estimate of one-time carbon loss from biomass and soils due to development. In maple-beech-birch forests, the estimated carbon loss was 56.2 tC/acre; in oak-hickory forests, it was 49.2 tC/acre. In both forest types, this estimate of carbon loss due to development is calculated as the sum of 100 percent of average standing vegetation carbon stocks (live + dead) and 35 percent of average soil carbon stocks (forest floor + mineral soil). This overall avoided carbon emissions estimate was then converted to $MMtCO_2e$ (Table 3).

(2) Annual Sequestration Potential in Protected Forests

The calculations below use default carbon sequestration values for oak-hickory and maple-beech-birch forest types in the northeastern United States (U.S. Forest Service [USFS] General Technical Report (GTR)-343, Tables A2 and A3) (Table 2). Average annual carbon sequestration for these forest types was calculated over 125 years by subtracting carbon stocks in 125-year-old stands from carbon stocks in new stands and dividing by 125. Soil carbon density was assumed constant and is not included in the calculation because default values for soil carbon density are constant over time in USFS GTR-343.

Table 2. Forest Carbon Sequestration Rates in Protected Acreage

Forest Types	**tC/ac (0 yr)**	**tC/ac (125 yr)**	**tC/ac/yr (average)**
Oak-Hickory	23.0	110.7	0.7
Map-Bee-Birch	25.0	88.6	0.5

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[84] U.S. Census, http://www.census.gov/hhes/www/housing/ahs/ahs.html.

tC/ac/yr = metric tons of carbon per acre per year.

The total carbon savings associated with this option are summarized in Table 3.

Table 3. Carbon Avoided and Sequestered as a Result of Forest Protection Easements

Year	Cumulative Acreage Preserved	Avoided one-time C emissions (MMtCO2e/ yr)	C storage in Protected Acreage (MMtCO_2e/ yr)	Total C Savings (MMtCO2e/ yr)
2013	2,000	0.259	0.004	0.263
2014	4,000	0.259	0.009	0.268
2015	6,000	0.259	0.013	0.272
2016	8,000	0.259	0.018	0.277
2017	10,000	0.259	0.022	0.281
2018	12,000	0.259	0.027	0.286
2019	14,000	0.259	0.031	0.290
2020	16,000	0.259	0.036	0.294
Total	**16,000**	**2.072**	**0.160**	**2.231**

C = carbon; MMtCO_2e - million metric tons of carbon dioxide equivalent.

Total Reductions: 2.2 million metric tons of carbon dioxide equivalent (MMtCO_2e)

Cost to Regulated Entities:

The cost of protecting forestland through this policy initiative is calculated as the cost of easement purchase for private land. While in some regions of PA easement costs will be higher than in other regions, the estimated statewide easement cost is $1,000/ acre. Note that the easement cost calculated here could be used as a proxy for the “project implementation agreement” prescribed as part of the Climate Action Reserve forestry protocols. The cost-effectiveness of this option increases with time, as the acreage is preserved in the first four years of the program (Table 4). The levelized cost-effectiveness of the program over the full implementation period is $52.5 per metric ton of carbon dioxide equivalent (tCO_2e).

Table 4. Economic Costs of Protecting Forestland

Year	Acres Protected This Year	Total Cost ($2010)	Discounted Costs ($2010)	Annual Cost-Effectiveness ($/t CO2e)
2013	2,000	$2,000,000	$1,727,675	$6.56
2014	2,000	$2,000,000	$1,645,405	$6.14
2015	2,000	$2,000,000	$1,567,052	$5.76
2016	2,000	$2,000,000	$1,492,431	$5.39
2017	2,000	$2,000,000	$1,421,363	$5.06
2018	2,000	$2,000,000	$1,353,679	$4.74
2019	2,000	$2,000,000	$1,289,218	$4.45
2020	2,000	$2,000,000	$1,227,827	$4.17
Total	**16,000**	**$16,000,000**	**$11,724,649**	**$5.28**

Implementation Steps:

- Develop a set of criteria for evaluating proposed projects involving the protection of existing forestland to identify potentially significant carbon sequestration opportunities at low marginal costs and with associated environmental co-benefits.
  - Consider using criteria, such as forest type/age and related carbon values—current and projected, landscape context (e.g., size, contiguity, connectivity), threat of conversion, economic analysis (e.g., opportunity, conversion and maintenance costs, potential credit eligibility), stocking levels/regeneration rates, ecological values, etc.
  - To the greatest extent possible, use data that are currently available (e.g., FIA, Natural Resources Conservation Service [NRCS], etc.).
- There is some potential applicability of the PA electronic map program (PAMAP), which uses periodic (~ every 3 years) remote sensing to detect land-use/land-cover change and could also be used to estimate changes in net biomass (or ecosystem) productivity.
- Through Light Detection And Ranging (LIDAR)/high-resolution land-cover data, identify and characterize baseline information on priority carbon sinks—high-value natural sequestration areas, including the largest remaining intact blocks of ecologically and economically functional interior forest. (See also Related Policies/Programs in Place.)
- Consider enabling actions to reduce leakage and investigate ways to estimate and understand leakage issues, including improvements in data capabilities to track land-use change.
- Focus efforts of multiple programs/agencies to reach out to landowners in these priority areas in order to share information on funding/technical assistance/management options that create alternatives to parcelization/fragmentation.
- Create financial incentives for landowners and land trusts to accomplish the objectives described above.
  - Increase state (e.g., Community Conservation Partnership Program [C2P2]) funding for acquisition of priority forestland and for working forest conservation easements to protect forestland from conversion.
  - Consider re-tooling the state's Forest Legacy Program to reward landowners for retaining carbon value.
  - Create a state tax credit for conservation of forestland by businesses and individuals.
  - Review the Clean and Green Program to identify opportunities for improving benefits to forest landowners.
  - Explore opportunities for converting Conservation Reserve Enhancement Program (CREP) contracts and other forested riparian buffer projects to permanent riparian easements.
  - Encourage and assist counties and municipalities that are interested in creating funding for local forest conservation projects.
- Develop a model conservation easement that would incorporate carbon sequestration and trading and that would seamlessly work with emerging state and federal laws and regulations.
- Incorporate the land trust community's capacity and experience in monitoring and enforcing easements into emerging carbon monitoring programs to avoid reinventing the wheel.
- Beyond the objectives described above, determine how to interweave emerging state and federal policy and carbon management mechanisms so that Pennsylvania stakeholders can act expeditiously.
  - DEP, the Pennsylvania Department of Transportation, and Department of Conservation and Natural Resources (DCNR) might consider establishing a joint "Carbon Service" to

assist nonprofits, businesses and consumers in the same way that agriculture agencies assist farmers. Or perhaps the cooperative extension services, chambers of commerce, and other existing entities might assume this responsibility.

- DCNR and the Pennsylvania Land Trust Association might consider creating a program to enlist private forest landowners in a PA carbon-trading co-op or similar entity.
- Depending on the eventual makeup of a federal climate regulatory system, PA should consider complementary programs to enhance it and speed up its implementation. For example, if programs to avoid deforestation are insufficient at the federal level, PA should enhance that aspect to incentivize landowners to participate, much in the way that many PA counties add their own funds to the state agricultural preservation program.

Currently, the standard practice for development in wooded areas is to completely clear the land. Incentives, education, and regulations should be put in place at the state and local levels to alter this practice and require replacement sufficient to actually make a difference. This will necessitate expanding the current tree-planting infrastructure, which includes growers of native trees, recruitment of volunteers, and husbandry training for landowners in suburban and urban areas.

PA will need some adaptive structure(s) to monitor changes, disseminate information and assist ecosystem managers as natural communities change as a result of a changing climate.

References:

- J.E. Smith et al. 2006. *Methods for Calculating Forest Ecosystem and Harvested Carbon with Standards Estimates for Forest Types of the United States*, GTR NE-343. USFS Northern Research Station. (Also published as part of the U.S. Department of Energy (DOE) Voluntary GHG Reporting Program.)
- Data provided by the USFS for the PA Forestry Inventory and Forecast (I&F); program costs provided by DCNR.
- Austin, K. 2007. "The Intersection of Land Use History and Exurban Development: Implications for Carbon Storage in the Northeast." Undergraduate Thesis, Brown University.

CCAC Member Comments:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.
- This work plan is not cost effective. Other work plans that exhibit cost effective measures should be pursued first.

Forestland Protection Initiative — Acquisition

Initiative Summary:
This policy initiative analyzes three scenarios aimed at reducing the permanent loss of forest acreage through direct acquisition. The GHG benefit is twofold: avoided carbon emissions that might otherwise have taken place on converted acreage, and carbon storage on cumulative protected acreage.

Goal:
Protect private forestland conversion and reduce the likelihood of forestland conversion to developed use through direct acquisition.

Scenarios:

- Scenario 1: Reduce conversion rate by 25 percent by 2020
- Scenario 2: Reduce conversion rate by 50 percent by 2020
- Scenario 3: Achieve no net loss of forest development by 2020

Implementation Period: 2013–2020

Data Sources/ Assumptions/ Methods:
GHG benefits were estimated from two sources: (1) the amount of carbon that would be lost as a result of forest conversion to developed uses (i.e., “avoided emissions”); and (2) the amount of annual carbon sequestration potential that is maintained by protecting the forest area.

In Pennsylvania, the Natural Resources Inventory (NRI) estimated roughly 15.5 million acres of forest in 1997. Between 1982 and 1997, 902,900 acres of forest were converted to non-forest use (61,393 acres annually). Of this total, 597,900 acres were converted to developed use for a net annual loss of 39,860 forested acres to development statewide.

This corresponds to a net forest loss of 0.40 percent per year to all non-forest uses, or 0.26 percent loss annually to development alone. In this analysis, a baseline conversion rate of 39,860 acres per year was used, representing the rate at which forestland was lost to development annually between 1982 and 1997. Updated data on land conversion trends have not been released by NRI as of May 2009.

Analysis for each of these types of carbon savings (avoided emissions and sequestration on protected acreage) was conducted on each scenario. The scenarios differ with regard to the number of acres not converted to development each year (see Table 1). In all scenarios, 50 percent of preserved forests is assumed to be Oak-Hickory and 50 percent is assumed to be Maple-Beech-Birch. These forest types were used because they are most predominant, each making up about 44 percent of total forest cover in Pennsylvania (FIA).

Table 1. Alternative Acreage Scenarios Used to Quantify Carbon Savings From Avoided Forest Conversion to Developed Use

Scenarios	Goal and Cumulative Acreage Protected 2013–2020 (acres)	Annual Incremental Acreage Protected to Reach Goal (acres/ year)
Scenario 1: Reduce conversion rate by 25% by 2020	79,720	9,965
Scenario 2: Reduce conversion rate by 50% by 2020	159,440	19,930
Scenario 3: Achieve no net loss of forest to development by 2020	318,880	39,860

1. Avoided Emissions

The forest carbon stocks (tons of carbon per acre) and annual carbon flux (annual change in tons of carbon per acre) data are based on default carbon sequestration values for Maple-Beech-Birch forest types in the northeastern United States (USFS GTR-343, Table A2). Annual rates of carbon sequestration (metric tons of carbon sequestered per acre per year) were calculated by subtracting total carbon stocks in forest biomass of 125-year-old stands from total carbon stocks in forest biomass of new stands and dividing the remainder by 125. Soil carbon density was assumed constant, and is not included in the annual carbon flux calculations because default values for soil carbon density are constant over time in USFS GTR-343. See Table 2 for an overview of forest carbon storage and sequestration information used in this analysis.

Table 2. Annual Sequestration Potential in Protected Forests

Year	Cumulative Acres Preserved			C Storage in Protected Acreage ($MMtCO_2e$)		
	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
2013	9,965	19,930	39,860	0.02	0.04	0.09
2014	19,930	39,860	79,720	0.07	0.13	0.27
2015	28,895	59,790	119,580	0.13	0.27	0.53
2016	39,860	79,720	159,440	0.22	0.44	0.88
2017	49,825	99,650	199,300	0.33	0.66	1.33
2018	59,790	119,580	239,160	0.46	0.93	1.86
2019	69,755	139,510	279,020	0.62	1.24	2.48
2020	79,720	159,440	318,880	0.80	1.59	3.18
Total	**79,720**	**159,440**	**318,880**	**2.65**	**5.31**	**10.61**

C = carbon; $MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

Loss of forests to development results in a large, one-time surge of carbon emissions. In this case, it was assumed that 100 percent of the vegetation carbon stocks would be lost in the event of forest conversion to developed uses, with no appreciable carbon sequestration in soils or biomass following development. The soil carbon loss assumption is based on a study that shows about a 35 percent loss of soil carbon when woodlots are converted to developed uses (Austin, 2007). A comparison of data from the American Housing Survey[85] with land use conversion data from the NRI suggests that, on average, two-thirds of the land area in a given residential lot is cleared during land conversion. Thus, it was assumed that, during forest conversion to developed use, 100 percent of the forest vegetation carbon and 35 percent of the soil carbon would be lost on 67 percent of the converted acreage. For each scenario it was assumed that 100 percent of the protected land would otherwise have been converted to a developed use. Thus, the avoided emissions calculation was made on 100 percent of the protected acreage.

To estimate avoided emissions, the total number of acres protected in a year was multiplied by the estimate of one-time carbon loss from biomass and soils due to development. In Maple-Beech-Birch forests, this estimated C loss was 56.2 tC/ac; in Oak-Hickory forests, it was 49.2 tC/ac. In both forest types, this estimate of carbon loss due to development is calculated as the sum of 100 percent of average standing vegetation carbon stocks (live + dead) and 35 percent of average soil carbon stocks (forest floor + mineral soil). This overall avoided carbon emissions estimate was then converted to MMtCO2e. While some of the biomass lost during clearing might be used for bioenergy production, the effect was not quantified in this analysis.

2. Sequestration in Protected Forest

Forests not converted in a given year continue to sequester carbon each year they remain in a forested use. Thus, the carbon sequestration in protected forestland is calculated as annual sequestration in cumulative protected acreage. Annual sequestration for PA forest (tC/ac/yr) is calculated from NE-GTR-343 and is given in Table 3. As with avoided emissions from initial conversion, it is assumed that half of the protected forest acreage is in Maple-Beech-Birch forest and half is in Oak-Hickory forest. Because acres protected in one year continue to store carbon in subsequent years, annual benefits of forest protection tend to accrue in later years of policy implementation (Figure 1).

Table 3. Summary of Avoided One-Time Emissions and Sequestration in Protected Forest Due to Reduced Forest Conversion (2013–2020)

Scenarios	Cumulative Acres Protected (acres)	Cumulative GHG Benefit From Avoided One-Time Emissions ($MMtCO_2e$)	Cumulative GHG Benefit From Carbon Sequestration ($MMtCO_2e$)	Total Carbon Reductions (MMtCO2e)
Scenario 1	79,720	46.45	2.65	49.10
Scenario 2	159,440	92.90	5.31	98.21
Scenario 3	318,880	185.80	10.61	196.41

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent.

