BUILDING LOW EMISSION ALTERNATIVES TO DEVELOP ECONOMIC RESILIENCE AND SUSTAINABILITY PROJECT (B-LEADERS)

PHILIPPINES MITIGATION COST-BENEFIT ANALYSIS

November 2015

This document was produced for review by the United States Agency for International Development (USAID). It was prepared by the Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project implemented by International Resources Group for USAID Philippines.

BUILDING LOW EMISSION ALTERNATIVES TO DEVELOP ECONOMIC RESILIENCE AND SUSTAINABILITY PROJECT (B-LEADERS)

PHILIPPINES MITIGATION COST-BENEFIT ANALYSIS

Energy Sector Results

November 2015

DISCLAIMER

The author's views expressed in this publication do not necessarily reflect the views of the United States Agency for International Development or the United States Government.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACRONYMS

ADB	Asian Development Bank
AWD	Alternate wetting and drying
B-LEADERS	Building Low Emission Alternatives to Develop Economic Resilience and Sustainability
BSP	Banko Sentral ng Pilipinas
CBA	Cost-benefit analysis
CCC	Climate Change Commission
CEO	Chief executive officer
CH_4	Methane
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COPD	Chronic obstructive pulmonary disease
CRT	Cathode ray tube
DOE	Department of Energy
EPIMB	Electric Power Industry Management Bureau
EUMB	Energy Utilization Management Bureau
FPPKMD	Forest Policy, Planning and Knowledge Management Division
GDP	Gross domestic product
GHG	Greenhouse gas
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
GWP	Global warming potential
HECS	Household Energy Consumption Survey
HPS	High-pressure sodium
IEA	International Energy Agency
IER	Integrated exposure-response
iF	Intake fraction
IHD	Ischemic heart disease
INDC	Intended nationally determined contribution
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt hour
LCD	Liquid crystal display
LEAP	Long-range Energy Alternatives Planning System
LED	Light-emitting diode
LFG	Landfill gas
LPG	Liquefied petroleum gas
MAC	Marginal abatement cost
MACC	Marginal abatement cost curve
MJ	Megajoule
MSW	Municipal solid waste

$MtCO_2e$	Million metric tons carbon dioxide equivalent
MVIS	Motor Vehicle Inspection System
MVL	Mercury vapor lamp
MW	Megawatt
NAPOCOR	National Power Corporation
NGCC	Natural gas combined cycle
NMVOC	Non-methane volatile organic compounds
NO_x	Nitrogen oxides
N_2O	Nitrous oxide
NPV	Net present value
NREP	National Renewable Energy Program
NSWMC	National Solid Waste Management Council
O&M	Operating and maintenance
OECD	Organisation for Economic Cooperation and Development
OIMB	Oil Industry Management Bureau
PHP	Philippine peso
PM	Particulate matter
PPP GNI	Gross national income at purchasing power parity
SEI	Stockholm Environment Institute
SO_2	Sulfur dioxide
TPES	Total primary energy supply
TWG	Technical working group
UNDP	United Nations Development Programme
UNFCCC	United Nations Framework Convention on Climate Change
UP NEC	University of the Philippines National Engineering Center
USAID	Unite States Agency for International Development
USD	United States dollar
US EPA	United States Environmental Protection Agency
VSL	Value per statistical life
WTP	Willingness to pay

III. ENERGY

III.1 EXECUTIVE SUMMARY

As the Philippine economy continues to expand, the Government of the Philippines is working to address the sustainability and greenhouse gas (GHG) emission challenges related to sustaining this growth. As a part of this effort, the Climate Change Commission (CCC) partnered with the United States Agency for International Development (USAID) to develop the quantitative evidence base for prioritizing climate change mitigation by conducting a cost-benefit analysis (CBA) of climate change mitigation options. An economy-wide CBA is a systematic and transparent process that can be used to evaluate the impact of potential government interventions on the welfare of a country's citizens. Thus, the CBA is well-suited for the identification of socially-beneficial climate change mitigation opportunities in the Philippines.

The CBA Study is conducted under the USAID-funded Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project managed by Engility Corporation. The scope of the CBA covers all GHG emitting sectors in the Philippines, including agriculture, energy, forestry, industry, transport, and waste. The assessment is carried out relative to a 2010-2050 baseline projection of the sector-specific GHG emissions levels. The evaluation of the mitigation options covers the period spanning 2015-2050, except for the forestry sector where costs are assessed starting in 2010.

For each sector, the CBA evaluates a collection of nationally-appropriate mitigation options. To this end, each option is characterized in terms of:

- **The direct benefits** that are measured by the expected amount of GHG emissions reduced via the option. These GHG emission benefits are quantified, but not monetized;
- **The costs** associated with the mitigation option that can be quantified and monetized; and
- **The co-benefits** associated with the mitigation option that can be quantified and monetized. Depending on the option, the co-benefits may include beneficial economic/market impacts and non-market impacts.

The CBA employs two tools that are already being used by stakeholders in the country:

- **The Long-range Energy Alternatives Planning (LEAP) Tool** – LEAP is a flexible, widely used software tool for optimizing energy demand and supply and for modeling mitigation technologies and policies across the energy and transport sectors, as well as other sectors.
- **The Agriculture and Land Use Greenhouse Gas Inventory (ALU)** Software which was developed to guide a GHG inventory compiler through the process of estimating GHG emissions and removals related to agriculture, land use, land-use change, and forestry (LULUCF) activities.

The CBA is performed predominantly in the LEAP tool. The estimates of the agriculture and forestry sector GHG emissions are computed in the ALU tool and subsequently fed to LEAP. For some of the mitigation options, the estimates of costs and benefits are developed externally, with the LEAP model linking to the relevant datasets.

This Report represents the second update on the CBA model development work. It contains:

- A description of methods and sector-specific GHG emissions for the base year of 2010 and for the baseline projection spanning 2010-2050;
- A description of mitigation options evaluated for each sector;
- Estimates of the option/activity-specific direct benefits (i.e., the amount of GHG emissions reduced) as well as costs and economic co-benefits of the mitigation options for 2015-2050 time period, for which the Study Team already obtained data;
- Where relevant, estimates of indirect economic impacts (i.e., power sector impacts from mitigation activities in other sectors) and non-market co-benefits (congestion and public health) for those mitigation options where data are available;
- Where relevant, estimates of quantifiable energy security, employment, and public health-related gender impacts for the analyzed mitigation options;
- The development of a marginal abatement cost curve (MACC) which illustrates the cumulative abatement potential and costs per tonne of the mitigation options analyzed in this report

This study builds on the output of a series of consultations conducted from February until July of 2015. The results of these consultations were vetted by CCC and stakeholders in each of the relevant sectors. As such, this does not include results of discussions, new assumptions and data collected after July 2015. An updated version of these report shall be done in consultation with the relevant national government agencies led by the CCC and hopefully wlll reflect outcome of the Conference of Parties (COP) in Paris where CCC played a key role in the Philippine Delegation.

Table III. 1 summarizes the direct costs and benefits of mitigation options, including changes in capital, operating and maintenance (O&M), implementation, and fueling costs as well as GHG emissions. An option’s sequence number indicates its relative mitigation cost-effectiveness, accounting for direct costs and benefits only and assuming no interactions with other options. The lower the sequence number, the more cost-effective the option—i.e., the lower the direct cost per tonne of GHGs reduced. In the CBA, the ranking provided by sequence numbers is used in a separate assessment of interactions between options, called a retrospective systems analysis. This analysis assumes that options are implemented in the order given by the sequence numbers, and it defines the impacts of an option (costs and GHG abatement) as the marginal changes after the option is implemented. The Marginal Abatement Cost Curve (MACC) in Figure III. 1. Marginal Abatement Cost Curve for the Energy Sector excludes the two options that could not be evaluated in the retrospective systems framework due to mutual exclusivity as well as the MSW Combustion option, which does not reduce GHG emissions in the retrospective systems analysis.

Table III. 1. Direct Costs and Cost per Ton of Energy Sector Mitigation Options Excluding Co-benefits

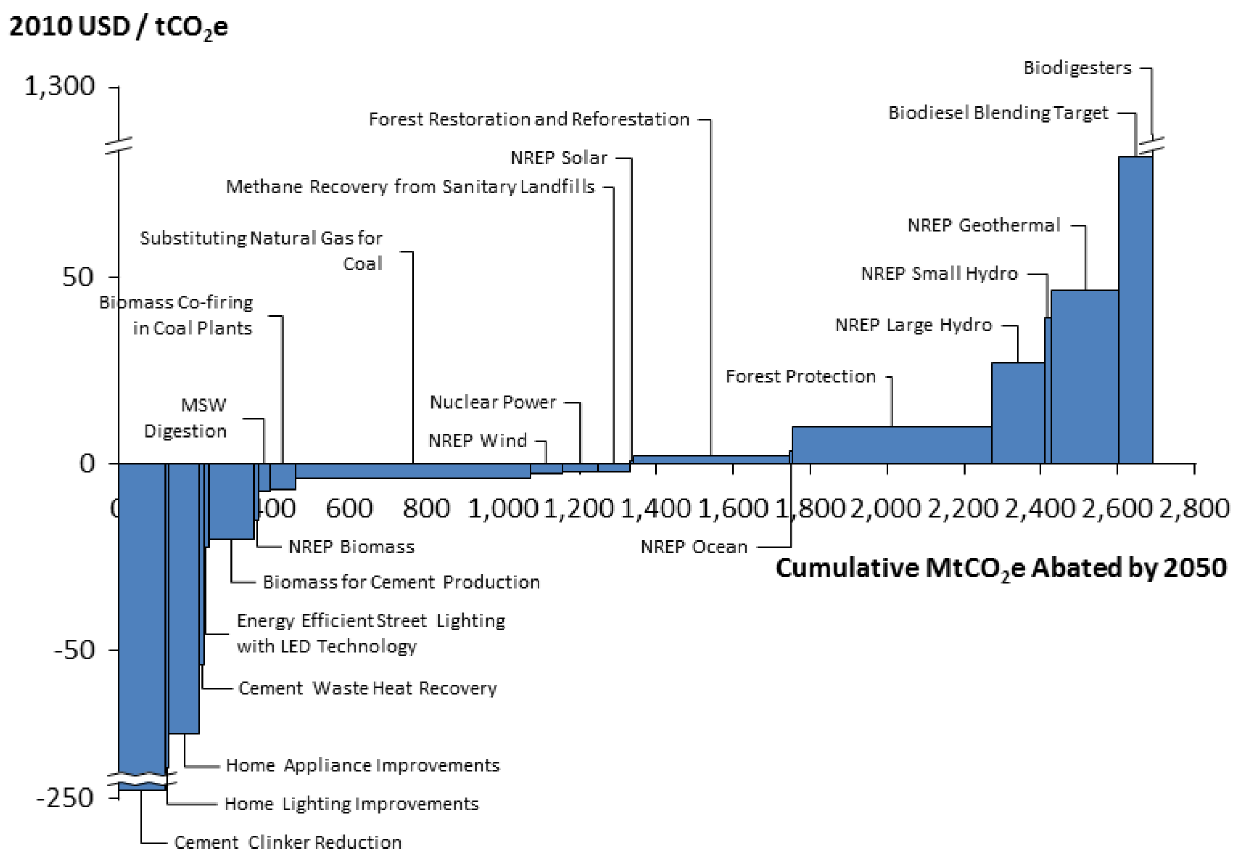
Sequence Number of Mitigation Option	Mitigation Option	Incremental Cost (Cumulative 2010-2050) [Billion 2010 USD] Discounted at 5%			Incremental GHG Mitigation Potential (2010-2050) [$MtCO_2e$]	Incremental Cost per Ton Mitigation [2010 USD / tCO_2e] *without co-benefits*
		Capital, O&M, Implementation Costs	Cost of Fuel and Other Inputs	**Total Net Cost**		
Symbol		*A*	*B*	*C*	*D*	*E*
Formula				*(A+B)=C*		*C/D=E*
33	Biodiesel Blending Target	0.00	6.94	6.94	84.4	82.2
35	Biodigesters	2.51	-1.16	1.35	1.0	1,287.2
13	Biomass Co-firing in Coal Plants	1.05	-1.53	-0.48	70.6	-6.8
11	Biomass for Cement Production	0.00	-2.35	-2.35	115.5	-20.4
2	Cement Clinker Reduction	-0.39	-29.48	-29.86	120.5	-247.8
9	Cement Waste Heat Recovery	-0.20	-0.36	-0.56	10.5	-53.9
* N/A	Energy Efficient Street Lighting with HPS Technology	0.18	-0.52	-0.33	11.3	-29.6
10	Energy Efficient Street Lighting with LED Technology	0.30	-0.60	-0.31	13.7	-22.4
25	Forest Protection	1.94	3.19	5.13	516.9	9.9
23	Forest Restoration and Reforestation	1.80	-0.94	0.86	405.9	2.1
8	Home Appliance Improvements	-2.57	-3.29	-5.86	81.3	-72.0
6	Home Lighting Improvements	-0.32	-0.41	-0.73	9.0	-81.5
* N/A	Methane Recovery from Dumpsites for Electricity	0.14	-0.29	-0.14	79.3	-1.8
20	Methane Recovery from Sanitary Landfills for Electricity	0.12	-0.27	-0.15	81.5	-1.9
37	MSW Combustion	0.59	-0.21	0.38	N/A[a]	N/A[a]
14	MSW Digestion	0.21	-0.39	-0.18	25.5	-7.1
12	NREP Biomass	0.21	-0.44	-0.24	15.6	-15.2
31	NREP Geothermal	16.03	-7.72	8.31	179.0	46.4
27	NREP Large Hydro	10.17	-6.41	3.76	137.9	27.3
26	NREP Ocean	0.43	-0.40	0.03	8.1	3.7
30	NREP Small Hydro	1.71	-1.03	0.67	17.1	39.4
16	NREP Solar	0.39	-0.38	0.01	11.0	0.9
19	NREP Wind	3.85	-4.08	-0.23	85.5	-2.7
15	Nuclear Power	2.64	-2.84	-0.20	91.5	-2.2
17	Substituting Natural Gas for Coal	-8.23	5.89	-2.34	608.9	-3.8

Notes:

Relatively Cost Effective. Negative Cost or Cost per Ton indicates lower costs than the baseline or preceding scenario.

* N/A indicates that a given mitigation option was not selected for inclusion in the retrospective systems analysis. These mitigation options were evaluated individually against the baseline.
[a] No mitigation potential.

Figure III. 1. Marginal Abatement Cost Curve for the Energy Sector



There are several non-market and market co-benefits which can add to the cost-effectiveness of a mitigation option. For this report the team have estimated the following co-benefits:

- *Non-market co-benefits*: the value of air quality-related improvements in public health as well as the value of congestion relief; and

- *Market co-benefits*: the value of timber and agroforestry commodities obtainable from reforested areas (designated for production) as well as the income generated from recyclables and composting.

Error! Not a valid bookmark self-reference. summarizes the value of co-benefits that could be monetized for the energy mitigation options. Column J shows the value of these benefits, normalized per ton of GHG mitigation potential. These "co-benefits only" results exclude direct costs; they are combined with direct costs and benefits in Table III. 3.

Table III. 2. Monetized Co-Benefits of Mitigation Options in the Energy Sector

Sequence Number of Mitigation Option	Mitigation Option	Incremental Co-benefits (Cumulative 2015-2050) [Billion 2010 USD] Discounted at 5%				Incremental Cost per Ton Mitigation [2010 USD / tCO_2e] *co-benefits only*
		Health	Congestion	Income Generation	**Total Co-benefit**	
Symbol		*F*	*G*	*H*	*I*	*J*
Formula					*sum(F,G,H)=I*	*-I/D=J*
33	Biodiesel Blending Target	0.00	N/A[a]	N/A[a]	0.00	0.0
35	Biodigesters	-0.36	N/A[a]	N/A[a]	-0.36	348.0
13	Biomass Co-firing in Coal Plants	4.74	N/A[a]	N/A[a]	4.74	-67.2
11	Biomass for Cement Production	0.00	N/A[a]	N/A[a]	0.00	0.0
2	Cement Clinker Reduction	0.04	N/A[a]	N/A[a]	0.04	-0.3
9	Cement Waste Heat Recovery	0.23	N/A[a]	N/A[a]	0.23	-22.0
* N/A	Energy Efficient Street Lighting with HPS Technology	N/A[b]	N/A[a]	N/A[a]	N/A[b]	N/A[b]
10	Energy Efficient Street Lighting with LED Technology	0.16	N/A[a]	N/A[a]	0.16	-11.7
25	Forest Protection	0.16	N/A[a]	N/A[a]	0.16	-0.3
23	Forest Restoration and Reforestation	-0.19	N/A[a]	N/A[a]	-0.19	0.5
8	Home Appliance Improvements	0.01	N/A[a]	N/A[a]	0.01	-0.2
6	Home Lighting Improvements	0.19	N/A[a]	N/A[a]	0.19	-21.6
* N/A	Methane Recovery from Dumpsites for Electricity	N/A[b]	N/A[a]	N/A[a]	N/A[b]	N/A[b]
20	Methane Recovery from Sanitary Landfills for Electricity	-0.13	N/A[a]	N/A[a]	-0.13	1.6
37	MSW Combustion	0.07	N/A[a]	N/A[a]	0.07	N/A[c]
14	MSW Digestion	0.18	N/A[a]	N/A[a]	0.18	-7.2
12	NREP Biomass	0.22	N/A[a]	N/A[a]	0.22	-14.0
31	NREP Geothermal	5.13	N/A[a]	N/A[a]	5.13	-28.7
27	NREP Large Hydro	3.38	N/A[a]	N/A[a]	3.38	-24.5
26	NREP Ocean	0.13	N/A[a]	N/A[a]	0.13	-16.0
30	NREP Small Hydro	0.24	N/A[a]	N/A[a]	0.24	-14.2
16	NREP Solar	0.37	N/A[a]	N/A[a]	0.37	-33.6
19	NREP Wind	1.27	N/A[a]	N/A[a]	1.27	-14.8
15	Nuclear Power	1.44	N/A[a]	N/A[a]	1.44	-15.7
17	Substituting Natural Gas for Coal	18.30	N/A[a]	N/A[a]	18.30	-30.1

Notes:

Relatively Cost Effective. Positive co-benefits reduce the net cost of mitigation options.

* N/A indicates that a given mitigation option was not selected for inclusion in the retrospective systems analysis. These mitigation options were evaluated individually against the baseline.

[a] This co-benefit was not calculated for energy sector mitigation options.

[b] Co-benefits were not calculated for this mitigation option.

[c] *No mitigation potential.*

Table III. 3 combines the cost per ton without co-benefits (Column E) with the cost per ton of co-benefits (Column J from Error! Not a **valid bookmark self-reference.** summarizes the value of co-benefits that could be monetized for the energy mitigation options. Column J shows the value of these benefits, normalized per ton of GHG mitigation potential. These "co-benefits only" results exclude direct costs; they are combined with direct costs and benefits in Table III. 3.

Table III. 2).

Table III. 3. Net Present Value of Mitigation Options in the Energy Sector

Sequence Number of Mitigation Option	Mitigation Option	Incremental GHG Mitigation Potential (2010-2050) [$MtCO_2e$]	Incremental Cost per Ton Mitigation [2010 USD / tCO_2e]		Net Present Value Excluding Value of GHG Reduction (2010-2050) [Billion 2010 USD] *with co-benefits*
			without co-benefits	with co-benefits	
Symbol		*D*	*E*	*K*	*L*
Formula			*C/D=E*	*E+J*	*D * -K*
33	Biodiesel Blending Target	84.4	82.2	82.2	-6.94
35	Biodigesters	1.0	1,287.2	1,635.2	-1.71
13	Biomass Co-firing in Coal Plants	70.6	-6.8	-74.0	5.22
11	Biomass for Cement Production	115.5	-20.4	-20.4	2.35
2	Cement Clinker Reduction	120.5	-247.8	-248.1	29.90
9	Cement Waste Heat Recovery	10.5	-53.9	-75.9	0.80
* N/A	Energy Efficient Street Lighting with HPS Technology	11.3	-29.6	N/A[a]	N/A[a]
10	Energy Efficient Street Lighting with LED Technology	13.7	-22.4	-34.2	0.47
25	Forest Protection	516.9	9.9	9.6	-4.97
23	Forest Restoration and Reforestation	405.9	2.1	2.6	-1.05
8	Home Appliance Improvements	81.3	-72.0	-72.2	5.87
6	Home Lighting Improvements	9.0	-81.5	-103.0	0.92

Sequence Number of Mitigation Option	Mitigation Option	Incremental GHG Mitigation Potential (2010-2050) [$MtCO_2e$]	Incremental Cost per Ton Mitigation [2010 USD / tCO_2e]		Net Present Value Excluding Value of GHG Reduction (2010-2050) [Billion 2010 USD] *with co-benefits*
			without co-benefits	with co-benefits	
* N/A	Methane Recovery from Dumpsites for Electricity	79.3	-1.8	N/A[a]	N/A[a]
20	Methane Recovery from Sanitary Landfills for Electricity	81.5	-1.9	-0.3	0.02
37	MSW Combustion	N/A[b]	N/A[b]	N/A[b]	-0.30[c]
14	MSW Digestion	25.5	-7.1	-14.3	0.36
12	NREP Biomass	15.6	-15.2	-29.1	0.45
31	NREP Geothermal	179.0	46.4	17.8	-3.18
27	NREP Large Hydro	137.9	27.3	2.7	-0.38
26	NREP Ocean	8.1	3.7	-12.3	0.10
30	NREP Small Hydro	17.1	39.4	25.2	-0.43
16	NREP Solar	11.0	0.9	-32.7	0.36
19	NREP Wind	85.5	-2.7	-17.5	1.50
15	Nuclear Power	91.5	-2.2	-17.9	1.64
17	Substituting Natural Gas for Coal	608.9	-3.8	-33.9	20.64

Notes:

Relatively Cost Effective. Negative Cost per Ton and Positive Net Present Value.

[a] Co-benefits were not calculated for this mitigation option.

[b] No mitigation potential.

[c] Calculated as -C + F.

III.2 BASE YEAR GHG EMISSIONS

III.2.1 Methods and Assumptions

CBA results for the energy sector were developed using an integrated model of the Philippines' energy system built on LEAP platform. This model accounts for key dependencies between energy demand and supply that may have a significant impact on emissions—for example, higher final demand for a fuel leading to increased emissions from fuel production, processing, and distribution. This section gives a brief introduction to the model before turning to methods underlying the estimation of base year GHG emissions.

III.2.1.1 Modeling Tool: LEAP

LEAP is a software platform for modeling energy and transport systems, air pollutant emissions, and costs and benefits of mitigation. Produced by the Stockholm Environment Institute (SEI) and offered free of charge to governments, academic organizations, and non-profits in developing countries, it is widely used for energy and climate policy analysis (SEI 2015). Key features of LEAP for mitigation planning include: support for representing different scenarios within a model; an annual time step for input data and results (with smaller time steps optionally considered for particular sources of energy demand and supply); and support for multiple modeling methodologies within an energy accounting framework (Bhattacharyya 2011). Further information about the features and algorithms of the LEAP platform is available in SEI (2014).

III.2.1.2 Model Scope and Boundaries

The CBA LEAP model simulates the Philippines' entire energy system, including all sources of energy demand and supply. Energy demand is categorized by economic sector, subsector, and fuel; with energy end uses and energy-using technologies. On the supply side, all energy producing industries—from primary resource extraction through conversion and delivery of fuels to end customers—are represented.[1] Physical constraints on primary (naturally occurring) energy sources are also represented, such as reserves of fossil fuels and annual yields of renewable resources. Energy imports and exports across the national border are allowed, although the origins of imports and the destinations for exports are not modeled explicitly. Thus, for example, purchases from particular trading partners are not distinguished within total imports.

The model estimates emissions of all GHGs and several other significant air pollutants from the energy sector. The following pollutants are covered:

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O)
- Carbon Monoxide (CO)
- Nitrogen Oxides (NO_x)
- Non-methane volatile organic compounds (NMVOC)
- Particulate matter (PM) (particle diameters less than 2.5 microns and less than 10 microns)
- Sulfur Dioxide (SO_2)

LEAP can report estimates of GHG emissions in terms of the mass of each individual pollutant (e.g., metric tonnes of methane) or as carbon dioxide equivalent (CO_2e). Conversions to CO_2e can be carried out using 20, 100, or 500-year global warming potentials (GWPs). All quantities of CO_2e reported in this chapter are calculated using the 100-year GWPs listed in Table III. 4.

Table III. 4. Greenhouse Gases Emitted by the Energy Sector and Their GWPs

GHG	100-Year GWP
Carbon Dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310

Source: (Intergovernmental Panel on Climate Change (IPCC) 1996b)

[1] A full outline of the model's structure is provided in Table III. 7 Structure of LEAP Energy Model (Demand Side) and Table III. 12. Structure of LEAP Energy Model (Supply Side).

The LEAP model includes an accounting of direct costs and benefits of the energy system and energy mitigation options. These costs and benefits are *social* costs and benefits, meaning that they are figured from the perspective of society as a whole without explicit consideration of distributional impacts (i.e., who pays or benefits). They comprise GHG emission reductions from mitigation, a benefit that is not monetized, and four types of monetized costs:

1) Capital (equipment) costs
2) Operating and Maintenance (O&M) costs
3) Fuel costs
4) Other implementation costs for mitigation measures (e.g., governmental program administration costs)

Reductions in any of these costs as a result of mitigation are considered a benefit—for instance, decreased fuel costs due to an efficiency measure would be a benefit. Monetized costs and benefits are expressed in real terms in the model (as 2010 USD), and a 5% real annual discount rate is applied when discounted amounts are required. The 5% rate was approved by CCC and is also commonly used in government analyses of air pollution regulations in the United States, where it represents a midpoint between the estimated cost of capital and the consumption rate of interest (U.S. Environmental Protection Agency (USEPA) 2010).

In building the model, it was sometimes necessary to convert input cost data from PhP or other-year dollars to 2010 USD. Table III. 5. Exchange Rates and Inflation Rates Used for Cost Conversions provides the exchange and inflation rates used for this purpose.

Table III. 5. Exchange Rates and Inflation Rates Used for Cost Conversions

Year	PhP per USD[a]	PhP Annual Inflation Rate [%][b]	USD Annual Inflation Rate [%][c]
1990	24.31	12.30	3.71
1991	27.48	19.40	3.32
1992	25.51	8.60	2.28
1993	27.12	6.70	2.38
1994	26.42	10.50	2.12
1995	25.71	6.70	2.09
1996	26.22	7.50	1.82
1997	29.47	5.60	1.72
1998	40.89	9.30	1.08
1999	39.09	5.90	1.43

Year	PhP per USD[a]	PhP Annual Inflation Rate [%][b]	USD Annual Inflation Rate [%][c]
2000	44.19	4.00	2.28
2001	50.99	6.80	2.28
2002	51.60	3.00	1.53
2003	54.20	3.50	1.99
2004	56.04	6.00	2.75
2005	55.09	7.60	3.22
2006	51.31	6.20	3.07
2007	46.15	2.80	2.67
2008	44.47	9.30	1.93
2009	47.64	3.20	0.79
2010	45.11	3.80	1.23
2011	43.31	4.40	2.06
2012	42.23	3.20	1.80
2013	42.45	3.00	1.49
2014	44.40	4.10	1.25

[a] Bangko Sentral Ng Pilipinas (BSP) (2014)

[b] 1990-2011: BSP (2011), 2012-2014: PSA(BSP) (2015j)

[c] 1990-2013: World Bank (2015a), 2014: Federal Reserve Bank of St. Louis (2015)

An important feature of the CBA is that it pairs the direct cost-benefit accounting just described with an assessment of mitigation co-benefits, such as health, energy security, and employment impacts. Co-benefits for the energy sector are calculated outside the LEAP model using results from the model as inputs (e.g., air pollution reductions under mitigation scenarios). Further details on the approach to co-benefit quantification and estimates of co-benefits for the energy sector are provided in Section III.4.1 Methods and III.3.2 Results

The LEAP model comprises both historical data and projections of energy use, emissions, and costs. The primary source of historical data for the model is the Philippines' national energy balances (Department of Energy (DOE) 2015d). Covering 1990-2013, the balances are a record of energy production, consumption, imports, and exports in the country. The model's structure and historical results are both based on the balances. The historical period in the model is from 1990-2013; projections start in 2014 and run through 2050.

III.2.1.3 Scenarios

Projections in the LEAP model are arranged into *scenarios*. A scenario is an internally consistent, physically plausible storyline that describes how the economy, energy system, pollutant emissions, and costs might evolve over time—in other words, a possible future. It includes exogenous inputs or assumptions and modeling outputs calculated on the basis of the assumptions. In LEAP, scenarios are developed in a hierarchy allowing each scenario to inherit assumptions from other scenarios as desired. In this way, a scenario can mirror a pre-existing scenario except for a few key parameters, isolating the effects of these changes.

The core scenario for the CBA is the baseline scenario. It envisions a future in which no significant new mitigation policies are enacted and historical trends in key drivers of energy use and emissions continue. Methods and results for the baseline scenario are detailed in Section III.3 Baseline Projection to 2050. The CBA's other scenarios are mitigation scenarios, which inherit from the baseline scenario and are measured in comparison to it. Two types of mitigation scenarios are considered: scenarios that add one discrete mitigation option to the baseline ("mitigation mini-scenarios") and scenarios that combine multiple mini-scenarios into a portfolio of mitigation options ("combined mitigation scenarios"). This arrangement facilitates the analysis of particular mitigation options in isolation, as well as their potential interactions with other options. SectionIII.4.1 Methods describes the mitigation mini-scenarios analyzed for the energy sector, and Section III.4.2 Resultspresents their respective costs and MACC analysis.

III.2.1.4 Modeling the Base Year

In reality, as stated above, the historical period in the energy sector model spans 1990-2013. However, historical results for 2010 are singled out here because 2010 is the base year for the CBA study as a whole. Results for 2010, like for all other historical years, begin with energy: the quantities of fuels produced by energy industries and consumed by users in various sectors and subsectors. These quantities are primarily determined by the national energy balances. In building the energy model, firstly the B-LEADERS team calibrated the historical period to the balances so the model reproduced them exactly for every year, fuel, and flow of energy (e.g., indigenous production, imports, exports, transformation requirements, final demand). The data in the balances were then augmented in three ways:

1) The fuel called "biomass" in the balances was disaggregated into rice hull, bagasse, coconut residue, animal waste, charcoal, and wood using the University of the Philippines National Engineering Center (UPNEC) (2015a).

2) For 2010-2013, the CBA's forestry modeling shows a total harvest of wood for fuel that substantially exceeds the wood use calculated in item 1 (i.e., wood use reflected in the formal energy balances).[2] This gap was assumed to represent informal consumption of wood and charcoal in the residential sector. The proportions of informal consumption going to fuelwood versus charcoal production were assumed to be the same as the proportions of formal consumption figured in item 1.

[2] Estimates of the total wood harvest are not available for 1990-2009.

3) Fuel inputs for electricity generation were divided between on-grid and off-grid plants using the energy balances and historical electricity production data in DOE (2012b), and National Power Corporation (NAPOCOR) – Small Power Utilities Group (2008 and 2014).

Accounting for informal wood and charcoal consumption has a significant impact on residential energy demand, increasing final demand in 2010 by over 40% compared to the inclusion of only formally tracked wood and charcoal. It also affects estimates of residential GHG emissions since combustion of wood and charcoal releases some CH_4 and N_2O (carbon emissions from wood and charcoal use are counted in the forestry sector, where carbon stock changes due to wood harvesting are recorded).

To derive emissions of GHGs and other air pollutants, the model multiplies fuel quantities by sector- and fuel-specific emission factors. These factors were compiled from the following sources, prioritizing the sources in the order shown:

1) Philippines' GHG inventory manual (Department of Environment and Natural Resources (DENR) 2011)
2) Philippines' 2000 GHG Inventory (Manila Observatory 2010)
3) IPCC Database on GHG Emission Factors (IPCC 2015)
4) USEPA's WebFIRE Database of Emission Factors (USEPAUSEPA 2014b)
5) Global Atmospheric Pollution Forum's Inventory Workbook (SEI 2012)
6) International Energy Agency's (IEA) Energy Technology Perspectives (IEA) 2012)
7) USEPA Report on Emissions from Charcoal Production (USEPA 1999a)[3]

In general, Philippine sources were used for all pollutants except PM. As the available Philippine sources do not cover PM, factors for this pollutant were taken from international literature. International sources were also consulted to fill gaps in the Philippine sources relating to particular pollutants and fuels or fuels and technologies (e.g., emissions from ultrasupercritical coal power plants). Table III. 6 Sources of Emission Factors in the Energy Sector Model shows the sources used by sector/energy industry and pollutant.

[3] The model does not include emission factors from USAID's Low Emissions Asian Development (LEAD) Program's project on Emission Factor Improvement for Combustion Related Activities in the Philippines. These factors may be incorporated in a future version of the model depending on their availability.

