National Energy Policy Framework

"Energy By the People … For the People"

2011

TOWARDS

Energy Efficiency, Sustainability and Resilience for BELIZE in the 21st Century

PREPARED for

The GOVERNMENT OF BELIZE

By:

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All costs and prices given in this document are in 2010 US Dollars unless otherwise stated.

“The significant problems we face today cannot be solved at the same level of thinking as when they were created"…. *Albert Einstein*

Electric vehicles “refilling” at a solar-powered charging station[1]

[1] SOURCE: Mukhar, N. (2011). *What do Electric Cars have to do with Solar Energy?* Retrieved April 2011, from getSolar.com: http://www.getsolar.com

LIST OF ACRONYMS & ABBREVIATIONS

AC	Alternating Current (Electricity)
A/C	Air Conditioning (or Air Conditioner)
AEI	American Enterprise Institute for Public Policy Research
AEO	Annual Energy Outlook (EIA Publication)
AST	Active Solar Thermal
BAL	Belize Aquaculture Limited
BAT	Best Available Technologies
Bbl, bbl	Barrel
BCCI	Belize Chamber of Commerce and Industry
BECOL	Belize Electric Company Limited
BEEC	Building Energy Efficiency Codes
BEL	Belize Electricity Limited
BELCOGEN	Belize Cogeneration Energy Limited
BELTRAIDE	Belize Trade and Investment Development
BNE	Belize Natural Energy Limited
BPT	Best Practice Technologies
BSI	Belize Sugar Industries Limited
BTB	Belize Tourism Board
BTIA	Belize Tourism Industry Association
BTU	British Thermal Unit
BZ	Belize
BZD	Belize Dollar
^{o}C	Degrees Celsius (Measurement of temperature)
CA	Central America
CARICOM	Caribbean Community
CBA	Central Building Authority (Belize)
CBO	Congressional Budget Office (USA)
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Sequestration
CDB	Caribbean Development Bank
CDM	Clean Development Mechanism
CER	Certifiable Emission Reduction (per CDM)
CF	Capacity Factor
CFC	Chlorofluorocarbon
CFE	Comisión Federal de Electricidad (Mexico)
CFL	Compact Fluorescent Lamp
CHENACT	Caribbean Hotel Energy Efficiency Action Program
CHP	Combined Heat and Power
CIA	Central Intelligence Agency (USA)
CIF	Cost, Insurance and Freight

CIPS, CIPower	Canadian International Power Services Inc.
CNG	Compressed Natural Gas
CO2, CO_2	Carbon Dioxide
COP	Coefficient of Performance (Heat Pumps)
CPRSA	Cost of Power Rate Stabilization Account (BEL)
CP	Carbon Pricing
CPV	Concentrator Photovoltaic
CREDP	Caribbean Renewable Energy Development Programme
CRS	Congressional Research Service (USA)
c-Si, C-Si	Crystalline Silicon (Solar PV)
CSP	Concentrating Solar Power
CTZ	Constant-Temperature Zone
DA	Distribution Area (Belize)
DAO	Distribution Area Operator (Belize)
DC	Direct Current (Electricity)
DG	Distributed Generation
DNI	Direct Normal Irradiance (Measured in kWh/square meter/day)
DTI	Department of Trade and Industry (United Kingdom)
€	EU Currency Symbol
EE	Energy Efficiency
EEP	Energy and Environment Partnership with Central America
EER	Energy Efficiency Ratio
EERE	Energy Efficiency & Renewable Energy (of the US DOE)
EGS	Enhanced Geothermal System (or Engineered Geothermal System)
EIA	Energy Information Administration (United States)
EPA	Environmental Protection Agency (United States)
EPC	Energy Performance Contract
ESCO	Energy Service Company
ESMAP	Energy Sector Management Assistance Program (World Bank)
ESP	Energy Supply Provider
ETSAP	Energy Technology Systems and Analysis Programme (IEA)
EU	European Union
EV	Electric Vehicle
^{o}F	Degrees Fahrenheit (Measurement of temperature)
FAO	Forestry Administration Organization
FC	Firm Capacity
FFV	Flex Fuel Vehicle
FIT	Feed-in Tariff