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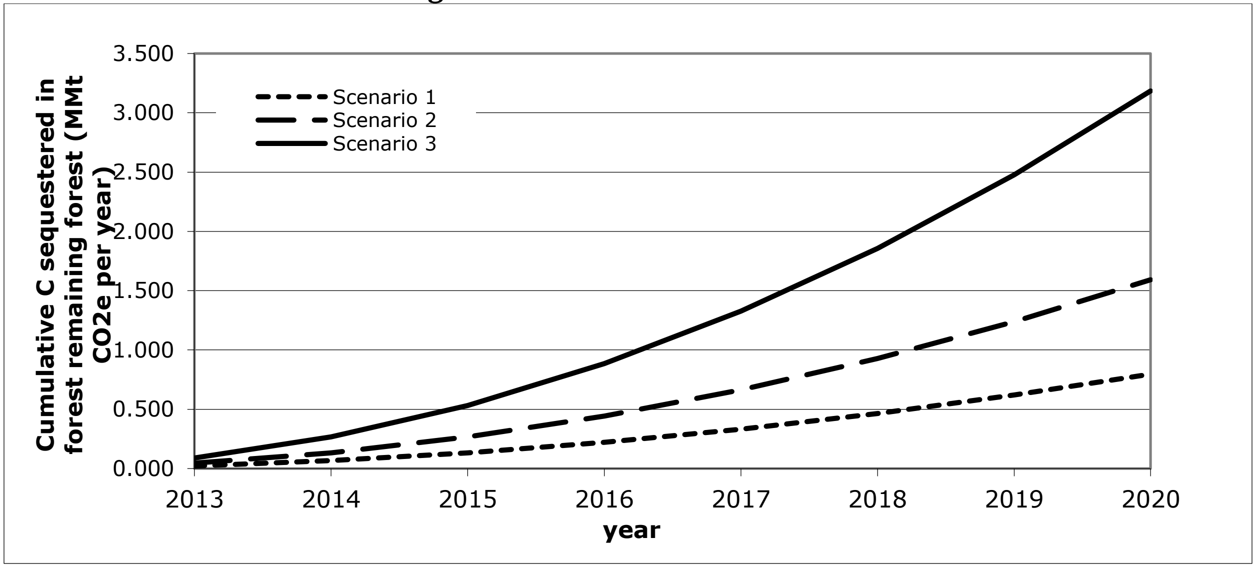
[85] U.S. Census, http://www.census.gov/hhes/www/housing/ahs/ahs.html

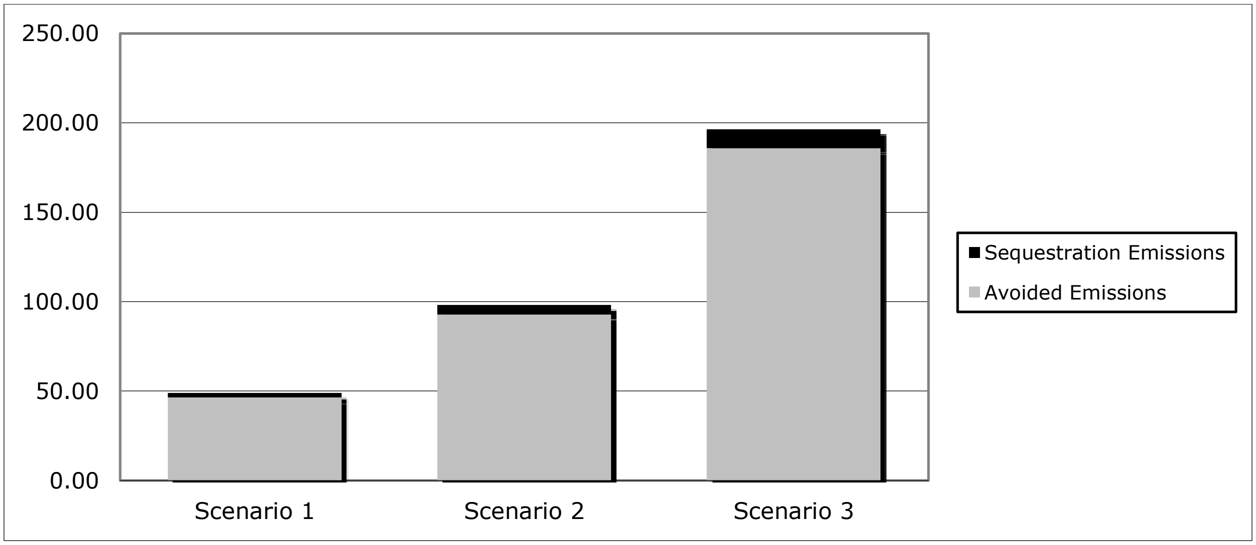
Figure 1. Impact of Forest Protection From Conversion on Annual Carbon Sequestration in Cumulative Protected Acreage.



C = carbon; MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

For Scenarios 1–3, the relative impact of avoided one-time emissions due to reduced forest conversion is roughly 14 times the impact of cumulative sequestration in protected acreage for all scenarios (Table 3 and Figure 2).

Figure 2. Cumulative Effect of Three Scenarios on GHG Emissions Between 2013 and 2020



MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

<u>Economic Costs</u>:
The economic cost of avoiding conversion was calculated as the cost of acquiring land minus the costs of land clearing and site grading. The cost per acre for acquisition is estimated at $3,500 per acre. The cost for land clearing was estimated at $3,000 per acre ($2,000 clearing + $1,000 site grading). The results of the economic analysis, without discounting, are shown in Table 4.

Table 4. Net Economic Costs of Avoided Forest Conversion (not discounted)

Year	Scenario 1	Scenario 2	Scenario 3
2013	$4,982,500	$9,965,000	$19,930,000
2014	$9,965,000	$19,930,000	$39,860,000
2015	$14,947,500	$29,895,000	$59,790.000
2016	$19,930,000	$39,860,000	$79,720,000
2017	$24,912,500	$49,825,000	$99,650,000
2018	$29,895,000	$59,790,000	$119,580,000
2019	$34,877,500	$69,755,000	$139,510,000
2020	$39,860,000	$79,720,000	$159,440,000
Cumulative	$179,370,000	$358,740,000	$717,480,000

A summary of the discounted and non-discounted costs is shown in Table 5, and overall results of the analysis are given in Table 6. Discounted costs were calculated assuming a 5 percent discount rate and 2010 dollars. The net present value (NPV) of each scenario is the sum of the discounted costs between 2013 and 2020. Levelized cost-effectiveness is calculated as the cost associated with avoiding or storing each tCO2e The levelized cost-effectiveness for all scenarios is $2.52 per metric ton CO2e.

Table 5. Summary of Economic Costs of Each Scenario

Types of Economic Costs	Scenario 1	Scenario 2	Scenario 3
Net Economic Costs (non-discounted) ($ million)	$179.3	$358.7	$717.4
Net Economic Costs (NPV) ($2010) ($ million)	$123.9	$247.9	$495.9

NPV = net present value.

Table 6. Summary of GHG Benefits and Economic Costs for Each Scenario

Scenarios	GHG Reduction in 2020 ($MMtCO_2e$)	Cumulative GHG Reduction 2013–2020 ($MMtCO_2e$)	Cost-Effectiveness ($2010 per tCO_2e)
Scenario 1: Reduce rate of conversion by 25% by 2020	11.12	49.10	$2.71
Scenario 2: Reduce rate of conversion by 50% by 2020	22.24	98.21	$2.71
Scenario 3: Achieve no net forest loss by 2020	44.47	196.41	$2.71

$MMtCO_2e$ = million metric tons of carbon dioxide equivalent; tCO_2e = metric tons of carbon dioxide equivalent.

Key Assumptions: Forest protection will occur via acquisition at an approximate cost of $3,500/acre; 50 percent of protected forest will be in a maple-beech-birch forest type, and 50 percent of protected forest will be in an oak-hickory forest type. Conversion threat values may range from 10 percent to 100 percent.

<u>Implementation Steps</u>:
Develop a set of criteria for evaluating proposed projects involving the protection of existing forestland to identify potentially significant carbon sequestration opportunities at low marginal costs and with associated environmental co-benefits. Consider using criteria, such as forest type/age and related carbon values—current and projected, landscape context (e.g., size, contiguity, connectivity), threat of conversion, economic analysis (e.g., opportunity, conversion and maintenance costs, potential credit eligibility), stocking levels/regeneration rates, ecological values, etc. To the greatest extent possible, use data that are currently available (e.g., FIA, Natural Resources Conservation Service [NRCS], etc.).

There is some potential applicability of the planned PA electronic map program (PAMAP), which will use periodic (~ every 3 years) remote sensing to detect land-use/land-cover change and could also be used to estimate changes in net biomass (or ecosystem) productivity.

Through Light Detection And Ranging (LIDAR)/high-resolution land-cover data, identify and characterize baseline information on priority carbon sinks—high-value natural sequestration areas, including the largest remaining intact blocks of ecologically and economically functional interior forest. (See also Related Policies/Programs in Place.)

Consider enabling actions to reduce leakage. Investigate ways to estimate and understand leakage issues, including improvements in data capabilities to track land-use change. Focus efforts of multiple programs/agencies to reach out to landowners in these priority areas in order to share information on funding/technical assistance/management options that create alternatives to parcelization/fragmentation. Increase state (e.g., Community Conservation Partnership Program [C2P2]) funding for acquisition of priority forestland and for working forest conservation easements to protect forestland from conversion. Consider re-tooling the state's Forest Legacy program to reward landowners for retaining carbon value. Create a state tax credit for conservation of forestland by businesses and individuals. Review the Clean and Green program to identify opportunities for improving benefits to forest landowners. Explore opportunities for converting Conservation Reserve Enhancement Program (CREP) contracts and other forested riparian buffer projects to permanent riparian easements. Encourage and assist counties and municipalities that are interested in creating funding for local forest conservation projects.

Develop a model conservation easement that would incorporate carbon sequestration and trading and that would seamlessly work with emerging state and federal laws and regulations. Incorporate the land trust community’s capacity and experience in monitoring and enforcing easements into emerging carbon monitoring programs to avoid reinventing the wheel.

Create financial incentives for landowners and land trusts to accomplish the objectives described above.

Beyond the objectives described above, determine how to interweave emerging state and federal policy and carbon management mechanisms so that PA stakeholders can act expeditiously. DEP, the Pennsylvania Department of Transportation, and Department of Conservation and Natural Resources (DCNR) might consider establishing a joint "Carbon Service" to assist nonprofits, businesses and consumers in the same way that agriculture agencies assist farmers. Or perhaps the cooperative extension services, chambers of commerce and other existing entities might assume this responsibility.

DCNR and the Pennsylvania Land Trust Association might consider creating a program to enlist private forest landowners in a Pennsylvania carbon-trading co-op or similar entity.

Depending on the eventual makeup of the federal climate regulatory system, Pennsylvania should consider complementary programs to enhance it and speed up its implementation. For example, if programs to avoid deforestation are insufficient at the federal level, the Commonwealth should enhance that aspect to incentivize landowners to participate, much in the way that many counties in Pennsylvania add their own funds to the state agricultural preservation program.

Currently, the standard practice for development in wooded areas is to completely clear the land. Incentives, education and regulations should be put in place at the state and local levels to alter this practice and require replacement sufficient to actually make a difference. This will necessitate expanding the current tree-planting infrastructure, which includes growers of native trees, recruitment of volunteers, and husbandry training for landowners in suburban and urban areas.

PA will need some adaptive structure(s) to monitor changes, disseminate information, and assist ecosystem managers as natural communities change as a result of a changing climate.

Potential Overlap: None.

References:

- J.E. Smith et al. 2006. *Methods for Calculating Forest Ecosystem and Harvested Carbon with Standards Estimates for Forest Types of the United States*, GTR NE-343. USFS Northern Research Station. (Also published as part of the U.S. Department of Energy (DOE) Voluntary GHG Reporting Program.)
- Data provided by the USFS for the PA Forestry Inventory and Forecast (I&F); program costs provided by DCNR.
- Strong, T.F. 1997. "Harvesting intensity influences the carbon distribution in a northern hardwood ecosystem." U.S. Department of Agriculture (USDA) Forest Service North Central Forest Experiment Station Research Paper NC-329.
- Austin, K. 2007. "The Intersection of Land Use History and Exurban Development: Implications for Carbon Storage in the Northeast." Undergraduate Thesis, Brown University.

<u>CCAC Member Comments:</u>

One member provided the following comments:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.
- I am very supportive of preserving existing forest lands.
- Oil and Gas Fund monies could be used to capitalize this initiative.
- I have concerns about the technical accuracy of the work plan calculations. Previous versions of this work plan had much lower total acreage and associated GHG reductions. Similarly, the calculations in this work plan seem inconsistent with the quantitative analysis in the 2009 climate action plan, even when correcting for the reduced time span (i.e. 2009-2020 vs. 2013-2020).
- There is a lack of clarity about what would happen to the timber if it was not acquired, and how this impacts GHG reductions. For example, would the timber be harvest? Incorporated into durable wood? Something else?

Urban Forestry

Initiative Summary: This option seeks to increase carbon stored in urban forests, and thereby to reduce residential, commercial and institutional energy use for heating and cooling. Carbon stocks in trees and soils in urban land uses—such as in parks, along roadways, and in residential settings—can be enhanced in a number of ways, including planting additional trees, reducing the mortality and increasing the growth of existing trees, and avoiding tree removal (or deforestation). Forest canopy cover, properly designed, can also reduce energy demand by reducing building heating and cooling needs.

Goal: Increase existing urban and suburban tree cover through one of the following three scenarios:

- Scenario 1: Increase existing tree cover in PA urban and suburban forests by 10 percent by 2020.
- Scenario 2: Increase existing tree cover by 25 percent by 2020.
- Scenario 3: Increase existing tree cover by 50 percent by 2020.

Implementation Period: 2013–2020

Potential GHG Reduction (MMtCO$_2$e):
This work plan documents the cumulative impact on carbon sequestration and avoided fossil fuel emissions of adding trees to existing canopy cover in Pennsylvania. Specifically, Scenarios 1, 2, and 3 seek to increase the total number of trees in urban and suburban PA by 10 percent, 25 percent and 50 percent, respectively, by 2020. Currently, the Commonwealth contains about 139 million urban trees: thus this option quantifies the effect of adding 13.9, 34.8, and 69.5 million trees by 2020. The number of trees planted each year is constant, with the target number of trees planted by 2020. GHG benefits are twofold:

A. Direct Carbon Sequestration in Urban Trees

A linear rate of increase in tree planting was assumed, with full scenario implementation occurring in 2020 for all three scenarios. Annual carbon sequestration per urban tree is calculated as 0.006 tC/tree/year, based on statewide average data reported by USFS. This is the average annual per-tree carbon sequestration value when the total estimated urban forest carbon accumulation (863,000 tC/year) in Pennsylvania is divided by the total number of urban trees (139.0 million) in the Commonwealth. Since trees planted in one year continue to accumulate carbon in subsequent years, annual carbon sequestration in any given year is calculated as the sum of carbon stored in trees planted in that year, plus the sequestration by trees that were planted in prior years.

B. Avoided Fossil Fuel Emissions

Offsets from avoided fossil fuel use for heating and cooling are the sum of three different types of savings: avoided emissions from reduced cooling demand, avoided emissions from reduced demand for heating due to wind reduction (this benefit is only available for evergreen trees), and enhanced fossil fuel emissions needed for heat due to wintertime shading. Calculations for avoided fossil fuel offsets are based on calculations presented by McPherson et al. in GTR-PSW-171 (Table 1). For this analysis, it is assumed that the trees planted are evenly split among residential settings with pre-1950, 1950–1980, and post-1980 homes, and that all trees planted are medium-sized, with 50 percent deciduous and 50 percent evergreen. These avoided emission factors assume average tree distribution around buildings (i.e., these fossil fuel emissions reduction factors are averages for existing buildings, but do not necessarily assume that trees are optimally placed around buildings to maximize energy efficiency). These factors are also dependent on the fuel mix (coal, hydroelectric, nuclear, etc.) for electricity generation, and thus change as the mix changes.

Overall GHG Benefit of Urban Tree Planting

Total GHG benefits are calculated as the sum of direct carbon sequestration plus fossil fuel offset from reduced cooling demand and wind reduction (Tables 2, 3, and 4).