Table III. 6 Sources of Emission Factors in the Energy Sector Model

Sector / Energy Industry	CO_2	CH_4	N_2O	CO	NO_x	NMVOC	PM	SO_2
Industry (demand-side)	(Manila Observatory 2010), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (Manila Observatory 2010)	(DENR 2011), (Manila Observatory 2010)	(DENR 2011), (Manila Observatory 2010)	(USEPA 2014b)	(Manila Observatory 2010)
Residential	(Manila Observatory 2010), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(USEPA 2014b), (Stockholm Environment Institute 2012)	(Manila Observatory 2010)
Commercial	(Manila Observatory 2010), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(USEPA 2014b)	(Manila Observatory 2010)
Agriculture, Forestry, and Fishing	(Manila Observatory 2010), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(USEPA 2014b)	(Manila Observatory 2010)
Electricity Generation	(Manila Observatory 2010), (IPCC 2015), [IEA(IEA) 2012]	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014b)	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014b), (IEA2012)	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014b)	(USEPA 2014b), (IEA2012)	(Manila Observatory 2010), (USEPA 2014b), (IEA2012)
Fossil Fuel Production (Oil, Gas, and Coal)	(Manila Observatory 2010)	(DENR 2011), (Manila Observatory 2010)	(DENR 2011)	(DENR 2011), (Manila Observatory 2010)	(DENR 2011), (Manila Observatory 2010)	(DENR 2011), (Manila Observatory 2010)	(USEPA 2014b)	(Manila Observatory 2010)

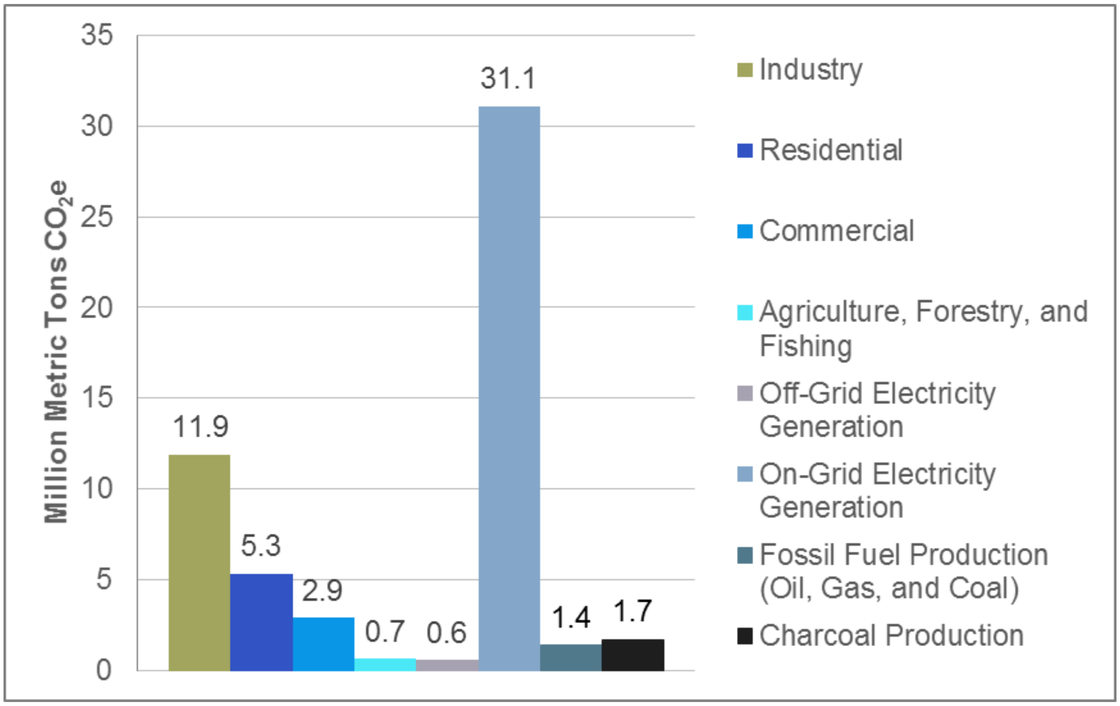
Sector / Energy Industry	CO_2	CH_4	N_2O	CO	NO_x	NMVOC	PM	SO_2
Charcoal Production	(USEPA 1999a)	(USEPA 1999a)	(USEPA 1999a)	(USEPA 1999a)	(USEPA 2014b)	(USEPA 1999a)	(USEPA 1999a)	N/A
Other Energy Producing Industries	(Manila Observatory 2010), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (IPCC 2015)	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014	(DENR 2011), (Manila Observatory 2010), (IPCC 2015), (USEPA 2014	(USEPA 2014b)	(Manila Observatory 2010), (USEPA 2014b)

Notably, some fuel uses in the model are assumed not to generate emissions or to produce emissions that should not be counted in the national totals considered in the CBA. Non-energy uses and historical statistical differences are in the former category, while consumption of international bunkers and combustion of biomass and biofuels are in the latter.[4]

III.2.2 Results

The results of the energy and emissions accounting for 2010 are shown in Figure III. 2. 2010 Base Year GHG Emissions from the Energy Sector.

Figure III. 2. 2010 Base Year GHG Emissions from the Energy Sector



Total GHG emissions from the energy sector are estimated at 55.7 million metric tons CO_2e ($MtCO_2e$). The leading contributors are electricity generation (31.7 $MtCO_2e$ from on- and off-grid plants together), industry (11.9 $MtCO_2e$), and the residential sector (5.3 $MtCO_2e$). Combustion emissions from other sources of energy demand and emissions from the production of fossil fuels and charcoal make up the remainder of the total.

It is worth pointing out that costs and benefits are not reported for the base year (nor for the baseline scenario described in the next section) because the CBA's purpose is to quantify costs and benefits of mitigation options specifically. These options are possibilities in the energy model's projection period—

[4] As indicated above, CO_2 emissions from the combustion of biomass and biofuels were excluded from national totals because biomass carbon stock changes were represented in the CBA's non-energy modeling. Counting the same carbon in the energy sector (at the point of combustion) would be duplicative. Emissions of other pollutants from burning biomass and biofuels were included and reported in the energy sector results.

they do not apply in the historical period—and their costs and benefits are defined in comparison to the baseline scenario. This implies that the baseline scenario need not model every direct social cost and benefit of the baseline energy system (which, in fact, it does not). Instead, what matters is that *differences* in costs between the baseline and mitigation scenarios are captured. With the model configured in this way, the cost-benefit outputs are only meaningful in the context of mitigation options or scenarios.

III.3 BASELINE PROJECTION TO 2050

III.3.1 Methods and Assumptions

As noted in Section III.2.1 Methods and Assumptions, the central narrative of the baseline scenario is that no significant new mitigation policies are implemented and historical trends in the major determinants of energy use and emissions continue. Accordingly, the baseline excludes a few recent energy sector policies that have important mitigation implications but whose effects are incipient or not yet manifest:

- National Renewable Energy Program (NREP) (DOE 2011b)
- Future targets for biofuel blending and economy-wide energy efficiency in the Philippine Energy Plan 2012-2030 (DOE 2012c; DOE 2012k)

The mitigation potential and costs and benefits of NREP, biofuel blending targets, and efficiency measures are instead explored in separate mitigation scenarios, enabling stakeholders to assess their specific impact.

At a high level, GHG emissions in the baseline scenario are calculated in the same way as in the historical period: by multiplying quantities of fuels by emission factors. These factors themselves are described in Section III.2.1 Methods and Assumptionsand do not change during the projection. Baseline emissions therefore depend on the baseline projection of energy supply and demand. The LEAP energy system model enforces a few basic accounting rules as a framework for this projection:

1) Final demand (by fuel) is determined first, then supply is matched to demand. Requirements for intermediate fuels (inputs to energy production processes) are determined by final demand and production technologies and efficiencies. Ultimately, the identity (below) is satisfied in every year and for every fuel:

$$\begin{aligned} &demand = domestic\ demand + exports \\ &= domestic\ production + imports \\ &= supply \end{aligned}$$

Equation III. 1

2) Annual fuel imports and exports observed in 2013 (in the national energy balances) are assumed to continue.[5] These ongoing fuel trades represent an exogenous input to the baseline scenario.

3) After accounting for domestic demand and the exogenous imports and exports in the above rule, domestic energy production is utilized to meet remaining supply requirements. However, domestic production is limited by natural resource and production capacity constraints.

4) Any remaining requirements that cannot be met by domestic production are satisfied by additional imports.

III.3.1.1 Domestic Final Energy Demand

With a few exceptions, the baseline projection of domestic final energy demand is built up through an activity analysis of demand in each economic sector or subsector. This is most clearly shown in Table III. 7 Structure of LEAP Energy Model (Demand Side) below, which provides a list of the sectors and subsectors modeled.

Table III. 7 Structure of LEAP Energy Model (Demand Side)

<table>
<tr><th></th><th>Sector</th><th colspan="3">Subsectors</th></tr>
<tr><td rowspan="9">Demand</td><td rowspan="9">Industry</td><td rowspan="9">Manufacturing</td><td rowspan="5">Food, Beverages, and Tobacco</td><td>Beverages</td></tr>
<tr><td>Tobacco</td></tr>
<tr><td>Coco and Vegetable Oil</td></tr>
<tr><td>Sugar</td></tr>
<tr><td>Other Food Processing</td></tr>
<tr><td colspan="2">Textile and Leather</td></tr>
<tr><td colspan="2">Wood and Wood Products</td></tr>
<tr><td colspan="2">Paper, Pulp, and Print</td></tr>
<tr><td>Chemical and Petrochemical</td><td>Chemicals Except Fertilizer</td></tr>
</table>

[5] Ethanol was an exception from this rule when generating results for this report due to uncertainty about the future utilization of domestic ethanol production capacity. Later consultations with DOE stakeholders provided additional guidance on ethanol capacity utilization and the implications for imports and exports, detailed in Table III. 23. Further Improvements to Baseline Modeling Assumptions. This guidance should be incorporated in any later versions of the LEAP model.

<table>
<tr><th>Sector</th><th colspan="3">Subsectors</th></tr>
<tr><td rowspan="11"></td><td rowspan="9"></td><td rowspan="2"></td><td>Fertilizer</td></tr>
<tr><td>Lube Refining</td></tr>
<tr><td rowspan="3">Non-Metallic Minerals</td><td>Glass and Glass Products</td></tr>
<tr><td>Cement</td></tr>
<tr><td>Other Non-Metallic Minerals</td></tr>
<tr><td colspan="2">Iron and Steel</td></tr>
<tr><td colspan="2">Machinery</td></tr>
<tr><td rowspan="2">Not Elsewhere Specified</td><td>Rubber and Rubber Products</td></tr>
<tr><td>Other Manufacturing</td></tr>
<tr><td colspan="3">Mining</td></tr>
<tr><td colspan="3">Construction</td></tr>
<tr><td rowspan="2">Residential</td><td colspan="3">Utility or Co-op (on-grid electricity only)</td></tr>
<tr><td colspan="3">Generator or Off Grid (off-grid electricity only)</td></tr>
<tr><td colspan="4">Commercial[6]</td></tr>
<tr><td rowspan="5">Agriculture, Forestry, and Fishing</td><td rowspan="3">Agri-Industry</td><td colspan="2">Agri-Crops Product</td></tr>
<tr><td colspan="2">Livestock and Poultry</td></tr>
<tr><td colspan="2">Agri-Services</td></tr>
<tr><td colspan="3">Forestry</td></tr>
<tr><td colspan="3">Fishing</td></tr>
<tr><td colspan="4">Non-Energy Use</td></tr>
<tr><td>International Bunkers</td><td colspan="3">Marine</td></tr>
</table>

[6] Includes institutional and public buildings and energy demand.

	Sector	Subsectors
		Civil Aviation

The activity analysis technique describes final demand as the product of an activity level and an energy intensity per unit of activity:

$$final\ energy\ demand = activity\ level\ \times energy\ intensity$$

Equation III. 2

Total final demand is distributed among the fuels used in each sector or subsector by multiplying the demand by fuel shares. Table III. 8 Activity Variables in Energy Demand Projection lists the activity variables in the demand projection.

Table III. 8 Activity Variables in Energy Demand Projection

Sector/Subsector	Activity Variable
All industrial subsectors except cement	Sub-sectoral value added
Cement	Cement production
Residential	Population
Commercial	Commercial value added
Agriculture, forestry, and fishing subsectors	Sub-sectoral value added
Non-energy uses	GDP
International bunkers – marine	GDP
International bunkers – civil aviation	Population

Each of these activity variables is exogenous to the energy model and must be independently projected in the baseline scenario. The projections used are based on GPH and industry sources and extrapolation of historical trends as further described in Table III. 9 Data Sources and Projections of Population, GDP, Economic Sector-Specific Value Added, and Cement Production below. Included after the table are semi-decadal data and projections for each of these key activity drivers.

Table III. 9 Data Sources and Projections of Population, GDP, Economic Sector-Specific Value Added, and Cement Production

Variable	Sources of Historical Data	Projection Method

Variable	Sources of Historical Data	Projection Method
Population	1990-2010: Philippine Statistics Authority (PSA) (2010)	2011-2020: Projection is taken from PSAand Inter-Agency Working Group on Population Projections (2015b). 2021-2045: Projection is taken from PSAand Inter-Agency Working Group on Population Projections (2015a). 2045-2050: Population is assumed to grow at average annual rate established 2035-2045.
GDP	1990-2010: PSA(2015c) 2011: PSA(2015a) 2012-2014: PSA(2015b)	GDP is assumed to grow at similar rate as that projected in UPNEC(2015c).
Cement Production	2000-2012: Cement Manufacturers Association of the Philippines (2015)	After 2012, cement production is projected to grow at the same rate as value added by the non-metallic mineral industrial subsector.
Value Added by Industrial Subsectors	1998-2010: PSA(2015i) 2011-2013: PSA(2015a) 2014: PSA(2015g; 2015h; 2015e; 2015f)	Shares of total GDP for sectoral and sub-sectoral values added are projected based on historical trends. Projected shares in each year are multiplied by GDP to obtain projected values added.
Value Added by Commercial Sector	1998-2010: PSA(2015i) 2011-2013: PSA(2015a) 2014: PSA(2015b)	

Variable	Sources of Historical Data	Projection Method
Value Added by Agriculture, Forestry, Fishing Subsectors	1998-2010: PSA(2015i) 2011-2013: PSA(2015a) 2014: PSA(2015d)	

Table III. 10 Data and Projections for Population, GDP, Cement Production, and Value Added

	Historical Data					Baseline							
Year	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Population [Million People]	61	69	77	85	92	102	110	118	125	132	138	142	147
GDP [Billion 2010 USD]	98	106	132	161	200	274	336	474	611	793	1,060	1,433	1,895
Cement Production [Million Tonnes]	-	-	12	12	16	22	25	28	31	35	40	47	53
Value Added by Economic Sectors and Subsectors [Million 2010 USD]													
Beverages	1,094	1,187	1,413	1,232	1,573	2,166	2,392	2,631	2,884	3,152	3,437	3,739	4,059
Tobacco	515	558	725	364	169	129	119	110	100	92	83	76	69
Food Manufactures	7,123	7,725	10,420	14,346	18,193	23,711	30,501	39,089	49,929	63,590	80,780	102,383	129,502
Textile and Leather	2,785	3,021	3,314	3,156	2,508	2,542	2,343	2,153	1,971	1,799	1,638	1,488	1,349
Wood and Wood Products	819	888	954	1,049	777	1,006	965	923	879	835	792	748	706
Paper Pulp and Print	684	742	879	650	627	865	837	807	776	743	710	677	645
Chemical and Petrochemical	1,694	1,837	2,126	2,468	2,595	5,697	7,351	9,449	12,106	15,465	19,705	25,050	31,782
Non Metallic	762	827	795	771	1,146	1,274	1,338	1,400	1,460	1,518	1,575	1,629	1,683

	Historical Data					Baseline							
Minerals													
Iron and Steel	661	717	650	819	1,040	835	808	778	748	716	684	652	620
Machinery	1,532	1,662	2,624	2,668	2,603	2,469	2,566	2,657	2,742	2,821	2,895	2,965	3,030
Rubber and Rubber Products	424	460	534	532	616	634	644	652	657	661	663	664	664
Petroleum and Other Fuel Products	1,080	1,171	1,892	2,616	2,984	3,126	3,859	4,746	5,819	7,112	8,672	10,548	12,805
Other Manufacturing	3,791	4,112	5,913	8,029	7,972	7,010	7,586	8,177	8,786	9,413	10,058	10,724	11,410
Mining	830	900	829	1,972	2,854	2,493	3,111	3,868	4,794	5,923	7,300	8,976	11,015
Construction	6,225	6,752	7,504	7,625	12,220	16,201	19,385	23,107	27,453	32,522	38,427	45,302	53,298
Electricity Gas Water Supply	3,649	3,958	4,828	6,139	7,128	8,200	9,398	10,729	12,208	13,851	15,675	17,699	19,943
All Commercial	49,783	53,995	67,958	86,076	110,009	145,430	180,027	222,018	272,898	334,462	408,861	498,673	606,984
Agri Crops Product	7,201	7,810	9,214	10,318	13,304	16,309	18,733	21,437	24,449	27,804	31,537	35,691	40,310
Livestock and Poultry	3,666	3,976	4,725	5,177	5,592	5,882	6,106	6,313	6,507	6,687	6,854	7,009	7,153
Agri Services	946	1,026	1,172	1,314	1,633	1,907	2,117	2,341	2,580	2,836	3,109	3,400	3,711
Forestry	94	102	192	129	54	91	84	77	70	64	58	53	48
Fishing	2,544	2,759	3,100	3,439	3,995	3,799	3,860	3,908	3,943	3,967	3,981	3,986	3,982

As the activity levels change over time, sectoral and subsectoral energy intensities and fuel shares change as well. Starting from their current values, intensities and fuel shares increase or decrease at the average annual rate observed in the historical data (but not more than 3% per year).[7] Fuel shares are subject to an additional constraint that they must sum to 100% in each sector or subsector.

[7] Two exceptions are:

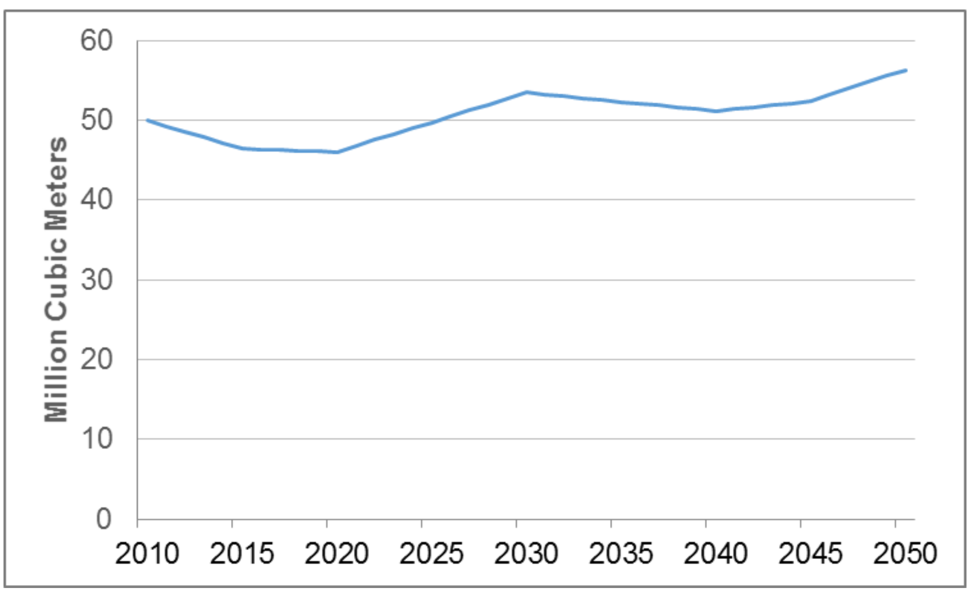
1) The energy intensity of cement production, which is held constant at its last observed value due to significant volatility in recent historical data.
2) The energy intensity of liquid fuels consumed in the residential sector, which is projected using the average annual growth rate for residential energy intensity in non-Organization for Economic Cooperation Development Asian countries in U.S. Energy Information Administration (2013), Baseline Scenario. This approach was taken because the default method of projecting the intensity lead to unreasonably low final demand in the long run.

This basic activity analysis is superseded by other methods in four cases:

Biomass **– Projections of final demand for biomass by sector and commodity (rice hull, bagasse, coconut residue, animal waste, charcoal, and wood) are taken from UPNEC(2015a). Informal consumption of wood in the residential sector is then calculated as the total projected harvest of wood for fuel (from the CBA's forestry modeling;**

1) Figure III. 3. Wood Harvest for Energy, Baseline Scenario minus wood required to satisfy the "formal" wood and charcoal demand in UPNEC(2015a). Informal consumption of wood is divided into fuelwood and wood used for charcoal according to the shares of these fuels in the residential sector in UPNEC(2015a).

Figure III. 3. Wood Harvest for Energy, Baseline Scenario



2) **Residential electricity** – While still a form of activity analysis, the approach used for household electricity demand is more disaggregated than the analysis in other sectors and contains more end-use detail. Demand for on- and off-grid electricity is projected separately, using a bottom-up accounting of household electrical devices. Each device is categorized by device type, end-use, and electricity demand category as demonstrated in the schematic in Table III. 11 Schematic of Bottom-up Household Electricity Demand Model. Demand categories are modeled separately for households that are connected to an electrical utility or cooperative (where demand categories span all of the technologies listed in Table III. 11 Schematic of Bottom-up

Household Electricity Demand Model, consuming on-grid electricity), and households that primarily utilize generators or are situated entirely off the grid (where demand categories span only those technologies marked with a †, which consume off-grid electricity).

Table III. 11 Schematic of Bottom-up Household Electricity Demand Model

Demand Category	End-Use	Technology
Lighting	Bulbs	Incandescent†
		Linear Fluorescent†
		Circular Fluorescent
		Compact Fluorescent†
		LED†
		Other†
	Other	Rechargeable
Television	TVs	CRT† (includes black and white)
		Non-CRT† (includes LED, LCD and plasma)
	Players	VHS and Disc†
		Karaoke†
		Gaming Systems
Refrigeration	Refrigerators	Refrigerator† (ordinary and frost-free)
	Freezers	Freezer
Ventilation	Fans	Fan† (electric and exhaust)
Heating and Cooling	Air Conditioners	Split (inverter and non-inverter)
		Window
	Heaters	Portable Heater
Water Heating	Water Heaters	Water Heater
Cooking	Stoves	Stove
	Ovens	Oven
		Turbo Broiler
	Rice Cookers	Rice Cooker

Demand Category	End-Use	Technology
	Toasters	Toaster (oven toasters and bread toasters)
	Microwaves	Microwave
	Other	Blenders and Mixers
		Coffeemaker
		Electric Kettle
		Dishwasher
		Other
Ironing	Irons	Iron†
Audio	Radios and Recorders	Player† (radios and cassette players)
	Stereos	Stereo†
Water Pumping	Water Pumps	Water Pump
Laundry	Washing Machines	Manual†
		Automatic†
Computing	Computers	CRT†
		Non-CRT†
	Printers	Printer
Other		Sewing Machine
		Shaver
		Hair Dryer
		Other†

For the whole of the Philippines, the total number of electricity-consuming devices of each technology type can be derived from the Philippine Household Energy Consumption Survey (HECS) (DOE and National Statistics Office (NSO) 2011). Survey responses from over 20,000 households found in the HECS sample were assumed to be representative of the entire national population, with an average household membership of 4.80 persons. The number of electricity-consuming devices in Philippine households was calculated as the product of four numbers:

1) The total number of households (national population divided by average household size)
2) The fraction of households requiring electricity for each demand category (HECS Result Code A.4a-h)

3) The total number of devices per household satisfying each end-use within the category (HECS Result Code 4.2C03, 4.2C08 for lighting, 4.3C03, 4.3C08 for other appliances)

4) The fractions of devices corresponding to different technology options for the end-use (HECS Result Code 4.2C03, 4.2C08 for lighting, 4.3C03, 4.3C08 for other appliances)

This analysis was repeated for on- and off-grid homes using HECS Result Code 1.a-c, as the two types exhibit different consumption patterns.

Final energy intensity for each technology was calculated by multiplying the annual number of hours of usage by the rated device wattage. Each of these values is unique to each technology, and differs between on- and off-grid households. Hours of device usage per day as well as days of usage per week/month/year are taken from HECS (Result Codes 4.2C03 for lighting, 4.3C03, 4.3C13 for other appliances). Average device wattage ratings must also be calculated, since a single technology type may encompass devices of many different power ratings. Average power was estimated from reported device wattage in the HECS (Result Codes 4.2C03 for lighting, 4.3C03 for other appliances), after first binning each individual device's power rating into 10 W intervals. From these intervals, the weighted average power consumption of each device was calculated from the interval midpoints and the number of devices contained in each interval.[8] Finally, the annual hours of usage for all devices was scaled by a multiplicative factor, so that in 2013 (the final year of historical data) the residential electricity consumption calculated using a bottom-up accounting of technologies matches the total consumption observed in that year in the national energy balances (DOE 2015d). This scaling factor—0.89 for on-grid electricity, 1.15 for off-grid electricity—may be physically motivated by a number of phenomena: possible differences in device usage between 2010 (the HECS result year) and 2013 or standby power consumption that is not captured by operational hours per year, to name two.

Each of the parameters calculated from HECS (number of household members, number of each device per household, and annual energy consumption per device) was assumed to remain constant throughout the baseline scenario. Changes in total on- and off-grid electricity consumption through 2050 were then driven by growth in the number of households, which was directly proportional to national population.

3) **Industrial and commercial off-grid electricity** – Off-grid electricity demand in the industrial and commercial sectors was modeled by multiplying a projection of total national off-grid demand by sectoral shares. The national projection for years before 2017 was derived from DOE (2012b), while in later years it was assumed to be 1% of national on-grid electricity demand (a ratio observed in historical data). The demand shares for industry and the commercial sector were from NAPOCOR – Small Power Utilities Group (2008).

[8] Devices under the "Lighting" demand category are not binned into intervals. Instead, a weighted average wattage for each lighting technology option is determined directly from reported power ratings in the HECS.

4) **Biofuels production** – Production of sugar-based ethanol and coconut methyl ester, the liquid biofuels used in the Philippines, requires inputs of both raw materials and energy (Argonne National Laboratory 2015; Gopal and Kammen 2009; Tan, Culaba, and Purvis 2004). These inputs are not explicitly shown in the Philippines' national energy balances, complicating historical modeling and projections of biofuels production (DOE 2015d). The raw materials—sugarcane and molasses for ethanol, copra for coconut methyl ester biodiesel—were presumably excluded from the balances because they are not in themselves a fuel. According to informal feedback from stakeholders in B-LEADERS consultations conducted in April 2015, the energy inputs (including process heat and electricity) appear to be counted under industrial energy demand in the balances rather than on the supply side.

   For historical years, as indicated in Section III.2.1 Methods and Assumptions, the energy model reproduces the balances' accounting of industrial energy demand. Because this demand is assumed to comprise energy used for biofuels production, no additional energy inputs for the production are shown on the supply side of the model. In the baseline and other projections, however, a different approach was taken. The energy inputs for biofuels production were moved to the supply side and projected based on the quantity of biofuels produced and energy intensities of production from Argonne National Laboratory (2015), Gopal and Kammen (2009), and Tan et al. (2004). At the same time, the projection of final energy demand for other manufacturing, the industrial subsector assumed to cover biofuels production in the historical data, was based on trends in energy intensity and fuel shares *excluding estimated historical energy inputs for biofuels production.* These inputs were calculated by multiplying historical production of biofuels and the energy intensities of production just referenced. In the first projection year, then, there was a drop in final demand for other manufacturing and a corresponding increase in energy inputs under biofuels supply.

III.3.1.2 Domestic Energy Production

The supply side of the model describes domestic energy production by representing major energy producing industries. The level of detail in the representation varies across industries depending on data availability and each industry's importance to national GHG emissions. Energy own use, losses during transformation of energy from one form to another, and GHG emissions are modeled for every industry. In addition, for selected industries as shown in Table III. 12. Structure of LEAP Energy Model (Supply Side), production capacity[9] and specific production technologies were modeled.

Table III. 12. Structure of LEAP Energy Model (Supply Side)

Industry	Fuel & Technology	Capacity Modeled?

[9] If production capacity is not modeled, the energy industry is assumed to be able to generate any required quantity of fuel subject to the availability of inputs.

	Industry	Fuel & Technology		Capacity Modeled?
Supply	Electricity Transmission and Distribution			No
	Off-Grid Electricity Generation	Oil	Diesel/Oil	Yes
		Renewables	Small Hydro (≤ 10 megawatts [MW])	
			Solar Photovoltaic	
			On-Shore Wind	
	On-Grid Electricity Generation	Coal	Subcritical Pulverized	Yes
			Supercritical Pulverized	
			Ultrasupercritical Pulverized	
			Circulating Fluidized Bed Combustion	
		Oil	Diesel	
			Oil Combined Cycle	
			Oil Thermal	
		Natural Gas	Natural Gas Combined Cycle	
		Renewables Excluding Wastes	Biomass Combustion	
			Geothermal	
			Large Hydro (> 10 MW)	
			Small Hydro (≤ 10 MW)	
			Ocean Thermal	

<table>
<tr><th></th><th>Industry</th><th colspan="2">Fuel & Technology</th><th>Capacity Modeled?</th></tr>
<tr><td rowspan="21"></td><td rowspan="8"></td><td rowspan="2"></td><td>Solar Photovoltaic</td><td rowspan="8"></td></tr>
<tr><td>On-Shore Wind</td></tr>
<tr><td rowspan="4">Wastes</td><td>Agricultural Waste Digestion (Biogas)</td></tr>
<tr><td>Landfill Gas</td></tr>
<tr><td>Municipal Solid Waste Digestion (Biogas)</td></tr>
<tr><td>Municipal Solid Waste (MSW) Incineration</td></tr>
<tr><td>Nuclear</td><td>Nuclear</td></tr>
<tr><td colspan="3">CNG Compression</td><td>No</td></tr>
<tr><td rowspan="2">Ethanol Production</td><td colspan="2">Production from Sugarcane</td><td rowspan="2">Yes</td></tr>
<tr><td colspan="2">Production from Molasses</td></tr>
<tr><td>Biodiesel Production</td><td colspan="2">Production from Copra</td><td>Yes</td></tr>
<tr><td colspan="3">Oil Refining and Storage</td><td>Yes</td></tr>
<tr><td colspan="3">Oil Production and Transport</td><td>No</td></tr>
<tr><td colspan="3">Natural Gas Transmission and Distribution</td><td>No</td></tr>
<tr><td colspan="3">Natural Gas Production and Processing</td><td>No</td></tr>
<tr><td rowspan="2">Coal Mining</td><td colspan="2">Underground Mining</td><td rowspan="2">No</td></tr>
<tr><td colspan="2">Surface Mining</td></tr>
<tr><td colspan="3">Charcoal Production</td><td>No</td></tr>
<tr><td colspan="3">Biomass Production and Harvesting</td><td>No</td></tr>
</table>

Additional details about the modeling of each industry are provided in the following subsections.

III.3.1.3 Electricity Generation

The submodel for electricity generation is a bottom-up representation of the power sector in which current and future generation technologies and capacities are simulated. The technologies considered are listed under the On-Grid and Off-Grid Electricity Generation industries in Table III. 12. Structure of LEAP Energy Model (Supply Side). Individual plants or generating units were not explicitly represented in the model but were instead aggregated by technology. A number of technical and cost parameters were modeled for each technology as shown in Table III. 13. Technical and Cost Parameters for Electricity Generation Technologies – Sources.

Table III. 13. Technical and Cost Parameters for Electricity Generation Technologies – Sources

On- or Off-Grid	Technology	Parameter	Data Sources
On	Subcritical Pulverized Coal	Efficiency or heat rate	(DOE 2015d)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit (credit toward reserve margin[10])	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2012i)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Supercritical Pulverized Coal	Efficiency or heat rate	(DOE 2015d; IEA2012)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)

[10] The reserve margin refers to extra capacity beyond that necessary to meet generation requirements and expected peak load. It is maintained as a safeguard against system failure in the event of unexpected loads or plant downtime. The reserve margin used in the CBA is further described below.