ft	Feet (Measurement of length or distance)
FX	Foreign Exchange
g	Gram (Measurement of weight)
gals	US gallons (Measurement of volume)
GBC	Green Building Certification (Belize)
GCEP	Global Climate & Energy Project
GDP	Gross Domestic Product
GHG	Green House Gas
GOB	Government of Belize
GPD	Geology and Petroleum Department (in the Ministry of Natural Resources, Government of Belize)
g/p-m	Gallons per Passenger-mile
gpm	Gallons per Mile
GSHP	Ground-source Heat Pump (Geothermal Heat Pump)
GST	General Sales Tax (Belize)
GT	Gas Turbine
GW	Gigawatt
GWh	Gigawatt-hour
HCFC	Hydro-chlorofluorocarbon
HDR	Hot Dry Rock (Geothermal Systems)
HEV	Hybrid Electric Vehicle
HFC	Hydrofluorocarbon
HFO	Heavy Fuel Oil
HP	High Pressure (Steam)
HTF	Heat Transfer Fluid
HVAC	Heating, Ventilation and Air-conditioning
Hydro	Hydro-electric Power
IAEA	International Atomic Energy Agency
ICE	Internal Combustion Engine
IDB	Inter-American Development Bank
IEA	International Energy Agency
IPP	Independent Power Producer (Electricity)
ISO	International Organisation for Standardization
kg	Kilogram
KJ	Kilojoule
km	Kilometre
km^2	Square Kilometre
KV	Kilovolt
KW	Kilowatt
KWh	Kilowatt-hour
KW-Yr	Kilowatt-year
LAC	Latin America and the Caribbean
LCODE	Levelized Cost of Delivered Energy

LCOE	Levelized Cost of Energy
LCV	Lower Calorific Value
LED	Light-emitting Diode
LEED	Leadership in Energy and Environmental Design (USA)
LFL	Linear Fluorescent Lamp
LGE	Litre of Gasoline Equivalent
LNG	Liquefied Natural Gas
LP	Liquefied Petroleum (Gas)
LPG	Liquefied Petroleum Gas
LRMC	Long-run Marginal Cost
LSD	Low Speed Diesel
m	Metre (Measurement of length or distance)
m^2	Square Metre
m/s	Metres per Second
MER	Mercado Eléctrico Regional (Regional Electricity Market of SIEPAC)
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MMBTU	Million British Thermal Units
mpg	Miles per Gallon
mph	Miles per Hour
mpk	Miles per Kilowatt-hour
MRV	Measurement, Reporting and Verification (for GHG emissions)
MSD	Medium Speed Diesel
MSW	Municipal Solid Waste
MW	Megawatt
MWh	Megawatt-hour
NECC	National Electricity Control Center (Belize)
NEEPI	National Energy and Electricity Planning Institute (Belize)
NEMS	National Energy Modeling System (United States)
NEP	National Energy Policy (Belize)
NEPD	National Energy Policy Development (Belize)
NETS	National Electricity Transmission System (Belize)
NETSO	National Electricity Transmission System Operator (Belize)
NG	Natural Gas
NGL	Natural Gas Liquid
NGO	Non-Government Organization
NMS	National Meteorological Service (Belize)
NPV	Net Present Value
NREL	National Renewable Energy Laboratory (United