Table 1. Factors Used to Calculate CO$_2$e Savings (MMtCO$_2$e/Tree/Year) From Reduced Need for Fossil Fuel for Heating and Cooling, and From Windbreak Effect of Evergreen Trees

Fossil Fuel Offsets: Evergreen Trees (Mid-Atlantic Climate Region)				
Housing Vintage	*Shade–Cooling*	*Shade–Heating*	*Wind–Heating*	*Net Effect*
Pre-1950	0.0168	–0.0315	0.1294	0.1147
1950–1980	0.0275	–0.0403	0.1555	0.1427
Post-1980	0.0232	–0.0324	0.133	0.1238
Average	**0.0225**	**–0.0347**	**0.1393**	**0.1271**
Average (MMtCO$_2$e)				**0.1271**
Fossil Fuel Offsets: Deciduous Trees (Mid-Atlantic Climate Region)				
Housing Vintage	*Shade–cooling*	*Shade–Heating*	*Wind–Heating*	*Net Effect*
Pre-1950	0.0260	–0.0320		–0.0060
1950–1980	0.0425	–0.0409		0.0016
Post-1980	0.0358	–0.0329		0.0029
Average	**0.0348**	**–0.0353**		**–0.0005**
Average (MMtCO$_2$e)				**0.0633**

Source: McPherson et al., 1999.

MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table 2. Overall GHG Benefit (MMtCO$_2$e/year) of Scenario 1: Increase Existing Urban Tree Canopy in Pennsylvania by 10 Percent

Year	Trees Planted This Year	Trees Planted in Previous Years	GHG Sequestered	GHG Avoided	Overall GHG Savings
2013	1,158,500	0	0.026	0.073	0.10
2014	1,158,500	1,158,500	0.053	0.147	0.20
2015	1,158,500	2,317,000	0.079	0.220	0.30
2016	1,158,500	3,475,500	0.105	0.293	0.40
2017	1,158,500	4,634,000	0.132	0.367	0.50
2018	1,158,500	5,792,500	0.158	0.440	0.60
2019	1,158,500	6,951,000	0.185	0.513	0.70
2020	1,158,500	8,109,500	0.211	0.587	0.80
Cumulative Totals	**9,268,000**	**32,438,000**	**0.949**	**2.639**	**3.59**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table 3. Overall GHG Benefit (MMtCO$_2$e/year) of Scenario 2: Increase Existing Urban Tree Canopy in Pennsylvania by 25 Percent

Year	Trees Planted This Year	Trees Planted in Previous Years	GHG Sequestered	GHG Avoided	Overall GHG Savings
2013	2,896,250	0	0.066	0.183	0.25
2014	2,896,250	2,896,250	0.132	0.367	0.50
2015	2,896,250	5,792,500	0.198	0.550	0.75
2016	2,896,250	8,688,750	0.264	0.733	1.00
2017	2,896,250	11,585,000	0.330	0.916	1.25
2018	2,896,250	14,481,250	0.396	1.100	1.50
2019	2,896,250	17,377,500	0.461	1.283	1.74
2020	2,896,250	20,273,750	0.527	1.466	1.99
Cumulative Totals	**23,170,000**		**2.374**	**6.598**	**8.97**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Table 4. Overall GHG Benefit (MMtCO$_2$e/year) of Scenario 3: Increase Existing Urban Tree Canopy in Pennsylvania by 50 percent

Year	Trees Planted This Year	Trees Planted in Previous Years	GHG Sequestered	GHG Avoided	Overall GHG Savings
2013	5,792,500	0	0.132	0.367	0.50
2014	5,792,500	5,792,500	0.264	0.733	1.00
2015	5,792,500	11,585,000	0.396	1.100	1.50
2016	5,792,500	17,377,500	0.527	1.466	1.99
2017	5,792,500	23,170,000	0.659	1.833	2.49
2018	5,792,500	28,962,500	0.791	2.199	2.99
2019	5,792,500	34,755,000	0.923	2.566	3.49
2020	5,792,500	40,547,500	1.055	2.933	3.99
Cumulative Totals	**46,340,000**		**4.747**	**13.196**	**17.94**

MMtCO$_2$e = million metric tons of carbon dioxide equivalent.

Economic Cost:

Economic costs of tree planting are calculated as the sum of tree planting and annual maintenance, including the costs of program administration and waste disposal. Economic benefits of tree planting include the cost offset from reduced energy use, as well as the estimated economic benefits of services, such as provision of clean air, hydrologic benefits such as storm water control, and aesthetic enhancement.

Data were not available to assess the cost of tree planting specifically in Pennsylvania communities. As a result, the cost of planting urban trees in Pennsylvania is taken from Peper et al. (2007), whose analysis was conducted in New York City. The average annualized cost per tree is estimated at $39.24 ($2010), and includes planting, pruning, pest management, administration, removal and infrastructure repair due to damage from trees.

Two types of data were available to quantify the economic benefit of planting urban trees. The first data source is the New York City analysis of Peper et al. (2007). Average annual cost savings of –$217.80 ($2010) per tree from this work is the average of all trees in the city, and includes benefits of energy savings, improved air quality, improved storm water quality, and improved aesthetics.

A second estimate of economic benefit per tree, specifically for Philadelphia, PA, was also used (Nowak et al., 2007). This analysis quantified the structural benefit of urban trees (i.e., replacement costs) as well as the annual functional benefits of urban trees (i.e., pollution abatement, energy savings). Total structural benefit of Philadelphia's 2.1 million urban trees was estimated at $1.8 billion. To determine the annual structural benefit of the urban tree canopy, this total citywide structural benefit was divided by 50 (the average lifetime of an urban tree). Annual functional economic benefits for the urban tree canopy were calculated as the value of pollution abatement ($3.9 million) plus the value of avoided energy costs ($1.19 million). The citywide structural and functional benefits were divided by the number of trees to estimate the annual economic benefit per tree in Pennsylvania. From this source, the average annual (structural + functional) benefit per tree per year in Pennsylvania was calculated at –$20.60.

For this analysis, –$217.80/tree/year and –$20.60/tree/year were averaged to estimate the economic benefits of planting urban trees (–$119.20/tree/year). While these values clearly diverge substantially from one another, the methods used to estimate economic benefits of non-market services, such as clean air and water and pollution abatement, are inexact and variable. The value of –$119.20/tree/year is consistent with results obtained for similar analyses in other states.

Net economic costs for this option, as illustrated in Tables 5 through 7, are calculated as the difference between costs of planting + maintenance and economic benefit realized by urban trees. Negative costs therefore refer to net economic benefits, where estimated benefits exceed overall costs. For this analysis, net economic benefit per tree was estimated at –$75.96/tree/year. Discounted costs were calculated in 2010 dollars and assuming a 5 percent discount rate. For all scenarios, the cost-effectiveness of implementation is –$610.16/tCO2e, which indicates a net cost savings per tCO_2e reduced.

Table 5. Annual and Cumulative Economics of Implementing Scenario 1

Year	Non-discounted ($)	Discounted ($2010)	Levelized Cost-Effectiveness ($/tCO2e)
2013	-$87,997,729	-$76,015,747	
2014	-$175,995,458	-$144,791,899	
2015	-$263,993,188	-$206,845,570	
2016	-$351,990,917	-$262,661,041	
2017	-$439,988,646	-$312,691,716	
2018	-$527,986,375	-$357,361,961	
2019	-$615,984,104	-$397,068,846	
2020	-$703,981,833	-$432,183,778	-$541.95
Cumulative Totals	**-$3,167,918,250**	**-$2,189,620,559**	**-$610.16**

Table 6. Annual and Cumulative Economics of Implementing Scenario 2

Year	Non-discounted ($)	Discounted ($2010)	Levelized Cost-Effectiveness ($/tCO2e)
2013	-$219,994,323	-$190,039,368	
2014	-$439,988,646	-$361,979,748	
2015	-$659,982,969	-$517,113,925	
2016	-$879,977,292	-$656,652,604	
2017	-$1,099,971,615	-$781,729,290	
2018	-$1,319,965,938	-$893,404,903	
2019	-$1,539,960,260	-$992,672,114	
2020	-$1,759,954,583	-$1,080,459,444	-$541.95
Cumulative Totals	**-$7,919,795,625**	**-$5,474,051,397**	**-$610.16**

Table 7. Annual and Cumulative Economics of Implementing Scenario 3

Year	Non-discounted ($)	Discounted ($2010)	Levelized Cost-Effectiveness ($/tCO2e)
2013	-$439,988,646	-$380,078,735	
2014	-$879,977,292	-$723,959,496	
2015	-$1,319,965,938	-$1,034,227,851	
2016	-$1,759,954,583	-$1,313,305,207	
2017	-$2,199,943,229	-$1,563,458,580	
2018	-$2,639,931,875	-$1,786,809,806	
2019	-$3,079,920,521	-$1,985,344,229	
2020	-$3,519,909,167	-$2,160,918,889	-$541.95
Cumulative Totals	**-$15,839,591,250**	**-$10,948,102,793**	**-$610.16**

Implementation Steps:

- Leverage/expand TreeVitalize program.
- Consider a comprehensive approach to school tree planting.
- Provide incentives for private landowners to plant trees in residential areas.

Goals Support Full Implementation of Target Programs

The TreeVitalize initially sought an $8 million investment in tree planting and care in southeastern Pennsylvania over a four year period. The goals of the program included planting 20,000 shade trees, restoring 1,000 acres of forests along streams and water-protection areas, and training 2,000 citizens to plant and care for trees. The PA Department of Conservation and Natural Resources (DCNR) initiated preliminary discussions with regional stakeholders in the summer of 2003, and appointed a Project Director in January 2004. Planning, assessment, and resource development continued through 2004. Tree-planting activities began in the fall of 2004 and have continued. Subsequently, the regional Tree Tenders program was launched in 2005. Although TreeVitalize is not a permanent entity, the collaborations created and capacity built will continue to increase tree cover and promote stewardship through expansion across other regions of the state. See: http://www.treevitalize.net/aboutus.aspx.

Enabling Programs May Provide Relevant Information in Support of Implementation

The Rural & Community Forestry Section provides professional forestry leadership and technical assistance promoting forestry and the knowledge of forestry by advising and assisting other government agencies, communities, landowners, the forest industry, and the general public in the wise stewardship and utilization of forest resources. The section also coordinates the Bureau of Forestry's (BOF) conservation education efforts, and provides professional forestry leadership and technical assistance to rural communities and urban areas. Efforts include coordination with Penn State's regional urban foresters, Arbor Day activities, Tree City USA, Penn ReLeaf, the Harrisburg Greenbelt project, the Municipal Tree Restoration program, and the Urban & Community Forestry Council. See: http://www.dcnr.state.pa.us/forestry/rural/index.aspx.

Major funding streams are through U. S. Forest Service (USFS) state and private forestry through urban forestry funds. These support the work at Penn State by the Statewide Urban and

Community Forestry Committee, which also receives some funding from the Bureau of Recreation and Conservation, as well other smaller grants from utilities. There is a Northeast Pennsylvania Urban & Community Forestry Program, which is funded through the tenth congressional district. This northeast area does not include Scranton/Wilkes Barre. Williamsport is the largest city included in this area.

The Animal Plant and Health Inspection Service of the USDA (http://www.aphis.usda.gov/) gets involved in and makes funds available to combat specific issues, such as protection of urban forests from disease, fire, other risks and proper management of urban forests and street trees.

Develop a package of incentives and programs to encourage retention/enhancement of tree cover on new developments (e.g., Department of Community and Economic Development planning/technical assistance, state funding bonus/priority, model subdivision and land-use development ordinances (SALDOs) for carbon sequestration maintenance/offset requirements associated with tree cover, tax breaks for tree-friendly development, etc.).

Re-greening underutilized/abandoned properties through targeted tree planting programs and comprehensive local/county planning for urban/suburban terrestrial carbon sequestration.

Data Sources:

- Information about current numbers of trees in urban forest and annual carbon storage in urban trees in PA from D.J. Nowak et al., USFS, Northern Research Station, *Urban Forest Effects on Environmental Quality*, State Summary data for Washington (http://www.fs.fed.us/ne/syracuse/Data/State/data_PA.htm).
- Fossil fuel reductions through reduced demand for cooling and protection from wind from: E. McPherson and J.R. Simpson. 1999. *Carbon Dioxide Reduction Through Urban Forestry: Guidelines for Professional and Volunteer Tree Planters*. USFS GTR-PSW-171. USFS, Pacific Southwest Research Station.
- Data on the costs of tree planting and maintenance from Peper, P.J., et al. 2007. *New York City, New York Municipal Forest Resource Analysis*. Center for Urban Forest Research, USFS Pacific Southwest Research Station.
- Additional data on benefits of tree canopy in PA are from D.J. Nowak et al. 2007. *Assessing Urban Forest Effects and Values: Philadelphia's Urban Forest.* Resource Bulletin NRS-7. USFS, Northern Research Station

CCAC Member Comments:

One member provided the following comments commented:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.

No-Till Farming

Summary:

No-till cropping systems sequester soil carbon that would otherwise be released to the atmosphere through conventional cultivation practices. No-till farming also reduces the amount of nitrogen-based fertilizer being applied therefore, providing reductions in nitrous oxide (N_2O) emissions. No-till also results in reduced time spent preparing the fields such that diesel fuel consumption is reduced and therefore, provides a third source of GHG reductions.

Goal:

Increase no-till acreage by approximately 22 percent to 1.8 million acres in 2020.

Implementation Period:

2013 to 2020

No-till Data Sources/Assumptions/Methods for GHG:

Total harvested cropland in Pennsylvania was estimated at about 2.3 million acres[86] in 2011. For the purposes of this analysis, only no-till acreage was considered, excluding other conservation tillage practices. Based on the policy design parameters, the schedule for acres to be put into no-till acreage cultivation is displayed in Table 1.

It is estimated that approximately 1.5 million acres of Pennsylvania cropland were cultivated using no-till practices in 2011.[2] Therefore, to reach the goal of 1.8 million total acres, 353,000 additional acres are needed. It is assumed that carbon is sequestered at a rate of 0.6 tCO_2/acre/year (404 kilograms of carbon per hectare per year [kg C/ha/year]) and that that this rate of accumulation occurs for 20 years, which extends beyond the policy period.

Additional GHG savings associated with avoided fertilizer and diesel fuel use are identified in Table 1. Differences in the application of nitrogen (N) fertilizer and the estimated 10 percent volatization rate associated with N fertilizers yield incremental greenhouse gas reductions. Reduced diesel fuel consumption is estimated and multiplied by a life-cycle emissions factor of 12.6 metric tons per 1,000 gallons consumed to calculate the associated emissions reductions.

Data Sources/Assumptions/Methods for Costs:

Changes in equipment necessary to convert from conventional to no-till cultivation result in increased costs. These costs are estimated based on data from the Minnesota Agriculture Best Management Practices (AgBMP) Program.[87] This program provides farmers a low-interest loan as an incentive to initiate or improve their current tillage practices. The equipment funded is generally specialized tillage or planting implements that leave crop residues covering at least 15%–30% of the ground after planting. The average total cost for this equipment is $23,000, though the average loan for tillage equipment is $16,000. The average-size farm using an

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[86] USDA/NASS, 2012survey of tillage practices for major field crops http://www.nass.usda.gov/Statistics_by_State/Pennsylvania/Publications/Survey_Results/tillage_practices12.pdf

[87] Minnesota Department of Agriculture, Agricultural Best Management Practices Loan Program State Revolving Fund Status Report, February 28, 2006.

AgBMP loan to purchase conservation tillage equipment is 984 acres. The average loan size was determined based on the average size of a farm in Pennsylvania (124 acres),[88] and the amount of a loan per acre as estimated in the Minnesota AgBMP Program ($16.26/acre).[89] This put the average loan size at $2,016 to finance no-till/conservation tillage practices. This loan payment was applied to each new acre entering the program. The cost savings for this program come from a combination of carbon credits, nutrient reduction credits and reduced diesel fuel costs. Carbon credits can accrue through the increased accumulation of soil carbon sequestration as well as via decreased N_2O emissions from fertilizer application. Nutrient credits are available from reduced runoff of applied nitrogen and phosphorus fertilizers that enter waterways. Carbon and nutrient credit values were estimated at $3/metric ton and $3.50/metric ton, respectively. Diesel fuel savings were estimated using U.S. Department of Energy fuel price forecasts.[90] The cost-effectiveness for this work plan of –$86/tCO$_2$e was derived by dividing the cumulative discounted costs shown in Table 2 by the cumulative GHG reductions shown in Table 1.