		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(B-LEADERS 2015b)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Ultrasupercritical Pulverized Coal	Efficiency or heat rate	(IEA 2012)
		Current and planned capacity	*N/A*
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(IEA2012)
		Fixed O&M cost	(IEA2012)
		Variable O&M cost	(Schlömer et al. 2014)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Circulating Fluidized Bed Combustion Coal	Efficiency or heat rate	(IEA 2010)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2012i)
		Fixed O&M cost	(IEA 2010)
		Variable O&M cost	(IEA 2010)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Diesel	Efficiency or heat rate	(DOE 2015g)

		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(B-LEADERS 2015b)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Oil Combined Cycle	Efficiency or heat rate	(DOE 2015g)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2012i)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Oil Thermal	Efficiency or heat rate	(DOE 2015g)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2015g)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)

		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Natural Gas Combined Cycle	Efficiency or heat rate	(DOE 2015d; IEA 2012)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2012i)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Biomass Combustion	Efficiency or heat rate	(ERC 2015)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(ERC 2015)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015)
		Fixed O&M cost	(ERC 2015)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Geothermal	Efficiency or heat rate	(DOE 2015d)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2015g)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)

		Capital cost	(DOE 2012i; Edenhofer et al. 2012)
		Fixed O&M cost	(B-LEADERS 2015a; Edenhofer et al. 2012)
		Variable O&M cost	(B-LEADERS 2015a; Edenhofer et al. 2012)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Large Hydro	Efficiency or heat rate	(DOE 2015d)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2011a)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2012i)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Small Hydro	Efficiency or heat rate	(DOE 2015d)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(DOE 2011a)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015)
		Fixed O&M cost	(ERC 2015)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Ocean Thermal	Efficiency or heat rate	*N/A*
		Current and planned capacity	*N/A*

		Availability factor	(ERC 2015)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(ERC 2015)
		Capital cost	[ERC 2015; IREA (IREA) 2014]
		Fixed O&M cost	(ERC 2015)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Solar Photovoltaic	Efficiency or heat rate	*N/A*
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(ERC 2015)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015; IEA 2012)
		Fixed O&M cost	(ERC 2015; IEA 2012)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III. 6*
On	On-Shore Wind	Efficiency or heat rate	*N/A*
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(ERC 2015)
		Capacity credit	(DOE 2014b)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015; IEA 2012)
		Fixed O&M cost	(ERC 2015; IEA 2012)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III. 6*
On	Agricultural Waste	Efficiency or heat rate	(Edenhofer et al. 2012)

	Digestion	Current and planned capacity	*N/A*
		Availability factor	(Edenhofer et al. 2012)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(Edenhofer et al. 2012)
		Capital cost	(IREA 2012)
		Fixed O&M cost	(IREA 2012)
		Variable O&M cost	(IREA 2012)
		Emission factors	*See Table III. 6* Sources of Emission Factors in the Energy Sector Model
On	Landfill Gas	Efficiency or heat rate	(Mitsubishi Securities Clean Energy Finance Committee 2004)
		Current and planned capacity	(DOE 2014b; DOE 2015c; DOE 2012e)
		Availability factor	(MCWMC 2010)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(MCWMC 2010)
		Capital cost	(IREA 2012)
		Fixed O&M cost	(MCWMC 2010)
		Variable O&M cost	(MCWMC 2010)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	MSW Digestion	Efficiency or heat rate	(Endesa Generación, S.A. 2011; Spuhler 2015)
		Current and planned capacity	*N/A*
		Availability factor	(Endesa Generación, S.A. 2011)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(Endesa Generación, S.A. 2011)
		Capital cost	(Endesa Generación, S.A. 2011)
		Fixed O&M cost	(Endesa Generación, S.A. 2011)

		Variable O&M cost	(Endesa Generación, S.A. 2011)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	MSW Incineration	Efficiency or heat rate	(Edenhofer et al. 2012)
		Current and planned capacity	*N/A*
		Availability factor	(Edenhofer et al. 2012)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(Edenhofer et al. 2012)
		Capital cost	(IREA 2012)
		Fixed O&M cost	(Edenhofer et al. 2012)
		Variable O&M cost	(Schlömer et al. 2014)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
On	Nuclear	Efficiency or heat rate	(IEA 2012)
		Current and planned capacity	*N/A*
		Availability factor	(DOE 2015g)
		Capacity credit	*Set to availability factor*
		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2015g; IEA2012)
		Fixed O&M cost	(IEA 2012)
		Variable O&M cost	(Schlömer et al. 2014)
		Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model
Off	Diesel/Oil	Efficiency or heat rate	(DOE 2015g)
		Current and planned capacity	(NAPOCOR – Small Power Utilities Group 2014; DOE 2012b)
		Availability factor	(DOE 2015g)
		Capacity credit	(NAPOCOR – Small Power Utilities Group 2014)

		Plant lifetime	(DOE 2015g)
		Capital cost	(DOE 2015g)
		Fixed O&M cost	(B-LEADERS 2015a)
		Variable O&M cost	(B-LEADERS 2015a)
		Emission factors	*See Table III. 6*
Off	Small Hydro	Efficiency or heat rate	(DOE 2015d)
		Current and planned capacity	(NAPOCOR – Small Power Utilities Group 2014; DOE 2012b)
		Availability factor	(DOE 2011a)
		Capacity credit	(NAPOCOR – Small Power Utilities Group 2014)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015)
		Fixed O&M cost	(ERC 2015)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*SeeTable III. 6*
Off	Solar Photovoltaic	Efficiency or heat rate	*N/A*
		Current and planned capacity	(NAPOCOR – Small Power Utilities Group 2014; DOE 2012b)
		Availability factor	(ERC 2015)
		Capacity credit	(NAPOCOR – Small Power Utilities Group 2014)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015; IEA2012)
		Fixed O&M cost	(ERC 2015; IEA2012)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*Table III. 6*
Off	On-Shore Wind	Efficiency or heat rate	*N/A*
		Current and planned capacity	(NAPOCOR – Small Power Utilities Group 2014; DOE 2012b)

		Availability factor	(ERC 2015)
		Capacity credit	(ERC 2015)
		Plant lifetime	(ERC 2015)
		Capital cost	(ERC 2015; IEA2012)
		Fixed O&M cost	(ERC 2015; IEA2012)
		Variable O&M cost	*Included in fixed O&M*
		Emission factors	*See Table III. 6*

Values for key technical and cost parameters for generation technologies are listed in Table III. 14. Key Technical and Cost Parameters for Electricity Generation Technologies – Baseline Values. As this table indicates, certain parameters vary during the projection period. These changes reflect two different situations:

1) For mature, established technologies, gradual convergence to international averages in cases where current (Philippine) costs are substantially higher or performance parameters are substantially worse than international norms.
2) For developing technologies, expected cost and performance improvements due to technological learning, commercialization, and economies of scale.

Expected changes in both cases were determined by consulting the international sources noted in Table III. 13. Technical and Cost Parameters for Electricity Generation Technologies – Sources.

Table III. 14. Key Technical and Cost Parameters for Electricity Generation Technologies – Baseline Values

Technology	Efficiency [%]		Availability [%]	Lifetime [Years]	Capital Cost [Million 2010 USD/MW]		Fixed O&M Cost [Thousand 2010 USD/MW]		Variable O&M Cost [2010 USD/MWh]	
	2014	2050			2014	2050	2014	2050	2014	2050
On-Grid Technologies										
Subcritical Pulverized Coal	35	35	80	35	1.6	1.6	85	85	9.0	9.0
Supercritical Pulverized Coal	36	43	80	35	1.9	1.9	112	112	6.4	6.4

Technology	Efficiency [%]		Availability [%]	Lifetime [Years]	Capital Cost [Million 2010 USD/MW]		Fixed O&M Cost [Thousand 2010 USD/MW]		Variable O&M Cost [2010 USD/MWh]	
Ultrasupercritical Pulverized Coal	48	52	80	35	2.3	2.3	46	46	3.4	3.4
Circulating Fluidized Bed Combustion Coal	41	41	80	35	2.1	2.1	44	44	2.6	2.6
Diesel	36	36	80	20	1.1	1.1	42	42	18	18
Oil Combined Cycle	36	36	80	20	0.8	0.8	42	42	18	18
Oil Thermal	36	36	80	20	0.9	0.9	42	42	18	18
Natural Gas Combined Cycle	60	63	80	25	0.6	0.6	37	37	1.9	1.9
Large Hydro	35	35	26	30	2.3	2.3	48	48	23	23
Small Hydro	35	35	26	25	2.9	2.9	65	65	0	0
Geothermal	10	10	70	30	4.5	4.1	326	187	75	28
Biomass Combustion	35	35	80	20	2.6	2.6	132	132	0	0
On-Shore Wind	100	100	28	20	2.1	1.8	73	65	0	0
Solar Photovoltaic	100	100	19	25	1.7	0.6	52	19	0	0
Ocean Thermal	100	100	95	20	10.9	5.0	122	122	0	0
Nuclear	36	37	80	40	4.5	4.0	115	104	13	13
Landfill Gas	28	28	90	25	1.8	1.8	23	23	15	15
MSW Incineration	30	30	86	15	5.5	5.5	73	73	3.8	3.8
MSW Digestion	63	63	80	25	2.7	2.7	19	19	15	15
Agriculture Waste Digestion	25	25	80	20	2.7	2.7	89	89	4.2	4.2

Technology	Efficiency [%]		Availability [%]	Lifetime [Years]	Capital Cost [Million 2010 USD/MW]		Fixed O&M Cost [Thousand 2010 USD/MW]		Variable O&M Cost [2010 USD/MWh]	
Off-Grid Technologies										
Diesel/Oil	30	30	80	20	0.5	0.5	42	42	18	18
Small Hydro	35	35	26	25	2.9	2.9	65	65	0	0
On-Shore Wind	100	100	28	20	2.1	1.8	73	65	0	0
Solar Photovoltaic	100	100	19	25	1.7	0.6	52	19	0	0

As explained above, in the baseline (and other) projections, the power submodel simulated meeting projected final demand for electricity. Given that the submodel was based on specific technologies and production capacities, there were two pivotal questions in determining the power sector's energy and emissions impacts: 1) what capacity was used to satisfy power requirements (capacity dispatch) and 2) how new capacity was added if needed (capacity expansion). These questions were resolved by applying simulation rules.

For capacity dispatch, technologies were utilized according to dispatch priorities that follow patterns observed in the historical record (DOE 2012a; DOE 2014a; DOE 2015d). These priorities are listed in Table III. 15 (lower values indicate higher priorities).

Table III. 15. Dispatch Priorities in Electricity Generation Submodel

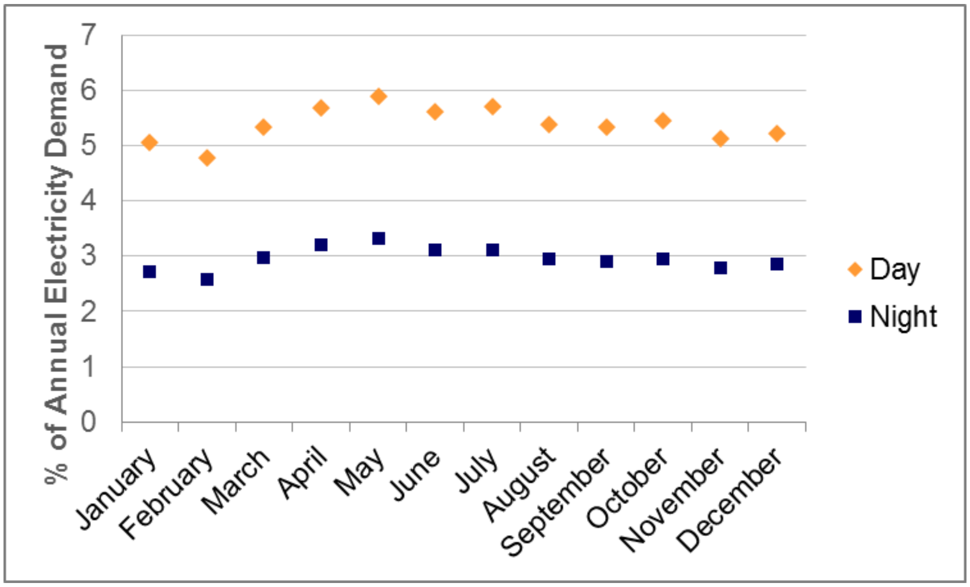
Technology	Dispatch Priority
On-Grid Technologies	
Subcritical Pulverized	2
Supercritical Pulverized	2
Ultrasupercritical Pulverized	2
Circulating Fluidized Bed Combustion	2
Diesel	3
Oil Combined Cycle	3
Oil Thermal	3

Technology	Dispatch Priority
Natural Gas Combined Cycle	2
Biomass Combustion	2
Geothermal	1
Large Hydro (> 10 MW)	2
Small Hydro (≤ 10 MW)	1
Ocean Thermal	1
Solar Photovoltaic	1
On-Shore Wind	1
Agricultural Waste Digestion (Biogas)	2
Landfill Gas	1
MSW Digestion (Biogas)	1
MSW Incineration	1
Nuclear	1
Off-Grid Technologies	
Diesel/Oil	2
Small Hydro (≤ 10 MW)	1
Solar Photovoltaic	1
Wind	1

Technologies at a given priority level are not run until all higher priority technologies have been dispatched. In rough terms, this means that renewables (except large hydro and biomass/biogas) are used when available; large hydro, natural gas, coal, and biomass/biogas plants meet most other power requirements; and diesel and oil technologies provide peaking capacity.

The dispatch simulation divides annual electricity requirements into 24 periods: a daily period and a nightly period for each month. Sufficient capacity must be available and utilized to satisfy power demands in every period. Figure III. 4 illustrates the share of annual electrical energy requirements in each period, for on- and off-grid electricity separately.

Figure III. 4. Electricity Demand by Period, Baseline Scenario



Source: DOE (2014c)

For capacity expansion, the principal rule is that capacity is added as needed to maintain the specified reserve margin: 20% of peak load (taken from Tamang 2015). LEAP differentiates between two types of capacity in the model, *exogenous* and *endogenous*. Exogenous capacity is entered as an input to a model, whereas endogenous capacity is added by the model itself to maintain the reserve margin. Exogenous capacity in the baseline scenario includes all existing plants and reflects the following additional assumptions:

1) All plants, both currently existing and built in the future, are retired at the end of their expected lifetime.
2) Committed projects in DOE (2015c) go forward as planned.
3) The installed capacity targets in the Philippine Energy Plan 2012-2030 are met, and the 2030 targets continue in effect through 2050 (DOE 2012e).

If exogenous capacity is insufficient to satisfy the reserve margin, endogenous capacity is allowed. If the deficiency is in on-grid power, technologies are prioritized for capacity additions according to the committed and indicative power projects reported in the Philippine Energy Plan (DOE 2012f; DOE 2012i). New coal, natural gas, oil, and renewables plants are all used, although coal and natural gas are weighted more heavily in the mix. Subcritical and supercritical pulverized coal technologies are eventually phased out in favor of ultrasupercritical technology. For off-grid power, technologies are prioritized for additions in a way that approximately maintains each technology's current share of off-grid capacity.

Total generation in power sector simulations necessarily exceeds final demand for electricity due to own use of electricity by power producers and transmission and distribution losses. For the baseline scenario, the average own use factor for the power sector (5%) and average losses in transmission and distribution (13%) are taken from DOE (2015j). Average transmission and distribution costs (0.047 2010 USD/kilowatt hour [kWh]) are sourced from B-LEADERS (2015c).

III.3.1.4 Ethanol and Biodiesel Production

Although the modeling of ethanol and biodiesel production considered both production capacity and technologies, it is substantially simpler than the power sector submodel. Two production pathways were represented for ethanol (ethanol from sugarcane and from molasses), and one was modeled for biodiesel (coconut methyl ester from copra). Sources and values for the technical parameters used to model these pathways are shown in Table III. 16. Technical Parameters for Biofuels Production Technologies – Sources and Table III. 17. Key Technical Parameters for Biofuels Production Technologies – Baseline Values.

Table III. 16. Technical Parameters for Biofuels Production Technologies – Sources

Technology	Parameter	Data Sources
Ethanol From Sugarcane	Efficiency (sugarcane in/ethanol out)	(Argonne National Laboratory 2015)
	Auxiliary fuel use (heat and electricity)	(Argonne National Laboratory 2015)
	Current and planned capacity	(DOE 2012h; DOE 2015a)
	Availability factor	*Set to 100% in absence of better information*
	Capacity credit	*Set to availability factor*
	Plant lifetime	*Set to 30 years in absence of better information*
	Emission Factors	*See Table III*. 6 Sources of Emission Factors in the Energy Sector Model
Ethanol From Molasses	Efficiency (molasses in/ethanol out)	(Gopal and Kammen 2009)
	Auxiliary fuel use (heat and electricity)	(Argonne National Laboratory 2015; Gopal and Kammen 2009)
	Current and planned capacity	(DOE 2012h; DOE 2015a)
	Availability factor	*Set to 100% in absence of better information*
	Capacity credit	*Set to availability factor*
	Plant lifetime	*Set to 30 years in absence of better information*
	Emission Factors	*See Table III*. 6 Sources of Emission Factors in the Energy Sector Model
Biodiesel	Efficiency	(Tan, Culaba, and Purvis 2004)

From Copra	(copra in/biodiesel out)	
	Auxiliary fuel use (heat and electricity)	(Tan, Culaba, and Purvis 2004)
	Current and planned capacity	(DOE 2012g; DOE 2015a)
	Availability factor	*Set to 100% in absence of better information*
	Capacity credit	*Set to availability factor*
	Plant lifetime	*Set to 30 years in absence of better information*
	Emission Factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model

Table III. 17. Key Technical Parameters for Biofuels Production Technologies – Baseline Values

Technology	Efficiency		Auxiliary Fuel Use	Availability [%]	Lifetime [Years]
	Value	Unit			
Ethanol From Sugarcane	46.729	kg sugarcane / U.S. gallon ethanol	0.62 MJ bagasse and 0.004 MJ residual fuel oil / MJ ethanol	100	30
Ethanol From Molasses	56	kg molasses / 18.6 liters ethanol		100	30
Biodiesel From Copra	1.667	kg copra / kg biodiesel	0.06 MJ natural gas and 0.10 MJ electricity / MJ biodiesel	100	30

When ethanol production was simulated, the model followed an elementary rule to choose between the two possible pathways. Available sugarcane (sugarcane that is not milled for sugar production) was first used in its entirety, and molasses was used thereafter to meet remaining demand. This approach acknowledges that several production facilities can in fact use either feedstock and may vary their selection depending on resource availability. The methods for projecting the availability of sugarcane and molasses are described at the end of Section III.3.1 Methods and Assumptions. If exogenous capacity was required to maintain a reserve margin (set at a default value of 30%), molasses capacity was added.

In the case of biodiesel, the copra pathway fulfills all demand, and additional copra capacity was added as required to maintain a 30% reserve margin. A description of the projection of available copra is also provided at the end of Section III.3.1 Methods and Assumptions.

As Table III. 16. Technical Parameters for Biofuels Production Technologies – Sources suggests, the simulation of the biofuels industries does not include an explicit representation of production costs. This configuration contrasts with the electricity sector submodel: there, capital, O&M, input, and transmission and distribution costs are all explicitly modeled, and the sum of these production costs is taken to be the social cost of electricity. Because data limitations prevented a similar approach for biofuels, the social cost of ethanol and biodiesel was instead calculated using the projected consumer prices described in Section III.4.1 Methods (total social cost is price multiplied by domestic demand). This costing technique was also used for all other fuels besides electricity, such as refined petroleum products, natural gas, and charcoal (for a complete listing, refer to Table III. 27. Historical and Projected Fuel Prices, All Scenarios [2010 USD/GJ]). Fundamentally, it assumed that consumer or market prices for these fuels satisfactorily represent the social cost of producing them.

III.3.1.5 Oil Refining

For oil refining, the aggregate capacity of all refineries was modeled, but specific refining technologies were not. Instead, an average efficiency for all technologies (comprising both losses and own use during refining) was used to calculate crude oil inputs for any required outputs of petroleum products. A simplifying assumption was also made that outputs from refineries were in proportion to the requirements for refined products rather than in fixed proportions (e.g., x tonnes gasoline to y tonnes diesel to z tonnes kerosene in all cases). Table III. 18. Technical Parameters for Oil Refining – Sources and Baseline Values lists sources and key technical parameters in the modeling of oil refining.

Table III. 18. Technical Parameters for Oil Refining – Sources and Baseline Values

Parameter	Data Sources	Value
Efficiency[a]	(DOE 2015d; IEA2014a)[11]	94%
Current and planned capacity	(DOE 2015h)	285.2 thousand barrels per stream day[b]
Availability factor	(DOE 2015d; DOE 2015h)	85%
Emission factors	*See Table III.* 6 Sources of Emission Factors in the Energy Sector Model	

[a] Including production losses and own use.

[b] Following a decade of variable production capacity, the baseline scenario assumes that total refining capacity does not increase during the projection period (following from Ayson (2015)). The 2014 capacity of 285.2 thousand barrels per stream day is maintained through 2050.

[11] Efficiency losses during refining are specified in DOE's balances. Total own use of each fuel by all energy industries is also shown in the DOE balances; the IEA balances were used to distribute these totals among the industries represented in the model. The results apply here and to the energy industries discussed in the next subsection. This approach seems reasonable since DOE's own use totals match IEA's.

III.3.1.6 Other Energy Industries: CNG Compression, Natural Gas and Crude Oil Production, Coal Mining, and Charcoal Production

The treatment of the remaining energy industries in the supply model was quite basic and focused on an accounting of energy use and GHG emissions. CNG compression was assumed to be by electric compressor with a total efficiency (defined in Equation III. 3) of 97.87% (Argonne National Laboratory 2015).

$$total\ efficiency\ of\ CNG\ compression = \frac{CNG\ energy\ out}{natural\ gas + electric\ energy\ in}$$

Equation III. 3

For crude oil, natural gas, and coal production, own use factors were determined from DOE (2015d) and IEA (2014a), and factors for fugitive emissions are taken from the sources identified in Table III. 6 Sources of Emission Factors in the Energy Sector Model. Different factors were applied for underground and surface coal mining, which necessitates an estimate of the fraction of coal production occurring in each context. The baseline scenario assumed that the fractions defined by Manila Observatory (2010)—96% surface mining and 4% underground mining—hold through 2050.

Charcoal production was modeled using the most recent wood-to-charcoal conversion efficiency shown for the Philippines, 35%, in IEA (2014a). Emission factors were taken from the sources listed in Table III. 6 Sources of Emission Factors in the Energy Sector Model. Although CO_2 emissions from charcoal production do not count as energy sector GHG emissions (the carbon is instead counted in the forestry sector), charcoal production does release CH_4, N_2O, and other air pollutants.

By not explicitly representing capacity constraints for these energy industries, the model in essence assumed that required quantities of the outputs can be produced subject only to the availability of inputs. Limits on the availability of primary energy inputs are discussed in the next subsection.

III.3.1.7 Natural Resources

Backstopping the projection of domestic energy production are assumptions about natural resource availability. These include estimates of domestic fossil fuel reserves and annual yields for renewable resources. Table III. 19 reviews the derivation of these estimates for natural resources represented in the energy model. Table III. 20, Table III. 21, Figure III. 5, and Figure III. 6 summarize the projected availability of major resources in the baseline scenario.

Table III. 19. Methods for Estimating Natural Resource Availability

Resource	Method
Crude Oil, Natural Gas, and Condensate	Estimate of current reserves taken from DOE (2011c). Reserves drawn down during projection as domestic resource is used.
Coal	Estimate of current reserves and expected discoveries taken from DOE (2012j;

	2012d). Reserves drawn down during projection as domestic resource is used.
Wood	Use of wood for energy based on CBA's forestry modeling (see Figure III. 3. Wood Harvest for Energy, Baseline Scenario
Rice Hull	Annual availability based on projection of rice production from CBA's agriculture modeling (see Figure III. 5) and assumption that 1 metric tonne rice produces 0.2 metric tonnes rice hull.
Bagasse	Annual availability based on projection of sugarcane production from CBA's agriculture modeling (see Figure III. 5) and assumption that 1.0 metric tonne sugarcane produces 0.3 metric tonnes bagasse.
Sugarcane	Annual availability of unprocessed sugarcane as input for ethanol production based on projection of sugarcane production from CBA's agriculture modeling (see Figure III. 5 (Sugar Regulatory Administration 2013).
Molasses	Annual availability based on amount of sugarcane milled for sugar and assumption that 1.0 metric tonne sugarcane milled yields 0.056 metric tonnes molasses (Gopal and Kammen 2009).
Copra	Annual availability based on projection of coconut production from CBA's agriculture modeling (see Figure III. 5) and yield of copra from fresh coconut reported in Guarte, Mühlbauer, and Kellert (1996).
Coconut Residue	Annual availability based on projection of coconut production from CBA's agriculture modeling (see Figure III. 5) and assumption that 1 kg. coconut residue is available per kg. of copra produced (Tan, Culaba, and Purvis 2004).
Animal Wastes	Annual availability based on projections of livestock population from CBA's agriculture modeling (see Figure III. 6) and estimates of manure production per head in USEPA (1999b) and FAO (1997).
Landfill Gas	Annual availability based on projections from CBA's waste modeling.
Organic MSW	Annual availability based on projections from CBA's waste modeling.
Other MSW	Annual availability based on projections from CBA's waste modeling.
Wind	Annual availability taken from National Renewable Energy Laboratory (2014).
Solar	Annual availability based on assumption that 0.1% of total national land area can be developed for solar, with an average irradiance of 161.7 W/m^2 (DOE 2015i).
Small Hydro	Annual availability based on DOE (2015f).

Large Hydro	Annual availability based on DOE (2015f).
Geothermal	Annual availability taken from DOE (2011b).
Ocean Thermal	Annual availability assumed to be unlimited.

Table III. 20. Historical and Projected Fossil Fuel Reserves, Baseline Scenario [Million Tonnes of Oil Equivalent]

Fuel	2010	2020	2030	2040	2050
Crude Oil	275.4	246.2	196.8	147.4	98.0
Natural Gas	239.4	189.4	92.0	-	-
Condensate	25.1	17.4	2.4	-	-
Coal	196.7	153.6	40.8	-	-

Table III. 21. Annual Yield of Renewable Resources, Baseline Scenario [Thousand Tonnes of Oil Equivalent][12]

Fuel	2010	2020	2030	2040	2050
Animal Wastes	40,439	42,984	46,630	50,275	53,921
Bagasse	931	1,361	1,460	1,560	1,659
Coconut Residue	789	889	994	1,099	1,204
Copra[a]	999	1,126	1,259	1,392	1,525
Geothermal	23,236	23,236	23,236	23,236	23,236
Landfill Gas	17	17	17	17	17
Large Hydro	11,012	11,012	11,012	11,012	11,012
Molasses[b]	166	246	263	281	299
Municipal Solid Waste (Other)	1,241	1,988	3,409	6,047	11,079
Municipal Solid	1,626	2,836	4,864	8,628	15,808

[12] Wood is not shown because the annual wood harvest for energy is determined directly from the CBA's forestry modeling; thus, it is not necessary to model wood availability *per se*. Ocean thermal is not shown because it is assumed to be effectively unlimited.

Fuel	2010	2020	2030	2040	2050
Waste (Organic)					
Rice Hull	976	1,263	1,500	1,738	1,976
Small Hydro	917	917	917	917	917
Solar	37	37	37	37	37
Sugarcane[c]	11	4	4	5	5
Wind	110,892	110,892	110,892	110,892	110,892

[a] Represents the biodiesel energy that could be produced from available copra.
[b] Represents the ethanol energy that could be produced from available molasses.
[c] Represents the ethanol energy that could be produced from available sugarcane.

Figure III. 5. Production of Rice, Sugarcane, and Coconut, Baseline Scenario

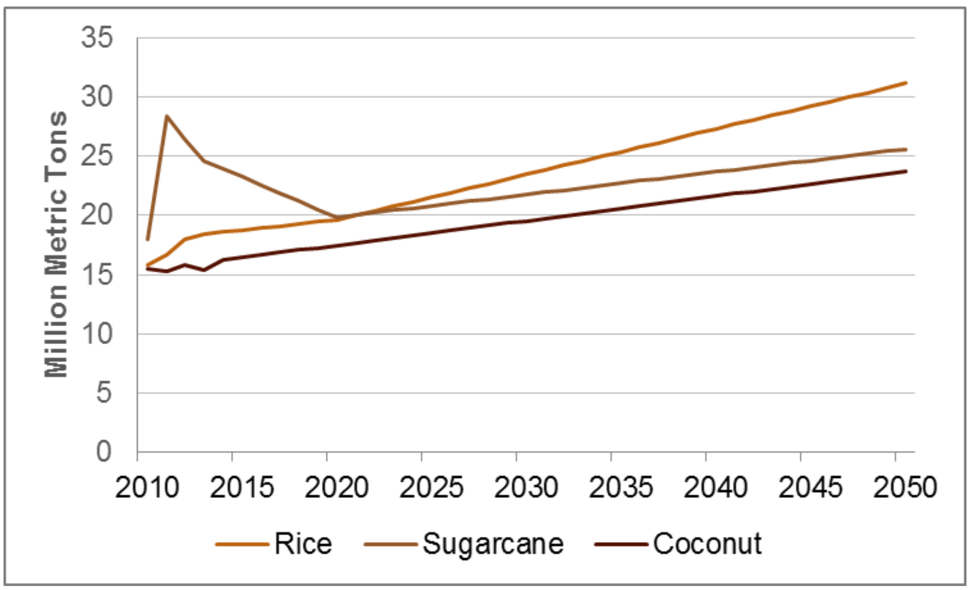
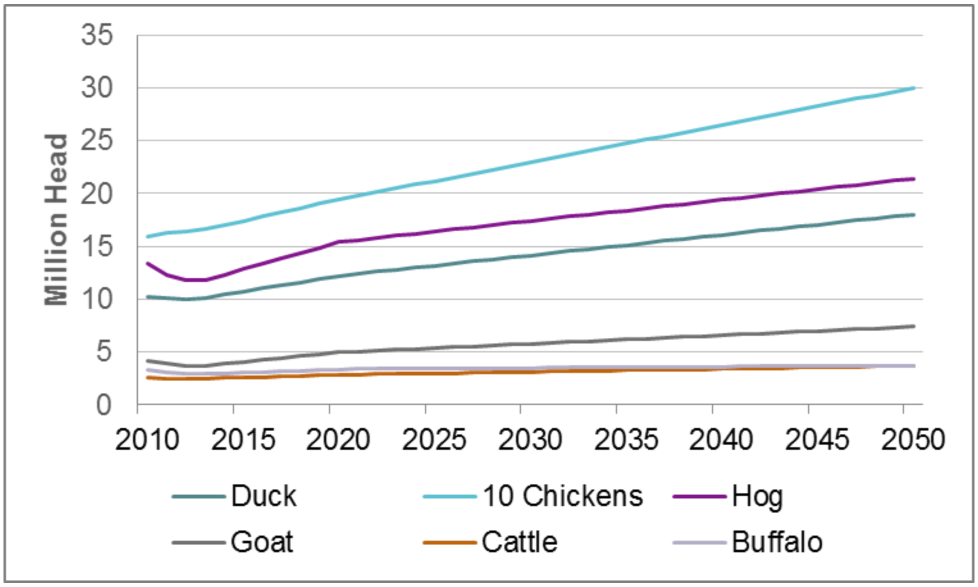


Figure III. 6. Livestock Populations, Baseline Scenario



In general, as suggested in Table III.19 , renewable resource projections in the model characterize the resources' technical potential. Only a fraction of this potential was used in the baseline and other projection scenarios.

III.3.1.8 Stakeholder Feedback on Baseline Assumptions

Throughout the data collection and modeling processes for the CBA, local experts, government agencies, and national documentation were regularly consulted. This close contact ensured the modeling team was responsive to emerging assumptions and to the availability of the most nationally appropriate data. **Table III. 22. Key Stakeholders Consulted for CBA**Table III. 22. lists key stakeholders consulted for the CBA.

Table III. 22. Key Stakeholders Consulted for CBA

Agency or Organization	Department	Stakeholders Consulted
CCC		Secretary Mary Ann Lucille Sering Asst. Secretary Joy Goco Sandee Recabar Arnold Grant Belver Alona Areza Theresa Lim
DOE		Loreta G. Ayson, DOE Undersecretary

Agency or Organization	Department	Stakeholders Consulted
	Renewable Energy Management Bureau	Michael John S. Velasco Rainier M. Halcon Art Torralba, Jr. Ramon O. Jaurigue Edward V. Neri Ida A. Madrideo
	Energy Policy and Planning Bureau	Dir. Jess Tamang Asst. Dir. Carmencita Bariso Marietta Quejada Letty G. Abella Hershey dela Cruz Caroline Quitaleg
	Oil Industry Management Bureau	Mr. Rick Infante Edison O. Subala
	Electric Power Industry Management Bureau	Dir. Mylene C. Capongcol Mr. Emmanuel Talag Jhoana B. Limabaga
	Energy Utilization Management Bureau	Janet Capricho Mr. Art Habitan Mr. Rodel Limbaga Mr. Jonathan Teodosio Ms. Joan Sotelo Mr. Federico G. Domingo, Jr. Mr. Loreto B. Moncada
DENR	Forest Management Bureau	Edna Nuestro, Chief, Forest Policy, Planning and Knowledge Management Division (FPPKMD) Mark DV de Claro, Forest Resource Conservation Division

Agency or Organization	Department	Stakeholders Consulted
		Rene Siapno, Forest Resource Management Division Eugene Estrada, FPPKMD Nilda Patiga, FPPKMD Alejandrino Sibucao, Jr., FPPKMD Larlyn Faith Aggabao, FPPKMD Kenneth Tabliga Ma. Bernadeth O.C. Adriano Lummaba C. Rotol Rowel B. Velonza Nelissa Maria Jhun Barit
	Environment Management Bureau	Albert Magalang Ms. Winnie Passe Rolando Abad Jr.
	Air Quality Mgt. Section	Ms. Jean Rosete
	Water Quality Mgt. Section	Leza Cuevas, Engr., Section Chief
DOTC	Planning	Dr. Mike Gyeng Chul Kim Mr. Robert Siy Jr.
	Project Implementation	Dir. Florencia A. Creus
	Road Transport Planning	Mr. Arnel Manresa Mr. Lemar Jimenez
PSA	Bureau of Agricultural Statistics	Dulce Regala, Division Chief Lorna V. Gabito Jacinta U. Estrada Edward Eugenio Dee

Agency or Organization	Department	Stakeholders Consulted
DA	Climate Change Office	Mr. Nikko M. Macalintal – Planning Officer II
	Bureau of Soils and Water Management	Karen Salandanan-Bautista, Focal Person, Organic Agriculture Program Dir. Silvino Q. Tejada Engr. Samuel M. Contreras Grace Sheila Jalani
	Bureau of Animal Industry	Hernando F. Avilla, Supervising Science Research Specialist Angel Antonio B. Mateo, OIC, Research Division Reymer G. Martinez, Science Research Specialist II
	PhilRice	Jasper G. Tallada, Center Director Dr. Ricardo F. Orge – Director
DPWH		Mr. Kelvin Mamitag – Sr. EMS
Dept. of Trade and Industry	Bureau of Investments	Dino John B. Recto – Investments Specialist Dennis Bernabe – Policy Officer
Fertilizer and Pesticide Authority	Planning, Management and Information Division	Leonora C. Japon Alma G. Escasura
NEDA	Environment Services Division	Wilson Henson, Agriculture Staff Kathleen Capiroso Dorothy Bantasan
	Infrastructure Staff	Gilbert Ofina Francis Bryan Coballes, Division Chief
Land Transportation Office	Management Information	Ms. Paquita Dela Cruz
Metropolitan Development Authority		Ariel C. Decena Reynaldo M. Estipona
National Mapping and Resource	Resource Data Analysis	Dir. Rijalda N. Santos

Agency or Organization	Department	Stakeholders Consulted
Information Authority		Cristina Montoya
National Commission on Indigenous Peoples		Gillian Dunuan – Division Chief Atty. Rizzabel Madangeng
National Center for Transportation Studies (NCTS)		Dr. Jose Regin F. Regidor Engr. Sheila Flor Dominguez Javier Ernesto Abayan
National Solid Waste Management Council (NSWMC)		Eli Ildefonso, OIC, Executive Director Delia Valdez NSWMC Commissioner Lao 14 NSWMC TWG Members 1 NSWMC TWG Private
United Nations Development Programme (UNDP)	Low Emissions Capacity Building Program	Francis Benito Jec Andres Aimee Evangelista
Deutsche Gesellschaft für Internationale Zusammenarbeit		Voltaire Acosta
Asian Development Bank (ADB)		David Raitzer Jindra Samson
Industrial Associations and Representatives	HOLCIM	
	CEMEX	
	LaFarge	Mr. Cirilo M. Pesaono II
	Conpac Agro Enterprises, Inc.	Crispin Cruz, Operations Manager
	Sustainable Environment thru	Shielson Sibolboro, CEO

Agency or Organization	Department	Stakeholders Consulted
	Renewable Energy Development Environmental Consultancy	
	Cement Manufacturer's Association of the Phils.	Ma. Raysolyn Natividad – Internal Relations Manager
Non-governmental Organizations	Clean Air Asia	Mr. Alvin Mejia
	USAID's Analysis and Investment for Low-Emission Growth Project	Josephine Mangila-Tioseco
RE Developers	First Gen	Al Santos – Vice President Tonito Payumo – Asst. Vice Pres.