	States)
OAS	Organization of American States
OECD	Organization for Economic Co-operation and Development
OLADE	Organización Latinoamericana de Energía (Latin American Energy Organization)
O&M	Operations and Maintenance
OPEC	Organization of Petroleum Exporting Countries
PDVSA	Petroléos de Venezuela, S.A
PEe	Primary Energy Equivalent
PFBL	Petro Fuels Belize Limited
PHEV	Plug-in Hybrid Electric Vehicle
PM	Particulate Matter
PPA	Power Purchase Agreement (Electricity)
ppm	Parts per Million
PTC	Production Tax Credit
PUC	Public Utilities Commission (Belize)
PV	Photovoltaic
R&D	Research and Development
RD&D	Research, Development and Demonstration
RE	Renewable Energy
RFP	Request for Proposal
RFS	Renewable Fuel Standard
RO	Renewables Obligation
ROC	Renewables Obligation Certificate
ROLEDA	Rural or Low-Energy Density Area
RPS	Renewable Energy Portfolio Standard
RSA	Refer to CPRSA above
scf	Standard Cubic Feet (*Measurement of volume*)
SCGT	Simple Cycle Gas Turbine
SIEN	Sistema de Información Energética Nacional (National Energy Information System of OLADE)
SIEPAC	Sistema de Interconexion Eléctrica de los Paises de America Central (Electricity Interconnection System of the Countries of Central America)
SLC	Single Large Consumer (Belize)
SPE	Society of Petroleum Engineers (USA)
sq	Square
SUV	Sport Utility Vehicle
tCO2e	Metric Ton of CO2-equivalent (of GHG emissions)
T&D	Transmission and Distribution
TES	Thermal Energy Storage
TJ	Terajoule
TOE	Tonne (Metric Ton) of Oil Equivalent

TOR	Terms of Reference (for this Report)
TOU	Time of Use
TPES	Total Primary Energy Supply
TSDF	Tropical Studies and Development Foundation (Belize)
UB	University of Belize
UK	United Kingdom
UNEP	United Nations Environment Programme
UNFCCC, FCCC	United Nations Framework Convention on Climate Change
UNIDO	United Nations Industrial Development Organization
US, USA	United States (of America)
USD	United States Dollar
US DOE	United States Department of Energy
USGBC	United States Green Building Council
VAFE	Vehicle Average Fuel Economy
W	Watt (Measurement of power)
WBCSD	World Business Council for Sustainable Development
WEC	World Economic Council
WEO	World Energy Outlook
WHO	World Health Organization
WPD	Wind Power Density
WTE	Waste-to-Energy

TABLE OF CONTENTS

LIST OF FIGURES AND TABLES

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FOREWORD

Before setting out to prepare this National Energy Policy Framework, we sat down with the original sponsors - Minister of Public Utilities at the time, Honorable Melvin Hulse, and his CEO, Colonel George Lovell - to understand what particular expectations they had beyond the stipulations of the TOR. It became clear to us that what was required by them was a document that pointed the way to an efficient energy sector within the context of Belize's particular strengths and constraints. The Minister and his CEO were insistent that our recommendations should be practical, actionable and "local" – how can we best use our indigenous resources to achieve our objectives. Furthermore, they emphasized the need for us to establish national priorities given financing constraints and come up with ways to reverse the trend of the increasing foreign exchange outflows that is normally associated with the energy sector especially in these times of rising oil prices.

This document seeks to fulfill the wishes of the Government, as well as the requirements of the more detailed terms of reference. ***It is geared towards two main audiences: policy-makers and decision-makers, specifically Ministers of Government, CEOs and business leaders, whose full participation and support will be crucial to making these policies and plans work***. We have tried to present a document that will be immediately useful and actionable – and not another report destined to be shelved and used mainly as a reference for even more reports.

Some further explanations and caveats:

- The format of this Report does not adhere strictly to the Draft National Energy Policy Framework disseminated by the CARICOM Secretariat. We have, for instance, intentionally refrained from presenting general situational analysis-type data and information describing the economy, geography and other aspects of Belize that have already been well documented and repeated countless times in so many other reports.