Table 1. GHG Reductions from No-till Practices

Year	**Acres Under No-till (%)**	**New Acreage Under No-till**	**Carbon Sequestered (MMtCO$_2$e)**	**Reduced Volatization from Nitrogen Fertilizer (MMtCO2e)**	**Avoided Diesel Emissions (MMtCO2e)**	**Total Annual GHG Reductions (MMtCO$_2$e)**
2013	64%	44,125	0.03	0.01	0.002	0.04
2014	66%	88,250	0.05	0.02	0.004	0.07
2015	68%	132,375	0.08	0.03	0.007	0.11
2016	70%	176,500	0.11	0.03	0.009	0.15
2017	72%	220,625	0.13	0.04	0.011	0.19
2018	74%	264,750	0.16	0.05	0.013	0.22
2019	76%	308,875	0.19	0.06	0.016	0.26
2020	78%	353,000	0.21	0.07	0.018	0.30
					Total	**1.3**

GHG = greenhouse gas; MMtCO$_2$e = million metric tons of carbon dioxide equivalent; tCO$_2$e = metric tons of carbon dioxide equivalent; gal = gallon.

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[88] USDA, National Agricultural Statistical Service. Ag Census 2007, Table 1. Historical Highlights: 2007 and Earlier Census Years.

[89] Minnesota Department of Agriculture, Agricultural Best Management Practices Loan Program State Revolving Fund Status Report, February 28, 2006.

[90] AEO 2012 early release

Table 2. Costs/Cost Savings of No-till Program

Year	Cost of Funding No- till Equipment ($million)	Reduced Fertilizer Application Savings ($million)	Soil Carbon Offsets ($million)	Reduced Fertilizer Application Savings ($million)	N2O Fertilizer Offsets ($million)	Nutrient Credits ($million)	Diesel Saved ($million)	Net Costs/Cost Savings ($million)	Discounted Costs of Program (5%, 2010$)
2013	$0.717	0.96	0.08	0.96	0.026	0.003	3.67	-$4.02	-$3.47
2014	$1.435	1.92	0.16	1.92	0.052	0.005	7.75	-$8.45	-$6.95
2015	$2.152	2.88	0.24	2.88	0.078	0.008	12.12	-$13.18	-$10.32
2016	$2.870	3.84	0.32	3.84	0.104	0.010	16.43	-$17.83	-$13.30
2017	$3.587	4.80	0.40	4.80	0.130	0.013	20.96	-$22.71	-$16.14
2018	$4.305	5.76	0.48	5.76	0.155	0.015	25.33	-$27.44	-$18.57
2019	$5.022	6.72	0.56	6.72	0.181	0.018	29.84	-$32.29	-$20.81
2020	$5.740	7.68	0.64	7.68	0.207	0.020	34.38	-$37.19	-$22.83
								Total	-$112.40

Table 3 provides an assessment of the cost-effectiveness of this initiative, as expressed in 2010 dollars and assuming an annual discount rate of 5 percent. While the GHG reductions in 2020, as noted in Table 1 and summarized below are modest. this initiative is estimated to provide a cost savings of approximately $76 per ton of CO2 reduced. Carrying forward this effect is projected to result in a cumulative cost-effectiveness of -$85.97 (savings) per ton of CO2.

Table 3. Annual and Cumulative (2013 – 2020) Cost-Effectiveness

Annual 2020			Cumulative 2013-2020		
GHG Reductions (MMtCO2e)	**Cost ($ MM)**	**Cost-effectiveness ($/tCO2e)**	**GHG Reductions (MMtCO2e)**	**NPV (2010 $MM)**	**Cost-effectiveness ($/tCO2e)**
0.30	($22.83)	($76.39)	1.31	($112)	($85.97)

<u>Additional Costs/Benefits:</u>

- Reduction in nitrogen runoff.
- Reduction in erosion of soil by wind and water.
- Better water and nutrient holding capacity, which can lead to reduced synthetic fertilizer use, better water quality, better performance during droughts, and generally "healthier" soil.
- Increased water infiltration.
- Crop profitability is higher in a continuous no-till system.
- No-till provides the most cost-effective solution for reducing erosion and sediment loss.

<u>Implementation Steps:</u>

- Reaching the 78 percent goal will be primarily market-driven, but will be greatly assisted by continuing to offer Resource Enhancement and Protection Program (REAP) tax credits for no-till planting equipment, cost-share incentives for first-time no-tillers, and technical assistance to first-time and inexperienced no-tillers.
- Work with the Pennsylvania Office of the National Agricultural Statistics Service to revise its survey processes to capture additional information regarding no-till practices,

including a methodology to define and capture data on continuous no-till acres and cover crops.

- Encourage the PA No-Till Alliance to learn more about the opportunities of carbon offsets and nutrient credits and how no-till farmers can best access these markets.
- Coordinate a state Continuous No-Till action plan between the PA No-Till Alliance, the Pennsylvania State University Cooperative Extension Service, USDA NRCS, the State Conservation Commission, County Conservation Districts, farm organizations, and conservation/environmental groups.
- Utilize the First Industries Fund (FIF) and REAP tax credits to help farmers purchase no-till equipment. FIF is administered by the PA Department of Community and Economic Development with assistance from the PA Department of Agriculture and the PA Grows Program. REAP is administered through the State Conservation Commission.
- Implement a Core 4 approach to conservation in Pennsylvania. Core 4 is a common-sense approach to improving farm profitability while addressing environmental concerns. The approach is easily adaptable to virtually any farming situation and can be fine-tuned to meet the farmer's unique needs. The net result is better soil, cleaner water, and greater on-farm profits. No-till is a key component of Core 4.
- Secure a National No-Till Conference for the Pennsylvania Farm Show Complex.
- Host a No-till conference highlighting the many benefits and other aspects at the Pennsylvania Farm Show.

By crediting farmers for "carbon-positive" (sequestering) practices, the policy increases the potential for significant biological soil improvement that can, over time, both sequester carbon and reduce soil erosion, which is considered to be another major source of agriculturally released CO_2. Increasing soil carbon greatly improves a soil's ability to absorb and hold water, dramatically increasing yield potential during drought and decreasing flood potential.

CCAC Member Comments:

One member commented as follows:

- Accounting for GHG reductions beginning in 2013 is inappropriate because the work plan is only being proposed in late 2013. Therefore, the work plan cannot be implemented in a timeframe to deliver reductions throughout the year 2013.

Appendix D. Macroeconomic Assessment

The REMI Macroeconometric Model

Several modeling approaches can be used to estimate the total regional economic impacts of environmental policy, including both direct (on-site) effects and various types of indirect (off-site) effects. These include: input-output (I-O), computable generated equilibrium (CGE), mathematical programming (MP), and macroeconometric (ME) models. Each has its own strengths and weaknesses.

The choice of which model to use depends on the purpose of the analysis and various considerations that can be considered as performance criteria, such as accuracy, transparency, manageability, and costs. After careful consideration of these criteria, we chose to use a form of econometric model known as the REMI PI+[91] Model (REMI, 2012). The REMI model is superior to all the others in terms of its forecasting ability and is comparable to CGE models in terms of analytical power and accuracy. The availability of this model for the state of Pennsylvania made it, along with an I-O model, the least costly. With careful explanation of the model, its application, and its results, it can be made as transparent as any of the others.

The REMI model has evolved over the course of 30 years of refinement (see, e.g., Treyz, 1993). It is a (packaged) program, but is built with data that is region-specific. Government agencies in practically every state have used a REMI model for a variety of purposes, including evaluating the impacts of the change in tax rates, the exit or entry of major businesses in particular or economic programs in general, and, more recently, the impacts of energy and/or environmental policy actions.

A macroeconometric forecasting model covers the entire economy, typically in a "top-down" manner, based on macroeconomic aggregate relationships such as consumption and investment. REMI differs in that it includes these key relationships but is based on a more bottom-up approach. In fact, it makes use of the finely-grained sectoring detail of an I-O model, i.e., it divides the economy into 169 sectors, thereby allowing important differentials between them. This is especially important in a context like the Pennsylvania Climate Change Action Plan, where various work plans were fine-tuned to a given sector or where they directly affect several sectors somewhat differently.

The macroeconomic character of the model is able to analyze the interactions between sectors (ordinary multiplier effects) but with some refinement for price changes not found in I-O models. The REMI model also brings into play features of labor and capital markets, as well as trade with other states or countries, including changes in competitiveness.

The econometric feature of the model refers to two considerations. The first is that the model is based on inferential statistical estimation of key parameters based on a time series (historical) data for Pennsylvania (the other candidate models use "calibration," based on a single year's data). This gives the REMI model an additional capability of being better able to extrapolate or forecast the future course of the economy, a capability the other models lack. The major

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[91] PI stands for "Policy Insight".

limitation of the REMI model versus the others is that it is pre-packaged and not readily adjustable to any unique features of the case in point. The other models, because they are based on less data and a less formal estimation procedure, can more readily accommodate data changes in technology that might be inferred, for example from engineering data. However, these adjustments were not needed for the purpose at hand.

The use of the REMI model involves the generation of a baseline forecast of the economy through 2020. Then simulations are run of the changes brought about through the implementation of the various work plans included in the Pennsylvania Climate Change Action Plan. Again, this includes the direct effects in the sectors in which the work plans are implemented, and then the combination of multiplier (purely quantitative interactions) general equilibrium (price-quantity interactions) and macroeconomic (aggregate interactions) impacts. The differences between the baseline and the "counter-factual" simulation represent the total regional economic impacts of the Climate Change Action Plan.

REMI Model Input Development

Before undertaking any economic simulations, the key quantification results for each work plan conducted by the subcommittees are translated to model inputs that can be utilized in the Model. This step involves the selection of appropriate policy levers in the REMI Model to simulate the policy's changes. The input data include sectoral spending and savings over the full time horizon (2013-2020) of the analysis. In Tables D1-D3, we choose one example work plan from each of the RCI, forestry, and transportation sectors to illustrate how we translate, or map, the subcommittees' results into REMI economic variable inputs.

Using residential/commercial Energy Efficiency - Natural Gas work plan as an example, the first two columns of Table E1 show the quantification analysis results of this mitigation work plan according to their applicability to business (commercial and industrial) sectors and the household (residential) sector provided by the RCI subcommittee. The last column of Table D1 presents the corresponding economic variables in the REMI Model and their position within the model (i.e., in which one of the five major blocks, as introduced in Section D of this appendix, the policy variables can be found).

Energy Efficiency refers to programs implemented by the utilities aimed at reducing electricity consumptions in the business and household sectors. For both the commercial and household sectors, the selected REMI policy variables to represent energy savings are from the "compensation, prices, and costs block" and "output and demand block" respectively. For the former, the energy savings are simulated as the decrease of "electricity fuel cost for the commercial sector." For the latter, the energy savings are simulated as the "consumer spending" decrease of gas.

The natural gas consumption reduction from this mitigation work plan would result in a decrease in demand from the gas distribution sector. This is simulated by reducing the "exogenous final demand" from the gas distribution sector in REMI. This variable can be found in the "output and demand block".

Table D1. Mapping the Quantification Results of Res/Com Sector Energy Efficiency - Natural Gas Work Plan into REMI Inputs

Quantification Results		**Policy Variable Selection in REMI**
Natural Gas Savings of the Customers	Commercial Sectors	Compensation, Prices, and Costs Block→ Natural Gas (Commercial Sectors) Fuel Cost (amount) of All Commercial Sectors→Decrease
	Households (Residential Sector)	Output and Demand Block→Consumer Spending (amount)→Gas→Decrease Output and Demand Block →Consumption Reallocation (amount)→All Consumption Sectors →Increase
Natural Gas Demand Decrease from the NG Distribution Sector		Output and Demand Block →Exogenous Final Demand (amount) for Natural Gas Distribution sector→Decrease
NG Customer Outlay on Energy Efficiency (EE)	Commercial Sectors	Compensation, Prices, and Costs Block →Production Cost (amount)→Increase
	Households (Residential Sector)	Output and Demand Block→Consumer Spending (amount)→Kitchen & other household appliances→Increase Output and Demand Block→Consumer Spending (amount)→Owner-occupied nonfarm dwellings→Increase Output and Demand Block →Consumption Reallocation (amount)→All Consumption Sectors →Decrease
Investment on EE Technologies		Output and Demand Block →Exogenous Final Demand (amount) for Construction sector and Ventilation, Heating, Air-conditioning, and Electrical Equipment Manufacturing sector→Increase

The costs of this work plan are the levelized cost of saved natural gas. For commercial sector, the costs would include improved heating, ventilation, and air conditioning (HVAC) equipment, controls and building shell measures, and efficient cooking equipment. The total costs are distributed among the individual commercial sectors based on the reference case natural gas sales to the corresponding sectors. This is simulated in REMI by increasing the value of the "production cost" variable of individual commercial sectors under the "compensation, prices, and costs block". For the residential sector, the costs would involve improvement in space heating efficiency (including adopting insulation measures of the home envelope and investing in more efficient heating and ventilation equipment and systems). These are simulated in REMI by increasing the "consumer spending" on "owner-occupied nonfarm dwellings" and "kitchen & other household appliances" (and decrease in all the other consumptions correspondingly). The "consumer spending" variable can be found in the "output and demand block" in the REMI model.

Finally, the Energy Efficiency program would increase the demand for goods and services from the industries that supply energy-efficiency equipment and appliances and the construction sector. We simulated this in REMI by increasing the "exogenous final demand" from the ventilation, heating, air-conditioning and electrical equipment manufacturing sector and construction sector.

Table D2. Mapping the Quantification Results of the Forestry Sector Urban Forestry Work Plan into REMI Inputs

Quantification Results	Policy Variable Selection in REMI
Spending Stimulation	Output and Demand Block →Exogenous Final Demand (amount) for Nursery→Increase
Cost of Urban Forestry[a]	Reduction of Government Spending Elsewhere: Output and Demand Block →State Government spending (amount) → Decrease
	Residential Sector: Output and Demand Block→Consumer Spending (amount)→Other household operation→Increase Output and Demand Block →Consumption Reallocation (amount)→All Consumption Categories →Decrease
Energy Savings (reduction in electricity consumption)	Compensation, Prices, and Costs Block(Electricity (Commercial Sectors) Fuel Cost (amount) of All Commercial Sectors (Decrease Output and Demand Block(Consumer Spending (amount)(Electricity)-Decrease Output and Demand Block (Consumption Reallocation (amount)(All Consumption Categories)-Increase
Electricity Demand Decrease from the Utility Sector	Output and Demand Block (Exogenous Final Demand (amount) for Electric Power Generation, Transmission, and Distribution sector→Decrease
Non-pecuniary Benefits	Output and Demand Block (exogenous Final Demand (amount) for non-pecuniary effects- increase

[a] We assume that one-third of the program funding comes from the state government budget. The other two-thirds will be borne by the commercial sector and residential sector.