After the modeling for this report had been completed, stakeholders shared with the CBA team some additional improvements to baseline assumptions that could be incorporated in a later version of the energy sector LEAP model. Table III. 23. Further Improvements to Baseline Modeling Assumptions documents these recommendations. Without using the revised assumptions in the model, it could be difficult to determine the combined impact of the assumptions on the baseline and mitigation results. Exploring this question should be a priority in any further development of the model.

Table III. 23. Further Improvements to Baseline Modeling Assumptions

	Technology	Current Assumption	Improved Assumption
Demand	**Residential**		
	Average occupants per household	4.80 (DOE and NSONSO 2011)	4.57 (PSA2010), with downward trend through 2050
	Industrial and Commercial		
	Off-Grid Electricity	Annual off-grid electricity demand is approximately 1% of national electricity demand	Off-grid demand constituted 1.6% of all electricity demand in 2014 (DOE 2015l), expected to rise through

	Technology	Current Assumption	Improved Assumption
			2050
Supply	**Electricity Generation**		
	Power Plant Dispatch Priority	**Run First**: Geothermal, Landfill Gas, MSW Digestion, MSW Incineration, Nuclear, Ocean Thermal, Wind, Small Hydro, Solar **Baseload**: Agricultural Waste Digestion, Biomass Combustion, all coal technologies, Large Hydro, Natural Gas Combined Cycle (NGCC) **Peak**: Diesel, Oil Combined Cycle, Oil Thermal	**Must-run**: Landfill Gas, MSW Incineration, MSW Digestion, Solar PV, Wind, Ocean Thermal, Geothermal, Small Hydro, all existing NGCC **Baseload**: Biomass, Large Hydro, all coal technologies, Nuclear, portion of new NGCC, Agricultural Waste Digestion **Mid-peak**: Remainder of new NGCC **Peak**: Diesel, Oil Combined Cycle, Oil Thermal
	Exogenous Power Plant Capacity	*See Table III.* 13. Technical and Cost Parameters for Electricity Generation Technologies – Sources *for sources*	Revised list of committed capacity for all plant types through 2019 from DOE (2015m)
	Endogenous Power Plant Capacity	*Sources and methods described earlier in this section*	Revised list of indicative capacity for all plant types through 2019 from DOE (2015m)
	Nuclear Power	No nuclear power plants are constructed	A small quantity of nuclear capacity is likely to be constructed during 2025-2030 as an emerging technology (DOE 2015l)
	Electrical Transmission	Off- and on-grid electricity incur the same T&D loss of 13.7% in 2014 (DOE 2015j)	Off-grid T&D loss was 2.14% in 2014 (DOE 2015l), should be used for all years
	Other Sectors		
	Oil Refining Own Use	Own use determined from DOE (2015d), IEA (2014a)	Historical own use calculated from DOE (2015e)

	Technology	Current Assumption	Improved Assumption
	Oil Products Export	Planned export of products through 2050 is fixed at 2013 levels	Exports should constitute the same percentage share of oil production as observed historically
	Bioethanol Production	Availability of domestic production is sufficient to meet demand in all years	Bioethanol has largely been imported, and will continue to be in the future. Availability of bioethanol will be fixed at most recently observed historical value.
Resources	**Fossil Fuels**		
	Reserves	Crude Oil: 271.9 MTOE Condensate: 22.9 MTOE Natural Gas: 225.6 MTOE Coal: 189.7 MTOE *(reserve estimates for 2014 are projected from most recent data available)*	Crude Oil: 2.1 MTOE Condensate: 8.1 MTOE Natural Gas: 16.3 MTOE Coal: 111.9 MTOE *(proven reserves in 2014)*

III.3.2 Results

Baseline GHG emissions from the energy sector are shown in Figure III. 7. **Baseline GHG Emissions from the Energy Sector** and

Table III. **24**.

Figure III. 7. Baseline GHG Emissions from the Energy Sector

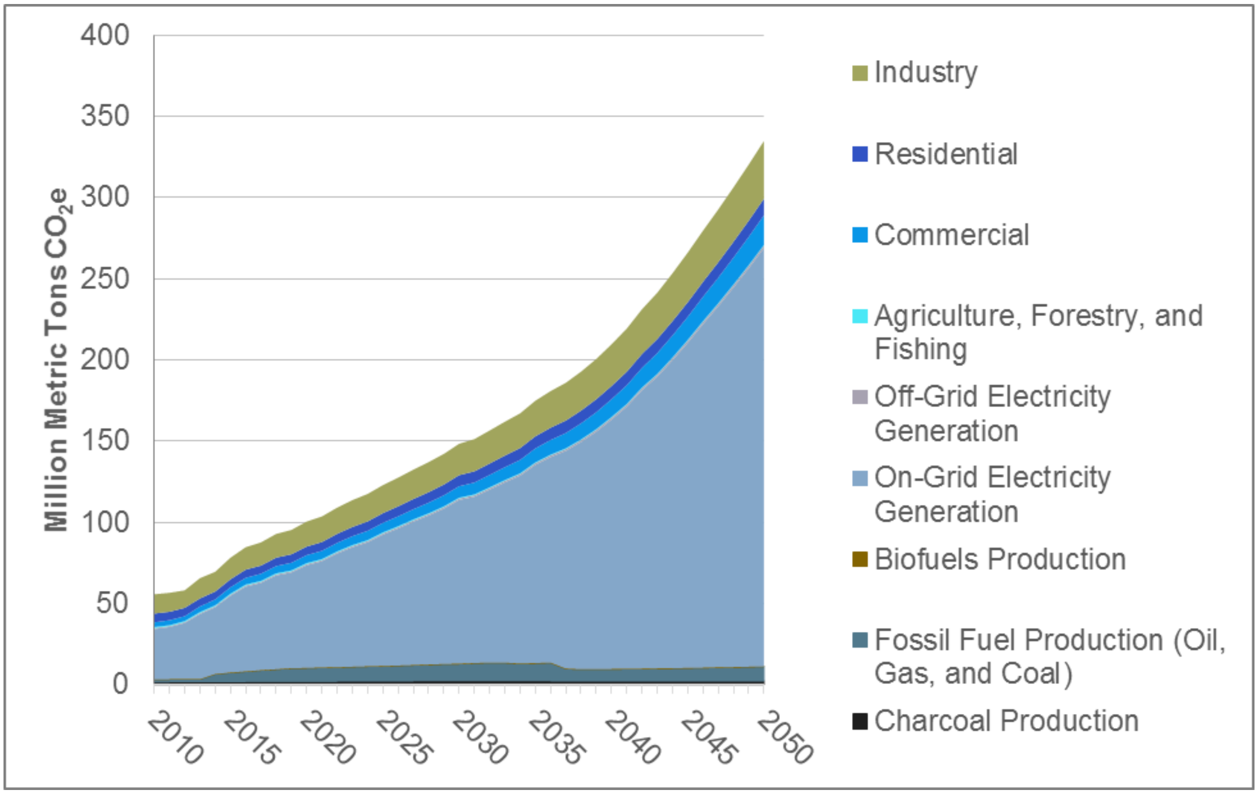
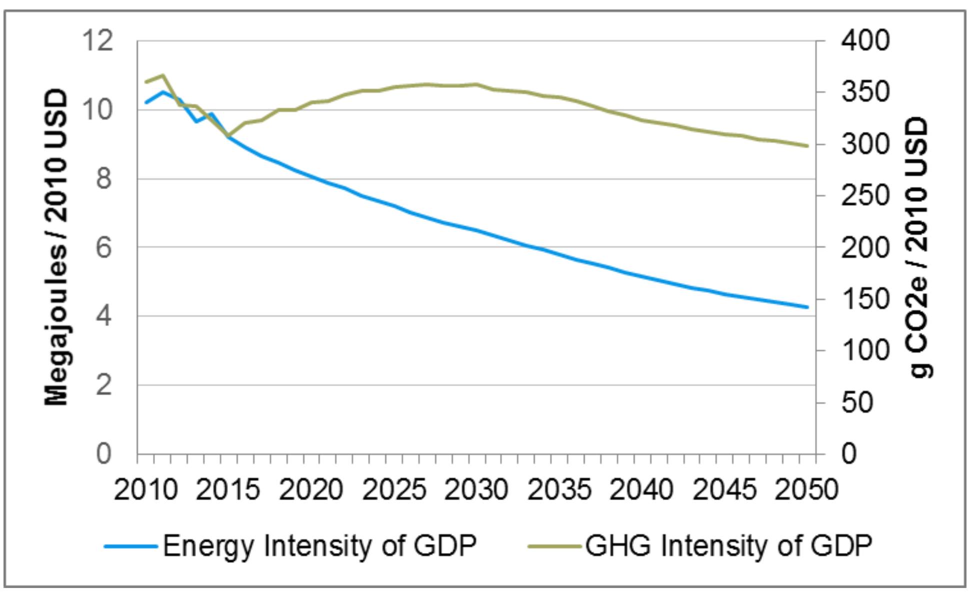


Table III. 24. Baseline GHG Emissions from the Energy Sector [$MtCO_2e$]

Sector	2010	2020	2030	2040	2050
Industry	11.91	15.37	19.36	25.67	35.55
Residential	5.34	5.31	6.80	8.17	10.22
Commercial	2.91	4.89	7.05	10.96	18.31
Agriculture, Forestry, and Fishing	0.66	0.56	0.47	0.40	0.35
Off-Grid Electricity Generation	0.60	0.74	0.92	1.18	1.59
On-Grid Electricity Generation	31.06	63.26	100.85	153.59	257.68
Biofuels Production	0.00	0.04	0.06	0.09	0.09
Fossil Fuel Production (Oil, Gas, and Coal)	1.45	8.18	10.39	7.33	8.88
Charcoal Production	1.73	2.07	2.46	2.24	2.30
Total	**55.66**	**100.43**	**148.36**	**209.63**	**334.96**

Total emissions from energy demand and supply (excluding transport) reach nearly 335 MtCO2e by 2050, six times higher than in 2010. At its core, the increase in emissions is driven by a growing national population and economy. The economy plays an especially important role as rising GDP and industrial and commercial value added induce significant growth in energy demand. Real GDP increases almost tenfold between 2010 and 2050, outweighing the downward secular trend in the energy intensity of GDP (Figure III. 8. Energy and GHG Intensities of GDP, Baseline Scenario).

Figure III. 8. Energy and GHG Intensities of GDP, Baseline Scenario



Both final energy demand and primary energy supply requirements rise as a result (Figure III. 9 and Figure III. 10). As the GHG intensity of the energy supply does not change substantially over the projection period, total emissions increase correspondingly.

Figure III. 9. Final Energy Demand (Excluding Transport), Baseline Scenario

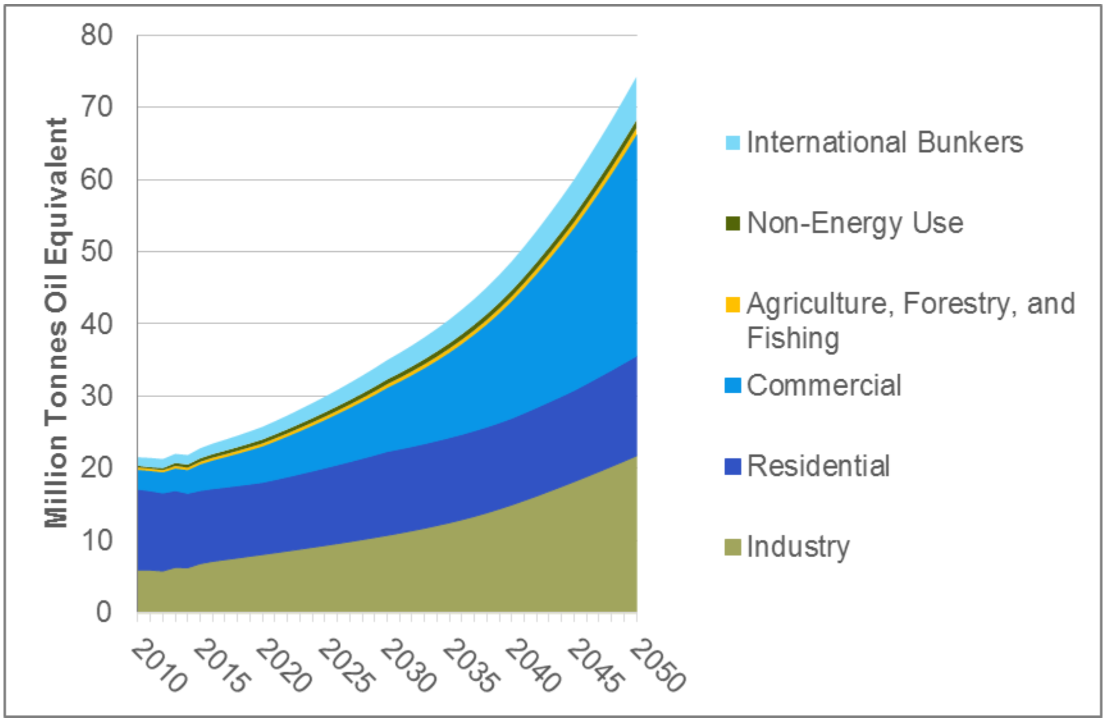
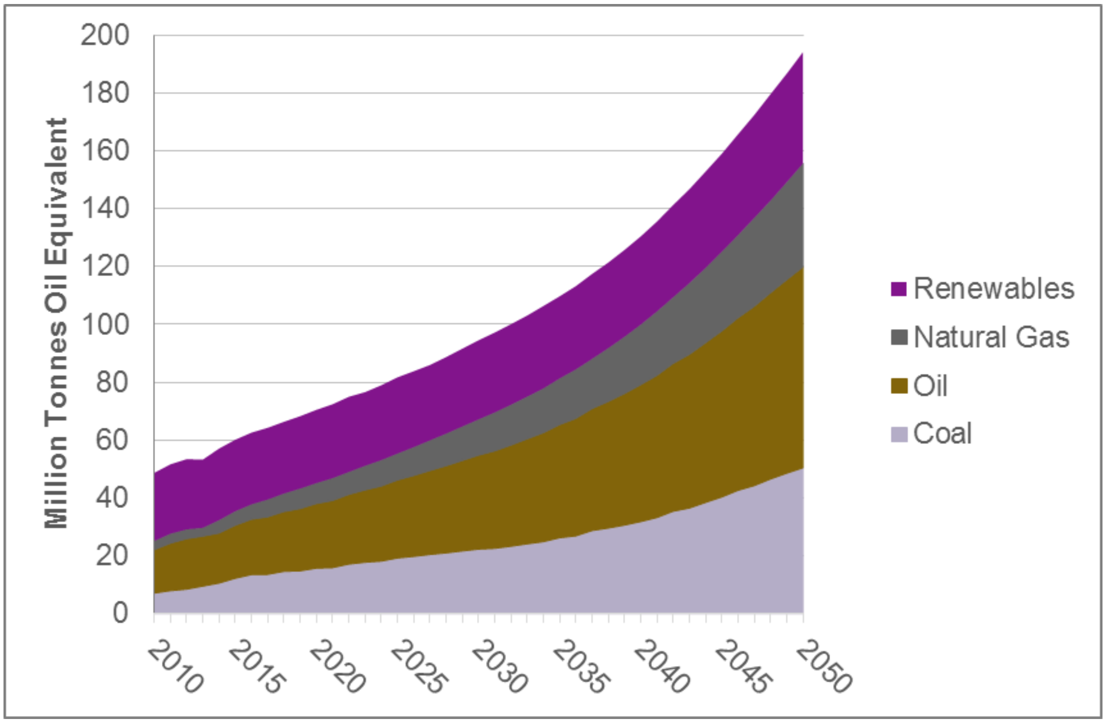


Figure III. 10. Total Primary Energy Supply, Baseline Scenario



Within final energy demand, the share for electricity grows over time: from 16% in 2010 to over 30% in 2050. This development extends a historical trend (the share for electricity was 9.5% in 1990) and is consistent with the projected increase in affluence. Greater reliance on electricity lessens the direct GHG implications of higher final energy demand while prompting considerable growth in power sector emissions. In the power sector, an expanded deployment of coal and natural gas generation to meet rising electricity requirements causes emissions to grow sharply and to dominate energy sector emissions by 2050. This development is also reflected in the expansion of coal and gas in the primary energy supply as depicted in Figure III. 10.

III.4 MITIGATION COST-BENEFIT ANALYSIS

III.4.1 Methods

III.4.1.1 Identification and Description of Mitigation Options

Mitigation options were selected for this study based on two primary criteria: government support and data availability. Both follow from the study's aim to inform Philippine climate and energy policy in a practical way. The CBA team prioritized mitigation options that are reflected in Philippine policies, regulations, and development plans or that are mentioned in past studies conducted with Philippine government collaboration. Additional input was gathered through the team's own consultations with government stakeholders, particularly from CCC and DOE. Key documents and other studies that were considered include the following:

- Philippines' National Framework Strategy on Climate Change and National Climate Change Action Plan (CCC 2010; CCC 2011)
- Philippines' Second National Communication to the UNFCCC (Republic of the Philippines 2014)

- Documentation on Philippines' NREP and supporting legislation (DOE 2011b; Congress of the Philippines 2008)
- Philippine Energy Plan 2012-2030 (DOE 2012c; DOE 2012k)
- Documentation on Philippine Energy Efficiency Project (2012)
- ADB's study on Low-Carbon Scenario and Development Pathways for the Philippines (UPNEC2015c)
- UNDP's study of nationally appropriate mitigation options for the Philippines (Low Emission Capacity Building Project - Philippines 2015)
- Asia Pacific Energy Research Centre's (APERC) Compendium of Energy Efficiency Policies of Asia-Pacific Economic Cooperation (APEC) Economies (APEC 2013)
- World Bank's Assessment of Low-Carbon Interventions in the Transport and Power Sectors in the Philippines (Transport and Traffic Planners Inc. and CPI Energy Phils., Inc. 2010)
- ADB's report on Asia Least-Cost GHG Abatement Strategy: Philippines 1998)

Data availability was another important concern. Various data inputs were required to estimate the emissions and cost impacts of a mitigation option—for example, operating parameters and unit costs of alternative technologies. The CBA team conducted significant data collection activities in the Philippines to develop the necessary inputs, supplementing national data sources with international sources in some cases.

Table III. 25. Energy Sector Mitigation Options Analyzed in CBA lists the energy sector mitigation options chosen for the study. As indicated in Section III.2.1 Methods and Assumptions, each option is modeled as a separate mitigation scenario (an option-specific "mini-scenario") in LEAP. The principal assumptions and characteristics of each mini-scenario are noted in the table. Assumptions not explicitly discussed in the table are inherited from the baseline scenario (described in Section III.3.1 Methods and Assumptions.

Table III. 25. Energy Sector Mitigation Options Analyzed in CBA

Option	Description	Assumptions
Electricity Supply		
NREP	Current trends suggest that substantial growth in electricity demand and generating capacity are on the horizon for the Philippines. In the baseline scenario, much of the required new capacity is powered by fossil fuels, leading to a significant rise in emissions of GHGs and other air pollutants. Deploying renewable power capacity instead could help expand the electricity supply with lower climate and other impacts. This option considers the realization of the renewable capacity goals in NREP, which sets the following installation targets to be attained by 2030 (DOE 2011b):[13] • Biomass – 315.7 MW • Geothermal – 3,461 MW[14] • Hydro – 8,794.1 MW • Ocean – 70.5 MW • Solar – 285 MW • Wind – 2,378 MW The Program's 2030 goals are assumed to remain in effect through 2050.	Technical: Technical parameters for renewable and non-renewable generation technologies and the approach to modeling baseline capacities and dispatch in the power sector are described in Section III.3.1 Methods and Assumptions above. Under NREP, additional renewable capacity is built and made available to the dispatch model. As it is utilized, it displaces more carbon-intensive generation that would otherwise occur, particularly coal, gas, and oil power. It also delays or prevents the addition of some endogenous capacity, fossil capacity in particular.[15] Electricity demand and total electricity production are not affected. The additional biomass capacity required to meet the NREP target is assumed to be biomass combustion, the ocean capacity is assumed to be ocean thermal, the solar capacity photovoltaic, and the wind capacity on-shore. The additional hydropower capacity is split between small (≤ 10 MW) and large (> 10 MW) plants using the ratio of small to large hydropower projects (committed and indicative) in the Philippine Energy Plan (DOE 2012f; DOE 2012i). Changes in requirements for fossil fuels affect upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: Capital and O&M costs for power technologies are described in Section III.3.1 Methods and Assumptions Projected fuel costs are discussed later in this section. No program implementation costs besides capital, O&M, and fuel are modeled.

[13] A separate mini-scenario is modeled for each NREP technology, including mini-scenarios for large and small hydropower. Results are reported by technology in Sections III.4.2 Results and III.4.3 Discussion.

[14] The CBA team understands that DOE intends to lower the geothermal capacity target in a forthcoming revision of NREP (DOE 2015l). The results reported here are based on the original target; the new target may be incorporated in a future version of the LEAP model.

[15] See Section III.3.1 Methods and Assumptions for a discussion of endogenous versus exogenous capacity in the LEAP model.

Option	Description	Assumptions
Substituting Natural Gas for Coal	Despite challenges in supplying natural gas in the Philippines (including the possibility of fugitive GHG emissions from methane leakage), natural gas power has potential climate and air pollution benefits relative to coal. These stem from the chemical composition of gas as well as the efficiency advantages of contemporary combined cycle gas plants. This option analyzes the substitution of natural gas for coal power in two stages: 1) Through 2030, natural gas combined cycle capacity is substituted for approximately 1/3 of endogenous subcritical pulverized coal capacity that would otherwise be built. 2) After 2030, new endogenous coal capacity is disallowed, and resulting capacity shortfalls are filled primarily with new natural gas combined cycle plants.	Technical: The endogenous capacity substitutions just described are the only change to the baseline power model characterized in Section III.3.1 Methods and Assumptions. Technical parameters of gas and coal generation technologies, dispatch priorities, and other attributes of the power model are not altered. Electricity demand and total production are not affected, either. The reduction in coal capacity and the increase in gas capacity leads to more gas power and less coal power delivered to the grid, particularly after 2030. Changes in requirements for fossil fuels affect upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: Capital and O&M costs for power technologies are described in Section III.3.1 Methods and Assumptions. Projected fuel costs are discussed later in this section. No program implementation costs besides capital, O&M, and fuel are modeled.
Methane Recovery from Sanitary Landfills for Electricity Methane Recovery from Dumpsites for Electricity	Capturing landfill gas (LFG) and using it for power generation can have considerable climate and economic benefits. Though the constituents of LFG can vary from site to site, it is generally about half methane, making it a potent GHG and a valuable fuel for many applications. LFG power technology in particular is mature and widely used outside the Philippines (USEPA 2015). Building on the initial LFG power projects currently underway in the country, these options analyze an expansion of LFG power at large landfills and dumpsites, respectively.	Technical: Additional LFG is collected for power generation under each of these options (Figure III. 11. LFG Collected for Electricity Generation, Baseline and Methane Recovery Scenarios).[16] The LFG is assumed to be 50% methane by mass. New LFG generation capacity is then constructed to utilize the additional fuel. Paralleling NREP, this capacity is deployed into the baseline power model described in Section III.3.1 Methods and Assumptions, displacing baseline generation and some endogenously built capacity. Electricity demand and total electricity production are not affected. Changes in requirements for fossil fuels impact upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Collected LFG is not vented to the atmosphere, providing a non-energy GHG benefit that is further characterized in the waste chapter

[16] For a full explanation of the assumptions and modeling underlying the projections of LFG availability, see the waste chapter of this report: *Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project: Philippines Mitigation Cost-Benefit Analysis Waste Sector Results*.

Option	Description	Assumptions
		of this report. Cost: Capital and O&M costs for LFG and other power technologies are described in Section III.3.1 Methods and Assumptions. Excepting LFG, relevant projected fuel costs are discussed later in this section. The incremental costs of collecting additional LFG are documented in the waste chapter of this report.
MSW Digestion MSW Combustion	MSW can also be used to generate electricity. It can be incinerated or pyrolized directly as a fuel, or digested to produce biogas from which power can be generated. While each of these options is potentially controversial in the Philippines, generating power from MSW is a common practice in the U.S. and many European countries (USEPA 2014a; European Environment Agency 2013). Provided that waste-to-energy plants include robust emission controls, they can be an effective way of reducing landfilling and related methane emissions while contributing to energy security. These options comprise a limited deployment of MSW digestion and incineration generating stations built to U.S. and European technical standards, including electrostatic precipitator pollution control technology.	Technical: For the MSW Digestion option, sufficient MSW digestion capacity is constructed between 2018 and 2025 to consume 1,000 short tons of organic MSW per day (116 MW). Similarly, for the MSW Combustion option, sufficient MSW combustion capacity is constructed in the same period to consume 1,000 short tons of residual MSW per day (51 MW). This capacity is deployed into the baseline power model described in Section III.3.1 Methods and Assumptions, displacing baseline generation and some endogenously built capacity. The new capacity is assumed to remain operational through 2050. Electricity demand and total electricity production are not affected. Changes in requirements for fossil fuels impact upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. The diversion of MSW to power stations also provides a non-energy GHG benefit, which is further characterized in the waste chapter of this report. Cost: Capital and O&M costs for MSW and other power technologies are described in Section III.3.1 Methods and Assumptions. Excepting MSW, relevant projected fuel costs are discussed later in this section. The incremental costs of collecting and sorting MSW for power generation are documented in the waste chapter of this report.
Biodigesters	This option involves power generation from biogas produced by anaerobic digestion of swine waste. Focusing on large commercial farms where waste digestion is economically feasible, it assumes that by 2030 12% of commercially	Technical: By 2030, sufficient agricultural waste digestion capacity is constructed to consume 12% of hog waste produced on large commercial farms. Large commercial farms are assumed to raise 35% of the country’s hogs (Figure III. 6), and each hog is assumed to generate 1.8 tonnes of waste per year (USEPA 1999b). The new agricultural

Option	Description	Assumptions
	available swine waste across the country is digested and used to generate electricity.[17]	waste digestion capacity is deployed into the baseline power model described in Section III.3.1 Methods and Assumptions, displacing baseline generation and some endogenously built capacity. Electricity demand and total electricity production are not affected. Changes in requirements for fossil fuels impact upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. The diversion of hog waste to power stations also provides a non-energy GHG benefit, which is further characterized in the agriculture chapter of this report. Cost: Capital and O&M costs for agriculture waste digestion and other power technologies are described in Section III.3.1 Methods and Assumptions. Projected fuel costs are discussed later in this section.
Biomass Co-firing in Coal Plants	Using biomass as a secondary fuel in coal plants is a widely applied, cost-effective technique for mitigating the climate impact of coal power (Turkenburg et al. 2012). It does, however, require a sustainable source of biomass, which could be a challenge in the Philippines. This option explores the potential for biomass co-firing in the country's least efficient coal plants. It models replacing 5% of coal used in subcritical pulverized coal plants with biomass by 2020 (the percentage remains constant through 2050).	Technical: Besides the change in the feedstocks for subcritical coal plants, no other changes to the baseline power model are implemented. Electricity demand and total electricity supply are also unaffected. Subcritical plants are assumed to be retrofitted with direct co-firing (co-feed) technology. The biomass used for co-firing is assumed to be 25% coconut residue and 75% rice hull.[18] Reduced demand for coal lowers upstream GHG emissions from coal production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: Incremental costs for retrofitting plants are taken from IREA and IEA Energy Technology Systems Analysis Programme (2013). Projected fuel costs are discussed later in this section.
Nuclear Power	Based on guidance from CCC, this option models the construction of a 1 GW nuclear power plant in 2025.	Technical: The new nuclear capacity is deployed into the baseline power model described in Section III.3.1 Methods and Assumptions, displacing baseline

[17] For more details on the analysis of the economic feasibility of waste digestion, see the agriculture chapter of this report: *Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project: Philippines Mitigation Cost-Benefit Analysis Agriculture Sector Results*.

[18] Using alternate biomass fuels or these two fuels in different proportions would not materially change the impact of this mitigation option.

Option	Description	Assumptions
		generation and some endogenously built capacity. It operates according to the technical parameters provided in Section III.3.1 Methods and Assumptions. Electricity demand and total electricity production are not affected. Changes in requirements for fossil fuels impact upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: Capital and O&M costs for nuclear and other power technologies are described in Section III.3.1 Methods and Assumptions. Projected fuel costs are discussed later in this section. As noted in the fuel cost discussion, the cost of nuclear fuel covers all phases of the fuel cycle, including uranium mining and milling, conversion, enrichment, fuel fabrication, spent fuel transport, storage, reprocessing, and disposal (Schlömer et al. 2014).
Industrial Energy Use		
Cement Waste Heat Recovery	Cement manufacturing is heat intensive and creates substantial amounts of waste heat. In some instances, this energy can be reclaimed and used for productive purposes such as electricity generation. This option examines deploying waste heat-to-power technology in the cement industry, taking current waste heat recovery initiatives as examples. Based on Institute for Industrial Productivity and International Finance Corporation (2014), it evaluates adding 60 MW of new heat-to-power capacity during 2016-2025. After 2025, installed heat-to-power capacity is assumed to grow at the same rate as national cement production.	Technical: A capacity factor of 74% is assumed for heat-to-power technology based on Philippine data in Institute for Industrial Productivity and International Finance Corporation (2014). The lifetime of new heat-to-power capacity is assumed to be 25 years. Electricity generated by heat-to-power installations displaces grid produced electricity, lowering demands on the baseline power and fossil fuel supply models described in Section III.3.1 Methods and Assumptions. Cost: The capital costs of new heat-to-power capacity are assumed to be 2.98 million 2010 USD/MW, a figure calculated from Philippine data in Institute for Industrial Productivity and International Finance Corporation (2014). O&M costs are assumed to be 2.5% of capital costs per year according to the same source. Capital and O&M costs for on-grid power are described in Section III.3.1 Methods and Assumptions; projected fuel input costs for on-grid power generation are discussed later in this section.
Biomass for	Coal is the dominant fuel used in the Philippine cement industry, primarily for process heat. Cement industry	Technical: By 2020, rice hull meets 35% of energy requirements satisfied by coal in the baseline scenario. The percentage remains constant through 2050. Consistent with

Option	Description	Assumptions
Cement Production	stakeholders consulted by B-LEADERS estimate that by 2020, 35% of coal inputs to cement production could be replaced with biomass without modifying existing kilns or production processes. This option analyzes such a substitution using rice hull waste from agriculture.[19]	industry stakeholders' guidance, no other technical changes in cement production are modeled. Emission factors for combustion of rice hull are taken from the sources listed in Table III. 6. Reduced demand for coal lowers upstream GHG emissions from coal production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: Per industry stakeholders' guidance, the introduction of biomass does not change capital or O&M costs in cement production. Projected fuel costs are discussed later in this section.
Cement Clinker Reduction	Clinker is an important but highly energy and GHG intensive input to cement production, where it is used as a binding compound. Currently, cement manufactured in the Philippines is about 80% clinker by mass on average (World Business Council for Sustainable Development Cement Sustainability Initiative 2015). This option considers the introduction of lower-clinker cement—60% clinker by mass.	Technical: Thirty-five percent of national cement production is assumed to be lower-clinker by 2020, 50% by 2030, and 70% by 2050 (targets developed by the CBA team in consultation with industry stakeholders). Producing a tonne of clinker is assumed to require 3,510 MJ of heat and 74.1 kWh of electricity (World Business Council for Sustainable Development Cement Sustainability Initiative 2015). The heat saved by producing less clinker is assumed to come from coal and biomass in proportion to their usage in the cement industry in the absence of this mitigation option. Emission factors for coal and biomass combustion are from the sources noted in Table III. 6. The electricity saved is taken to be grid produced, lowering demands on the baseline power model described in Section III.3.1 Methods and Assumptions. Net changes in fossil fuel requirements impact upstream energy use and emissions from fossil fuel production in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Any incremental energy demand associated with producing and using clinker substitutes (e.g., coal fly ash, volcanic ash) is assumed to be negligible. Reducing clinker content also provides a non-energy GHG benefit as detailed in the industry chapter of this report.[20]

[19] Using alternate biomass fuels would not materially change the impact of this mitigation option.

[20] *Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project: Philippines Mitigation Cost-Benefit Analysis Industrial Sector Results*.