  Moreover, we have also generally shied away from doing any in-depth analysis of the strengths, weaknesses and peculiarities of the various institutional structures that currently govern and regulate the various sub-sectors of the energy sector. Though understanding how these work is critical to final policy formulation, we decided instead on what we believe is a more foundational approach: focusing mainly on understanding the current energy supply and demand situation in Belize; assessing the energy supply-side and demand-side options we have at hand – or will soon have – to solve the problems that face us now and in the future; proposing a least cost plan(s) for achieving our objectives, in the form of a sequenced roll-out of the most cost-effective of these options; and finally recommending policies that can be implemented to stimulate and guide action along the path of the least cost plan(s). It is our hope that this emphasis on "what can be" and "what should be" instead of "what is and what is not" will engage policy-makers and engender forward-looking and innovative policy decision-making and action in the energy sector.

- Secondly, there is a particular emphasis on numbers and financial analyses in this Report. There are two main reasons for this focus: so that policy makers reading this document are able to understand what perspective was taken when making our policy recommendations and what assumptions were made, and in any event to provide and document a methodological framework for future reference.

  Consequently, the meticulous reader might probably be surprised at the number of "assumptions" made in the financial analyses done throughout the document. There are two kinds of such "assumptions": estimates of a past or present condition and estimates of a future condition. For the former, these estimates are, for the most part, backed-up by previous studies or findings that are appropriately cited in the document. For the latter, these estimates are presented as goals or objectives and should be interpreted in the context of a *what-if* analysis. Therefore, the numerous "assumptions" in no way undermine or water down the factual foundation of the analyses. Even so, where estimates of a past or present condition are not substantially supported, these should be regarded as data shortcomings that point to the need for further research and study in the specific area.

- We have also been particularly concerned about ensuring that the solutions that we propose make sense within Belize's context, and to avoid as much as possible falling into the trap of proffering ideas that are driven by special-interest agendas and popular hype with weak supporting bases. For this reason, as earlier mentioned, our specific recommendations are as much as possible underpinned by analyses that are based on available scientific data and facts (or at least our best estimates and assumptions of what the facts are).

- Finally, we are well aware that energy policy formulation should *as much as practicable* be based on pertinent data and facts; otherwise recommendations may well end up altogether irrelevant or – worse - lead to counter-productive action. ***The major challenge we faced in preparing these policy recommendations was getting relevant and reliable data***, especially with regard to the current state of the energy sector, and given the time constraints and scope of the study. In many cases, data and information on local activities were simply not available.

  We decided very early on that this would not deter us from performing the supporting analyses – and so establishing a methodological framework – that are so critical to policy-making. Where data on local activities were not available, we opted to extrapolate from years with more reliable data, or use regional or international averages or benchmark data or what we felt were reasonable assumptions; on the premise that they would be updated with more accurate data in future iterations of the National Energy Policy.

If there is one last point we wish to reiterate therefore, it is this: With this Energy Policy Document, the Government of Belize has now taken a first necessary and bold step to guide the development of the energy sector along a path of efficiency, sustainability and resilience. **The number one priority at this juncture must now be to build a vast compendium of continuously-updated data, technical knowledge and analytical tools needed to support policy-making for this sector**. For it is only when we have the correct data and the facts in hand are we able to make the sound decisions that lead to targeted, timely and efficient action!

Ambrose Tillett, *Team Leader*

Jeffrey Locke

John Mencias

INTRODUCTION

> **"If I am asked today what is the most important issue for global security and development - the issue with the highest potential for solutions, but also for serious problems if we do not act in the right way - it is Energy and Climate Change."**
>
> *Jose Manuel Barroso, President of the European Commission (EC), Opening Speech at World Energy Congress held in Rome, Italy on November 2007*

Background

At the start of the second decade of the 21st Century, Belize finds itself in midst of the throes of a looming global energy crisis. As economies around the world grow and consume energy at ever-increasing rates, traditional sources are drying up; as political and economic hotspots flare up and cool down, waves of oil price shocks and market uncertainty are felt around the globe; and as we burn more fossil fuels to maintain our lifestyles, the temperature of the earth's atmosphere continues to rise to precarious levels.