Table D3. Mapping the Quantification Results of the Transportation Sector Cutting Emissions from Freight Transportation Work Plan into REMI Inputs

TWGs Quantification Results	Policy Variable Selection in REMI
Cost of Cutting Emissions from Freight Transportation	Compensation, Prices, and Costs Block→Production Cost of Truck Transportation sector→Increase Compensation, Prices, and Costs Block→Production Cost of Rail Transportation sector→Increase
Investment to Improve Freight Movement Efficiencies	Output and Demand Block (Exogenous Final Demand (amount) for Motor Vehicle Body and Trailer Manufacturing sector)- Increase Output and Demand Block (Exogenous Final Demand (amount) for Other rail equipment mfg)- Increase
Fuel Savings from Improved Freight Movement Efficiencies	Compensation, Prices, and Costs Block (Residual Fuel Cost for Truck Transportation sector)- Decrease Compensation, Prices, and Costs Block (Residual Fuel Cost for Rail Transportation sector)- Decrease
Fuel Demand Decrease	Output and Demand Block (Exogenous Final Demand (amount) for Petroleum and Coal Products Manufacturing sector)- Decrease

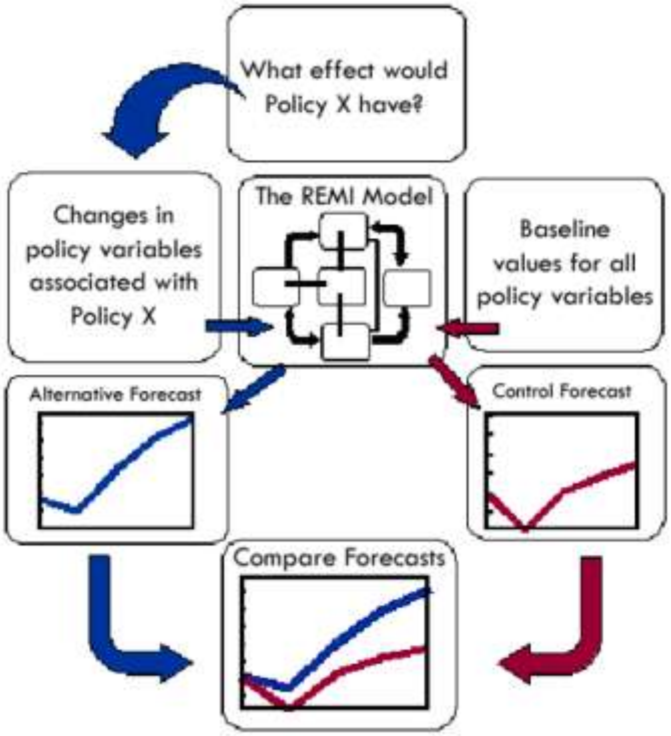
Simulation Set-up in REMI

Figure E1 shows how a policy simulation process is undertaken in the REMI model. First, a policy question is formulated (e.g., what would be the economic impacts of implementing Energy Efficiency - Natural Gas in the state. Second, external policy variables that would embody the effects of the policy are identified (take Energy Efficiency - Natural Gas as an example), relevant policy variables would include incremental costs and investment in energy efficient appliances; final demand increase in the sectors that produce the equipment and appliances; and the avoided consumption of natural gas. Third, baseline values for all the policy variables are used to generate the control forecast (baseline forecast). In REMI, the baseline forecast uses the most recent data available (i.e., 2012 data) for the study region and the external policy variables are set equal to their baseline values.

Fourth, an alternative forecast is generated by changing the values of the external policy variables. Usually, the changing values of these variables represent the direct effects of the simulated policy scenario. For example, in our analysis of the Energy Efficiency - Natural Gas natural gas work plan, the costs to the commercial and residential sectors and the avoided consumption of natural gas were based on the technical assessment of implementing this mitigation work plan. Fifth, the effects of the policy scenario are measured by comparing the baseline forecast and the alternative forecast. Sensitivity analysis can be undertaken by running a series of alternative forecasts with different assumptions on the values of the policy variables.

In this study, we first run the REMI model for each of the 31 quantified work plans individually in a comparative static manner, i.e., one at a time, holding everything else constant. Next, we run a simultaneous simulation in which we assume that all the work plans are implemented together. Then the simple summation of the effects of individual work plans is compared to the simultaneous simulation results to determine whether the “whole” is different from the “sum” of the parts. Differences can arise from non-linearities and/or synergies. The latter would stem from complex functional relationships in the REMI model. Before performing the simulations in REMI, overlaps between work plans within the same sector and across different sectors are eliminated.

Figure D1. Process of Policy Simulation in REMI



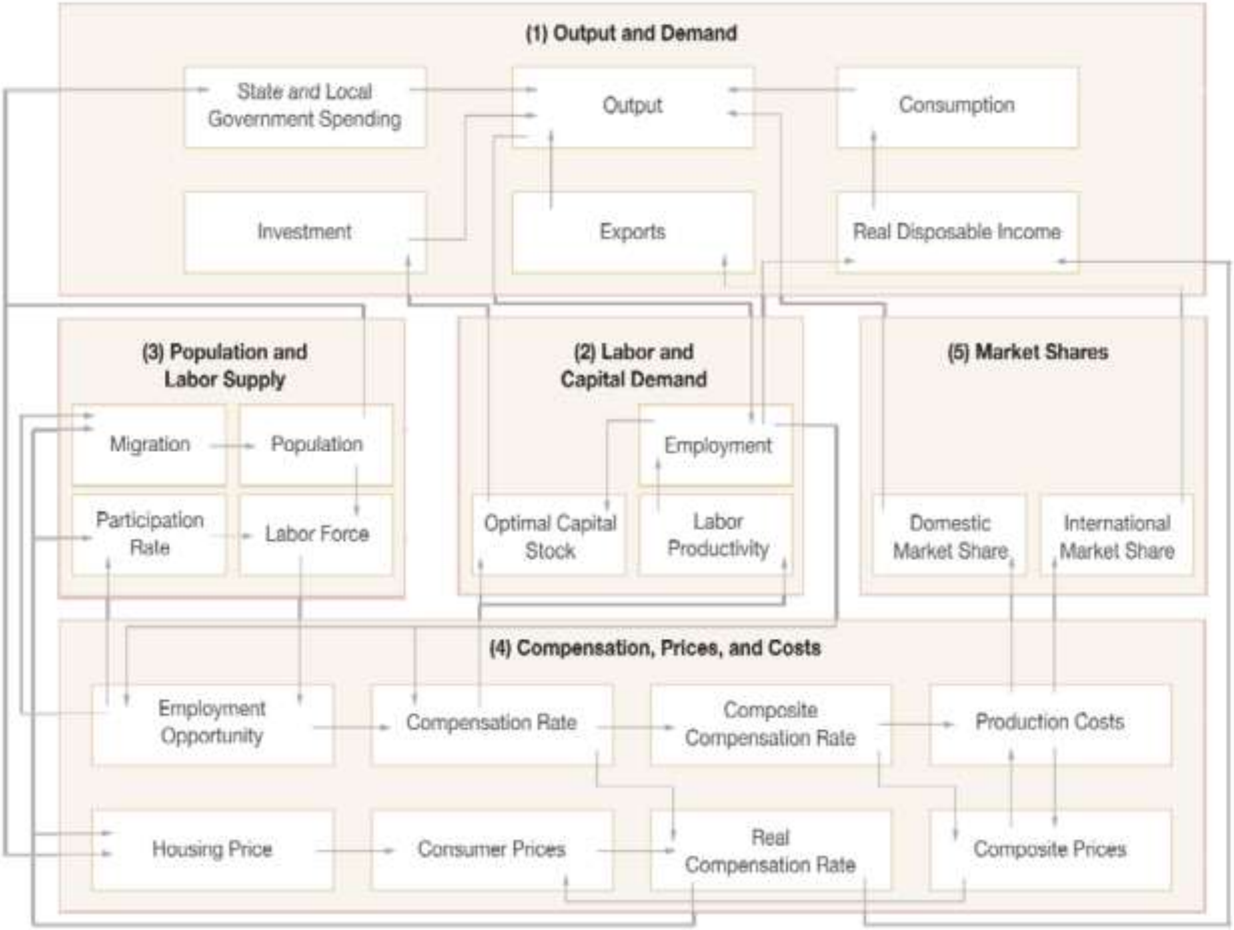
Description of the REMI PI+ Model

REMI PI+ is a structural economic forecasting and policy analysis model. It integrates input-output, computable general equilibrium, econometric and economic geography methodologies. The model is dynamic, with forecasts and simulations generated on an annual basis and behavioral responses to wage, price, and other economic factors.

The REMI model consists of thousands of simultaneous equations with a structure that is relatively straightforward. The exact number of equations used varies depending on the extent of industry, demographic, demand, and other detail in the model. The overall structure of the model can be summarized in five major blocks: (1) output and demand, (2) labor and capital demand, (3) population and labor supply, (4) compensation, prices and costs, and (5) market shares. The blocks and their key interactions are shown in Figures D2 and D3.

The output and demand block includes output, demand, consumption, investment, government spending, import, product access and export concepts. Output for each industry is determined by industry demand in a given region and its trade with the US market, and international imports and exports. For each industry, demand is determined by the amount of output, consumption, investment, and capital demand on that industry. Consumption depends on real disposable income per capita, relative prices, differential income elasticities and population. Input productivity depends on access to inputs because the larger the choice set of inputs, the more likely that the input with the specific characteristics required for the job will be formed. In the capital stock adjustment process, investment occurs to fill the difference between optimal and actual capital stock for residential, non-residential and equipment investment. Government spending changes are determined by changes in the population.

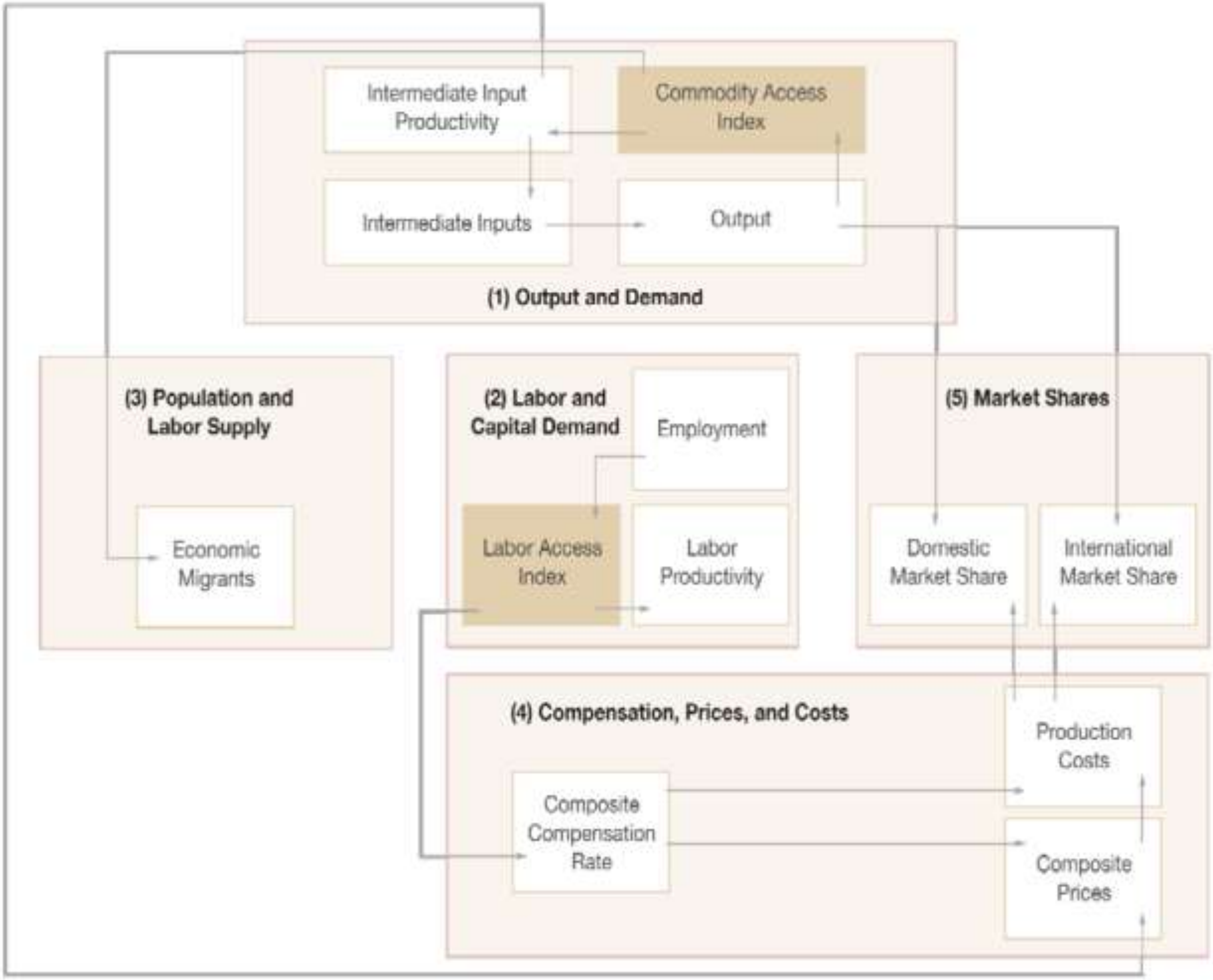
Figure D2. REMI Model Linkages (Excluding Economic Geography Linkages)



The labor and capital demand block includes the determination of labor productivity, labor intensity and the optimal capital stocks. Industry-specific labor productivity depends on the availability of workers with differentiated skills for the occupations used in each industry. The occupational labor supply and commuting costs determine firms' access to a specialized labor force.

Labor intensity is determined by the cost of labor relative to the other factor inputs, capital and fuel. Demand for capital is driven by the optimal capital stock equation for both non-residential capital and equipment. Optimal capital stock for each industry depends on the relative cost of labor and capital, and the employment weighted by capital use for each industry. Employment in private industries is determined by the value added and employment per unit of value added in each industry.

Figure D3. Economic Geography Linkages



The population and labor supply block includes detailed demographic information about the region. Population data is given for age and gender, with birth and survival rates for each group. The size and labor force participation rate of each group determines the labor supply. These participation rates respond to changes in employment relative to the potential labor force and to changes in the real after tax compensation rate. Migration includes retirement, military, international and economic migration. Economic migration is determined by the relative real after tax compensation rate, relative employment opportunity and consumer access to variety.

The compensation, prices and costs block includes delivered prices, production costs, equipment cost, the consumption deflator, consumer prices, the price of housing and the wage equation. Economic geography concepts account for the productivity and price effects of access to specialized labor, goods and services.

These prices measure the value of the industry output, taking into account the access to production locations. This access is important due to the specialization of production that takes place within each industry, and because transportation and transaction costs associated with distance are significant. Composite prices for each industry are then calculated based on the production costs of supplying regions, the effective distance to these regions, and the index of access to the variety of output in the industry relative to the access by other uses of the product. The cost of production for each industry is determined by cost of labor, capital, fuel and intermediate inputs. Labor costs reflect a productivity adjustment to account for access to specialized labor, as well as underlying compensation rates. Capital costs include costs of non-residential structures and equipment, while fuel costs incorporate electricity, natural gas and residual fuels.

The consumption deflator converts industry prices to prices for consumption commodities. For potential migrants, the consumer price is additionally calculated to include housing prices. Housing price changes from their initial level depend on changes in income and population density. Regional employee compensation changes are due to changes in labor demand and supply conditions, and changes in the national compensation rate. Changes in employment opportunities relative to the labor force and occupational demand change determine compensation rates by industry.

The market shares equations measure the proportion of local and export markets that are captured by each industry. These depend on relative production costs, the estimated price elasticity of demand and effective distance between the home region and each of the other regions. The change in share of a specific area in any region depends on changes in its delivered price and the quantity it produces compared with the same factors for competitors in that market. The share of local and external markets then drives the exports from and imports to the home economy.

As shown in Figure D3, the labor and capital demand block includes labor intensity and productivity, as well as demand for labor and capital. Labor force participation rate and migration equations are in the population and labor supply block. The compensation, prices and costs block includes composite prices, determinants of production costs, the consumption price deflator, housing prices, and the wage equations. The proportion of local, interregional and international markets captured by each region is included in the market shares block.

Detailed REMI Model Simulation Results of Selected Work Plans

Tables D4 and D5 show the detailed simulation results of two work plans, commission buildings and combined heat and power (CHP), for each year between 2013 and 2020. Dollars are shown in 2012 millions, and employment is shown in thousands of net jobs.