Option	Description	Assumptions
		Cost: As described in the industry chapter of this report, non-energy costs of this option are figured by comparing the prices of clinker and clinker substitutes. Energy-related costs depend on the change in demand for electricity, coal, and biomass; electricity sector costs are provided in Section III.3.1 Methods and Assumptions, and projected prices for other fuels are discussed later in this section.[21]
Residential and Commercial[22] Energy Use		
Home Lighting Improvements	This option models a moratorium on sales of incandescent, linear fluorescent, and circular fluorescent lightbulbs for use in residences. The measure starts in 2020. As the legacy bulbs wear out, they are replaced by more efficient compact fluorescent and light-emitting diode (LED) equivalents.	Technical: Incandescent and linear/circular fluorescent lightbulbs are assigned average wattages of 32.2 W and 27.1 W, respectively (DOE and NSONSO 2011). Beginning in 2020, the shares of these technologies in the total stock of residential bulbs decrease linearly, reaching zero percent after 1,000 hours (for incandescent) or 20,000 hours (for fluorescent) of use (bulb lifetime from U.S. Energy Information Administration (2015), annual hours of usage derived from DOE and NSONSO (2011)). The market share is absorbed by either compact fluorescent or LED bulbs with average wattages of 15.25 W and 9.89 W respectively, deployed in the same ratio as observed in the baseline scenario. The advent of more efficient bulbs reduces electricity demand, lowering production by the baseline power and fossil fuel supply models described in Section III.3.1 Methods and Assumptions. Cost: Purchase costs per bulb are annualized (using the model's 5% discount rate) over the number of years that the bulb is expected to last, resulting in the following annualized capital costs: **Incandescent**: 0.304 2010 USD/year **Linear Fluorescent**: 0.580 2010 USD/year **Circular Fluorescent**: 0.718 2010 USD/year

[21] This approach may double count the fuel cost savings of reduced clinker use if the costs in question are fully represented in the price of clinker. However, as those savings are about 5% of the total social cost impact of this option, any correction for double counting would not substantially affect the overall assessment of the option—including its relative attractiveness compared to the other options in this study.

[22] Includes commercial, institutional, and public buildings and energy uses (excluding transport).

Option	Description	Assumptions
		Compact Fluorescent: 0.403 2010 USD/year **LED**: 2.387 2010 USD/year (U.S. Energy Information Administration 2015; DOE and NSO 2011). Capital and O&M costs for the power system are described in Section III.3.1 Methods and Assumptions; projected fuel input costs for power generation and fuels production are discussed later in this section.
Home Appliance Improvements	A sibling of the Home Lighting Improvements option, this option characterizes the costs and impacts of switching to more efficient home appliances. Specific transitions include switching from both cathode ray tube (CRT) and non-CRT televisions to highly efficient LED and liquid crystal display (LCD) models; introducing efficient refrigerators, freezers, and fans; and deploying efficient split and window air conditioning units. Beginning in 2020, the new technologies are assumed to completely eclipse their inefficient counterparts after the lifetime of the old technology has elapsed. The new technologies are selected on the basis of their efficiency improvements over conventional technologies, likely availability in the Philippines, and reported cost-effectiveness from a variety of sources.	Technical and cost assumptions are broken down by technology type. **Televisions** Medium-sized efficient LED and LCD televisions are expected to draw 74 W, about 21 W less than non-CRT televisions and 29 W less than CRT models (Park 2013). Their average incremental cost (as compared to the legacy technologies) is 17.32 2010 USD, which is annualized over the 8-year lifespan of the set (Park 2013). CRT televisions are assumed to have a 10-year lifetime, while non-CRT televisions are assumed to have an 8-year lifetime (Park 2013). **Refrigerators** Efficient refrigerators can reduce energy consumption relative to a conventional model by 47%, at an incremental cost of 120 2010 USD annualized over the 15-year lifespan of the device (Letschert et al. 2012). **Freezers** ENERGY STAR-certified chest freezers reduce energy consumption by 10% relative to a conventional model, at an incremental cost of 9.48 2010 USD annualized over the 22-year lifespan of the device (U.S. Energy Information Administration 2015). **Fans**

Option	Description	Assumptions
		Efficient ceiling fans can reduce energy consumption by 45% relative to a conventional fan, at an incremental cost of 4.74 2010 USD (M. Sathaye et al. 2013) annualized over the 30-year lifespan of the device (UPNEC 2015b). **Air Conditioners** For an additional purchase cost of 160 2010 USD, efficient split air conditioners can reduce power consumption by 78 W relative to conventional split air conditioners (Letschert et al. 2012). For window-mounted units, the reduction is more dramatic, with 176 W of potential reduction for an additional 100 2010 USD (Letschert et al. 2012). Additional purchase prices are annualized over a 12-year (split) or 10-year (window) lifespan for the device. As with the Home Lighting Improvements option, deploying more efficient equipment reduces electricity demand, lowering production by the baseline power and fossil fuel supply models described in Section III.3.1 Methods and Assumptions. Capital and O&M costs for the power system are described in Section III.3.1 Methods and Assumptions; projected fuel input costs for power generation and fuels production are discussed later in this section.
Energy Efficient Street Lighting with HPS Technology Energy Efficient Street Lighting with LED Technology	These mutually exclusive options explore efficiency upgrades for outdoor street lighting. The baseline lighting technology, mercury vapor lamp (MVL), is replaced by efficient high-pressure sodium (HPS) lighting under the first option and LED technology under the second. Both options cover on- and off-grid street lighting, and in each case 100% of street lamps are switched to the new technology by 2025. Thereafter the new technology is used for all street lighting through 2050.	Technical: The average wattage of MVL street lighting bulbs is 170 W; HPS bulbs use 53% less energy, and LED bulbs use 64% less (DOE 2012l; Philippine News Agency 2015). Each bulb operates for 11.6 hours per day on average (DOE 2012l). The lifetime of HPS bulbs is assumed to be 24,000 hours, while that of LED bulbs is assumed to be 100,000 hours. The number of street lighting bulbs nationally is determined from the average wattage and run time of MVL bulbs and the projection of electricity demand for street lighting in UPNEC (2015d)—which is in turn based on 2015 distribution development plan submissions of distribution utilities. The projection in UPNEC (2015d) covers 2011-2024; in later years, the number of on-grid bulbs is assumed to grow at 3.6% annually and the number of off-grid bulbs at 6.7% annually (the average rates in 2011-2024). Electricity saved by the options reduces demands on the baseline power and fossil fuel supply models described in Section III.3.1 Methods and Assumptions.

Option	Description	Assumptions
		Cost: Technology and program implementation costs per unit of saved energy are taken from DOE (2012l) for the HPS option and Philippine News Agency (2015) for the LED option. These unit costs are multiplied by the total energy savings under each option. Capital and O&M costs for the power system are described in Section III.3.1 Methods and Assumptions; projected fuel input costs for power generation and fuels production are discussed later in this section.
Forest Protection	This option envisions a reduction in the harvesting of wood for energy as deforestation is slowed and existing forests are protected (Figure III. 12. Wood Harvest for Energy, Baseline and Forestry Mitigation Scenarios).[23] Consistent with the approach to modeling biomass demand described in Section III.3.1 Methods and Assumptions, the reduction in the wood harvest is assumed to lower informal demand for wood-based energy in the residential sector.	Technical: The wood energy saved is split between fuelwood and wood used for charcoal according to the shares of these fuels in the residential sector in UPNEC (2015a). It is assumed that residential demand for fuelwood and charcoal is for cooking, and that the useful energy requirements that would be met by the avoided demand must be satisfied with alternative fuels. Following Food and Agriculture Organization of the United Nations (2009), three alternatives are considered: LPG, electricity, and kerosene. Sixty-three percent of the affected useful energy is assumed to be met by LPG, 27% by electricity, and 10% by kerosene (Bensel and Remedio 2002). The useful energy efficiency of wood and charcoal cooking is taken to be 17.5%, the mid-point for Philippine stoves in Bhattacharya et al. (2002). The useful energy efficiencies of LPG and kerosene cooking are assumed to be 54% and 50%, respectively (Grieshop, Marshall, and Kandlikar 2011). Direct emission factors for residential wood, charcoal, LPG, and kerosene consumption are from the sources listed in Table III. 6. Increased demands for alternative cooking fuels are met by the power and fossil fuel supply models described in Section III.3.1 Methods and Assumptions.

[23] *A full description of the assumptions and modeling underlying the projections in Figure III. 12, including a discussion of the non-energy emissions implications of the Forest Protection and Forest Restoration and Reforestation options, is provided in the forestry chapter of this report: Building Low Emission Alternatives to Develop Economic Resilience and Sustainability (B-LEADERS) Project: Philippines Mitigation Cost-Benefit Analysis Forestry Sector Results. The energy implications of the options are reported here.*

Option	Description	Assumptions
		Cost: Capital and O&M costs for the power system are described in Section III.3.1 Methods and Assumptions; projected costs for other fuels are discussed later in this section. Other costs of implementing a program of forest protection are presented in the forestry chapter of this report. Equipment cost savings in households associated with reduced wood and charcoal consumption are assumed to offset incremental equipment costs related to greater consumption of alternative fuels.
Forest Restoration and Reforestation	For the energy sector, this option has an opposite effect to that of the Forest Protection option, increasing the harvest of wood for energy (Figure III. 12) and informal demand for wood by residences.	Technical and cost assumptions are as described above for the Forest Protection option.
Cross-Sectoral Energy Use		
Biodiesel Blending Target	This option considers the attainment of coconut methyl ester biodiesel blending targets described in the Philippine Energy Plan 2012-2030, culminating in a volumetric B20 blend by the year 2025 (DOE 2012g). It models the impact of increased biodiesel in the diesel fuel supply in all sectors except transport. After 2025, the B20 blend remains in effect through 2050.	Technical: Biodiesel mixing ratios are linearly interpolated through 2025, beginning in 2013. However, the rate of change in each sector depends upon that sector's observed biodiesel share in 2010: for example, the fishing subsector approaches the target at a slightly lower rate than the forestry subsector, as the latter exhibits a lower fuel share of biodiesel during the historical period. Mass and energy densities of both regular diesel and biodiesel are required to make conversions from volumetric to energetic fuel shares, which can be implemented in the model. Regular diesel fuel is assumed to have densities of 0.87 kg/liter and 43.33 MJ/kg respectively (IPCC 1996a), while biodiesel is 0.884 kg/liter (Chinnamma et al. 2015) but contains only 38 MJ/kg (Tan, Culaba, and Purvis 2004). Changes in biodiesel and diesel consumption affect upstream energy use and emissions from producing the fuels in keeping with the supply-side modeling outlined in Section III.3.1 Methods and Assumptions. Cost: No additional direct data are required to determine the abatement cost of this option. Instead, the net cost arises from differences between the cost of regular diesel and biodiesel. Projected costs for these fuels are discussed later in this section.

Figure III. 11. LFG Collected for Electricity Generation, Baseline and Methane Recovery Scenarios

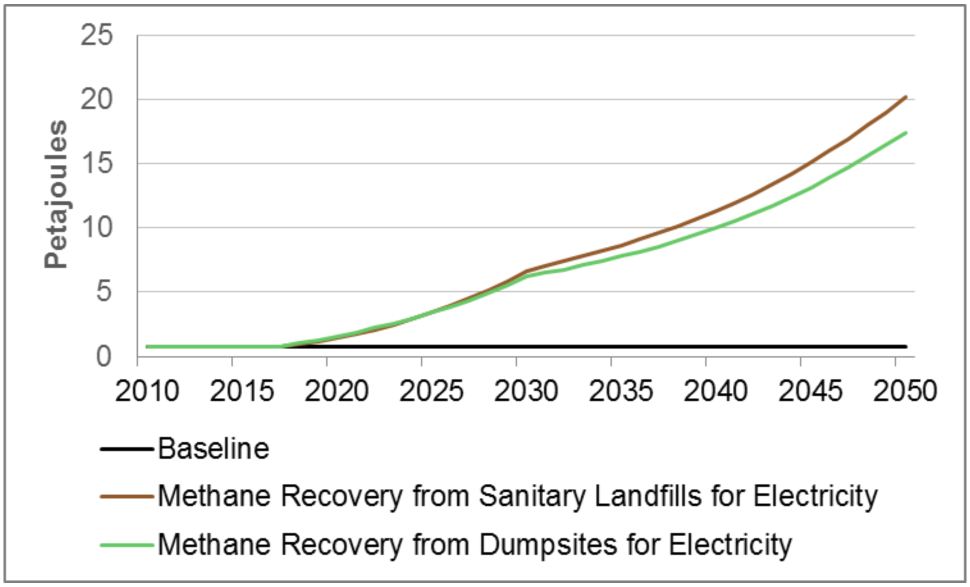
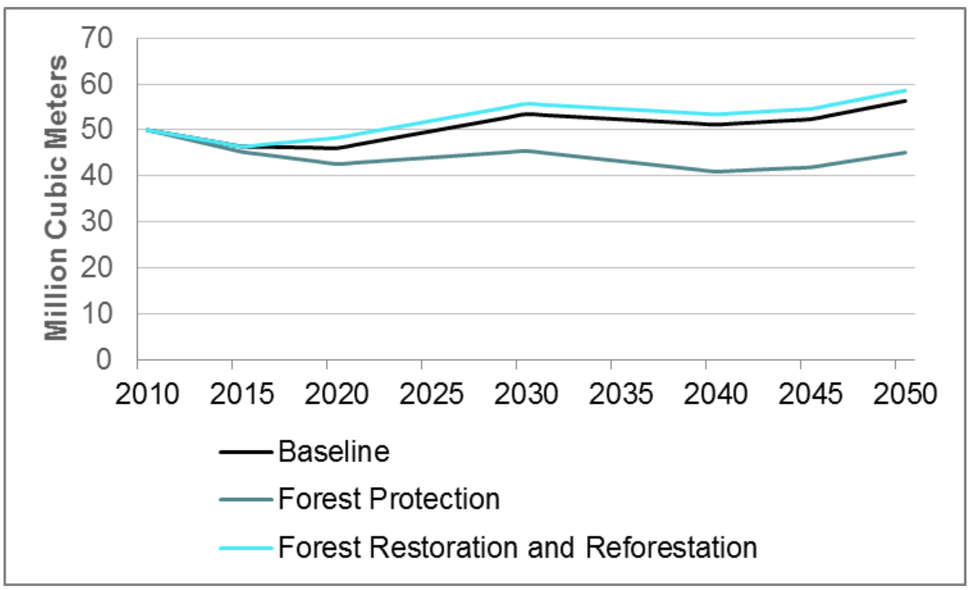


Figure III. 12. Wood Harvest for Energy, Baseline and Forestry Mitigation Scenarios



As Table III. 25 suggests, the energy sector mitigation options are primarily technical measures, involving increased deployment and utilization of lower-carbon technologies, production processes, and fuels. Studying such options provides insights into physically possible changes in the energy system and the implications for emissions and costs. The envisioned technical changes could be brought about by a variety of policies depending on the priorities of government and other stakeholders.

Some potentially viable mitigation options were not covered in this study. This situation reflects the CBA team's application of the criteria of government support and data availability, especially the latter. For example, CBA consultations with stakeholders indicated that there are likely important low or no-cost energy efficiency opportunities in a range of Philippine industries besides cement (Philippine Business for the Environment 2015). Unlocking many of these opportunities may simply be a matter of providing access to better education and knowledge sharing. However, the CBA team was not able to gather data that would allow this energy efficiency potential to be quantified at national scale, so a corresponding mitigation option could not be formulated for the study. It is also worth noting that some options included in the study might achieve greater impact with more aggressive deployment of the associated low-carbon technologies, processes, or fuels (e.g., an earlier shift to efficient lighting). Such expansion or acceleration of options could change their cost-effectiveness but may represent another possible path to deeper mitigation for the Philippines.

III.4.1.2 Direct Costs and Benefits of Mitigation Options

As stated in Section III.2.1 Methods and Assumptions, the analysis of direct costs and benefits of energy sector options considers capital, O&M, fuel, and other measure implementation costs (in addition to GHG emission reductions, a non-monetized benefit). Where appropriate, the costs were specified per unit of implementation, so that the total social cost could be derived by multiplying unit costs by equipment requirements, activity levels, or fuel consumption. The unit costs for fuels were established in two ways. In the case of electricity, the cost was determined endogenously by LEAP using modeled production costs—capital, O&M, and input fuel costs of generation, transmission, and distribution. For other fuels, the unit costs were based on historical and projected fuel prices as outlined in Table III. 26. Fuel Price Sources and Projection Methodology, All Scenarios. The corresponding price values used in the study, which do not change across the baseline and mitigation scenarios, are provided in Table III. 27. Historical and Projected Fuel Prices, All Scenarios [2010 USD/GJ].

Table III. 26. Fuel Price Sources and Projection Methodology, All Scenarios

Fuel	Sources of Historical Data[a]	Projection Method[b]
Biomass	DENR (2013)	Assumed same as the constant price for 2010-2014
Coal	B-LEADERS (2015d), DOE (2015d). Prices based on imported coal.	Price growth rate taken from *Current Policies* scenario, IEA (2014b)
Natural Gas	DOE (2015k)	Price growth rate taken from *Current Policies* scenario, IEA (2014b)
Nuclear	Schlömer et al. (2014). Comprises all fuel cycle costs, from uranium mining and enrichment to spent fuel reprocessing and disposal.	Assumed same as the constant price for 2010-2014
Crude Oil	DOE (2015k)	Price growth rate taken from *Current Policies* scenario, IEA (2014b)
Aviation Gasoline	DOE (2015k)	Grows at same rate as crude oil price

Fuel	Sources of Historical Data[a]	Projection Method[b]
Lubricants	Same as residual fuel oil	Grows at same rate as crude oil price
Bitumen	DOE (2015k)	Grows at same rate as crude oil price
Naphtha	DOE (2015k)	Grows at same rate as crude oil price
Other Oil	Same as residual fuel oil	Grows at same rate as crude oil price
LPG	DOE (2015k)	Grows at same rate as crude oil price
Residual Fuel Oil	DOE (2015k)	Grows at same rate as crude oil price
Diesel	DOE (2015k)	Grows at same rate as crude oil price
Kerosene	DOE (2015k)	Grows at same rate as crude oil price
Jet Kerosene	DOE (2015k)	Grows at same rate as crude oil price
Motor Gasoline	DOE (2015k)	Grows at same rate as crude oil price
Biodiesel	Renewable Energy Management Bureau (2015)	Grows at same rate as crude oil price
Ethanol	DOE (2015k)	Grows at same rate as crude oil price
CNG	DOE (2015b)	Price held constant until 2016 (Velasco 2014). After 2016, price based on price of natural gas plus cost additions for compression, distribution, refining, taxes, and retail mark-up shown in American Clean Skies Foundation (2013).

[a] Available historical data cover 1990-2014 or a subset of those years, depending on the fuel.

[b] Projections begin where the historical data end and run through 2050.

Table III. 27. Historical and Projected Fuel Prices, All Scenarios [2010 USD/GJ]

Year	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Biomass	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Coal	1.77	1.77	1.77	2.75	4.27	4.39	5.14	5.37	5.62	5.78	5.95	6.13	6.31
Natural Gas	1.46	1.46	1.46	6.54	8.89	9.96	9.43	9.83	10.24	10.55	10.87	11.20	11.54
Nuclear	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Crude Oil	5.13	5.13	5.13	8.67	12.49	15.68	16.73	18.31	20.05	21.18	22.37	23.63	24.96
Aviation Gasoline	14.44	14.44	14.44	21.70	32.79	33.45	35.69	39.07	42.78	45.19	47.73	50.41	53.24

Year	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Lubricants	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.70	29.25	30.90
Bitumen	5.50	5.50	5.50	5.24	13.12	13.14	14.01	15.34	16.80	17.74	18.74	19.80	20.91
Naphtha	7.51	7.51	7.51	7.74	11.19	14.13	15.07	16.50	18.07	19.09	20.16	21.29	22.49
Other Oil	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.70	29.25	30.90
LPG	6.80	5.59	7.69	11.24	15.34	16.38	17.47	19.13	20.95	22.13	23.37	24.69	26.07
Residual Fuel Oil	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.70	29.25	30.90
Diesel	11.99	9.34	11.90	21.60	19.93	21.47	22.91	25.08	27.46	29.00	30.63	32.36	34.18
Kerosene	12.47	9.71	11.89	23.04	25.35	26.23	27.97	30.63	33.54	35.42	37.41	39.52	41.74
Jet Kerosene	21.72	18.65	15.47	25.57	29.52	30.04	32.04	35.08	38.41	40.57	42.85	45.26	47.81
Motor Gasoline	20.42	13.65	17.85	27.27	29.09	30.58	32.62	35.71	39.10	41.30	43.62	46.08	48.67
Biodiesel	28.59	28.59	28.59	28.59	28.59	31.30	33.39	36.56	40.03	42.28	44.66	47.17	49.82
Ethanol	19.08	19.08	19.08	19.08	33.89	29.71	31.69	34.70	38.00	40.13	42.39	44.77	47.29
CNG	9.07	9.07	9.07	9.07	9.07	9.07	19.16	19.56	19.97	20.28	20.61	20.94	21.28

To support the evaluation of particular mitigation options, *incremental* direct cost-benefit results are reported for each option. These represent the marginal impact on society of implementing the option. This approach has obvious analytical advantages, but it required careful consideration of how to handle potential interactions between options. Implementing certain mitigation options together can lower (or raise) their total effectiveness—for example, an electric efficiency measure will result in greater abatement when the power system is carbon intensive, but less if a renewable power measure is deployed concurrently. For marginal analysis, then, the assumed precedence of options or order of option implementation is important. This study addresses this issue following the **retrospective systems approach** in Sathaye and Meyers (1995). In brief, this method involves four steps:

1) Each mitigation option is first evaluated individually compared to the baseline scenario (i.e., assuming that no other options are implemented), and the net social cost per tonne CO_2e abated is recorded.
2) The options are sorted according to these initial costs per tonne in ascending order.
3) The options are added one at a time and in order to a new combined mitigation scenario, and emissions and costs for the combined scenario are recorded after each addition.
4) The final incremental costs and benefits for each option are calculated as the change in emissions and costs after the option was added to the combined scenario. Thus, the first option is evaluated in comparison to the baseline scenario only, the second option in comparison to the baseline plus the first option, and so forth.

Excepting two mitigation options, the incremental direct costs and benefits reported in Sections III.4.2 Results and III.4.3 Discussion were calculated using this method. The retrospective systems ordering includes options from all sectors, not just energy, so energy sector options are sometimes compared to combined scenarios comprising energy, non-energy, and transport options with lower initial costs per tonne. This approach accounts for potential cross-sectoral interactions. The full ordering of all sectors' options by initial cost per tonne is shown in Table III. 28. Full Retrospective Systems Ordering of Mitigation Options, All Sectors.

Table III. 28. Full Retrospective Systems Ordering of Mitigation Options, All Sectors

Sequence	Sector(s)	Mitigation Option
1	Industry	Increase Glass Cullet Use
2	Energy and Industry	Cement Clinker Reduction
3	Transport	MVIS
4	Transport	Electric Jeepney
5	Transport	Congestion Charging
6	Energy	Home Lighting Improvements
7	Transport	Driver Training
8	Energy	Home Appliance Improvements
9	Energy and Industry	Cement Waste Heat Recovery
10	Energy	Energy Efficient Street Lighting with LED Technology
11	Energy and Industry	Biomass for Cement Production
12	Energy	NREP Biomass
13	Energy and Industry	Biomass Co-firing in Coal Plants
14	Energy and Waste	MSW Digestion
15	Energy	Nuclear Power
16	Energy	NREP Solar
17	Energy	Substituting Natural Gas for Coal
18	Agriculture	Organic Fertilizers
19	Energy	NREP Wind
20	Energy and Waste	Methane Recovery from Sanitary Landfills for Electricity
21	Agriculture	AWD
22	Waste	Methane Flaring

Sequence	Sector(s)	Mitigation Option
23	Energy and Forestry	Forest Restoration and Reforestation
24	Agriculture	Crop Diversification
25	Energy and Forestry	Forest Protection
26	Energy	NREP Ocean
27	Energy	NREP Large Hydro
28	Waste	Composting
29	Waste	Eco-Efficient Cover
30	Energy	NREP Small Hydro
31	Energy	NREP Geothermal
32	Transport	Biofuels
33	Energy	Biodiesel Blending Target
34	Transport	Buses and BRT
35	Energy and Agriculture	Biodigesters
36	Transport	Rail
37	Energy and Waste	MSW Combustion

The Energy Efficient Street Lighting with HPS Technology(which is mutually exclusive with Energy Efficient Street Lighting with LED Technology) and Methane Recovery from Dumpsites for Electricity(which is mutually exclusive with Methane Flaring, an industry sector-only option), are two options that cannot be evaluated via retrospective systems because they are mutually exclusive with other options in the ordering. For these options, incremental costs and benefits were calculated relative to the baseline scenario only.

The presentation of direct costs and benefits in Sections III.4.2 Results and III.4.3 Discussionfocuses especially on two key statistics, GHG reduction potential and net social cost per tonne of CO_2e avoided. These are generally expressed cumulatively through 2050. In this case, the cost per tonne includes the net present value of all incremental costs incurred between 2015 and 2050, and the reduction potential comprises incremental GHG abatement between 2015 and 2050. The cost per tonne was determined by dividing the net present value by the abatement.

III.4.1.3 Co-Benefits of Mitigation Options

The co-benefits analysis of energy sector options assessed air quality-related human health impacts, energy security impacts, and power sector employment impacts. Consistent with the analysis of direct costs and benefits, these impacts were estimated using the retrospective systems approach described above.[24] The marginal effects of each mitigation option were determined by adding it to a combined mitigation scenario including the baseline plus all mitigation options coming earlier in the retrospective systems ordering (Table III. 28. Full Retrospective Systems Ordering of Mitigation Options, All Sectors). Of the three types of co-benefits considered, only human health impacts were monetized; energy security and power sector employment impacts were characterized using non-monetary indicators.

III.4.1.4 Air Quality-Related Human Health Impacts

The analysis of human health impacts was limited to a consideration of impacts on premature mortality associated with exposure to ambient fine particulate matter ($PM_{2.5}$). These impacts were determined according to the basic framework presented in Figure III. 13. **General Framework for Health Co-Benefits Calculation**

Figure III. 13. General Framework for Health Co-Benefits Calculation

:

- Emissions from the LEAP model were converted to outdoor air pollution concentrations. The emissions from the baseline scenario informed the baseline concentration estimates, and the predicted change in emissions in each mitigation scenario was translated to air quality change. The analysis focused on concentrations of fine particulate matter ($PM_{2.5}$), which dominated the CBA of reduced air pollution.[25]
- The health benefits of reduced exposure to outdoor air pollution come from reduced risk of morbidity and premature mortality. However, as noted earlier, in this analysis only the reduced

[24] Co-benefits are not estimated for the two mitigation options that were not evaluated in the retrospective systems framework: Energy Efficient Street Lighting with HPS Technology and Methane Recovery from Dumpsites for Electricity.

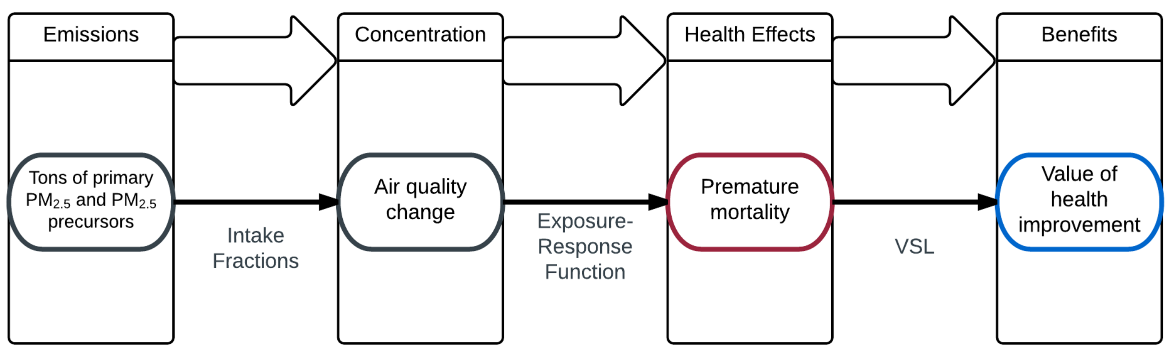
[25] Ozone is another important pollutant, but modeling ozone levels is outside of the scope of this analysis. Furthermore, the Global Burden of Disease Study found that deaths attributable to ambient ozone levels were less than 5% the number of deaths attributable to ambient $PM_{2.5}$ levels (Lim et al. 2012).

risk of premature mortality was estimated.[26] The risk reductions were calculated using research literature-based epidemiological relationships known as "exposure-response functions."

- To express the social benefit of fewer premature deaths in monetary terms, the analysis relied on the concept of the aggregate willingness to pay (WTP) for small reductions in annual mortality risk by a population of a given size. The WTP was estimated as a product of the number of premature deaths avoided due to a mitigation option and the value per statistical life (VSL), a risk reduction-normalized WTP estimate derived from the research literature.

Each of these steps is described in depth below.

Figure III. 13. General Framework for Health Co-Benefits Calculation



III.4.1.5 Emissions

The relevant emissions for the health co-benefits estimates are primary $PM_{2.5}$ and two gaseous precursors to secondary $PM_{2.5}$, NO_x and SO_2. Primary $PM_{2.5}$ is the mass of particulates that is emitted directly from an emissions source, while secondary $PM_{2.5}$ forms from the oxidation of primary gases in the atmosphere. The LEAP model provides national-scale estimates of primary $PM_{2.5}$ and secondary $PM_{2.5}$ precursors for each sector and each mitigation option.

[26] The analysis focuses on all-cause mortality, since there may not be sufficient data to estimate cause-specific mortality. There are also associations between $PM_{2.5}$ and non-fatal (morbidity) health endpoints, but these outcomes tend to be less important in monetized cost-benefit analysis.

Within the energy sector, only the health impacts of emissions from on-grid power generation were modeled. While on-grid power generation produces the largest share of $PM_{2.5}$, NO_x, and SO_2 emissions, other activities within the energy sector (e.g., demand-side combustion of fuels, off-grid electricity generation, other fuel production) also contribute to local air pollution and health impacts. The CBA team could not find sufficient information to characterize exposure to emissions from these sources, so their impacts were not included in the health co-benefits estimates. Sources of emission factors for on-grid power production are reported in Table III. 6 Sources of Emission Factors in the Energy Sector Model.

III.4.1.6 Concentrations

The next step in estimating health co-benefits is to use the projected emissions from the LEAP model to estimate the baseline $PM_{2.5}$ concentration and the change in $PM_{2.5}$ concentration resulting from each of the mitigation options. The annual average ambient $PM_{2.5}$ concentration was estimated in both urban and rural areas. The CBA team did not conduct dispersion modeling, but instead applied the results of previous dispersion modeling studies using intake fractions (iFs).

III.4.1.7 Baseline Concentrations

The exposure-response function used to estimate the change in health requires an estimate of the baseline $PM_{2.5}$ concentration and the concentration for each mitigation option. The baseline ambient $PM_{2.5}$ concentration was calculated using both measured data and modeled data, the latter from the previously discussed modeled emissions from the energy sector as well as emissions projected in the CBA's transport modeling.[27] For rural areas, baseline exposure integrated measured concentrations and changes from the power sector. For urban areas, baseline exposure was informed by measured concentrations and the contribution of the transport and power sectors. A single baseline urban exposure was assumed for energy sector impacts in all urban areas.

The urban baseline concentration was modeled in all years by estimating a background concentration, defined as the concentration without contributions from the transport and energy sectors, and then adding the additional modeled concentration from the baseline case for transport and energy sector emissions. This calculation is shown in Equation III. 4 and Equation III. 5 below.

Equation III. 4 $$C_{Background} = C_{Measured,2010} - (C_{Transport,2010} + C_{Energy,2010})$$

Equation III. 5 $$C_y = C_{Background} + C_{Transport,y} + C_{Energy,y}$$

The background concentration ($C_{Background}$) was calculated as the measured concentration in the year 2010 ($C_{Measured,2010}$) minus the modeled contribution from transport ($C_{Transport,2010}$) and energy ($C_{Energy,2010}$) in the year 2010. The background concentration was held constant through 2050, and the baseline concentration in a given year y (C_y) was calculated as the sum of the background concentration and the modeled contribution from transport ($C_{Transport,y}$) and energy ($C_{Energy,y}$) in the baseline scenario in

---

[27] See the transport chapter of this report for more details on the CBA's transport modeling.

the year y. The rural baseline concentration was calculated using similar methods, but excluding $C_{Transport,2010}$ and $C_{Transport,y}$.

There are limited data reporting measurements of $PM_{2.5}$ in the Philippines for use as $C_{Measured,2010}$ in Equation III. 4 above. Three measurements were available from monitoring sites for the year 2010 (Cities Act 2010), shown in Table III. 29, and two additional studies provided supplementary measurements from previous years. A value of 35 μg/m^3 was assumed for Manila, an average of monitoring data and concentrations reported in supplementary studies (Cities Act 2010; Oanh et al. 2012). For urban areas where there was no measurement data, a default value of 15 μg/m^3 was assumed. For rural areas, a $PM_{2.5}$ concentration of 9.5 μg/m^3 was taken from Oanh et al. (2012).