How can we make the most of the energy resources available to us to serve our economic and social needs in the present and in the foreseeable future as cost-efficiently as practicable, while simultaneously mitigating the ravages of energy price volatility and the environmentally-damaging effects of fossil fuel use? What part can we play to ensure that future generations are not relegated to diminished lifestyles or even mass calamity because of the way we harness and use energy now, but that they are instead bequeathed stable supplies of efficient and clean energy? What opportunities can we forge from our unique circumstances as a relatively energy abundant country in the midst of burgeoning demand all around us in the Central American mainland? The short answer is that we must transition to a path of **efficient** and **sustainable energy**, and build **resilience** within our energy supply chain(s) by using "effective rules and smart policy frameworks".

The purpose of this document therefore is to present a draft National Energy Policy Framework (NEPF) that puts Belize on a path to energy efficiency, sustainability and resilience over the next 30 years. This is, strictly speaking, not a policy document; but rather a document that provides policy recommendations to policy-makers and decision-makers, and – where appropriate - discusses the pros and cons of various policy instruments that can be used to achieve policy objectives. It is therefore a suggested roadmap of where – and how fast - we need to go, how we can get there and what it will take for us to get there.

Study Approach

The approach taken in formulating this draft NEPF comprised of six main activities:

1) Assessing the major factors driving energy policy-making in the 21st Century. *This is done in Chapter 1*.
2) Carrying out a brief overview of the main trends and players that are currently impacting and that may continue to impact the global and regional energy market, followed by a fairly in-depth analysis of the current state of Belize’s energy sector in terms of the inter-relationships between supply and demand, the cost of energy, and the related GHG emissions of the different sub-sectors. *The results of this analysis are presented in Chapter 2*.
3) Conducting a comprehensive assessment of the main supply options, both indigenous and external to Belize, available now and in the near future to meet our energy needs. *This is documented in Chapter 3*.
4) Analyzing various end-use efficiency and conservation measures that can be put in place to reduce local demand for energy. *This analysis is presented in Chapter 4*.
5) Developing goals and strategic objectives for Belize’s energy sector, and formulating and evaluating various plans for meeting these strategic energy objectives, and which utilize, to varying extents, the supply options and end-use efficiency measures referred to above. *This is documented in Chapter 5*.
6) Recommending specific policies for ensuring the realization of the optimal energy plan (from above) which best achieves the proposed strategic objectives over the planning horizon, as well as general policies and a supporting organizational framework for administering and guiding the development of the energy sector as a whole in line with these strategic objectives. *These are presented in Chapter 6*.

Main Study Outputs

There are four main outputs of this study:

- **Proposed Goals and Strategies** for Belize’s Energy Sector.
- **Three ‘Indicative’ Energy Plans** for achieving the proposed goals following the direction of the proposed strategies: These plans, among other things, result in lower energy costs for Belize over the next 30 years; and reflect the state of the art and technology trends around the world and how these intersect with our unique circumstances.
- **Policy Recommendations** designed to give life to the plans or subsequent iterations of or updates to these plans and generally to guide the development of the energy sector as a whole: These policy recommendations are also informed by the analyses of the supply options and demand-side measures available to Belize as well as the

policies and documented experiences – both successful and failed - in other developing and developed countries.

- **A Proposed Organizational Framework** for implementing the policy recommendations and administering the development of Belize's energy sector in general.