Table D4. Detailed Simulation Results of Work Plan - Commission Buildings

Differences from BAU Levels	2013	2014	2015	2016	2017	2018	2019	2020
Total Employment	0.93	1.18	1.45	1.74	2.04	2.06	2.05	2.04
Gross Domestic Product	0.01	0.02	0.03	0.04	0.05	0.06	0.06	0.07
Output	0.03	0.04	0.05	0.07	0.09	0.10	0.11	0.13
Disposable Personal Income	0.03	0.05	0.07	0.09	0.11	0.13	0.13	0.14
Real Disposable Personal Income per	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Capita								
State Revenues at State Average Rates	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Population	0.27	0.58	0.93	1.32	1.73	2.10	2.42	2.70
PCE-Price Index	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01
BAU	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Employment	7,454	7,612	7,776	7,952	8,130	8,275	8,374	8,448
Gross Domestic Product	660	680	701	723	745	768	788	804
Output	1,160	1,192	1,224	1,257	1,289	1,324	1,354	1,383
Disposable Personal Income	607	642	679	720	763	809	846	879
Real Disposable Personal Income per Capita	42	43	44	46	47	49	50	50
State Revenues at State Average Rates	72	74	75	76	77	78	79	81
Population	12,908	12,994	13,083	13,177	13,276	13,379	13,488	13,601
PCE-Price Index	112	114	117	119	121	124	127	129
Percent Difference from BAU Levels	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Employment	0.00012	0.00015	0.00019	0.00022	0.00025	0.00025	0.00024	0.00024
Gross Domestic Product	0.00002	0.00003	0.00004	0.00005	0.00007	0.00008	0.00008	0.00009
Output	0.00002	0.00003	0.00004	0.00005	0.00007	0.00008	0.00008	0.00009
Disposable Personal Income	0.00006	0.00008	0.00010	0.00012	0.00015	0.00015	0.00016	0.00016
Real Disposable Personal Income per Capita	0.00006	0.00006	0.00006	0.00006	0.00006	0.00004	0.00002	0.00000
State Revenues at State Average Rates	0.00006	0.00008	0.00010	0.00012	0.00014	0.00015	0.00015	0.00016
Population	0.00002	0.00005	0.00007	0.00010	0.00013	0.00016	0.00018	0.00020
PCE-Price Index	-0.00002	-0.00002	-0.00003	-0.00003	-0.00004	-0.00004	-0.00004	-0.00004

Note: BAU = business as usual.

Table D5. Detailed Simulation Results of Work Plan - Combined Heat and Power

CHP Differences from BAU Levels	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Employment	-1.11	-2.57	-4.96	-7.24	-9.62	-12.03	-14.36	-16.71
Gross Domestic Product	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.02
Output	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Disposable Personal Income	-0.01	-0.02	-0.04	-0.07	-0.10	-0.14	-0.17	-0.22
Real Disposable Personal Income per Capita	6.77	5.79	5.31	4.74	4.34	4.03	3.66	3.32
State Revenues at State Average Rates	12.15	8.38	6.19	4.97	4.20	3.63	3.12	2.70
Population	-0.57	-1.63	-3.43	-5.69	-8.37	-11.44	-14.87	-18.62

PCE-Price Index	0.02	0.03	0.05	0.06	0.08	0.09	0.10	0.12
BAU	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Employment	7,454	7,612	7,776	7,952	8,130	8,275	8,374	8,448
Gross Domestic Product	660	2,570	2,705	2,851	3,001	3,149	3,268	3,362
Output	103	402	426	451	476	504	528	551
Disposable Personal Income	94	101	107	114	121	129	137	144
Real Disposable Personal Income per Capita	39	11	11	12	12	13	13	13
State Revenues at State Average Rates	30	8	8	8	8	8	7	7
Population	12,908	12,994	13,083	13,177	13,276	13,379	13,488	13,601
PCE-Price Index	112	114	117	119	121	124	127	129
Percent Difference from BAU Levels	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Total Employment	-0.000	-0.000	-0.001	-0.001	-0.001	-0.001	-0.002	-0.002
Gross Domestic Product	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Output	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Disposable Personal Income	-0.000	-0.000	-0.000	-0.001	-0.001	-0.001	-0.001	-0.002
Real Disposable Personal Income per Capita	0.176	0.537	0.475	0.409	0.361	0.322	0.285	0.254
State Revenues at State Average Rates	0.411	1.062	0.794	0.644	0.550	0.480	0.419	0.370
Population	-0.000	-0.000	-0.000	-0.000	-0.001	-0.001	-0.001	-0.001
PCE-Price Index	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001

Note: BAU = business as usual.

GSP and Employment Impacts of Individual Economic Sectors

Tables D6 and D7 show the potential sectoral-level GSP and employment impacts, respectively, associated with the simultaneous analysis of the work plans combined after adjusting for overlaps. In Table D7, the high employment results for the agriculture and forest sectors are from investments for implementing the reforestation and durable wood products work plans, which re-establish the forest products industry on neglected lands.

Table D6. Sectoral GSP Impacts of the Pennsylvania Climate Action Plan—Simultaneous Simulation (Billions of Fixed 2012$)

					Discount Rate		
					0.05	**0.03**	**0.07**
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Forestry; Fishing, hunting, trapping	0.18	0.27	0.30	0.33	1.40	1.55	1.28
Logging	0.13	0.11	0.11	0.11	0.81	0.87	0.75
Support activities for agriculture and forestry	0.06	0.09	0.10	0.11	0.48	0.53	0.44
Oil and gas extraction	0.00	0.00	0.00	0.00	-0.03	-0.03	-0.02

					Discount Rate		
					0.05	0.03	0.07
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Coal mining	0.01	0.00	0.00	0.00	0.04	0.04	0.03
Metal ore mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral mining and quarrying	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Support activities for mining	0.00	-0.01	-0.01	-0.01	-0.03	-0.04	-0.03
Electric power generation, transmission, and distribution	-0.64	-0.95	-1.00	-1.03	-4.68	-5.16	-4.26
Natural gas distribution	-0.01	0.00	0.00	0.00	-0.05	-0.05	-0.04
Water, sewage, and other systems	-0.01	-0.01	-0.01	-0.01	-0.05	-0.06	-0.05
Construction	0.18	0.17	0.15	0.10	0.94	1.02	0.86
Sawmills and wood preservation	0.00	0.00	0.00	-0.01	-0.02	-0.02	-0.02
Veneer, plywood, and engineered wood product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Other wood product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.02	-0.01
Clay product and refractory manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Glass and glass product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Cement and concrete product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lime, gypsum product manufacturing; Other nonmetallic mineral product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Iron and steel mills and ferroalloy manufacturing	0.00	-0.01	-0.01	-0.02	-0.05	-0.06	-0.04
Steel product manufacturing from purchased steel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Alumina and aluminum production and processing	0.00	0.00	0.00	-0.01	-0.02	-0.02	-0.01
Nonferrous metal (except aluminum) production and processing	0.00	0.00	0.00	0.00	0.00	-0.01	0.00
Foundries	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Forging and stamping	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cutlery and hand tool manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Architectural and structural metals manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Boiler, tank, and shipping container manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hardware manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Spring and wire product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machine shops; turned product; and screw, nut, and bolt manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	0.00
Coating, engraving, heat treating, and allied activities	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other fabricated metal product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agriculture, construction, and mining machinery manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial machinery manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial and service industry machinery manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Ventilation, heating, air-conditioning, and commercial refrigeration equipment manufacturing	0.00	0.00	0.00	0.00	0.01	0.02	0.01
Metalworking machinery manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00

					Discount Rate		
					0.05	0.03	0.07
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Engine, turbine, power transmission equipment manufacturing	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Other general purpose machinery manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	0.00
Computer and peripheral equipment manufacturing	0.00	-0.01	-0.01	-0.01	-0.03	-0.03	-0.03
Communications equipment manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Audio and video equipment manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Semiconductor and other electronic component manufacturing	0.00	-0.01	-0.01	-0.01	-0.02	-0.03	-0.02
Navigational, measuring, electromedical, and control instruments manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Manufacturing and reproducing magnetic and optical media	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric lighting equipment manufacturing	0.01	0.01	0.01	0.01	0.07	0.08	0.07
Household appliance manufacturing	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Electrical equipment manufacturing	0.00	0.01	0.01	0.01	0.03	0.03	0.02
Other electrical equipment and component manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicle manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicle body and trailer manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicle parts manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aerospace product and parts manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Railroad rolling stock manufacturing	0.00	0.00	0.00	0.00	0.01	0.02	0.01
Ship and boat building	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Household and institutional furniture and kitchen cabinet manufacturing	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02
Office furniture (including fixtures) manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Other furniture related product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Medical equipment and supplies manufacturing	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.02
Other miscellaneous manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Animal food manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain and oilseed milling	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sugar and confectionery product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Fruit and vegetable preserving and specialty food manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	0.00
Dairy product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Animal slaughtering and processing	0.00	0.00	0.00	0.00	0.00	-0.01	0.00
Seafood product preparation and packaging	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bakeries and tortilla manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Other food manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Beverage manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tobacco manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00

					Discount Rate		
					0.05	0.03	0.07
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Fiber, yarn, and thread mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabric mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile and fabric finishing and fabric coating mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile furnishings mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other textile product mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel knitting mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cut and sew apparel manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel accessories and other apparel manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Leather, hide tanning, finishing; Other leather, allied product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Footwear manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pulp, paper, and paperboard mills	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Converted paper product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Printing and related support activities	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Petroleum and coal products manufacturing	-0.01	-0.01	-0.02	-0.02	-0.06	-0.07	-0.06
Basic chemical manufacturing	0.00	-0.01	-0.01	-0.01	-0.03	-0.04	-0.03
Resin, synthetic rubber, and artificial synthetic fibers and filaments manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Pesticide, fertilizer, and other agricultural chemical manufacturing	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Pharmaceutical and medicine manufacturing	-0.01	-0.01	-0.02	-0.02	-0.06	-0.07	-0.06
Paint, coating, and adhesive manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap, cleaning compound, and toilet preparation manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical product and preparation manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Plastics product manufacturing	0.00	-0.01	-0.01	-0.01	-0.03	-0.03	-0.02
Rubber product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wholesale trade	-0.01	-0.09	-0.13	-0.18	-0.35	-0.39	-0.30
Retail trade	-0.07	-0.21	-0.28	-0.35	-0.93	-1.05	-0.84
Air transportation	0.00	0.00	0.00	-0.01	0.00	-0.01	0.00
Rail transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Water transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Couriers and messengers	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Transit and ground passenger transportation	0.00	-0.01	-0.02	-0.02	-0.05	-0.06	-0.05
Pipeline transportation	0.00	0.00	-0.01	-0.01	-0.02	-0.03	-0.02
Scenic and sightseeing transportation and support activities for transportation	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Warehousing and storage	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Newspaper, periodical, book, and directory publishers	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.01
Software publishers	-0.01	-0.02	-0.02	-0.03	-0.08	-0.09	-0.07
Motion picture, video, and sound recording industries	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Data processing, hosting, related services, and other information services	0.00	-0.01	-0.02	-0.03	-0.06	-0.06	-0.05
Broadcasting (except internet)	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01

					Discount Rate		
					0.05	0.03	0.07
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Telecommunications	0.00	-0.02	-0.02	-0.04	-0.06	-0.07	-0.05
Monetary authorities, credit intermediation, and related activities	0.00	-0.02	-0.04	-0.05	-0.08	-0.10	-0.07
Funds, trusts, and other financial vehicles	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Securities, commodity contracts, and other financial investments and related activities	0.00	-0.01	-0.02	-0.03	-0.06	-0.06	-0.05
Insurance carriers	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Agencies, brokerages, and other insurance related activities	0.00	0.00	0.00	0.00	-0.01	-0.01	0.00
Real estate	-0.01	-0.12	-0.19	-0.29	-0.50	-0.57	-0.44
Automotive equipment rental and leasing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Consumer goods rental and general rental centers	0.00	0.00	0.00	0.00	0.00	-0.01	0.00
Commercial and industrial machinery and equipment rental and leasing	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lessors of nonfinancial intangible assets (except copyrighted works)	0.00	-0.01	-0.01	-0.02	-0.03	-0.04	-0.03
Legal services	0.00	-0.01	-0.01	-0.01	-0.03	-0.03	-0.02
Accounting, tax preparation, bookkeeping, and payroll services	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Architectural, engineering, and related services	0.01	0.01	0.01	0.00	0.06	0.07	0.06
Specialized design services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Computer systems design and related services	-0.01	-0.02	-0.03	-0.05	-0.10	-0.11	-0.09
Management, scientific, and technical consulting services	0.00	-0.01	-0.01	-0.02	-0.04	-0.04	-0.03
Scientific research and development services	0.00	0.00	0.00	-0.01	0.01	0.01	0.01
Advertising and related services	0.00	-0.01	-0.01	-0.01	-0.02	-0.03	-0.02
Other professional, scientific, and technical services	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.01
Management of companies and enterprises	0.00	-0.04	-0.06	-0.09	-0.17	-0.19	-0.15
Office administrative services; Facilities support services	0.00	0.00	0.00	0.00	-0.01	-0.01	0.00
Employment services	0.00	-0.01	-0.01	-0.02	-0.03	-0.03	-0.02
Business support services; Investigation and security services; Other support services	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02
Travel arrangement and reservation services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Services to buildings and dwellings	0.04	0.07	0.08	0.08	0.30	0.33	0.27
Waste management and remediation services	0.01	0.00	0.00	0.00	0.03	0.03	0.03
Elementary and secondary schools; Junior colleges, colleges, universities, and professional schools; Other educational services	0.01	0.01	0.00	0.00	0.04	0.04	0.04
Offices of health practitioners	0.02	-0.01	-0.03	-0.05	0.01	0.01	0.02
Outpatient, laboratory, and other ambulatory care services	0.00	0.00	0.00	0.00	0.02	0.02	0.02
Home health care services	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Hospitals	0.01	0.00	-0.01	-0.03	0.02	0.01	0.02
Nursing and residential care facilities	0.01	0.00	0.00	-0.01	0.02	0.02	0.02

					Discount Rate		
					0.05	0.03	0.07
Sector	**2015**	**2018**	**2019**	**2020**	**NPV**	**NPV**	**NPV**
Individual, family, community, and vocational rehabilitation services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Child day care services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Performing arts companies; Promoters of events, and agents and managers	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Spectator sports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Independent artists, writers, and performers	0.00	0.00	0.00	0.00	0.02	0.02	0.01
Museums, historical sites, and similar institutions	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Amusement, gambling, and recreation industries	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Accommodation	0.00	-0.01	-0.01	-0.02	-0.02	-0.02	-0.02
Food services and drinking places	0.01	0.00	-0.01	-0.03	0.00	0.00	0.00
Automotive repair and maintenance	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Electronic and precision equipment repair and maintenance	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Commercial and industrial equipment (except automotive and electronic) repair and maintenance	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Personal and household goods repair and maintenance	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Personal care services	0.00	0.00	0.00	-0.01	0.00	-0.01	0.00
Death care services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Drycleaning and laundry services	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other personal services	0.00	0.00	0.00	-0.01	0.00	0.00	0.00
Religious organizations; Grantmaking and giving services, and social advocacy organizations	0.00	0.00	0.00	0.00	0.00	0.01	0.00
Civic, social, professional, and similar organizations	0.00	0.00	0.00	0.00	0.01	0.01	0.01
Private households	0.00	0.00	0.00	0.00	0.02	0.02	0.02
Total	**-0.09**	**-1.04**	**-1.46**	**-2.03**	**-3.78**	**-4.33**	**-3.31**

* The total represents the sum of all the sectoral effects. The totals shown in this table differ from the simultaneous solutions shown in the last row of Table 4.2 in Chapter 4. The gap between the two is public employment, as well as rounding error.