Table III. 29. Urban and Rural Measurements of $PM_{2.5}$ Concentrations

City/Station	Annual Mean $PM_{2.5}$ [μg/m^3]	Year(s) of Measurement	Source
Baguio	49	2010	Cities Act (2010)
Cebu	22	2010	Cities Act (2010)
Manila	22	2010	Cities Act (2010)
Manila	46	2001-2007	Cohen et al. (2009)
Manila	45	2006-2008	Oanh et al. (2012)
Rural background	9.5	2006-2008	Oanh et al. (2012)

Converting Emissions to Concentrations Using Intake Fractions

Estimates of $C_{Transport}$, C_{Energy}, and the change in concentrations from both sectors resulting from each of the mitigation options are produced using source-specific iFs. The relationship between emissions of $PM_{2.5}$ and $PM_{2.5}$ precursor species (including NO_x and SO_2) and the change in ambient $PM_{2.5}$ concentrations is complex, and depends on numerous factors including local meteorological patterns (e.g. wind speed, temperature) and characteristics of the emissions source (location, plume height, exhaust temperature). Use of a chemical transport model would produce detailed, localized concentration estimates, but for the purposes of this study, this would introduce undue complexity to the task of projecting the air quality impacts of many scenarios up to 35 years into the future, with little baseline information about local air quality. For these reasons, a set of factors called iFs were used to estimate the contribution of emissions from the transport and energy sectors to ambient $PM_{2.5}$ levels, separately for the baseline scenario and for the mitigation options under consideration. Because of the uncertainty associated with this simplified method, this analysis is useful to indicate the order of magnitude of the health benefits but does produce highly precise results. The iFs were derived from more complex air quality modeling using Equation III. 6. They are specific to a given emissions source, such as on-road vehicles, and to a given pollutant, such as primary $PM_{2.5}$ or NO_x.

$$\text{intake fraction} = \frac{\text{population intake}}{\text{total emissions}} = \frac{\int_{T_1}^{\infty} \left(\sum_{i=1}^{P} \left(C_i(t) Q_i(t)\right)\right) dt}{\int_{T_1}^{T_2} E(t) dt}$$

Equation III. 6 Equation for Calculating Intake Fraction (Apte et al. 2012)

Equation III. 6 shows that an intake fraction is specific to a population of size P, with breathing rate Q. Once the value of the intake fraction has been calculated, and the population and breathing rate are known, the equation can be re-arranged and solved to directly give the relationship between total emissions E and concentration C. This ratio of unit of concentration per unit emissions is fixed over time in the CBA modeling, and used to calculate the air pollution concentration for each scenario.[28]

Transport Sector iFs

The set of iFs used for on-road vehicles were developed for major urban areas worldwide, and include 30 specific to the Philippines (Apte et al. 2012). These intake fractions apply only to conserved pollutants like primary $PM_{2.5}$, not pollutants that undergo significant transformation in the atmosphere, like NO_x and SO_2. These emission factors were used for the 18 largest cities in the Philippines, as reliable population projections for these cities were available. As described above, the intake fractions were divided by the relevant city populations (Angel et al. 2010; Apte et al. 2012) and a breathing rate of 5292.5 m^3/year to derive the ratio of unit concentration per unit emissions for each city, shown in Table III. 30. Variation in these values across cities occurs due to differences in city size, as well as meteorological factors such as average wind speed. In a city with a larger footprint, emissions are distributed over a larger area and so the ratio of concentration to emissions is lower. For example, the ratio is lowest in Metro Manila, which has a footprint of about 900 km^2 compared to an average of 100 km^2 across the other cities (Angel et al. 2010). However, a low ratio should not be understood to indicate a low impact; in fact, because of the large share of emissions and the large population in Manila, it was modeled to have the largest share of transportation-related health impacts.

Table III. 30. Concentration-to-Emissions Ratio Used for 18 Largest Cities in Philippines

[28] Rather than solving for the concentration-to-emissions ratio in a single year and holding that value constant, year-to-year change in city-specific intake fractions may be modeled using population projections and assumptions about linear population density (Chambliss et al. 2013; Marshall 2007). The concentration-to-emissions ratio is then calculated separately for each year. This approach was not applied in this analysis to maintain consistency in calculations across sectors.

City	Concentration-to-Emissions Ratio [ug/m^3 change per kiloton emitted]
Metro Manila	1.4
Lipa City	14.3
Butuan	19.8
Batangas City	9.5
Iligan	25.2
Cotabato	8.4
Baguio City	5.6
Angeles City	3.3
Mandaue City	11.2
Basilan City (including City of Isabela)	11.2
Lapu-Lapu City	11.2
Iloilo City	11.9
Bacolod	6.8
General Santos City	7.0
Cagayan de Oro City	10.5
Zamboanga City	17.4
Cebu City	2.5
Davao City	5.3

Although the iFs used for the transport sector covered only contributions to ambient $PM_{2.5}$ from primary $PM_{2.5}$ emissions, on-road vehicles contribute to the formation of secondary $PM_{2.5}$ in the atmosphere from emissions of NO_x and SO_2. The health impacts of secondary PM were not included in this analysis. The CBA team did make an initial estimate that compared both the scale of reductions of NO_x and SO_2 emissions expected from emission control policies and the iFs for secondary $PM_{2.5}$ from NO_x and SO_2 to those for primary $PM_{2.5}$ (Humbert et al. 2011). This estimate found that the health impacts from secondary particulates would add roughly 25% to the health co-benefits of policies focused on conventional pollutant reduction (e.g., emission standards).

Energy Sector iFs

For the energy sector, three iFs were used, one for primary $PM_{2.5}$ (6×10^{-7}), one for secondary $PM_{2.5}$ from SO_2 (2×10^{-7}), and one for secondary $PM_{2.5}$ from NO_2 (6×10^{-8}). These iFs were based on a study of exposure to energy sector emissions in the United States in Levy et al. (2003). The resulting concentration-to-emissions ratios are shown in Table III. 31. The concentration change was assumed to occur throughout the country.

Table III. 31. Concentration-to-Emissions Ratio Used for the Energy Sector

Concentration-to-Emissions Ratio [ug/m³ change per kiloton emitted]		
$PM_{2.5}$	NO_x	SO_2
0.91	0.09	0.30

Disaggregating National Transportation Emissions to Urban Areas

As the on-road iFs only apply to urban areas, the emissions outputs from the LEAP model must also be scaled to the urban level. The share of national emissions occurring in Metro Manila ($Share_{MM}$) was estimated for each mode based on the national share of vehicle registrations within NCR. Less information on registration share was available for the 17 remaining cities. The cumulative share of national emissions occurring in those cities and excluding Metro Manila (urban share without Manila, or $Share_{UR\text{-}M}$) was estimated from the share of population and highway infrastructure in urban areas following a methodology applied and described previously by Chambliss et al. (2013). The urban share for Metro Manila and the combined share across the other 17 cities are given in Table III. 32. $Share_{UR\text{-}M}$ is further subdivided across each of the 17 cities based on population.

Table III. 32. Share of National Emissions in Metro Manila and Aggregate of 17 Largest Cities in Philippines (Excluding Metro Manila)

Mode	Share of Emissions in Metro Manila, $Share_{MM}$	Share of Emissions Aggregated Across 17 Largest Cities Excluding Metro Manila, $Share_{UR\text{-}M}$
Bus	44%	24%
LDV	52%	15%
MC	18%	32%
TC	18%	32%
Truck	22%	13%
UV	32%	16%

III.4.1.8 Health Impacts

Outdoor air pollution is associated with adverse health effects ranging from worsened asthma symptoms to early death from heart and lung disease. This study focuses on the fatal impacts of $PM_{2.5}$, and estimates impacts using integrated exposure-response (IER) functions developed for the Global Burden of Disease 2010 study (Lim et al. 2012). The IER functions are described in depth in Burnett et al. (2014).

The Global Burden of Disease 2010 study applied the IER functions to estimate the mortality attributed to $PM_{2.5}$ from ambient sources, as well as indoor sources, such as cook stoves and smoking (Lim et al. 2012). The IER functions combine the results of several types of epidemiological studies, including those conducted in high $PM_{2.5}$ exposure settings (e.g., exposure to tobacco smoke). Therefore, a health impact assessment based on the IER functions is a better extrapolation of air pollution mortality risk for populations exposed to high ambient $PM_{2.5}$ levels, compared to extrapolations based on a single epidemiological study conducted in a population with low baseline $PM_{2.5}$ exposure.

The IER functions were developed for five types of mortality: lung cancer (for all ages), ischemic heart disease (IHD, for ages 25 or older), stroke (for ages 25 or older), chronic obstructive pulmonary disease (COPD, for all ages), and acute lower respiratory infection (for children). This assessment focuses on the first four causes of death, i.e., lung cancer, IHD, stroke, and COPD.

Application of the IER functions requires one other input in addition to changes in ambient exposure: cause-specific mortality rates, which are taken at a national level from the Global Health Data Exchange catalog created by the Institute for Health Metrics and Evaluation (Institute for Health Metrics and Evaluation 2013).

The analysis also accounts for the impact of a potential lag in reductions of mortality risk following reductions in $PM_{2.5}$ exposure. Specifically, a 20-year mortality lag is applied consistent with that used by the USEPA, which assumes that 30 percent of the total estimated mortality effects occur in the first year, 50 percent are distributed evenly among years 2 through 5, and the remaining 20 percent are distributed evenly among years 6 through 20 (USEPA Science Advisory Board 2004). However, there is uncertainty about the length and the structure of this lag.

The health impacts were computed using a Monte Carlo simulation. The statistical uncertainty in the risk estimates was characterized by taking 50 draws from the 1,000 available IER curve parameter sets. In addition, the analysis team also characterized the statistical uncertainty in the cause-specific mortality rates by sampling from lognormal distributions that were consistent with the mean and the uncertainty bounds reported by the Institute for Health Metrics and Evaluation. The simulation also represented the age and sex-related variability in health impacts. To this end, the health impacts for each cause were computed separately for 12 age groups and two sexes, by combining: 1) the CBA team's estimates of the age group and sex-specific exposed population sizes (based on national-level demographic data); 2) the age group-specific IER functions; and 3) the age group- and sex-specific mortality rates for each cause. It was not possible to model the likely important spatial variability in the health impacts, because the information on cause-specific mortality rates does not have sufficient spatial resolution.

III.4.1.9 Valuation

The VSL is a value that reflects the amount people are willing to pay for small reductions in risk of early death. The conceptual foundation and application of the VSL are described in detail elsewhere (Organisation for Economic Cooperation and Development 2011; Hammitt and Robinson 2011; Lindhjem et al. 2011). A range of values for VSL have been estimated worldwide based on stated preference (contingent valuation studies) and revealed preference (labor market studies) (Organisation for Economic Cooperation and Development 2011). In this analysis, the benefit transfer approach was used to take a VSL value calculated for broad international application and adjust it for use in the Philippine context. This approach has been applied in numerous contexts, as discussed by Minjares et al. (2014) and Miller et al. (2014). The benefit transfer equation is shown below.

$$VSL_b = VSL_a \; X \; \frac{PPP\ GNI\ per\ capita_b}{PPP\ GNI\ per\ capita_a}$$

Equation III. 7 Benefit Transfer Equation

VSL_a was taken from a recent meta-analysis of international studies that recommends a value of $2.9 million 2005 USD for OECD countries, adjusted to USD 3.2 million in 2010 (OECD 2011). . Values for gross national income at purchasing power parity ($PPP\ GNI$) in the year 2005 from World Bank (2015b) were used to transfer from the OECD to the Philippines. The value was transferred using the average per-capita $PPP\ GNI$ across OECD countries and in the Philippines, resulting in a VSL of $0.76 million in 2015. Future increases in VSL were projected based on an average annual GDP growth rate consistent with LEAP model assumptions. The present value was calculated assuming a 5% discount rate to the 2010 base year.

These calculations implicitly assumed that the income elasticity of the WTP for mortality risk reductions was 1: a 1% increase in income would result in a 1 % increase in the WTP (and, thus, the VSL). However, there was considerable uncertainty regarding the income elasticity appropriate for income-related VSL adjustments. A recent synthesis of the VSL studies conducted in high-income countries found the VSL income elasticity to be in the range of 0.25-0.63 (Doucouliagos, Stanley, and Viscusi 2014). On the other hand, Hammitt and Robinson (2011) suggested that a VSL income elasticity value in the range of 1-2 would be more appropriate for transfers in low income countries, because mortality risk reductions in these settings are likely to be perceived as a luxury good. Given that the Philippines is a lower-middle-income country, the CBA team opted for a proportional scaling of the VSL using an elasticity value of 1. An elasticity of 1 has been used in other recent studies valuing health benefits in lower- and upper-middle-income economies, including India (Garg 2011), Colombia (Castillo 2010), China (Rabl 2011), Thailand (Sakulniyomporn, Kubaha, and Chullabodhi 2011), Mexico (Crawford-Brown et al. 2012), and Iran (Hoveidi 2013). The uncertainty in VSL elasticity warrants a sensitivity analysis exploring the results with different elasticity values (e.g., 0.5 – 1.5), but this was not within the scope of this analysis.

III.4.1.10 Energy Security Impacts

Increased energy security means that the country's energy system is more resilient to a variety of shocks (e.g., global economic crises, international conflicts, spikes in individual fuel costs). In practice, as energy security within a country's system increases, the adverse impacts from these shocks on the country's economy will be less pronounced. Improvements in energy security can result from several changes in the energy sector, such as increasing combinations of fuel diversity, transport diversity, import diversity, energy efficiency, and infrastructure reliability. For example:

- Energy generation portfolios that are heavily dependent on a limited number of fuel inputs or generation sources can be highly affected by shocks to a single fuel or generation source. In contrast, energy systems that incorporate a relatively diverse mix of fuel inputs and a number of generation sources with redundancy will be less affected by shocks to any single fuel or generation source. Energy security concerns can be alleviated by increasing the diversity of both the source of input fuels (i.e., domestic or imported, including the country of origin), the type of fuel (e.g., oil, gas, solar, renewables), and the mix of technologies used to generate the energy.
- Energy system security is also a function of available fuel supplies/reserves compared to demand. An increase in available fuel supply would increase energy security. Supply can be increased through increased exploration for fossil fuels, increasing investment in renewable fuels, or encouraging energy efficiency measures to prolong the availability of known existing resources.

A number of indicators may be applied to assess whether a country is becoming more or less energy secure due to implementation of a mitigation option. For this study, the following indicators were computed:

- Energy intensity of GDP (total primary energy supply[29] [TPES] per unit of GDP)
- GHG intensity of GDP (CO_2e emissions from all sectors per unit of GDP)
- Percentage share of imports in TPES
- Percentage share of renewable[30] energy in TPES

Incremental values were calculated for each mitigation option (in the retrospective systems framework) showing the change in the indicators due to the option.

III.4.1.11 Power Sector Employment Impacts

The basic indicator used to capture potential employment impacts is the job-year, defined as "full-time employment for one person for a duration of one year" (Wei, Patadia, and Kammen 2010, 7). Estimates of the net change in power sector job-years associated with the mitigation options are calculated using results from Wei, Patadia, and Kammen (2010). Wei, Patadia, and Kammen conducted a literature review and produced a synthesis of results that quantified the employment impacts of new power

[29] In the energy security security calculations, total primary energy supply is defined as indigenous production of fuels + fuel imports - fuel exports.

[30] Includes all biomass and waste-derived fuels as well wind, solar, hydro, geothermal, and ocean energy.

projects in the United States over a defined project lifetime. By accounting for the power generation potential and anticipated use of the projects, the Wei, Patadia, and Kammen (2010) results are expressed in terms of the average number of job-years per gigawatt hour (GWh), as shown in Table III. 33.

Table III. 33. Average Job-Years/GWh in Power Sector by Type of Power Generation

Power Generation Technology	Average Job-Years/GWh of Generation[a]
Solar Photovoltaic	0.87
Landfill Gas	0.72
Large Hydro	0.27
Small Hydro	0.27
Geothermal	0.25
Agricultural Waste Digestion	0.21
Biomass Combustion	0.21
MSW Digestion	0.21
MSW Incineration	0.21
Ocean Thermal	0.17
On-Shore Wind	0.17
Nuclear	0.14
Circulating Fluidized Bed Combustion Coal	0.11
Natural Gas Combined Cycle	0.11
Subcritical Pulverized Coal	0.11
Supercritical Pulverized Coal	0.11
Ultrasupercritical Pulverized Coal	0.11

[a] Assumptions:

- Wei, Patadia, and Kammen (2010) provide a job-years factor for Small Hydro. The same factor is assigned to Large Hydro.
- MSW Incineration, MSW Digestion, and Agricultural Waste Digestion use the Biomass job-years factor.
- Ocean Thermal uses the Wind job-years factor.
- All coal types use the same job-years factor.

Using the factors in Table III. 33 and power generation projections by source, year, and scenario from the LEAP model, net changes in job-years were calculated.

This approach had some important limitations, implying that the job-year results should be interpreted cautiously. For one thing, the changes in job-years represented direct employment impacts in the power sector only and do not account for possible employment effects elsewhere in the economy. Additionally, because the Wei, Patadia, and Kammen (2010) factors are based on developing new generation facilities in the United States, it is uncertain how well they translate to the Philippines and to cases that involve changing the dispatch of existing generation resources. Finally, the application of the job-year factors as constant values over the period of analysis assumed that future changes in technology wouldnot affect the values and that they could be used regardless of the size of the Philippine power sector.

III.4.2 Results

III.4.2.1 Direct Costs and Benefits of Mitigation Options

Table III. 34 and

Figure III. 14 provide direct cost-benefit results for the energy sector mitigation options. The MAC curve in

Figure III. 14 excludes the two options that could not be evaluated in the retrospective systems framework due to mutual exclusivity as well as the MSW Combustion option, which does not reduce GHG emissions in the retrospective systems analysis.

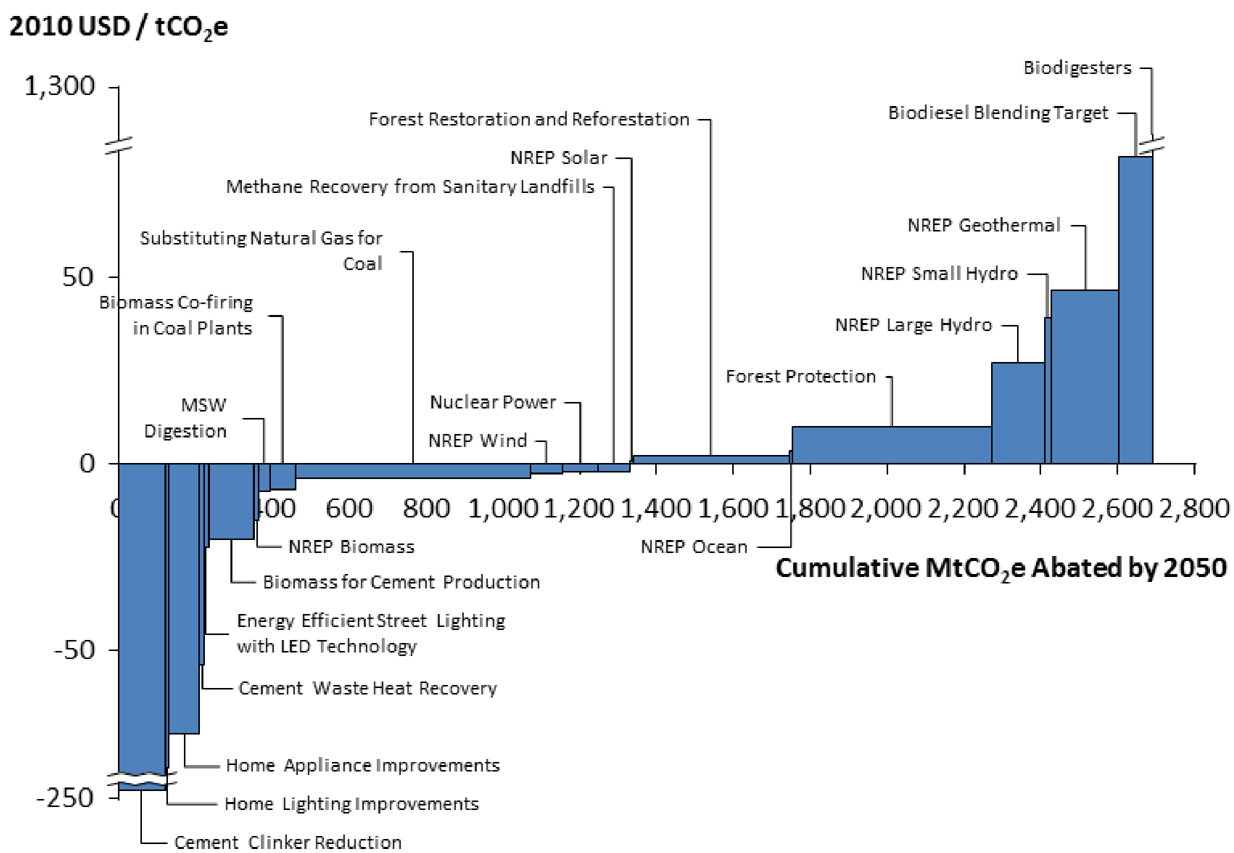
Table III. 34. Direct Cost-Benefit Results for Energy Sector Mitigation Options

Mitigation Option	Incremental Costs (Cumulative 2010 - 2050), Discounted at 5% [Billion 2010 USD]	Incremental GHG Mitigation Potential (Cumulative 2010 - 2050) [$MtCO_2e$]	Incremental Cost per Tonne Mitigation, Without Co-benefits [2010 USD/tCO_2e]
Biodiesel Blending Target	6.94	84.4	82.2
Biodigesters	1.35	1.0	1,287.2
Biomass Co-firing in Coal Plants	-0.48	70.6	-6.8
Biomass for Cement Production	-2.35	115.5	-20.4
Cement Clinker Reduction	-29.86	120.5	-247.8
Cement Waste Heat Recovery	-0.56	10.5	-53.9
Energy Efficient Street Lighting with HPS Technology[a]	-0.33	11.3	-29.6
Energy Efficient Street Lighting with LED Technology	-0.31	13.7	-22.4
Forest Protection	5.13	516.9	9.9
Forest Restoration and Reforestation	0.86	405.9	2.1
Home Appliance Improvements	-5.86	81.3	-72.0
Home Lighting Improvements	-0.73	9.0	-81.5

Mitigation Option	Incremental Costs (Cumulative 2010 - 2050), Discounted at 5% [Billion 2010 USD]	Incremental GHG Mitigation Potential (Cumulative 2010 - 2050) [$MtCO_2e$]	Incremental Cost per Tonne Mitigation, Without Co-benefits [2010 USD/tCO_2e]
Methane Recovery from Dumpsites for Electricity[a]	-0.14	79.3	-1.8
Methane Recovery from Sanitary Landfills for Electricity	-0.15	81.5	-1.9
MSW Combustion	0.38	*No mitigation potential*	*N/A*
MSW Digestion	-0.18	25.5	-7.1
NREP Biomass	-0.24	15.6	-15.2
NREP Geothermal	8.31	179.0	46.4
NREP Large Hydro	3.76	137.9	27.3
NREP Ocean	0.03	8.1	3.7
NREP Small Hydro	0.67	17.1	39.4
NREP Solar	0.01	11.0	0.9
NREP Wind	-0.23	85.5	-2.7
Nuclear Power	-0.20	91.5	-2.2
Substituting Natural Gas for Coal	-2.34	608.9	-3.8

[a] Incremental costs and benefits calculated relative to baseline scenario rather than via retrospective systems method.

Figure III. 14. MACC for Energy Sector



III.4.2.2 Co-Benefits of Mitigation Options

Table III. 35 presents the incremental human health impacts calculated for the energy sector mitigation options, and

Table III. 36 shows the average annual incremental impact of each option on the four energy security indicators. Table III. 37 provides estimates of changes in direct power sector employment due to the options.

Table III. 35. Incremental Human Health Impacts for Energy Sector Mitigation Options, Cumulative 2015-2050

Mitigation Option	Incremental Present Value, Discounted at 5% [Million 2010 USD]	Incremental Cases of Premature Death Avoided	Incremental Cases of Premature Death Avoided (Females)

Mitigation Option	Incremental Present Value, Discounted at 5% [Million 2010 USD]	Incremental Cases of Premature Death Avoided	Incremental Cases of Premature Death Avoided (Females)
Biodiesel Blending Target	*No impact on power sector emissions by design*		
Biodigesters	-364	-485	-157
Biomass Co-firing in Coal Plants	4,738	4,865	1,891
Biomass for Cement Production	*No impact on power sector emissions by design*		
Cement Clinker Reduction	38	50	18
Cement Waste Heat Recovery	231	243	95
Efficient Street Lighting with LED Technology	161	190	71
Forest Protection	158	173	*Not presented*[a]
Forest Restoration and Reforestation	-195	-210	-72
Home Appliance Improvements	13	8	3
Home Lighting Improvements	193	199	79
Methane Recovery from Sanitary Landfills for Electricity	-127	-130	-42
MSW Combustion	74	76	*Not presented*[a]
MSW Digestion	183	188	73
NREP Biomass	218	221	88
NREP Geothermal	5,134	5,346	2,018
NREP Large Hydro	3,385	3,496	1,393
NREP Ocean	129	132	59
NREP Small Hydro	243	255	*Not presented*[a]
NREP Solar	371	398	142
NREP Wind	1,265	1,379	482
Nuclear Power	1,438	1,508	593
Substituting Natural Gas for Coal	18,303	18,349	7,212

[a] The sampling routine used to calculate this result returned an unstable estimate, so it is not presented. The result would have the same sign as that for the incremental cases while being smaller in magnitude.

Table III. 36. Incremental Changes in Energy Security Indicators for Energy Sector Mitigation Options, Average Annual Impact During 2015-2050

Mitigation Option	Average Annual Incremental Impact 2015-2050[a]			
	Change in GHG Intensity of GDP [g CO_2e/2010 USD]	Change in Share of Renewables in TPES [%]	Change in Share of Imports in TPES [%]	Change in Energy Intensity of GDP [MJ/2010 USD]
Biodiesel Blending Target	-2.79	62	2	0
Biodigesters	0.58	18	-19	0.02
Biomass Co-firing in Coal Plants	-2.9	49	-42	0
Biomass for Cement Production	-4.39	78	-69	0
Cement Clinker Reduction	-4.11	9	-11	-0.02
Cement Waste Heat Recovery	-0.4	1	-2	-0.01
Energy Efficient Street Lighting with LED Technology	-0.54	2	-3	-0.01
Forest Protection	-19.1	-127	102	-0.07
Forest Restoration and Reforestation	-18.9	36	-28	0.02
Home Appliance Improvements	-2.35	8	-15	-0.04
Home Lighting Improvements	-0.29	1	-2	0
Methane Recovery	-2.22	8	-7	0

Mitigation Option	Average Annual Incremental Impact 2015-2050[a]			
from Sanitary Landfills for Electricity				
MSW Combustion	0.16	6	-5	0
MSW Digestion	-0.92	8	-8	0
NREP Biomass	-0.52	8	-8	0
NREP Geothermal	-7.69	564	-386	0.39
NREP Large Hydro	-5.76	160	-126	0.03
NREP Ocean	-0.34	5	-4	0
NREP Small Hydro	-0.8	25	-19	0.01
NREP Solar	-0.51	5	-2	0
NREP Wind	-3.93	48	-42	-0.03
Nuclear Power	-3.05	-17	27	0.01
Substituting Natural Gas for Coal	-14.18	33	-42	-0.08

[a] All indicators were calculated in the LEAP model. Results reflect the average of annual results from 2015-2050 that compare the indicator value for a given mitigation option relative to the value for the previous mitigation option. For reference, Figure III. 8. Energy and GHG Intensities of GDP, Baseline Scenario

shows the energy and GHG intensities of GDP in the baseline scenario.

Table III. 37. Incremental Changes in Power Sector Job-Years for Energy Sector Mitigation Options, Cumulative 2015-2050

Mitigation Option	Incremental Job-Years Impact (Unrounded Cumulative Job-Years 2015-2050)
Biodiesel Blending Target	*No change*[a]
Biodigesters	3,587
Biomass Co-firing in Coal Plants	0
Biomass for Cement Production	*No change*[a]
Cement Clinker Reduction	-1,582

Mitigation Option	Incremental Job-Years Impact (Unrounded Cumulative Job-Years 2015-2050)
Cement Waste Heat Recovery	-2,304
Energy Efficient Street Lighting with LED Technology	-3,020
Forest Protection	3,417
Forest Restoration and Reforestation	-1,020
Home Appliance Improvements	-21,578
Home Lighting Improvements	-1,560
Methane Recovery from Sanitary Landfills for Electricity	9,861
MSW Combustion	958
MSW Digestion	1,974
NREP Biomass	2,649
NREP Geothermal	44,860
NREP Large Hydro	42,732
NREP Ocean	904
NREP Small Hydro	6,344
NREP Solar	12,011
NREP Wind	8,978
Nuclear Power	3,639
Substituting Natural Gas for Coal	-496

[a] "No change" is indicated as there is no anticipated impact on the power sector by the design of the mitigation option.

III.4.2.3 Summary of Monetized Costs and Benefits

Table III. 38. Summary of Monetized Costs and Benefits of Energy Sector Mitigation Options combines the direct costs and benefits of the energy sector mitigation options with their estimated impacts on public health costs to arrive at co-benefits adjusted abatement costs per tonne and net present values. The table does not include the two options for which co-benefits were not calculated: Energy Efficient Street Lighting with HPS Technology and Methane Recovery from Dumpsites for Electricity. Direct costs per tonne and net present values excluding co-benefits for these options are provided in Table III. 34. Direct Cost-Benefit Results for Energy Sector Mitigation Options.

Table III. 38. Summary of Monetized Costs and Benefits of Energy Sector Mitigation Options

Mitigation Option	Incremental Cost per Tonne Mitigation, Without Co-benefits [2010 USD/tCO_2e]	Incremental Cost per Tonne Mitigation, Including Health Co-benefits [2010 USD/tCO_2e]	Net Present Value (Cumulative 2010 - 2050), Including Health Co-Benefits and Discounted at 5%[a] [Billion 2010 USD]
Biodiesel Blending Target	82.2	82.2	-6.9
Biodigesters	1,287.2	1,635.2	-1.7
Biomass Co-firing in Coal Plants	-6.8	-74.0	5.2
Biomass for Cement Production	-20.4	-20.4	2.4
Cement Clinker Reduction	-247.8	-248.1	29.9
Cement Waste Heat Recovery	-53.9	-75.9	0.8
Energy Efficient Street Lighting with LED Technology	-22.4	-34.2	0.5
Forest Protection	9.9	9.6	-5.0

Mitigation Option	Incremental Cost per Tonne Mitigation, Without Co-benefits [2010 USD/tCO_2e]	Incremental Cost per Tonne Mitigation, Including Health Co-benefits [2010 USD/tCO_2e]	Net Present Value (Cumulative 2010 - 2050), Including Health Co-Benefits and Discounted at 5%[a] [Billion 2010 USD]
Forest Restoration and Reforestation	2.1	2.6	-1.1
Home Appliance Improvements	-72.0	-72.2	5.9
Home Lighting Improvements	-81.5	-103.0	0.9
Methane Recovery from Sanitary Landfills for Electricity	-1.9	-0.3	0.0
MSW Combustion	*N/A – no abatement potential*	*N/A – no abatement potential*	-0.3
MSW Digestion	-7.1	-14.3	0.4
NREP Biomass	-15.2	-29.1	0.5
NREP Geothermal	46.4	17.8	-3.2
NREP Large Hydro	27.3	2.7	-0.4
NREP Ocean	3.7	-12.3	0.1
NREP Small Hydro	39.4	25.2	-0.4
NREP Solar	0.9	-32.7	0.4
NREP Wind	-2.7	-17.5	1.5
Nuclear Power	-2.2	-17.9	1.6
Substituting Natural Gas for Coal	-3.8	-33.9	20.6

[a] Excludes the value of GHG emission reductions, which were not monetized in this study.

III.4.3 Discussion of Mitigation Options

A number of useful insights emerge from the results of the energy sector analysis. The discussion here focuses first on results for each individual mitigation option, then considers implications for the energy sector as a whole.

III.4.3.1 Individual Mitigation Options

Biodiesel Blending Target

Costs associated with the Biodiesel Blending Target option derive entirely from fuel price differences between regular diesel fuel and the coconut methyl ester biodiesel used to replace it. Small emission reductions are found in off-grid electricity generation, which remains highly reliant on small-scale diesel generators. Much of the abatement occurs on the demand side, spread among mining, manufacturing, and the commercial sector. However, the largest single GHG abatement from the option occurs in the domestic shipping sector. This sector is heavily dependent on diesel and contributes nearly one-fifth of all transport emissions by 2050, relative to a scenario without implementation of Biodiesel Blending Target.

Biodigesters

Of the energy sector options with cumulative GHG abatement potential, Biodigesters has the highest direct costs per tonne CO_2e—almost 1,300 2010 USD. The relatively high fixed O&M costs of agricultural waste digestion (Table III. 14) play a role in this result, as does the option's low cumulative abatement potential (only 1 $MtCO_2e$ through 2050). The abatement potential is limited for two main reasons:

1) The incremental biogas power in the scenario substitutes primarily for natural gas power (because Biodigesters follows Substituting Natural Gas for Coal in the retrospective systems order, its new capacity is inserted into a natural gas-heavy system).

2) Paralleling the case of Methane Recovery from Sanitary Landfills for Electricity, deploying the new waste digestion capacity delays the construction of some natural gas plants, creating a few extra years where waste digestion facilities plus pre-existing coal plants can meet electricity demand. The additional coal utilization tempers the overall GHG impact.

The second of these factors explains the increased public health costs from the power sector under this option (Table III. 35). The option also leads to a notable rise in the share of renewables and a decline in the share of imports in the total primary energy supply (Table III. 36). These results indicate the significant energetic potential in domestically produced animal wastes, even if only a small fraction of the waste stream is captured as in this scenario.

Biomass Co-firing in Coal Plants

Given the projected size and average efficiency of the subcritical coal power fleet in the Philippines, substituting biomass for 5% of subcritical coal consumption has sizable impacts, avoiding over 70 $MtCO_2e$ through 2050 at a direct cost savings. Reduced combustion of coal lowers the public health costs of subcritical plants—the net present value of the health savings by 2050 totals almost five billion 2010 USD, and accounting for these benefits decreases the abatement cost per tonne by a factor of 10—and also contributes to energy security by a number of indicators (Table III. 36). The range of benefits realized by displacing just 5% of input coal underscores the considerable externalities of subcritical coal power. Co-firing may be especially useful as a short-term measure to lessen these costs while cleaner power sources are developed.