Next Steps

The original draft of this document was disseminated to the relevant Government authorities and various energy stakeholders for their review, input, correction, and discussion. The final draft incorporated the ideas and inputs received from those consultations: It was endorsed by the Cabinet in February of this year. Government is now setting up the requisite institutional structures, preparing to enact the necessary legislations, and taking the necessary steps to put these policies into effect

This current document is an updated version of the 'Final Version' that was endorsed by the Cabinet. Updates were done to some of the data, discussions and presentations in light of new or more current data and information. ***None of the proposed policies have been changed to any substantive extent from what was presented to the Government in the Final Version*****.**

1 WHY ENERGY POLICY MATTERS

Energy is an indispensable ingredient for growth, prosperity and social equity within and across nations. Statistics show that, as a general rule in developing countries and emerging economies, people who have access to modern forms of energy, such as electricity, also have access to better economic opportunities, better health care services, and better education. The WEC's *World Energy Insight 2010* states: "Energy services have a profound effect on productivity, health, education, safe water, and communication services. Therefore, it is no surprise that access to energy has a strong correlation to social and economic development indices (e.g. Human Development Index, life expectancy at birth, infant mortality rate, maternal mortality, and GDP per capita, to name just a few)."

The cost of energy to society is significant, however. Energy production and distribution processes consume resources, incur losses (of energy), and can cause harm and damage to people – usually, the most vulnerable populations - and the environment. In particular, some of these processes use large amounts of natural resources – usually, land and water– causing the displacement of people, flora and fauna. Moreover, energy supply processes are often highly dependent on critical inputs that have to be sourced from foreign suppliers or that may be in scarce supply; thus rendering the sector, and by extension, the economy more vulnerable to external price shocks and supply disruptions.

Energy policy-makers aim to balance the incurrence of these costs, losses and environmental damage with the achievement of national goals for economic growth and long-term prosperity, security, poverty reduction and social equity. The emerging consensus[2] is that, in order to do this, the national energy sector as a whole must be **efficient**, **sustainable** and **resilient**.

Energy Efficiency

The term *energy efficiency* has traditionally been used within a narrow context. In the past, energy efficiency meant supply-side energy efficiency: the efficiency of converting unit of input energy into useful energy. Nowadays, the energy efficiency focus has moved to the opposite side of the spectrum: end-use energy efficiency. However, energy efficiency is best understood - and measured - from the perspective of an entire energy supply chain or the entire energy sector.

Figure 1.1 below provides a schematic overview of a typical energy supply chain: that is, how energy is processed from its natural (primary) forms into end-use energy. The

[2] This is the consensus reached by us (the authors of the NEP) after studying the myriad viewpoints gleaned from the current literature on the topic of energy.

national energy sector is comprised of many, intersecting and overlapping individual energy supply chains that serve the energy needs of all the various end-use sub-sectors.