Table D7. Sectoral Employment Impacts of the Pennsylvania Climate Action Plan — Simultaneous Simulation (in thousands)

Sector	2013	2014	2015	2016	2017	2018	2019	2020
Forestry; Fishing, hunting, trapping	3.82	4.99	6.17	7.36	8.56	9.70	10.83	11.85
Logging	7.45	7.01	6.78	6.68	6.66	6.65	6.57	6.49
Support activities for agriculture and forestry	5.72	6.76	7.73	8.74	9.77	10.76	11.87	12.94
Oil and gas extraction	-0.03	-0.05	-0.05	-0.05	-0.05	-0.05	-0.06	-0.06
Coal mining	0.12	0.09	0.07	0.05	0.04	0.01	0.01	-0.01
Metal ore mining	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nonmetallic mineral mining and quarrying	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.02
Support activities for mining	-0.01	-0.02	-0.04	-0.05	-0.07	-0.08	-0.10	-0.12
Electric power generation, transmission, and distribution	-0.58	-1.01	-1.17	-1.30	-1.41	-1.60	-1.60	-1.58
Natural gas distribution	-0.07	-0.06	-0.05	-0.04	-0.04	-0.02	-0.01	0.03
Water, sewage, and other systems	-0.03	-0.04	-0.05	-0.06	-0.07	-0.08	-0.08	-0.09
Construction	1.92	1.91	3.35	3.24	3.15	2.84	2.51	1.66
Sawmills and wood preservation	-0.01	-0.03	-0.04	-0.05	-0.05	-0.06	-0.06	-0.06
Veneer, plywood, and engineered wood product manufacturing	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02
Other wood product manufacturing	-0.01	-0.01	-0.02	-0.03	-0.04	-0.05	-0.06	-0.06
Clay product and refractory manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Glass and glass product manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Cement and concrete product manufacturing	0.01	0.01	0.01	0.00	0.00	-0.01	-0.01	-0.02
Lime, gypsum product manufacturing; Other nonmetallic mineral product manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Iron and steel mills and ferroalloy manufacturing	0.00	-0.01	-0.02	-0.03	-0.04	-0.06	-0.07	-0.08
Steel product manufacturing from purchased steel	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02
Alumina and aluminum production and processing	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03
Nonferrous metal (except aluminum) production and processing	0.00	-0.01	-0.01	-0.02	-0.03	-0.04	-0.05	-0.06
Foundries	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.02
Forging and stamping	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Cutlery and handtool manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Architectural and structural metals manufacturing	0.02	0.01	0.02	0.02	0.01	0.00	0.00	-0.01
Boiler, tank, and shipping container manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Hardware manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Spring and wire product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Machine shops; turned product; and screw, nut, and bolt manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02
Coating, engraving, heat treating, and allied activities	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Other fabricated metal product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Agriculture, construction, and mining machinery manufacturing	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Industrial machinery manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Commercial and service industry machinery manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01
Ventilation, heating, air-conditioning, and commercial refrigeration equipment manufacturing	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01

Sector	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Metalworking machinery manufacturing	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02	-0.03
Engine, turbine, power transmission equipment manufacturing	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other general purpose machinery manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02
Computer and peripheral equipment manufacturing	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03
Communications equipment manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Audio and video equipment manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Semiconductor and other electronic component manufacturing	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03	-0.04
Navigational, measuring, electromedical, and control instruments manufacturing	0.00	0.00	-0.01	-0.02	-0.02	-0.02	-0.03	-0.04
Manufacturing and reproducing magnetic and optical media	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric lighting equipment manufacturing	0.19	0.17	0.15	0.14	0.12	0.11	0.10	0.07
Household appliance manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electrical equipment manufacturing	0.03	0.03	0.02	0.03	0.03	0.06	0.07	0.09
Other electrical equipment and component manufacturing	0.02	0.01	0.00	0.00	-0.01	-0.01	-0.02	-0.03
Motor vehicle manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor vehicle body and trailer manufacturing	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00
Motor vehicle parts manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aerospace product and parts manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02
Railroad rolling stock manufacturing	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.00
Ship and boat building	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other transportation equipment manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02
Household and institutional furniture and kitchen cabinet manufacturing	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03	-0.04
Office furniture (including fixtures) manufacturing	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02
Other furniture related product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Medical equipment and supplies manufacturing	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.04
Other miscellaneous manufacturing	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02
Animal food manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Grain and oilseed milling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sugar and confectionery product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Fruit and vegetable preserving and specialty food manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Dairy product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Animal slaughtering and processing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.02	-0.02
Seafood product preparation and packaging	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bakeries and tortilla manufacturing	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03	-0.03
Other food manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02
Beverage manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Tobacco manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fiber, yarn, and thread mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fabric mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile and fabric finishing and fabric coating mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Textile furnishings mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other textile product mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Apparel knitting mills	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cut and sew apparel manufacturing	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01
Apparel accessories and other apparel	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Sector	2013	2014	2015	2016	2017	2018	2019	2020
manufacturing								
Leather, hide tanning, finishing; Other leather, allied product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Footwear manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pulp, paper, and paperboard mills	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Converted paper product manufacturing	0.00	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01
Printing and related support activities	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03
Petroleum and coal products manufacturing	-0.02	-0.03	-0.04	-0.04	-0.05	-0.06	-0.06	-0.07
Basic chemical manufacturing	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02
Resin, synthetic rubber, and artificial synthetic fibers and filaments manufacturing	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Pesticide, fertilizer, and other agricultural chemical manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Pharmaceutical and medicine manufacturing	0.00	0.00	-0.01	-0.02	-0.03	-0.03	-0.04	-0.05
Paint, coating, and adhesive manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Soap, cleaning compound, and toilet preparation manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other chemical product and preparation manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Plastics product manufacturing	0.00	0.00	-0.01	-0.02	-0.03	-0.04	-0.06	-0.07
Rubber product manufacturing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Wholesale trade	0.09	0.08	-0.04	-0.17	-0.31	-0.45	-0.65	-0.86
Retail trade	-0.39	-0.47	-1.16	-1.78	-2.41	-2.97	-3.80	-4.53
Air transportation	0.01	0.01	0.00	0.00	-0.01	-0.02	-0.03	-0.05
Rail transportation	-0.01	-0.02	-0.03	-0.03	-0.04	-0.05	-0.07	-0.08
Water transportation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Truck transportation	-0.01	-0.05	-0.08	-0.13	-0.17	-0.21	-0.26	-0.30
Couriers and messengers	0.00	0.00	-0.01	-0.02	-0.02	-0.03	-0.03	-0.04
Transit and ground passenger transportation	-0.01	-0.04	-0.09	-0.15	-0.22	-0.29	-0.36	-0.44
Pipeline transportation	0.00	-0.01	-0.01	-0.01	-0.01	-0.02	-0.02	-0.02
Scenic and sightseeing transportation and support activities for transportation	0.00	-0.01	-0.02	-0.03	-0.04	-0.05	-0.07	-0.08
Warehousing and storage	0.00	0.01	-0.03	-0.08	-0.14	-0.21	-0.29	-0.41
Newspaper, periodical, book, and directory publishers	0.00	0.00	-0.02	-0.02	-0.03	-0.04	-0.06	-0.07
Software publishers	0.00	-0.01	-0.01	-0.02	-0.03	-0.03	-0.04	-0.06
Motion picture, video, and sound recording industries	0.00	0.00	0.00	-0.01	-0.01	-0.01	-0.01	-0.01
Data processing, hosting, related services, and other information services	0.00	0.00	-0.02	-0.03	-0.05	-0.07	-0.09	-0.12
Broadcasting (except internet)	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.03
Telecommunications	0.00	0.00	-0.01	-0.02	-0.03	-0.04	-0.06	-0.07
Monetary authorities, credit intermediation, and related activities	0.03	0.04	0.01	-0.02	-0.05	-0.08	-0.12	-0.17
Funds, trusts, and other financial vehicles	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Securities, commodity contracts, and other financial investments and related activities	0.00	0.00	-0.03	-0.06	-0.09	-0.12	-0.16	-0.21
Insurance carriers	0.01	0.01	0.01	0.01	0.00	0.00	-0.01	-0.02
Agencies, brokerages, and other insurance related activities	0.00	0.00	-0.01	-0.01	-0.02	-0.02	-0.02	-0.03
Real estate	0.03	0.09	-0.07	-0.24	-0.44	-0.60	-0.89	-1.27
Automotive equipment rental and leasing	0.00	0.00	0.00	0.00	0.00	0.00	-0.01	-0.01
Consumer goods rental and general rental centers	0.01	0.01	0.00	-0.01	-0.02	-0.04	-0.05	-0.07

Sector	2013	2014	2015	2016	2017	2018	2019	2020
Commercial and industrial machinery and equipment rental and leasing	0.01	0.01	0.01	0.00	0.00	0.00	0.00	-0.01
Lessors of nonfinancial intangible assets (except copyrighted works)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-0.01
Legal services	0.01	0.01	-0.01	-0.03	-0.06	-0.09	-0.12	-0.17
Accounting, tax preparation, bookkeeping, and payroll services	0.02	0.02	0.00	-0.02	-0.05	-0.07	-0.11	-0.16
Architectural, engineering, and related services	0.12	0.13	0.17	0.15	0.13	0.10	0.02	-0.10
Specialized design services	0.00	0.01	0.00	-0.01	-0.01	-0.02	-0.03	-0.05
Computer systems design and related services	-0.01	-0.04	-0.10	-0.17	-0.26	-0.37	-0.51	-0.69
Management, scientific, and technical consulting services	0.00	0.01	-0.02	-0.05	-0.10	-0.14	-0.20	-0.28
Scientific research and development services	0.00	0.01	0.00	-0.01	-0.02	-0.04	-0.07	-0.11
Advertising and related services	-0.01	-0.01	-0.03	-0.04	-0.06	-0.07	-0.09	-0.11
Other professional, scientific, and technical services	0.00	0.00	-0.01	-0.03	-0.05	-0.06	-0.08	-0.10
Management of companies and enterprises	0.01	-0.01	-0.06	-0.12	-0.18	-0.24	-0.31	-0.39
Office administrative services; Facilities support services	0.00	0.00	0.00	-0.01	-0.02	-0.03	-0.05	-0.07
Employment services	0.01	0.02	-0.01	-0.05	-0.09	-0.13	-0.20	-0.28
Business support services; Investigation and security services; Other support services	0.01	0.01	-0.04	-0.09	-0.15	-0.22	-0.30	-0.40
Travel arrangement and reservation services	0.00	0.01	0.00	0.00	0.00	0.00	-0.01	-0.02
Services to buildings and dwellings	0.23	0.45	0.57	0.63	0.66	0.64	0.58	0.38
Waste management and remediation services	0.04	0.04	0.05	0.04	0.03	0.02	0.01	-0.01
Elementary and secondary schools; Junior colleges, colleges, universities, and professional schools; Other educational services	0.15	0.22	0.07	-0.04	-0.16	-0.29	-0.42	-0.56
Offices of health practitioners	0.21	0.38	0.25	0.13	-0.02	-0.18	-0.41	-0.72
Outpatient, laboratory, and other ambulatory care services	0.03	0.06	0.05	0.04	0.03	0.01	-0.02	-0.06
Home health care services	0.02	0.04	0.05	0.05	0.05	0.06	0.06	0.04
Hospitals	0.08	0.19	0.07	-0.02	-0.13	-0.26	-0.42	-0.66
Nursing and residential care facilities	0.08	0.17	0.07	0.00	-0.09	-0.19	-0.32	-0.52
Individual, family, community, and vocational rehabilitation services	0.01	0.01	-0.01	-0.02	-0.04	-0.06	-0.07	-0.08
Child day care services	0.01	0.01	0.00	0.00	-0.01	-0.01	-0.02	-0.02
Performing arts companies; Promoters of events, and agents and managers	0.01	0.01	0.01	0.00	-0.01	-0.01	-0.02	-0.03
Spectator sports	0.00	0.01	0.00	-0.01	-0.01	-0.02	-0.03	-0.04
Independent artists, writers, and performers	0.10	0.13	0.16	0.18	0.21	0.23	0.25	0.26
Museums, historical sites, and similar institutions	0.00	0.00	0.00	-0.01	-0.01	-0.02	-0.03	-0.03
Amusement, gambling, and recreation industries	0.02	0.03	-0.01	-0.05	-0.10	-0.15	-0.20	-0.28
Accommodation	0.02	0.06	0.00	-0.06	-0.14	-0.23	-0.35	-0.53
Food services and drinking places	0.15	0.32	-0.04	-0.28	-0.56	-0.90	-1.30	-1.86
Automotive repair and maintenance	0.04	0.06	0.04	0.02	0.00	-0.02	-0.06	-0.10
Electronic and precision equipment repair and maintenance	0.01	0.01	0.00	0.00	-0.01	-0.01	-0.02	-0.03
Commercial and industrial equipment (except automotive and electronic) repair and maintenance	0.03	0.03	0.03	0.02	0.02	0.01	0.01	-0.01
Personal and household goods repair and maintenance	0.01	0.02	0.01	0.01	0.00	0.00	-0.01	-0.02
Personal care services	0.07	0.14	0.05	-0.01	-0.09	-0.17	-0.29	-0.46

Sector	2013	2014	2015	2016	2017	2018	2019	2020
Death care services	0.00	0.01	0.00	0.00	0.00	0.00	-0.01	-0.01
Drycleaning and laundry services	0.01	0.02	0.01	-0.01	-0.02	-0.03	-0.05	-0.08
Other personal services	0.01	0.02	0.01	0.00	-0.01	-0.02	-0.04	-0.06
Religious organizations; Grantmaking and giving services, and social advocacy organizations	0.03	0.06	0.06	0.05	0.04	0.03	0.00	-0.04
Civic, social, professional, and similar organizations	0.03	0.05	0.04	0.03	0.00	-0.02	-0.06	-0.12
Private households	0.24	0.39	0.40	0.40	0.40	0.37	0.34	0.22
Total	**20.16**	**22.51**	**22.93**	**22.09**	**21.04**	**19.48**	**16.95**	**12.67**

* The total represents the sum of all the sectoral effects. The totals shown in this table differ from the simultaneous solutions shown in the last row of Table 4.2 in Chapter 4. The gap between the two is public employment, as well as rounding error.

References

Regional Economic Models, Inc. 2012. *REMI PI+ User Guide*.

Treyz, G. 1993. *Regional Economic Modeling: A Systematic Approach to Economic Forecasting and Policy Analysis*. Boston: Kluwer.

Appendix E. Greenhouse Gas Inventory

The table below provides a summary of GHG emissions by sector which were estimated using the most current available EPA, SIT data for Pennsylvania and does not reflect recent activities and incentives undertaken by the commonwealth to reduce GHG emissions (refer to Chapter 2).

The years reported include historical data from 2009, current data available 2010 and projected data for years 2011 - 2013 and the target year 2020. As shown in Table E1, Pennsylvania is estimated to be a net source of GHG emissions (positive, or gross, emissions). Pennsylvania's forests serve as natural GHG emission sinks along with municipal solid waste (removal and/or store negative emissions). The net emissions for Pennsylvania are calculated by subtracting the equivalent GHG reduction obtained from emissions sinks from the gross GHG emission total. The data presented in the table indicates that the GHG emissions associated with electricity consumption have been and are projected to be the largest contributor to GHG emissions. GHG emissions for this sector show an increase throughout the time span while GHG emissions from the other sectors show both gains and reductions through the years and then decrease through the target year of 2020.

Historically the key component of Pennsylvania's GHG emissions has been the electricity sector and coal fired generating stations. However, with the availability of increased natural gas supplies, resulting from the unconventional shale formation development, a shift in energy generation in Pennsylvania has occurred due to the availability of lower-cost natural gas. Due to increased federal regulations, as well as the availability of natural gas, many coal-fired power plants have either retired, reduced run time, or are exploring fuel-switching to natural gas. When fired, natural gas has a lower GHG potency than coal.