Biomass for Cement Production

This option shifts the balance of thermal inputs to cement production, ultimately substituting biomass for 35% of coal consumption. Because substitution at this level does not substantially affect the capital or O&M costs of cement manufacture, the direct cost implications of the change are determined by the difference in costs between coal and biomass fuels. With the projected fuel costs in Table III. 27. Historical and Projected Fuel Prices, All Scenarios [2010 USD/GJ] , about 116 MtCO_2e of GHG abatement is available during the projection period at an average direct cost of -20 2010 USD per tonne. The option does not induce power-sector health or jobs impacts because electricity demand is unaltered, and it has a favorable effect on energy security indicators as domestically grown biomass replaces imported, GHG-intensive coal (Table III. 36).

Cement Clinker Reduction

Cement Clinker Reduction is the most cost-effective mitigation option analyzed for the energy sector. It provides over 120 MtCO_2e of GHG abatement through 2050 at a direct cost of nearly -250 2010 USD per tonne. This value becomes even more compelling when reduced health costs from power-sector pollution are considered (these result from lower electricity demand and power production overall). Lower power production also decreases labor requirements for electricity generation (Table III. 37), and the option's energy demand savings have benefits for energy security (Table III. 36).

The cumulative abatement potential splits almost evenly between avoided energy-related emissions (45%) and non-energy emissions (55%), reflecting the significant energy and process emissions intensities of clinker production. Accessing the mitigation potential will require continued engagement with cement manufacturers, building on the consultations conducted for this study, as well as educating builders and other cement consumers on appropriate uses for high and low-clinker cement. The costs of such outreach are difficult to quantify and are not included in the results reported here, but it seems unlikely that they would substantially alter this option's attractiveness.

Cement Waste Heat Recovery

The CBA analysis shows significant cost advantages of deploying waste heat-to-electricity technology in the cement industry. The cumulative GHG abatement is small due to the modest amount of capacity involved—60 MW by 2025, the low end of the estimate of current waste heat recovery potential in the Philippine cement industry in Institute for Industrial Productivity and International Finance Corporation (2014)—but it is realized at an average direct cost of -54 2010 USD per tonne CO_2e. Waste heat-to-electricity increases the energy self-sufficiency of cement producers while lowering requirements for grid-produced electricity. Between 2015 and 2050, about 16,000 gigawatt hours of grid-produced electricity are avoided. Reduced demands on the grid mean lower generation and air pollution from the power sector, providing a modest public health benefit (about 250 avoided premature deaths during 2015-2050). They also imply a reduction in power-sector employment (Table III. 37), although it is misleading to take this result in isolation because the co-benefits analysis does not consider employment impacts beyond the power sector, such as in companies producing heat-to-power technology or the cement industry itself.

Energy Efficient Street Lighting with HPS or LED Technology

As noted earlier, the Energy Efficient Street Lighting with HPS Technology option is excluded from the retrospective systems analysis, and therefore from the MACC (Figure III. 14), due to mutual exclusivity with the LED street lighting option. Still, due to their similarity, both of these measures were discussed together. The efficient LED option offers slightly more reduced emissions than HPS, but also reduced direct cost savings, making it the less cost-effective of the two measures. In each scenario, the capital costs of the efficient devices are compensated by reduced operation expenses—both variable O&M and fuel costs. To a lesser extent, cost savings also arise from the reduced or delayed need to construct new power plants. This is an important point because even those efficiency measures that only delay, but do not eliminate, the need to build new capacity can present cost savings due to the discounted nature of future costs.

Forest Protection and Forest Restoration and Reforestation

As described in Table III. 25. Energy Sector Mitigation Options Analyzed in CBA , these two options have opposing effects within the energy sector as the amount of wood used for energy increases (Forest Restoration and Reforestation) or decreases (Forest Protection). The change in wood consumption is offset by changes in LPG, electricity, and kerosene consumption, so Forest Protection actually raises energy-sector GHG emissions while Forest Restoration and Reforestation lowers them.[31] In each case, though, the energy-sector impact is dwarfed by the option's non-energy emission reductions, which largely determine the available abatement potential.

The role of the energy sector is more prominent when it comes to the options' costs. If the options had no interactions with the energy sector (i.e., if only non-energy emissions and costs were counted), the average cost per tonne of mitigation through 2050 would be 2.0 2010 USD for Forest Protection and 5.3 2010 USD for Forest Restoration and Reforestation. Including energy sector effects switches the order: Forest Restoration and Reforestation becomes the more cost-effective at 2.1 2010 USD per tonne, while Forest Protection costs 9.9 2010 USD per tonne. The energy sector costs are due to changes in fuel expenditures as well as capital and O&M costs in the power sector.

Home Appliance Improvements and Home Lighting Improvements

These two household measures are both highly cost-effective. The low cost of these scenarios derives mostly from the relatively small additional purchase price of efficient lighting technologies and home appliances, which deliver significant energy savings. In fact, in some cases an efficient technology may simply be less expensive than a conventional alternative even without regard for energy savings. Compact and linear fluorescent bulbs are one such example, where the cost of the linear bulb fixture renders it more expensive than the compact—and more efficient—alternative.

---

[31] The effect is mediated by assumptions about the share of the offset for each alternative fuel as well as useful energy efficiencies (see Table III. 25. Energy Sector Mitigation Options Analyzed in CBA), but ultimately it derives from exchanging biomass and non-renewable energy.

Those small costs that are incurred are offset by fuel savings in the electricity sector, and reduced capital requirements from avoiding about 3 GW of on-grid capacity (for both Home Appliance Improvements and Lighting Improvements together relative to a scenario without the measures). There are no direct emission benefits from introducing efficient technologies, so the abatement potential in this scenario derives from reduced emissions from both on- and off-grid electricity production.

When considering the household efficiency options, it is important to recall that the baseline by which their energy savings are measured considers no further technological change. The number of devices of each type, as well as the energy consumption of these devices, are both fixed in the model's baseline scenario. As a result, some of the efficiency attributable to this measure may already be happening.[32]

Methane Recovery from Sanitary Landfills/Dumpsites for Electricity

These options envision a similar deployment of LFG-to-electricity capacity Table III.39 and return similar mitigation results. Both provide about 80 $MtCO_2e$ of cumulative abatement through 2050 with directs costs around -2 USD per tonne.

Table III. 39. LFG Generation Capacity, Methane Recovery Scenarios [MW]

Mitigation Option	2010	2020	2030	2040	2050
Methane Recovery from Sanitary Landfills for Electricity	14.7	13.7	63.1	107.1	191.1
Methane Recovery from Dumpsites for Electricity	14.7	15.0	58.8	94.6	165.2

Methane Recovery from Sanitary Landfills also offers some mitigation co-benefits, in particular lower GHG intensity of GDP, greater use of RE, lower energy imports, and higher net employment in the power sector (Section III.4.2 Results).[33] Interestingly, though, the option increases the power sector's impacts on public health, inducing 130 additional premature deaths during 2015-2050. As new LFG capacity is brought online at landfills, it delays the construction of some natural gas plants, creating a few additional years when rising electricity demand can be met by a combination of the new LFG capacity and pre-existing, more polluting assets (especially pre-existing coal and oil plants). Higher cumulative emissions of PM and SO_2 result will lead to the negative effect on public health.

[32] This assertion is confirmed by DOE stakeholders, who propose that the mitigation measure should begin to take effect in 2012 instead of 2020 (DOE 2015l).

[33] The CBA's co-benefits team did not estimate co-benefits from Methane Recovery from Dumpsites for Electricity because this option is excluded from the retrospective systems analysis.

MSW Digestion/Combustion

These options model a relatively modest foray into generating power from MSW, with enough generation capacity deployed by 2025 to consume 1,000 short tons of organic MSW per day (MSW Digestion) and 1,000 short tons of residual MSW per day (MSW Combustion). This consumption represents about 4% of the Philippines' projected MSW stream in 2025. Because of the small amounts of capacity involved, the options have a limited impact on the power sector and serve mostly to illustrate the potential of MSW digestion and incineration technologies.

Viewed from this perspective, the two technologies have markedly different profiles. MSW Digestion provides net GHG abatement by 2050 at a direct cost savings, while MSW Combustion does not show any long-term abatement potential. As both options do lower non-energy GHG emissions from waste disposal, the difference is in the power sector, where two key factors influence the outcome. First, per kWh of electricity generated, MSW incineration produces more non-biogenic CO_2 than MSW digestion due to non-biogenic carbon in plastics and other materials in residual MSW. Second, the ordering of the options in the retrospective systems analysis means that the incremental power from MSW Digestion substitutes for more carbon-intensive electricity than the power from MSW Combustion. Under the MSW Digestion option, incremental MSW-based electricity displaces mostly coal power (about 77% of the displaced power through 2050), with gas making up the bulk of the remainder. The situation changes for MSW Combustion, however, since this option comes at the end of the retrospective systems order (Table III. 28. Full Retrospective Systems Ordering of Mitigation Options, All Sectors). Its position is due principally to the high costs of advanced pollution controls for MSW incinerators[34] and implies that the option is deployed into a substantially cleaner power system than MSW Digestion (i.e., multiple power sector mitigation options are assumed already to be effective). As a result, the incremental MSW-based power displaces more gas (53% of the substituted power through 2050). The first of these two factors is the most important—MSW Combustion does not reduce power-sector GHG emissions even when compared individually to the baseline scenario—but the second is another demonstration of the dependencies that can arise in a portfolio of multiple mitigation measures.

The direct cost and mitigation benefits of MSW Digestion are complemented by positive co-benefits, including reduced premature deaths due to air pollution from power generation, a reduction in energy imports, and an increase in power-sector employment (Section III.4.2 Results). MSW Combustion also shows co-benefits in these areas, suggesting some social value despite its failure to deliver GHG abatement. In this context, it is worth pointing out that this study does not quantify some potentially important co-benefits of improved waste management, such as reduced damages to public health and ecosystems from conventional disposal practices. Benefits of this sort may make MSW incineration (and digestion) worth pursuing for reasons that have little to do with mitigation.

[34] For example, as shown in Table III. 14. Key Technical and Cost Parameters for Electricity Generation Technologies – Baseline Values, the estimated capital and fixed O&M costs of MSW incineration are more than twice those of MSW digestion.

NREP (all technologies)

The Philippine NREP covers a number of separate clean power technologies that are discussed together. Generally speaking, the direct cost-effectiveness of each technology depends on the extent to which its capital and fixed O&M costs are offset by operating savings. For example, despite high capital and fixed O&M costs, NREP Biomass offers deep operating cost reductions (both fuel and variable O&M), which make it the most attractive NREP option from a direct cost standpoint. While primarily displacing combined cycle gas, oil turbines, and advanced coal technologies, it also displaces small quantities of other renewable capacity—mostly wind, geothermal, and large hydro. In contrast, the high capital and fixed O&M costs of the NREP Geothermal measure are not offset by variable cost savings. As a result, it is the highest direct-cost renewable technology assessed. The technologies that lie between show different balances among these cost categories. It is especially interesting to note that those technologies with either negative or small positive direct costs per tonne of abatement (ocean thermal, solar, wind, biomass combustion) are also those that show savings in both fuel and variable O&M costs. Thus, *measures that reduce the operating costs* of the power system can be attractive even if they are more capital-intensive. Accounting for health co-benefits improves the cost-effectiveness of all NREP technologies, particularly solar and geothermal (Table III. 38).

The series of NREP technology options offers some additional insight into the importance of interactions. For example, the table below hints at the diminishing returns of constructing additional renewable capacity. On the left of the table are options that are most expensive, which if indeed implemented after lower-cost options, show that an increasingly large fraction of the electricity that they displace was renewable in the first place.

Table III. 40. Percentages of RE Within Total Displaced Electricity, After Introduction of Each Subsequent NREP Technology in Retrospective Analysis

Geothermal	Small Hydro	Large Hydro	Ocean	Solar	Wind
6.4%	8.4%	5.5%	6.3%	5.0%	4.7%

Still, it is important to remember that even together, the NREP options only add a total of 15,304 MW of capacity, accounting for less than 13% of all installed capacity by the year 2050 (both NREP and non-NREP renewables represent only 21% of capacity and 23% of generation). This means that there is still a great deal of latitude for further abatement using renewable generation technologies. Since the current NREP covers the planning period through 2030 only, it will be important to ramp up committed renewable capacity in the long term if deeper reductions are sought.

Nuclear Power

Interestingly, the CBA finds that nuclear power is a negative direct cost measure in the Philippines. Though the technology is both more capital and O&M intensive than the power plants it displaces (primarily natural gas combined cycle, followed by advanced coal technologies and oil combined cycle), the cost of fueling nuclear plants is substantially less than for fossil-fueled alternatives. This input cost advantage, stemming from the high cost of imported fossil fuels, leads to a negative cost per tonne

CO_2e. It should be emphasized, however, that nuclear fuel costs in the CBA are taken from international sources for want of national data (Table III. 26. Fuel Price Sources and Projection Methodology, All Scenarios). Possible future costs in the Philippines may be quite different.

Substituting Natural Gas for Coal

The direct cost savings of this option are the result of reduced capital and operating costs of NGCC technology compared to coal technologies (particularly advanced coal technologies likely to come online in the future). The cost reduction is somewhat mitigated by the higher fuel cost of natural gas compared to coal—by nearly a factor of two in most years—but this effect is suppressed by NGCC's greater efficiency, and it does not meaningfully affect the overall cost-effectiveness of the measure. The cumulative abatement potential (more than 600 $MtCO_2e$ through 2050) is the largest of any energy sector option and bespeaks the significant gas capacity involved. Almost 30 GW of additional NGCC plants are built under the option, substituting for coal plants that would otherwise have been needed. The option also has considerable health co-benefits, with over 18,000 premature deaths avoided, and causes a notable reduction in the GHG intensity of GDP.

III.4.3.2 Sector-Level Implications

Consistent with similar, prior studies, this analysis finds significant mitigation potential in the Philippine energy sector. The portfolio of energy sector options evaluated yields emission reductions through 2050 of about 2,700 $MtCO_2e$, 27% of baseline national emissions between 2010 and 2050. Importantly, most of the estimated potential is low cost. Fifty percent is accessible at a negative average, discounted direct cost per tonne CO_2e (i.e., a direct cost savings), and 97% is available for less than 50 2010 USD per tonne.

Half of the available mitigation potential is in the power sector, including many options with medium-to-large projected abatement. The direct costs of power sector options cover a range from negative cost (e.g., NREP Biomass, MSW Digestion) to over 1,000 2010 USD per tonne (Biodigesters). The most cost-effective energy sector options overall relate to process and efficiency improvements in industry, buildings, and infrastructure. These measures are worth serious consideration irrespective of the Philippines' climate policy.

Many of the options have an impact on the co-benefits considered in the study: health effects of power sector emissions, energy security, and power sector employment. With respect to health, clean power options such as NREP show the largest benefits, while electric efficiency measures have a positive but somewhat smaller impact. Slightly less than 50% of the total health benefits accrue to females because their baseline mortality rates are lower than the baseline mortality rates for males. It is worth noting again that the health analysis does not comprise morbidity impacts of changes in ambient air pollution, nor does it quantify health costs of emissions outside the power sector, such as from household cooking. Changes in morbidity due to power sector emissions should have the same direction/sign as changes in premature mortality, however.

Mitigation options involving large-scale deployment of alternative technologies in the power sector (e.g., NREP Geothermal and Hydro, Substituting Natural Gas for Coal) have some of the most important effects on the energy security indicators. They reduce the GHG intensity of GDP and, in the case of renewable power, increase the share of renewables in the energy supply and reduce reliance on imported energy. Large-capacity renewable electricity options and Home Appliance Improvements, the latter induces substantial electricity savings, have the most significant estimated consequences for power sector employment.

The cost-benefit results reported in Section III.4.2 Results are the study team's best estimates given the available input data and the methodological framework described earlier. It is clear, however, that some uncertainty inheres in these numbers. Long-range projections are intrinsically uncertain—no one knows how the future will unfold—and in the Philippine context, some variables that are instrumental to the CBA modeling are the subject of active debate. For example, stakeholders consulted by the CBA team expressed a variety of opinions about what the study should assume concerning future GDP.

A full analysis of future uncertainties in the Philippine energy system is beyond the scope of this report, but still it is useful to consider what key uncertainties could mean for energy sector mitigation. Table III. 41. Energy Sector Mitigation Under High and Low GDP, Population, and Fuel Price Assumptions shows the effects on the study's energy sector options of varying several fundamental inputs to the energy model: GDP; population; and natural gas, biomass, coal, and oil prices.[35] In each case, the "high" scenario for the input raises the input's value by 25% relative to the study baseline during 2015-2050 (i.e., by 2050, the value is 125% of the baseline value). The "low" scenario decreases the input's value by 25% relative to the baseline over the same period. To focus the presentation on energy, cumulative emissions, mitigation potential, and costs are reported for the energy sector only (excluding transport, as usual). All energy sector options are grouped together and assumed to be implemented simultaneously.[36]

Table III. 41. Energy Sector Mitigation Under High and Low GDP, Population, and Fuel Price Assumptions

Scenario	2030			2050		
	Cumulative Energy Sector GHG Emissions from 2010 [$MtCO_2e$]	Cumulative Mitigation in Energy Sector, All Energy Sector Options[a] [$MtCO_2e$]	Direct Cost per Tonne Mitigation in Energy Sector, Discounted at 5% [2010 USD/tCO_2e]	Cumulative Energy Sector GHG Emissions from 2010 [$MtCO_2e$]	Cumulative Mitigation in Energy Sector, All Energy Sector Options[a] [$MtCO_2e$]	Direct Cost per Tonne Mitigation in Energy Sector, Discounted at 5% [2010 USD/tCO_2e]

[35] "Biomass" prices include prices for all primary biomass fuels, charcoal, and liquid biofuels; "oil" prices include prices for crude oil and all oil products.

[36] Except for Energy Efficient Street Lighting with HPS Technology, which is omitted because it is mutually exclusive with Energy Efficient Street Lighting with LED Technology.

Scenario	2030			2050		
Baseline	2,098.4	346.0	25.5	6,625.1	1,540.9	5.3
High GDP	2,175.0	355.5	24.8	7,382.7	1,705.6	3.5
Low GDP	2,018.9	336.7	27.0	5,866.4	1,368.5	7.8
High Population	2,115.2	345.9	25.7	6,730.3	1,565.0	4.7
Low Population	2,080.0	346.1	26.8	6,524.9	1,512.3	6.2
High Natural Gas Prices	2,098.4	345.9	24.1	6,625.1	1,540.9	6.6
Low Natural Gas Prices	2,098.4	345.9	26.9	6,625.1	1,540.9	4.0
High Biomass Prices	2,098.4	345.9	26.7	6,625.1	1,540.9	6.9
Low Biomass Prices	2,098.4	345.9	24.2	6,625.1	1,540.9	3.7
High Coal Prices	2,098.4	345.9	23.8	6,625.1	1,540.9	2.0
Low Coal Prices	2,098.4	345.9	27.1	6,625.1	1,540.9	8.6
High Oil Prices	2,098.4	345.9	24.8	6,625.1	1,540.9	4.5
Low Oil Prices	2,098.4	345.9	26.1	6,625.1	1,540.9	6.1

[a] Excludes mitigation in non-energy sectors and the transport sector.

GDP and population are critical variables to examine because, as explained in Section III.3.1 Methods and Assumptions they drive final energy demand in the energy sector LEAP model. Energy demand and supply projections are not linked explicitly to fuel prices (which is why the mitigation potential in the fuel price scenarios does not differ from that calculated using baseline prices); but fuel costs are an essential component of the cost of mitigation. It makes sense to evaluate the four selected fuels since a number of energy sector mitigation options depend on switching to natural gas or biomass, and the baseline energy projection is quite coal and oil-dependent (Figure III. 10. Total Primary Energy Supply, Baseline Scenario).

As Table III. 41. Energy Sector Mitigation Under High and Low GDP, Population, and Fuel Price Assumptions illustrates, the performance of the energy sector options does vary under the alternate GDP, population, and price assumptions. However, in all of the scenarios evaluated, the options continue to deliver significant abatement for a low average direct cost per tonne CO_2e. Because many of the options involve deploying a fixed amount of a low carbon technology (especially in the power sector), the cumulative abatement potential is not very sensitive to the changes in inputs. Notwithstanding, the potential is generally greater in the high GDP and population scenarios and smaller in their low counterparts. These changes reflect the scaling of measures such as Biodiesel Blending Target, whose impact depends on the level of final energy demand, and Home Appliance Improvements, whose effects vary directly with the number of households (and thereby the number of home appliances).

Mitigation costs are somewhat more responsive to the alternate assumptions. Increased deployment of demand-side measures in the high GDP and population scenarios leads to greater fuel savings, driving down the sector-wide cost per tonne of abatement in the long run. The opposite occurs in the low GDP and population scenarios. The impact is quite notable for GDP, the low GDP case raising the average direct cost per tonne of mitigation by almost 50% by 2050. Long-run abatement costs follow natural gas and biomass price changes due to increased consumption of these fuels under the energy sector mitigation options; and they have an inverse relationship with price changes for coal and oil, fuels whose consumption is lowered by mitigation. The average direct cost per tonne of abatement is particularly sensitive to variability in the price for coal owing to the scale of substitution for coal by multiple power sector measures.

The results of this simple uncertainty assessment provide some evidence of the robustness of the energy sector options and their capacity to reduce emissions even if this study's baseline scenario is not realized. These findings are especially relevant in light of the Philippines' recently published intended nationally determined contribution (INDC) to the next international climate agreement, which sets a conditional goal of reducing national GHG emissions (excluding the agriculture sector) of 70% from a business-as-usual baseline by 2030 (CCC 2015). With such an ambitious target, mitigation options that perform well under a range of possible future conditions are clearly valuable.

All told, the options in this study (all sectors) cut national emissions about 44% from the study baseline in 2030, leaving open the question of what additional measures may be necessary to reach the INDC's objective. While developing the CBA for the energy sector, the study team and stakeholders identified a few candidates that could help make up the difference, including increased deployment of renewable power, reductions in electricity transmission and distribution losses, improvements to building shells to reduce cooling loads, equipment upgrades in commercial buildings, and additional energy efficiency measures in industry. These options could not be quantified for the CBA due to insufficient data but warrant further study. Measures targeting electricity demand and supply should be a top priority (as they were in this CBA) given the likely importance of the power sector in determining energy-related emissions in coming decades (Figure III. 7).

ANNEX III.5 CROSS-CUTTING ECONOMIC ASSUMPTIONS

The sector-specific baseline projections are based on the common set of projections for the Philippine economy characteristics. Table III. 42 shows the data sources and assumptions used to generate these projections, while Table III. 43 presents historical and projected values in select years that were used in the analysis.

Table III. 44 lists historical exchange rates and inflation rates used for inter-temporal and cross-country currency conversions.

Table III. 42 Data Sources and Assumptions Used for Projections of Population, GDP, Economic Sector-Specific Value Added, and Fuel Price

Characteristic	Data Sources for 2010-2014 Estimates	Projection Method for 2015-2050
Population	1990-2010: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/secstat/d_popn.asp). Accessed 13 March 2015. 2011-2020: Philippine Statistics Authority, National Statistics Office (http://web0.psa.gov.ph/sites/default/files/attachments/hsd/pressrelease/Table4_9.pdf). Accessed 13 March 2015.	2011-2020: Philippine Statistics Authority, National Statistics Office (http://web0.psa.gov.ph/sites/default/files/attachments/hsd/pressrelease/Table4_9.pdf). Accessed 13 March 2015. 2021-2045: Philippine Statistics Authority, National Statistics Office (http://web0.psa.gov.ph/sites/default/files/attachments/hsd/pressrelease/Table1_8.pdf). Accessed 13 March 2015 2045-2050: Population is assumed to grow at average annual rate during 2035-2045.
GDP	1990-2010: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/Rev_Ann_Qtr/1946_2010_NAP_Linked_Series_NSIC.xls). Accessed 12 March 2015. 2011: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2013/4th2013_RevisedMay2014/Revised_Q1_to_Q4_2011_to%202013.rar). Accessed 12 March 2015. 2012-2014: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2014/4th2014/tables/1Q4-Rev_Summary_93SNA.pdf). Accessed 12 March 2015.	GDP assumed to grow at similar rate as that projected by ADB in *Low-Carbon Scenario and Development Pathways for the Philippines* (ADB, 2015)
Value Added by Industrial Sectors	1998-2010: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/revisedQuarterlyPSNA/Annual (revised,rebased%2098-2000.rar). Accessed 12 March 2015. 2011-2013: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2013/4th2013_RevisedMay2014/Revised_Q1_to_Q4	All value added variables projected based on trends in their historical share of GDP.

Characteristic	Data Sources for 2010-2014 Estimates	Projection Method for 2015-2050
	_2011_to%202013.rar). Accessed 12 March 2015. 2014: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2014/4th2014/tables/10MFG_93SNA_Q4.pdf, http://www.nscb.gov.ph/sna/2014/4th2014/tables/9MAQ_93SNA_Q4.pdf, http://www.nscb.gov.ph/sna/2014/4th2014/tables/11CNS_93SNA_Q4.pdf, and http://www.nscb.gov.ph/sna/2014/4th2014/tables/12EGW_93SNA_Q4.pdf). Accessed 12 March 2015.	
Value Added by Commercial Sector	1998-2010: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/revisedQuarterlyPSNA/Annual(revised,rebased%2098-2000.rar). Accessed 12 March 2015. 2011-2013: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2013/4th2013_RevisedMay2014/Revised_Q1_to_Q4_2011_to%202013.rar). Accessed 12 March 2015. 2014: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2014/4th2014/tables/1Q4-Rev_Summary_93SNA.pdf). Accessed 12 March 2015.	All value added variables projected based on trends in their historical share of GDP.
Value Added by Agriculture, Forestry, Fishing	1998-2010: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/revisedQuarterlyPSNA/Annual(revised,rebased%2098-2000.rar). Accessed 12 March 2015. 2011-2013: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2013/4th2013_RevisedMay2014/Revised_Q1_to_Q4_2011_to%202013.rar). Accessed 12 March 2015. 2014: Philippine Statistics Authority, National Statistical Coordination Board (http://www.nscb.gov.ph/sna/2014/4th2014/tables/8AFF_93SNA_Q4.pdf). Accessed 12 March 2015.	All value added variables projected based on trends in their historical share of GDP
Biomass	Department of Environment and Natural Resources, 2013 Philippine Forestry Statistics, Table 4.10 MONTHLY RETAIL PRICES OF FUELWOOD AND CHARCOAL: 2013 (http://forestry.denr.gov.ph/PFS2013.pdf)	Assumed same as the constant price for 2010-2014

Characteristic	Data Sources for 2010-2014 Estimates	Projection Method for 2015-2050
Coal Sub bituminous	Data gathered by B-LEADERS project, 2015 (Philippine Coal Importation.xlsx) and national energy balances. Note that prices are based on imported coal only.	IEA (2014), World Energy Outlook 2014, IEA, Paris. (Current Policies scenario)
Natural Gas	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	IEA (2014), World Energy Outlook 2014, IEA, Paris. (Current Policies scenario)
Nuclear	IPCC AR5 WG3 Annex III	Assumed same as the constant price for 2010-2014
Crude Oil	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	IEA (2014), World Energy Outlook 2014, IEA, Paris. (Current Policies scenario)
Avgas	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Lubricants	Same as Residual Fuel Oil	Same as Residual Fuel Oil
Bitumen	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Naphtha	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Other Oil	Same as Residual Fuel Oil	Same as Residual Fuel Oil
LPG	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Residual Fuel Oil	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Diesel	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Kerosene	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Jet Kerosene	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Motor Gasoline	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil
Biodiesel	Renewable Energy Management Bureau, DOE	Grows at the rate of crude oil
Ethanol	Fuel price data provided by DOE to B-LEADERS project, 2015 (USAID Request_historical prices-03.04.2015.xls)	Grows at the rate of crude oil

Characteristic	Data Sources for 2010-2014 Estimates	Projection Method for 2015-2050
CNG	Department of Energy. "Compressed Natural Gas," 2015. http://www.doe.gov.ph/programs-projects-alternative-fuels/297-compressed-natural-gas	CNG price held constant until 2016 per Velasco, Myrna. "DOE Admits Delayed Rollout of CNG Buses." Manila Bulletin, 2014. http://www.mb.com.ph/doe-admits-delayed-rollout-of-cng-buses/. After 2016, CNG price based on price of natural gas plus cost adders for compression, distribution, refining, taxes, and retail mark-up shown in American Clean Skies Foundation. Driving on Natural Gas: Fuel Price and Demand Scenarios for Natural Gas Vehicles to 2025, 2013.

Table III. 43 Data and Projections of Population, GDP, Economic Sector-Specific Value Added, and Fuel Price in Select Historical and Baseline Years

	Historical Data				Baseline								
Year	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Population (Millions)	61	69	77	85	92	102	110	118	125	132	138	142	147
GDP (Billions 2010 USD)	98	106	132	161	200	274	336	474	611	793	1,060	1,433	1,895
Value Added by Economic Sectors (Millions 2010 USD)													
Beverages	1094	1187	1413	1232	1573	2166	2392	2631	2884	3152	3437	3739	4059

Year	Historical Data				Baseline								
	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Tobacco	515	558	725	364	169	129	119	110	100	92	83	76	69
Food Manufactures	7123	7725	10420	14346	18193	23711	30501	39089	49929	63590	80780	102383	129502
Textile and Leather	2785	3021	3314	3156	2508	2542	2343	2153	1971	1799	1638	1488	1349
Wood and Wood Products	819	888	954	1049	777	1006	965	923	879	835	792	748	706
Paper Pulp and Print	684	742	879	650	627	865	837	807	776	743	710	677	645
Chemical and Petrochemical	1694	1837	2126	2468	2595	5697	7351	9449	12106	15465	19705	25050	31782
Non Metallic Minerals	762	827	795	771	1146	1274	1338	1400	1460	1518	1575	1629	1683
Iron and Steel	661	717	650	819	1040	835	808	778	748	716	684	652	620
Machinery	1532	1662	2624	2668	2603	2469	2566	2657	2742	2821	2895	2965	3030
Rubber and Rubber Products	424	460	534	532	616	634	644	652	657	661	663	664	664
Petroleum and Other Fuel Products	1080	1171	1892	2616	2984	3126	3859	4746	5819	7112	8672	10548	12805
Other Manufacturing	3791	4112	5913	8029	7972	7010	7586	8177	8786	9413	10058	10724	11410
Mining	830	900	829	1972	2854	2493	3111	3868	4794	5923	7300	8976	11015
Construction	6225	6752	7504	7625	12220	16201	19385	23107	27453	32522	38427	45302	53298
Electricity Gas Water Supply	3649	3958	4828	6139	7128	8200	9398	10729	12208	13851	15675	17699	19943
All Commercial	49783	53995	67958	86076	110009	145430	180027	222018	272898	334462	408861	498673	606984
Agri Crops Product	7201	7810	9214	10318	13304	16309	18733	21437	24449	27804	31537	35691	40310
Livestock and Poultry	3666	3976	4725	5177	5592	5882	6106	6313	6507	6687	6854	7009	7153

Year	Historical Data				Baseline								
	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Agri Services	946	1026	1172	1314	1633	1907	2117	2341	2580	2836	3109	3400	3711
Forestry	94	102	192	129	54	91	84	77	70	64	58	53	48
Fishing	2544	2759	3100	3439	3995	3799	3860	3908	3943	3967	3981	3986	3982
Value Added by Economic Sectors (Millions 2010 USD)													
Biomass	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
Coal Sub bituminous	1.77	1.77	1.77	2.75	4.27	4.39	5.14	5.37	5.62	5.78	5.95	6.13	6.31
Natural Gas	1.46	1.46	1.46	6.54	8.89	9.96	9.43	9.83	10.24	10.55	10.87	11.2	11.54
Nuclear	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81	0.81
Crude Oil	5.13	5.13	5.13	8.67	12.49	15.68	16.73	18.31	20.05	21.18	22.37	23.63	24.96
Avgas	14.44	14.44	14.44	21.7	32.79	33.45	35.69	39.07	42.78	45.19	47.73	50.41	53.24
Lubricants	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.7	29.25	30.9
Bitumen	5.5	5.5	5.5	5.24	13.12	13.14	14.01	15.34	16.8	17.74	18.74	19.8	20.91
Naphtha	7.51	7.51	7.51	7.74	11.19	14.13	15.07	16.5	18.07	19.09	20.16	21.29	22.49
Other Oil	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.7	29.25	30.9
LPG	6.8	5.59	7.69	11.24	15.34	16.38	17.47	19.13	20.95	22.13	23.37	24.69	26.07
Residual Fuel Oil	8.46	3.49	9.33	14.02	18.76	19.41	20.71	22.68	24.83	26.22	27.7	29.25	30.9
Diesel	11.99	9.34	11.9	21.6	19.93	21.47	22.91	25.08	27.46	29	30.63	32.36	34.18
Kerosene	12.47	9.71	11.89	23.04	25.35	26.23	27.97	30.63	33.54	35.42	37.41	39.52	41.74
Jet Kerosene	21.72	18.65	15.47	25.57	29.52	30.04	32.04	35.08	38.41	40.57	42.85	45.26	47.81
Motor Gasoline	20.42	13.65	17.85	27.27	29.09	30.58	32.62	35.71	39.1	41.3	43.62	46.08	48.67
Biodiesel	28.59	28.59	28.59	28.59	28.59	31.3	33.39	36.56	40.03	42.28	44.66	47.17	49.82

Year	Historical Data				Baseline								
	1990	1995	2000	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050
Ethanol	19.08	19.08	19.08	19.08	33.89	29.71	31.69	34.7	38	40.13	42.39	44.77	47.29
CNG	9.07	9.07	9.07	9.07	9.07	9.07	19.16	19.56	19.97	20.28	20.61	20.94	21.28

Table III. 44 Historical Exchange Rates and Inflation Rates used to Build the Baseline

Year	Philippine Peso per US Dollar[1]	Philippine Peso Annual Inflation Rate (%)[2]	US Dollar Annual Inflation Rate (%) [3]
1990	24.31	12.30	3.71
1991	27.48	19.40	3.32
1992	25.51	8.60	2.28
1993	27.12	6.70	2.38
1994	26.42	10.50	2.12
1995	25.71	6.70	2.09
1996	26.22	7.50	1.82
1997	29.47	5.60	1.72
1998	40.89	9.30	1.08
1999	39.09	5.90	1.43
2000	44.19	4.00	2.28
2001	50.99	6.80	2.28
2002	51.60	3.00	1.53
2003	54.20	3.50	1.99
2004	56.04	6.00	2.75
2005	55.09	7.60	3.22
2006	51.31	6.20	3.07
2007	46.15	2.80	2.67
2008	44.47	9.30	1.93
2009	47.64	3.20	0.79
2010	45.11	3.80	1.23
2011	43.31	4.40	2.06
2012	42.23	3.20	1.80
2013	42.45	3.00	1.49
2014	44.40	4.10	1.25

Notes:
[1] Source: Bangko Sentral Ng Pilipinas (http://www.bsp.gov.ph/statistics/statistics_online.asp -> Online Statistical Interactive Database -> Exchange Rates -> Philippine Peso per US Dollar). Accessed 12 March 2015.
Bankers Association of the Philppines (BAP) reference rate from December 13,1984 to August 3,1992 weighted average rate. Philippine Dealing System (PDS) starting August 14,1992 From: Reference Exchange Rate Bulletin, TD-BSP
[2] Sources:
1990-2011: Bangko Sentral Ng Pilipinas (http://www.bsp.gov.ph/statistics/statistics_online.asp -> Online Statistical Interactive Database -> Prices -> Consumer Price Index, Inflation Rate, and Purchasing Power of the Peso). Accessed 12 March 2015.
2012-2014: http://web0.psa.gov.ph/statistics/survey/price/summary-inflation-report-consumer-price-index-2006100-february-2015. Accessed 12 March 2015.
[3] Sources:
1990-2013: World Bank World Development Indicators (http://data.worldbank.org/indicator/NY.GDP.DEFL.KD.ZG). Accessed 12 March 2015.
2014: US. Bureau of Economic Analysis, Gross Domestic Product: Implicit Price Deflator [GDPDEF], retrieved from

Year	Philippine Peso per US Dollar[1]	Philippine Peso Annual Inflation Rate (%)[2]	US Dollar Annual Inflation Rate (%) [3]
FRED, Federal Reserve Bank of St. Louis https://research.stlouisfed.org/fred2/series/GDPDEF/, March 25, 2015.			