DEP believes that natural gas will continue to play a more significant role in electricity generation in Pennsylvania. However, emissions associated with electricity generation are still projected to be the largest contributor to future GHG emissions growth.

Table E1 is broken down into six sectors, each sector accounting for the following emissions sources:

1. **Energy** – fossil fuel combustion from, residential and commercial sources, stationary combustion sources, mobile combustion sources (includes motor fuels all types) coal mining and abandoned coal mines, natural gas and oil systems.
2. **Industrial Process –** coking coal, other coal, natural gas, distillate fuel, petrochemical feedstock, residual fuel, and other petroleum.
3. **Agriculture –** enteric fermentation, manure management agricultural soil management, and burning of agricultural crop waste.
4. **LULUCF –** forestry and land use.
5. **Waste –** municipal solid waste generation, industrial generation, industrial landfills, waste combustion, wastewater, LGTE, and flaring.
6. **Electricity Consumption-** coal, natural gas, oil, MSW/LFG, and other fuels.

Table E1. Pennsylvania Greenhouse Inventory

Emissions (MMTCO$_2$E)	**2009**	**2010**	**2011**	**2012**	**2013**	**2020**
Energy	**269.42**	**272.67**	**265.50**	**266.49**	**267.02**	**257.7**
Fossil Fuel Combustion	249.30	253.72	245.97	247.66	248.33	239.23
Stationary Combustion	1.00	1.05	0.64	0.69	0.69	0.41
Mobile Combustion	1.10	0.92	0.91	0.89	0.88	0.81
Coal Mining	9.83	10.10	10.89	10.02	9.68	9.05
Natural Gas /Oil Systems	8.19	6.88	7.01	7.23	7.44	8.2
Industrial Processes	**11.69**	**13.02**	**12.51**	**12.62**	**12.73**	**14.78**
Agriculture	**6.45**	**6.12**	**4.13**	**4.12**	**4.12**	**4.26**
Enteric Fermentation	2.97	3.01	2.9	2.89	2.88	2.91
Manure Management	1.14	1.14	1.21	1.22	1.22	1.24
Ag Soil Management	2.33	1.97	nd	nd	nd	nd
Burning of Ag Crop Waste	0.01	0.01	0.004	0.004	0.004	0.004
LULUCF	**(33.90)**	**(33.99)**	**(33.99)**	**(33.99)**	**(33.99)**	**(33.99)**
Waste	**0.44**	**(2.40)**	**(0.32)**	**(0.30)**	**(0.32)**	**0.02**
Municipal Solid Waste	(0.82)	(0.99)	(1.21)	(1.19)	(1.20)	(0.84)
Wastewater	1.26	1.27	0.89	0.89	0.88	0.86
Electricity Consumption	**82.96**	**85.97**	**92.58**	**95.62**	**96.64**	**93.63**
Gross Emissions	**287.99**	**377.78**	374.40	378.55	380.19	370.39
Sinks	**(33.90)**	**(36.39)**	**(34.31)**	**(34.29)**	**(34.31)**	**(33.99)**
Net Emissions	**254.09**	**341.39**	**340.09**	**344.26**	**345.88**	**336.40**

Appendix F. CCAC Member Comments on the Climate Change Action Plan Update

State Representative Greg Vitali provided the following comments:

1. Plan should contain specific emission reduction goals.

The plan does not contain a specific numerical greenhouse gas emissions reduction goal and a specific timeframe to reach the goal. The initial action plan of 2009 called for a 30% reduction in greenhouse gas emissions by 2020. The updated plan should either incorporate this goal or revise this goal to be consistent with global emissions reductions necessary to stabilize the earth's climate.

2. Plan's recommendations should enable the Commonwealth to reach its greenhouse gas emissions target reduction goals.

The Plan should describe how the enactment of its recommendations will enable the Commonwealth to meet its target GHG reduction goals. The current recommendations lack sufficient specificity. There is no analysis to demonstrate how the enactment of these recommendations will result in the necessary GHG reductions.

3. Action plan does not sufficiently incentivize renewable energy.

Expanded use of renewable energy is imperative to the stabilization of the earth's climate yet scant mention of renewable energy is made in this plan. The best way to increase renewable energy in Pennsylvania is to increase its Alternative Energy Portfolio standard. Pennsylvania's AEPS (8% by 2020) is currently significantly lower than its neighboring states of New Jersey (17.88% by 2021) Maryland (18% by 2022) and Delaware (25% by 2026). The Plan should contain a recommendation that Pennsylvania's AEPS be increased to be consistent with neighboring states.

4. Plan's Inventory does not appear to meet the requirements of The Pa. Climate Change Act.

The Act requires an annual inventory yet the plan's inventory contains only 2010 data from EPA sources.

A. Steven Krug, Spiezle Group, provided the following comments:

Geothermal systems are recognized as a long-term energy efficient approach to GHG reduction. The Department of Environmental Protection Analysis for the period of study did not take into account the levelized cost over the duration of geothermal life. The work plan as presented was not endorsed using the short term analysis and the Department of Environmental Protection intends to re-visit the geothermal work plan in the subsequent update using a long term levelized cost analysis.

Christina Simeone, PennFuture, provided the following comments:

1. Failure to Adhere to Industry Standard Practices on Climate Change Action Planning Absence of Greenhouse Gas Reduction Target – According to the U.S. EPA a critical step in developing any climate change action plan is establishing quantitative goals for greenhouse gas reductions. EPA states that "Quantitative goals provide structure and facilitate the evaluation of progress. Goals should include a specific timeframe, and can be stated in terms of emissions reductions, energy savings, or cost savings. Goals can be sector-specific or more general."[92] At the October 8, 2013 meeting of the CCAC, DEP informed the committee that the final report would not include a GHG reduction target, maintaining that a GHG target was not specifically required by the Pennsylvania Climate Change Act. Establishing a GHG reduction goal is part of the definition of a climate change action plan.

2. Failure to Consider Increasing Renewable Energy–
   This report relies almost solely on the 2009 action plan reduction initiatives, failing to adequately consider new or innovative GHG reduction strategies. For example, the report does not consider increasing renewable energy in Pennsylvania by expanding the Alternative Energy Portfolio Standard (AEPS). DEP informed the CCAC at the October 8, 2013 committee meeting that the department would not consider any recommendation to increase the AEPS renewable energy requirement. Pennsylvania's electric power sector is the number one contributor to GHGs in the state. Increasing energy efficiency and renewable energy are two of the most standard, cost effective strategies for decreasing GHG emissions in the electric power sector. Members of the CCAC were told consistently throughout the process that DEP would not be considering any new initiatives, due to resource constraints.

   The 2009 DEP action plan was the department's first attempt at developing a stakeholder-informed climate action plan. The comprehensive 2009 effort was well supported with technical and administrative resources. However, there were many opportunities to improve upon this first report. In addition, there have been significant market and technology changes that occurred between the 2009 and this 2013 report. The DEP missed an opportunity to advance Pennsylvania's understanding of climate change

3. Over-Reliance on Voluntary and Market-Based Initiatives
   This action plan relies too greatly on voluntary initiatives. Voluntary or market driven strategies to reduce GHGs are an important part of any comprehensive plan to address climate change. However, these initiatives are not enforceable and therefore the associated GHG reductions are not guaranteed.

4. Insufficient Analysis and Resources
   DEP's resource management decisions resulted in insufficient technical and administrative resources being devoted to the action plan effort, further resulting in

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[92] U.S. EPA website, Developing an Action Plan, located at http://epa.gov/statelocalclimate/state/activities/action-plan.html, accessed December 23, 2013

constant delays in the report development process. This report does not represent an effort to improve upon the state first climate change planning effort. The first action plan was supported by a team of 12-15 climate science, technical, economic and administrative experts, in addition to 2-5 full time climate change staff from DEP. For the 2013 effort, there was 1-2 full time DEP climate staff and one macro-economic analyst. Some examples include:

- No Change in Timeframe – The 2009 action plan used 2020 as its target year, examining reductions that could take place between 2009 and 2020. Four years later, best practices would be to extend the timeframe to 2023 or 2024. DEP did not do this.
- The CCAC was continually frustrated by the low quality of DEP's work. The technical analysis was continually flawed, assumptions and methodology often lacked transparency, work plans continually included outdated language and data, technical terms and constants were used inconsistently, quantitative analysis lacked transparency, etc.

5. Lack of Process Transparency Prevented Meaningful CCAC or Public Involvement
    - *No Public Comment Period* – DEP did not allow the public to review and comment on the draft climate action plan, prior to its finalization. DEP informed the CCAC that since the PA Climate Change Act did not require public comment, they would not allow for one. The 2009 action plan included a public comment period and DEP also published responses to public comments.
    - *Preventing CCAC Members from Performing their Duties* – Members of the CCAC asked DEP several times for clarity about the report development process. DEP provided no clear answers. At the December 5, 2013 CCAC meeting, DEP for the first time informed the committee that the department intended to submit the action plan to the governor's office on December 31, 2013. This meant that without notice, the committee would have approximately one week (the CCAC received the draft report on 12/13, and comments were due 12/20) to review the 300+ page report and provide comment. Much of this report would be new material the committee had not yet reviewed, including: the macro economic analysis, DEP legislative recommendations, updated GHG inventory and projections, and DEP's revision to some GHG reduction work plans. DEP rejected requests to move the report submission date and rejected requests to have the macroeconomic analyst brief the committee on his results, methodologies and assumptions. DEP's surprise deadline also prevented the potential development of a minority report. DEP's actions prevented the committee from performing the statutory duties they were legislatively appointed to complete.

Mark C. Hammond, Land Air Water Legal Solutions LLC, provided the following comments:

I support the Department's decision to allow individual Climate Change Advisory Committee (CCAC) members to submit, for inclusion in the 2013 Climate Change Action Plan (2013 Plan), comments memorializing areas of agreements and disagreement with the plan. The Department's decision to publish those comments is consistent with the PA

Climate Change Act, and is an appropriate and welcome departure from the procedures used by the previous administration, which limited public disclosure of member disagreements with the 2009 Climate Change Action Plan (2009 Plan). Overall, I believe that the substance of the 2013 Plan comports with the Climate Change Act, including the Department's decision not to include an overall target for GHG emission reductions, and that the 2013 Plan effectively builds upon the Department and CCAC's previous efforts, as documented in the 2009 Plan. More specifically, I believe that the major achievement of the CCAC over the last four years is the development (and inclusion by the Department) of realistic and specific implementation steps to many of the GHG emission reduction "work plans". If adopted, these implementation steps will generate real and significant GHG emission reductions.

Targets and Goals

The mandatory elements for inclusion in the 2013 Plan are set forth in detail in Section 1361.7(a)(I) through (5) of the PA Climate Change Act. The PA Climate Change Act does not require or discuss establishing any specific GHG emission reduction target or goal, nor does it discuss or establish any timeline for implementation or evaluation of the GHG emission reduction strategies. The only guidance the Act provides regarding evaluation of GHG emission reductions is that the Department is required to "evaluate cost-effective strategies for reducing or offsetting GHG emissions" and that the Department must "identify costs, benefits and cobenefits of GHG reduction strategies" as well as document the "impact on the capability of meeting future energy demand within this commonwealth" of the strategies recommended by the Department.[93] For these reasons, I agree with the Department that it is not required to recommend any specific "target" or "goals" for GHG emission reductions in the 2013 Plan. Whether inclusion of such a target or goal is appropriate (or even helpful) is a different matter; and was the subject of lengthy and contentious debate spanning numerous CCAC meetings during preparation of the 2009 Plan. In 2009, the CCAC voted to make the following recommendation to the Department:

> "The Committee agrees to DEP' s proposed target of a 30 percent reduction from 2000 GHG emission levels by 2020 as a reasonable aspirational non-binding goal for implementation of the program and policies recommended by the DEP and that the goal should be used to assess the progress of implementation of the Committee's recommendations." [Emphasis added]

During the four-year development period that led to the issuance of the draft 2013 Plan on December 12, 2013, neither the CCAC nor any individual member of the CCAC ever raised the issue of including a goal or target in the 2013 Plan. Whether the CCAC should recommend a goal or target, and if so, what it would recommend as a goal or target, is a complicated issue that requires significant scientific and policy data, analysis and consideration. Based on the discussion at the December 20, 2013 CCAC meeting, there is clearly no consensus among the CCAC members regarding inclusion of a target or goal, and no CCAC member proffered a

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[93] Because the Act mandates that the Department only consider cost-effective strategies, there is an implication that selection of a numeric target or goal is not permitted to the extent it may conflict with the Department's statutory duty.

motion for a CCAC vote that the Department should include a target or goal in the 2013 Plan.

Renewable Energy

I disagree with the proposition expressed by a fellow CCAC member that the 2013 Plan does not adequately address the topic of renewable energy. Thirteen of the fifteen (86.7%) GHG emission reduction work plans included in the Energy and RIC sections of the draft 2013 Plan directly increase the generation of qualified sources of renewable energy (including demand side management) as defined by the Alternative Energy Portfolio Standards Act (AEPS).[94] While it is true that neither the CCAC nor the Department have recommended or endorsed legislation to increase the levels of renewable energy required under the Alternative Portfolio Standards Act, the 2013 Plan very clearly supports renewable energy generation, as evidenced by the specific recommendations included in those thirteen work plans. In every meaningful way, renewable energy is the central theme of the work plans recommended by the CCAC and included in the 2013 Plan by the Department. For these reasons, I reject the premise that the Department's decision not to recommend an increase in the mandates of the AEPS is a de facto rejection of renewable energy.

Legislative Action

Chapter 7 of the draft 2013 Plan sets forth nine recommendations by the Department for legislative action. An overview of these nine recommendations was given by the Department at the December 20, 2013 CCAC meeting. At that time, the Department recognized that the CCAC had not previously reviewed these recommendations, and that the Department was not requesting CCAC endorsement of any of the nine recommendations. These nine recommendations are additive to the legislative recommendations that are imbedded in many of the GHG emission reduction work plans; each of those imbedded recommendations was reviewed and discussed[95] by both the full CCAC and the relevant CCAC subcommittee.

Some, but not all, of the Department's legislative recommendations were discussed in in other contexts with the CCAC. For example, the concepts embodied in recommendation 4 *Enact legislation incentivizing and directing natural gas utilities to expand existing service territory to un-served customers in a cost-effective manner* were discussed extensively during CCAC meetings relative to the *Heating Oil Conservation and Fuel Switching* work plan. On the other hand, recommendation 9: *Amend AEPS to permit the inclusion of additional waste-to-energy facilities*, was not previously presented to CCAC. For this reason, I lack a sufficient understanding to either agree or disagree with the Department's basis for its decision to make a recommendation to amend the AEPS to allow new WTE facilities to qualify as Tier II resources. However, I note that the original Waste & Industry subcommittee convened for the 2009 Plan

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[94] The 2013 Plan categorizes the GHG emission reduction workplans based on which of four subcommittees initially evaluated the workplan. The workplans reviewed by the other two subcommittees address topics outside of the purview of the AEPS (Land Use and Transportation, and Agriculture and Forestry).

[95] With the exception of any GHG emission reduction workplans included in the final 20 13 Plan that did not receive "endorsements" by majority vote of the CCAC, each of those imbedded legislative recommendations was also endorsed by both the relevant subcommittee and the full CCAC.

preparation, the original CCAC which voted on the work plans included in the 2009 Plan, the Energy subcommittee convened for the 2013 Plan preparation, and the CCAC (at the June 21, 2012 meeting) each considered and explicitly rejected construction of new WTE facility/facilities within the commonwealth as a GHG emission reduction strategy.

I believe the 2013 Plan provides meaningful, specific advice to the Governor and the legislature regarding opportunities to reduce GHG emissions within the Commonwealth.