ANNEX III.6 REFERENCES

American Clean Skies Foundation. 2013. “Driving on Natural Gas: Fuel Price and Demand Scenarios for Natural Gas Vehicles to 2025.” http://www.cleanskies.org/wp-content/uploads/2013/04/driving-natural-gas-report.pdf.

Angel, S., J. Parent, D. Civco, A. Blei, and D. Potere. 2010. “A Planet of Cities: Urban Land Cover Estimates and Projections for All Countries, 2000-2050.” Lincoln Institute of Land Policy. http://www.alnap.org/pool/files/1861-1171-angel-iii-final.pdf.

Apte, Joshua S., Emilie Bombrun, Julian D. Marshall, and William W. Nazaroff. 2012. “Global Intraurban Intake Fractions for Primary Air Pollutants from Vehicles and Other Distributed Sources.” *Environmental Science & Technology* 46 (6): 3415–23. doi:10.1021/es204021h.

Argonne National Laboratory. 2015. “The GHGes, Regulated Emissions, and Energy Use in Transportation (GREET) Model Version 1.2.0.” https://greet.es.anl.gov/.

Asian Development Bank. 1998. “Asia Least-Cost GHG Abatement Strategy: Philippines.”

Asia Pacific Energy Research Centre. 2013. “Compendium of Energy Efficiency Policies of APEC Economies: 2012.”

Ayson, Loreta. 2015. Consultation with DOE, Energy Policy and Planning Bureau.

Bangko Sentral Ng Pilipinas. 2011. “Online Statistical Interactive Database, Consumer Price Index, Inflation Rate, and Purchasing Power of the Peso.” http://www.bsp.gov.ph/statistics/statistics_online.asp.

———. 2014. “Online Statistical Interactive Database, Philippine Peso per US Dollar.” http://www.bsp.gov.ph/statistics/statistics_online.asp.

Bensel, T.G., and Elizabeth M. Remedio. 2002. “Woodfuel Consumption and Production in the Philippines: A Desk Study.” FAO Bangkok, unpublished report.

Bhattacharya, S.C., D.O. Albina, and P. Abdul Salam. 2002. “Emission Factors of Wood and Charcoal-Fired Cookstoves.” *Biomass and Bioenergy* 23 (6): 453–69. doi:10.1016/S0961-9534(02)00072-7.

Bhattacharyya, Subhes C. 2011. “Integrated Analysis of Energy Systems.” In *Energy Economics*, 393–416. Springer London. http://link.springer.com/chapter/10.1007/978-0-85729-268-1_17.

B-LEADERS. 2015a. “Compilation of Generation Company Reports (2007-2014).”

———. 2015b. “Compilation of Power Plant Investment Costs.”

———. 2015c. “Compilation of URRs Filed With ERC.”

———. 2015d. “Philippine Coal Importation.” philippine coal importation.xlsx.

Burnett, Richard T., C. Arden Pope III, Majid Ezzati, Casey Olives, Stephen S. Lim, Sumi Mehta, Hwashin H. Shin, et al. 2014. “An Integrated Risk Function for Estimating the Global Burden of Disease Attributable to Ambient Fine Particulate Matter Exposure.” *Environmental Health Perspectives*, February. doi:10.1289/ehp.1307049.

Castillo, J. 2010. “Estimación de Los Beneficios En Salud Asociados a La Reducción de La Contaminación Atmosferica En Bogotá, Colombia.” Universidad de Los Andes.

Cement Manufacturers Association of the Philippines. 2015. Consultation with Cement Manufacturers Association of the Philippines.

Chambliss, S., J. Miller, C. Facanha, R. Minjares, and K. Blumberg. 2013. “The Impact of Stringent Fuel and Vehicle Standards on Premature Mortality and Emissions.” The International Council on Clean Transportation.

Chinnamma, Mohankumar, Salini Bhasker, Harish Madhav, Rajesh Mamkulathil Devasia, Anisha Shashidharan, Balachandran Chandrasekaran Pillai, and Pradeep Thevannoor. 2015. “Production of Coconut Methyl Ester (CME) and Glycerol from Coconut (Cocos Nucifera) Oil and the Functional Feasibility of CME as Biofuel in Diesel Engine.” *Fuel* 140 (January): 4–9. doi:10.1016/j.fuel.2014.09.057.

Cities Act. 2010. “Clean Air Asia Database; Phillipines Air Quality Profile 2010 Edition, Clean Air Initiative for Asian Cities.”

Climate Change Commission. 2010. “National Framework Strategy on Climate Change 2010-2022.” http://www.neda.gov.ph/wp-content/uploads/2013/10/nfscc_sgd.pdf.

———. 2011. “National Climate Change Action Plan 2011-2028.”

———. 2015. “Republic of the Philippines Intended Nationally Determined Contributions Communicated to the UNFCCC on October 2015.” Accessed November 3. http://www4.unfccc.int/submissions/INDC/Published%20Documents/Philippines/1/Philippines%20-%20Final%20INDC%20submission.pdf.

Cohen, David D., E. Stelcer, Flora L. Santos, Michael Prior, Craig Thompson, and Preciosa C. B. Pabroa. 2009. “Fingerprinting and Source Apportionment of Fine Particle Pollution in Manila by IBA and PMF Techniques: A 7-Year Study.” *X-Ray Spectrometry* 38 (1): 18–25. doi:10.1002/xrs.1112.

Congress of the Philippines. 2008. “Republic Act No. 9513 - An Act Promoting the Development, Utilization and Commercialization of Renewable Energy Resources and for Other Purposes.” http://www.doe.gov.ph/issuances/republic-act/627-ra-9513.

Crawford-Brown, Douglas, Terry Barker, Annela Anger, and Olivier Dessens. 2012. “Ozone and PM Related Health Co-Benefits of Climate Change Policies in Mexico.” *Environmental Science & Policy* 17 (March): 33–40. doi:10.1016/j.envsci.2011.12.006.

DOE. 2011a. “2010 Philippine Power Sector Situationer.”

———. 2011b. “National Renewable Energy Program: III. Renewable Energy Plans and Programs (2011-2030).” http://www.c-cred.org/userfiles/files/nrepbook/08.%20021-087%20III%20RE%20Plans%20%26%20Programs.pdf.

———. 2011c. “Oil and Gas.” http://www.doe.gov.ph/fossil-fuels/oil-gas.

———. 2012a. “2011 Philippine Power Statistics.” http://www.doe.gov.ph/doe_files/pdf/02_Energy_Statistics/Power-Statistics-2011.pdf.

———. 2012b. “2012-2016 Missionary Electrification Development Plan.” http://www.doe.gov.ph/power-and-electrification/development-plans/318-missionary-electrification-development-plan.

———. 2012c. “Philippine Energy Plan: 2012-2030.” http://www.doe.gov.ph/doe_files/pdf/01_Energy_Situationer/2012-2030-PEP.pdf.

———. 2012d. “Philippine Energy Plan 2012-2030, Annex A.1.15 Coal Sector Targets.”

———. 2012e. “Philippine Energy Plan 2012-2030, Annex A.1.23 Cumulative Installed Capacity.”

———. 2012f. “Philippine Energy Plan 2012-2030, Annex A.1.27 Committed Power Projects.”

———. 2012g. “Philippine Energy Plan 2012-2030, Annex A.1.49 Biodiesel Investment Requirements.”

———. 2012h. “Philippine Energy Plan 2012-2030, Annex A.1.50 Bioethanol Investment Requirements.”

———. 2012i. “Philippine Energy Plan 2012-2030, Annex A.1.53 Indicative Power Generation Investment Requirements.”

———. 2012j. “Philippine Energy Plan 2012-2030, Annex B.4 Coal Sector Highlights.”

———. 2012k. “Philippine Energy Plan 2012-2030: Overview and Executive Summary.” http://www.doe.gov.ph/doe_files/pdf/01_Energy_Situationer/2012-2030-PEP-Executive-Summary_revised.pdf.

———. 2012l. “Philippine Energy Efficiency Project, Calculating Savings Generated by the Project, Cagayan de Oro City.” http://www.phileep.org/index.php?option=com_content&view=article&id=148:peep-results-calculating-savings-generated-by-the-project&catid=55:demonstration-of-equipment-lighting-technologies&Itemid=179.

———. 2014a. “2013 Philippine Power Statistics.” http://www.doe.gov.ph/doe_files/pdf/02_Energy_Statistics/Power-Statistics-2013.pdf.

———. 2014b. “List of Existing Power Plants.” http://www.doe.gov.ph/power-and-electrification/list-of-existing-power-plants.

———. 2014c. “Philippines Hourly Demand (LVM Hourly Demand - CY 2013).”

———. 2015a. “Compilation of Biofuels Data.”

———. 2015b. “Compressed Natural Gas.” http://www.doe.gov.ph/programs-projects-alternative-fuels/297-compressed-natural-gas.

———. 2015c. “Data on Committed Power Plant Capacities in 2014-2017.”

———. 2015d. “Energy Balance Table.”

———. 2015e. “Historical Refinery Production and Own Use.”

———. 2015f. “Hydropower.” http://www.doe.gov.ph/renewable-energy-res/hydropower.

———. 2015g. “Power Plant Data Used for Planning Purposes.”

———. 2015h. “Refining Capacity 2000-2014.”

———. 2015i. “Solar Energy Potential Sites.” http://www.doe.gov.ph/renewable-energy-res/resource-maps/278-solar.

———. 2015j. “T&D Losses, Utility Own-Use Consumption: Planning Values of DOE Philippines.”

———. 2015k. “Historical Prices of Fuels.” USAID Request_historical prices-03.04.2015.xls.

———. 2015l. Consultation with DOE at Balay Indang, Cavite.

———. 2015m. “Updated Data on Committed and Indicative Power Plant Capacities in 2014-2019.”
DOE, and NSONSO. 2011. “Household Energy Consumption Survey.”

DENR. 2011. “Tracking GHGes: An Inventory Manual.”
———. 2013. “2013 Philippine Forestry Statistics.” Table 4.10: MONTHLY RETAIL PRICES OF FUELWOOD AND CHARCOAL. http://forestry.denr.gov.ph/PFS2013.pdf.

Doucouliagos, Hristos, T.D. Stanley, and W. Kip Viscusi. 2014. “Publication Selection and the Income Elasticity of the Value of a Statistical Life.” *Journal of Health Economics* 33 (January): 67–75. doi:10.1016/j.jhealeco.2013.10.010.

Edenhofer, Ottmar, Ramón Pichs Madruga, Y. Sokona, United Nations Environment Programme, World Meteorological Organization, IPCC, and Potsdam-Institut für Klimafolgenforschung, eds. 2012. *Renewable Energy Sources and Climate Change Mitigation: Special Report of the IPCC*. New York: Cambridge University Press.

Endesa Generación, S.A. 2011. “Project 4669: Cebu City Landfill Gas and Waste to Energy Project.” https://cdm.unfccc.int/Projects/DB/DNV-CUK1302525026.11/view.
ERC. 2015. “Financial Models for FIT Calculations.”

European Environment Agency. 2013. “Managing Municipal Solid Waste - A Review of Achievements in 32 European Countries.” http://www.eea.europa.eu/publications/managing-municipal-solid-waste/at_download/file.

Federal Reserve Bank of St. Louis. 2015. “Gross Domestic Product: Implicit Price Deflator.” US Bureau of Economic Analysis. https://research.stlouisfed.org/fred2/series/GDPDEF.
Food and Agriculture Organization of the United Nations. 1997. “Aquaculture Feed and Fertilizer Resource Atlas of the Philippines.” http://www.fao.org/3/contents/c4f963c4-3b02-5d86-ad9d-7312b83283d8/W6928E00.HTM.

———. 2009. “Criteria and Indicators for Sustainable Woodfuels: Case Studies from Brazil, Guyana, Nepal, Philippines and Tanzania.” http://www.fao.org/docrep/012/i1321e/i1321e08.pdf.
Garg, Amit. 2011. “Pro-Equity Effects of Ancillary Benefits of Climate Change Policies: A Case Study of Human Health Impacts of Outdoor Air Pollution in New Delhi.” *World Development* 39 (6): 1002–25. doi:10.1016/j.worlddev.2010.01.003.

Gopal, Anand R, and Daniel M Kammen. 2009. “Molasses for Ethanol: The Economic and Environmental Impacts of a New Pathway for the Lifecycle GHG Analysis of Sugarcane Ethanol.” *Environmental Research Letters* 4 (4): 044005. doi:10.1088/1748-9326/4/4/044005.

Grieshop, Andrew P., Julian D. Marshall, and Milind Kandlikar. 2011. “Health and Climate Benefits of Cookstove Replacement Options.” *Energy Policy* 39 (12): 7530–42. doi:10.1016/j.enpol.2011.03.024.

Guarte, Roberto C., Werner Mühlbauer, and Manfred Kellert. 1996. “Drying Characteristics of Copra and Quality of Copra and Coconut Oil.” *Postharvest Biology and Technology* 9 (3): 361–72. doi:10.1016/S0925-5214(96)00032-4.

Hammitt, James K., and Lisa A Robinson. 2011. “The Income Elasticity of the Value per Statistical Life: Transferring Estimates between High and Low Income Populations.” *Journal of Benefit-Cost Analysis* 2 (1). doi:10.2202/2152-2812.1009.

Hoveidi, Hassan. 2013. “Cost Emission of Pm10 on Human Health Due to the Solid Waste Disposal Scenarios, Case Study; Tehran, Iran.” *Journal of Earth Science & Climatic Change* 04 (03). doi:10.4172/2157-7617.1000139.

Humbert, Sebastien, Julian D. Marshall, Shanna Shaked, Joseph V. Spadaro, Yurika Nishioka, Philipp Preiss, Thomas E. McKone, Arpad Horvath, and Olivier Jolliet. 2011. “Intake Fraction for Particulate Matter: Recommendations for Life Cycle Impact Assessment.” *Environmental Science & Technology* 45 (11): 4808–16. doi:10.1021/es103563z.

International Energy Agency. 2012. *Energy Technology Perspectives 2012*. Paris: Organisation for Economic Co-operation and Development. http://www.oecd-ilibrary.org/content/book/energy_tech-2012-en.

Institute for Health Metrics and Evaluation. 2013. “Global Burden of Disease Study 2010. Philippines Global Burden of Disease Study 2010 (GBD 2010) Results 1990-2010.” http://ghdx.healthdata.org/record/philippines-global-burden-disease-study-2010-gbd-2010-results-1990-2010.

Institute for Industrial Productivity, and International Finance Corporation. 2014. “Waste Heat Recovery for the Cement Sector: Market and Supplier Analysis.”

IPCC. 1996a. “Revised 1996 IPCC Guidelines for National GHG Inventories. Volume 3 (Reference Manual).”

———. 1996b. “The Science of Climate Change.” In *Second Assessment Report of the Intergovernmental Panel on Climate Change*, edited by J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell. Cambridge University Press.

———. 2015. “IPCC Database on GHG Emission Factors (IPCC-EFDB).” http://www.ipcc-nggip.iges.or.jp/EFDB/main.php.

International Energy Agency. 2010. “Projected Costs of Generating Electricity 2010 Edition.”
———. 2014a. “Extended World Energy Balances.” OECD Publishing. http://www.oecd-ilibrary.org/energy/data/iea-world-energy-statistics-and-balances/extended-world-energy-balances_data-00513-en.

———. 2014b. “World Energy Outlook 2014.”
IREA. 2012. “Renewable Energy Technologies: Cost Analysis Series: Biomass for Power Generation.” https://www.irena.org/DocumentDownloads/Publications/RE_Technologies_Cost_Analysis-BIOMASS.pdf.

———. 2014. “Ocean Thermal Energy Conversion Technology Brief.” http://www.irena.org/DocumentDownloads/Publications/Ocean_Thermal_Energy_V4_web.pdf.
IREA, and IEAEnergy Technology Systems Analysis Programme. 2013. “Biomass Co-Firing Technology Brief.” https://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E21%20Biomass%20Co-firing.pdf.

Letschert, Virginie, Micholas Bojda, Jing Ke, and Michael McNiel. 2012. “Estimate of Cost-Effective Potential for Minimum Efficiency Performance Standards in 13 Major World Economies.” Ernest Orlando Lawrence Berkeley National Laboratory.

Levy, Jonathan I., Andrew M. Wilson, John S. Evans, and John D. Spengler. 2003. “Estimation of Primary and Secondary Particulate Matter Intake Fractions for Power Plants in Georgia.” *Environmental Science & Technology* 37 (24): 5528–36. doi:10.1021/es034484l.

Lim, Stephen S, Theo Vos, Abraham D Flaxman, Goodarz Danaei, Kenji Shibuya, Heather Adair-Rohani, Mohammad A AlMazroa, et al. 2012. “A Comparative Risk Assessment of Burden of Disease and Injury Attributable to 67 Risk Factors and Risk Factor Clusters in 21 Regions, 1990–2010: A Systematic Analysis for the Global Burden of Disease Study 2010.” *The Lancet* 380 (9859): 2224–60. doi:10.1016/S0140-6736(12)61766-8.

Lindhjem, Henrik, Ståle Navrud, Nils Axel Braathen, and Vincent Biausque. 2011. “Valuing Mortality Risk Reductions from Environmental, Transport, and Health Policies: A Global Meta-Analysis of Stated Preference Studies: Valuing Mortality Risk Reductions from Environmental, Transport, and Health Policies.” *Risk Analysis* 31 (9): 1381–1407. doi:10.1111/j.1539-6924.2011.01694.x.
Low Emission Capacity Building Project - Philippines. 2015. “NAMA List for USAID.”
Manila Observatory. 2010. “Philippine GHG Inventory for the Year 2000.”

Marshall, Julian D. 2007. “Urban Land Area and Population Growth: A New Scaling Relationship for Metropolitan Expansion.” *Urban Studies* 44 (10): 1889–1904. doi:10.1080/00420980701471943.

MCWMC. 2010. “Project 2524: Metro Clark Landfill Gas Capture System.” https://cdm.unfccc.int/Projects/DB/DNV-CUK1239822363.37/view.

Miller, J., K. Blumberg, and B. Sharpe. 2014. “Cost-Benefit Analysis of Mexico’s Heavy-Duty Emission Standards (NOM 044).” The International Council on Clean Transportation. http://www.indiaenvironmentportal.org.in/files/file/ICCT_MexicoNOM-044_CBA.pdf.

Minjares, R., D. Wagner, and S. Akbar. 2014. “Reducing Black Carbon Emissions from Diesel Vehicles : Impacts, Control Strategies, and Cost-Benefit Analysis.” World Bank Group. http://documents.worldbank.org/curated/en/2014/04/19342185/reducing-black-carbon-emissions-diesel-vehicles-impacts-control-strategies-cost-benefit-analysis.

Mitsubishi Securities Clean Energy Finance Committee. 2004. “Project Design Document for PNOC EC Payatas Landfill Gas to Energy Project in the Philippines.” http://gec.jp/gec/jp/Activities/cdm/OE/PDD03_Mitubishi.pdf.

NAPOCOR – Small Power Utilities Group. 2008. “Missionary Electrification Plan 2009-2018.”
———. 2014. “NPC-SPUG Power Plant Operational Reports, May 2014.”

National Renewable Energy Laboratory. 2014. “Philippine Wind Resource Assessment: Modern Approaches to Support the Development of a Nation’s Wind Energy Potential.” https://drive.google.com/file/d/0B6CJydtZ_c_abUdyQ0hZbGlEOUk/view?pli=1.

Oanh, NTK, P. Pongkiatkul, MT Cruz, DT Ngheim, L. Phillip, and G. Zhuang. 2012. “Monitoring and Source Apportionment for Particulate Matter Pollution in Six Asian Cities. Integrated Air Quality Management: Asian Case Studies 97.”

Organisation for Economic Cooperation and Development. 2011. “Valuing Mortality Risk Reductions in Regulatory Analysis of Environmental, Health and Transport Policies: Policy Implications.” www.oecd.org/env/policies/vsl.

Park, Won Young. 2013. “Assessment of SEAD Global Efficiency Medals for Televisions.” Ernest Orlando Lawrence Berkeley National Laboratory.

Philippine Business for the Environment. 2015. Consultation with Philippine Business for the Environment.

Philippine Energy Efficiency Project. 2012. “Philippine Energy Efficiency Project (PEEP): Project Components.” http://www.phileep.org/index.php/project-components.

Philippine News Agency. 2015. “LED Lighting Ensures Brighter Roads in Gensan,” January 6. http://www.mb.com.ph/led-street-lights-ensure-brighter-roads-in-gensan.

Philippine Statistics Authority. 2010. "Census of Population and Housing." http://www.nscb.gov.ph/secstat/d_popn.asp.

———. 2015a. "1st Quarter 2011 to 4th Quarter 2013 and Annual 2011 to 2013, Revision." National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2013/4th2013_RevisedMay2014/Revised_Q1_to_Q4_2011_to%202013.rar.

———. 2015b. "1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 1-9. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/1Q4-Rev_Summary_93SNA.pdf.

———. 2015c. "Gross National Income and Gross Domestic Product 1946 to 2010." National Accounts of the Philippines. http://www.nscb.gov.ph/sna/Rev_Ann_Qtr/1946_2010_NAP_Linked_Series_NSIC.xls.

———. 2015d. "Gross Value Added in Agriculture, Hunting, Forestry and Fishing, 1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 26-28. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/8AFF_93SNA_Q4.pdf.

———. 2015e. "Gross Value Added in Construction, 1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 35-37. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/11CNS_93SNA_Q4.pdf.

———. 2015f. "Gross Value Added in Electricity, Gas and Water Supply, 1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 38-40. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/12EGW_93SNA_Q4.pdf.

———. 2015g. "Gross Value Added in Manufacturing, 1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 32-34. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/10MFG_93SNA_Q4.pdf.

———. 2015h. "Gross Value Added in Mining and Quarrying, 1st Quarter 2012 to 4th Quarter 2014, Revision." Tables 29-31. National Accounts of the Philippines. http://www.nscb.gov.ph/sna/2014/4th2014/tables/9MAQ_93SNA_Q4.pdf.

———. 2015i. "National Accounts of the Philippines, 1998 to 2010." http://www.nscb.gov.ph/sna/revisedQuarterlyPSNA/Annual(revised,rebased%2098-2000.rar.

———. 2015j. "Summary Inflation Report Consumer Price Index." http://web0.psa.gov.ph/statistics/survey/price/summary-inflation-report-consumer-price-index-2006100-february-2015.

Philippine Statistics Authority, and Inter-Agency Working Group on Population Projections. 2015a. "Projected Population, by Age Group, Sex, and by Five-Calendar Year Interval, Philippines: 2010 - 2045 (Medium Assumption)." Table 1. 2010 Census-based Population Projections. https://psa.gov.ph/sites/default/files/attachments/hsd/pressrelease/Table1_8.pdf.

———. 2015b. "Projected Population, by Age Group, Sex, and by Single-Calendar Year Interval, Philippines: 2010 - 2020 (Medium Assumption)." Table 4. 2010 Census-based Population Projections. https://psa.gov.ph/sites/default/files/attachments/hsd/pressrelease/Table4_9.pdf.

Rabl, A. 2011. "How to Use The ExternE Methodology in China." https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0CB0QFjAA&url=http%3A%2F%2Fwww.amse-aixmarseille.fr%2Fsites%2Fdefault%2Ffiles%2F_valorisation%2Fcontrats%2Fpaper_4.1_rabl.pdf&ei=hritU9r6EcXdoATfh4GwDg&usg=AFQjCNFANDlVqrCaUVCTyXL4NJd-xojfFg&sig2=gbkGVvbWSrQALOkkPr7Htw.

Renewable Energy Management Bureau. 2015. "Biodiesel Price in the Philippines." CME data - biodiesel prices.xlsx.

Republic of the Philippines. 2014. "Second National Communication to the United Nations Framework Convention on Climate Change: Philippines." http://unfccc.int/resource/docs/natc/phlnc2.pdf.

Sakulniyomporn, Songsak, Kuskana Kubaha, and Chullapong Chullabodhi. 2011. "External Costs of Fossil Electricity Generation: Health-Based Assessment in Thailand." *Renewable and Sustainable Energy Reviews* 15 (8): 3470–79. doi:10.1016/j.rser.2011.05.004.

Sathaye, Jayant, and Stephen Meyers. 1995. "Mitigation Assessment of the Energy Sector: An Overview." In *GHG Mitigation Assessment: A Guidebook*, 21–53. Springer. http://unfccc.int/resource/cd_roms/na1/mitigation/Resource_materials/Greenhouse_Gas_Mitigation_Assessment_Guidebook_1995/chap03.pdf.

Sathaye, Makul, Amol Phadke, Nihar Shah, and Virginie Letschert. 2013. "Potential Global Benefits of Improved Ceiling Fan Energy Efficiency." Super-Efficient Equipment and Appliance Deployment. http://www.superefficient.org/en/Resources/~/media/Files/SEAD%20Technical%20Analysis%20Reports/SEAD%20Ceiling%20Fan%20Analysis/SEAD%20Ceiling%20Fans%20Report%20Executive%20Summary.pdf.

Schlömer, Steffen, Thomas Bruckner, Lew Fulton, Edgar Hertwich, Alan McKinnon, Daniel Perczyk, Joyashree Roy, et al. 2014. "Annex III: Technology-Specific Cost and Performance Parameters." In *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the IPCC [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S.*

Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

Spuhler, Dorothee. 2015. “Anaerobic Digestion (Organic Waste).” Accessed June 2. http://www.sswm.info/content/anaerobic-digestion-organic-waste.

Stockholm Environment Institute. 2012. “Global Atmospheric Pollution Forum Emissions Inventory Workbook Template - Version 5.0.” http://www.sei-international.org/gap-the-global-air-pollution-forum-emission-manual.

———. 2014. “LEAP 2014 User Guide.” http://www.energycommunity.org/WebHelpPro/LEAP.htm.

———. 2015. “Long-Range Energy Alternatives Planning System.” www.energycommunity.org.

Sugar Regulatory Administration. 2013. “Tons Cane Milled by Month (CY 2008-09 to 2012-13).” http://www.sra.gov.ph/wp-content/uploads/2013/12/Tons-Cane-Milled-by-Month.pdf.

Tamang, Jess. 2015. Consultation with DOE, Energy Policy and Planning Bureau.

Tan, Raymond R., Alvin B. Culaba, and Michael R.I. Purvis. 2004. “Carbon Balance Implications of Coconut Biodiesel Utilization in the Philippine Automotive Transport Sector.” *Biomass and Bioenergy* 26 (6): 579–85. doi:10.1016/j.biombioe.2003.10.002.

Transport and Traffic Planners Inc., and CPI Energy Phils., Inc. 2010. “A Strategic Approach to Climate Change in the Philippines: An Assessment of Low-Carbon Interventions in the Transport and Power Sectors.” http://siteresources.worldbank.org/INTPHILIPPINES/Resources/PH_Low_Carbon_Transport_and_Power.pdf.

Turkenburg, Wim C., Doug J. Arent, Ruggero Bertani, Andre Faaij, Maureen Hand, Wolfram Krewitt, Eric D. Larson, et al. 2012. “Chapter 11 - Renewable Energy.” In *Global Energy Assessment - Toward a Sustainable Future*, 761–900. Cambridge University Press, Cambridge, UK and New York, NY, USA and the International Institute for Applied Systems Analysis, Laxenburg, Austria.

University of the Philippines National Engineering Center. 2015a. “Biomass Demand Analysis (BLEADERS - BAU Data Gathering v1).”

———. 2015b. “Catalog of EnergyStar-Certified Household Appliances (BLEADERS - BAU Data Gathering v1).”

———. 2015c. “Low-Carbon Scenario and Development Pathways for the Philippines (Draft Copy: 23 March 2015): Technical Report Submitted under Asian Development Bank TA-7645: ‘Strengthening Planning Capacity for Low Carbon Growth Development in Developing Asia.’”

———. 2015d. “Road Lighting MWh Consumption (BLEADERS - LEDS Data Gathering 1 v1).”

U.S. Energy Information Administration. 2013. “International Energy Outlook 2013.” DOE/EIA-0484(2013). http://www.eia.gov/forecasts/archive/ieo13/.

———. 2015. “Updated Buildings Sector Appliance and Equipment Costs and Efficiencies.” http://www.eia.gov/analysis/studies/buildings/equipcosts/pdf/full.pdf.

USEPA. 1999a. “GHGes from Small-Scale Combustion Devices in Developing Countries: Charcoal-Making Kilns in Thailand.” EPA-600/R-99-109. http://nepis.epa.gov/Exe/ZyNET.exe/P1007KD4.TXT?ZyActionD=ZyDocument&Client=EPA&Index=1995+Thru+1999&Docs=&Query=&Time=&EndTime=&SearchMethod=1&TocRestrict=n&Toc=&TocEntry=&QField=&QFieldYear=&QFieldMonth=&QFieldDay=&IntQFieldOp=0&ExtQFieldOp=0&XmlQuery=&File=D%3A\zyfiles\Index%20Data\95thru99\Txt\00000026\P1007KD4.txt&User=ANONYMOUS&Password=anonymous&SortMethod=h|-&MaximumDocuments=1&FuzzyDegree=0&ImageQuality=r75g8/r75g8/x150y150g16/i425&Display=p|f&DefSeekPage=x&SearchBack=ZyActionL&Back=ZyActionS&BackDesc=Results%20page&MaximumPages=1&ZyEntry=1&SeekPage=x&ZyPURL.

———. 1999b. “U.S. Methane Emissions 1990–2020: Inventories, Projections, and Opportunities for Reductions. Appendix 5: Livestock Manure Management.” http://www.epa.gov/methane/reports/05-manure.pd.

———. 2010. “Chapter 6: Discounting Future Benefits and Costs.” In *Guidelines for Preparing Economic Analyses*.

———. 2014a. “Energy Recovery from Waste.” http://www.epa.gov/waste/nonhaz/municipal/wte/.

———. 2014b. “Web Factor Information Retrieval System (WebFIRE).” http://epa.gov/ttn/chief/webfire/index.html.

———. 2015. “Landfill Methane Outreach Program - Basic Information.” http://www.epa.gov/lmop/basic-info/index.html.

USEPA Science Advisory Board. 2004. “Advisory Council on Clean Air Compliance Analysis Response to Agency Request on Cessation Lag. Letter from the Health Effects Subcommittee to the USEPA Administrator.”

Velasco, Myrna. 2014. “DOE Admits Delayed Rollout of CNG Buses.” *Manila Bulletin*. http://www.mb.com.ph/doe-admits-delayed-rollout-of-cng-buses/.

Wei, Max, Shana Patadia, and Daniel M. Kammen. 2010. “Putting Renewables and Energy Efficiency to Work: How Many Jobs Can the Clean Energy Industry Generate in the US?” *Energy Policy* 38 (2): 919–31. doi:10.1016/j.enpol.2009.10.044.

World Bank. 2015a. “Inflation, GDP Deflator (annual %).” http://data.worldbank.org/indicator/NY.GDP.DEFL.KD.ZG.

———. 2015b. “GNI per Capita, PPP (current International $).” http://data.worldbank.org/indicator/NY.GNP.PCAP.PP.CD.

World Business Council for Sustainable Development Cement Sustainability Initiative. 2015. “Global Cement Database on CO_2 and Energy Information.” http://www.wbcsdcement.org/index.php/key-issues/climate-protection/gnr-database.

U.S. Agency for International Development
1300 Pennsylvania Avenue, NW
Washington, DC 20523
Tel: (202) 712-0000
Fax: (202) 216-3524
www.usaid.gov