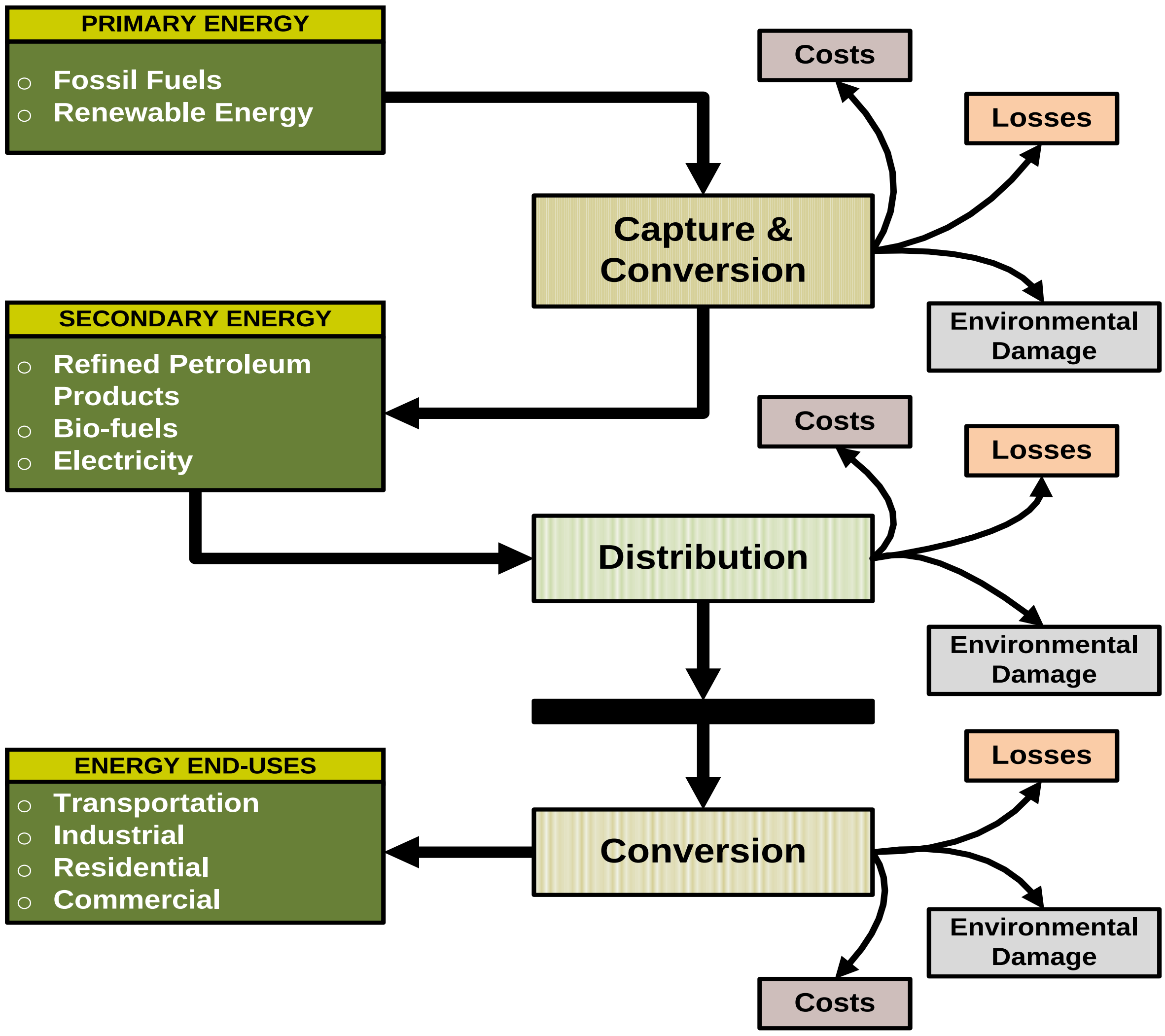

Figure 1.1: Processes, Inputs and Outputs of the Energy Supply Chain[3]

Primary energy refers to energy (or fuel) in its un-processed natural form: oil deposits, natural gas fields, sunlight, wind, flowing water (hydro). **Secondary energy** is energy that has been extracted from primary energy sources - for example, electricity and gasoline - and that will be converted into useful energy. Secondary energy forms are also referred to as energy carriers because they "carry" energy from the primary source to the final end users. **End-use energy** or useful energy is the work done by the engine of a vehicle or the heat which cooks a meal or the illumination from a light source.

There are three main processes in each individual energy supply chain: primary energy capture and conversion into secondary energy form; distribution and delivery of the secondary energy to the point where it will be consumed; and finally conversion of the secondary energy into useful energy. Using biofuel as an example: "Energy crops" (the primary energy form) are cultivated, harvested and then processed in a local factory into biofuel such as bioethanol or biodiesel (the secondary energy form). The biofuel is then transported in tankers from the factory into storage tanks at a main depot where it is stored, before being moved from the main depot to storage tanks at a filling station; and then delivered from the filling station into a consumer's car. Finally, the internal

[3] Adapted from (Evans, 2009)

combustion engine of the car converts the biofuel into mechanical power (useful energy) that propels it along.

Each of the processes in the energy supply chain consumes resources (giving rise to costs), incurs losses (of energy), and causes damage to the environment, while contributing to the production of energy that ultimately drives economic growth and long-term prosperity.

Beyond Traditional Supply-Side Efficiency

As mentioned earlier, in the past, energy policy-makers have focused on improving the efficiency of the individual processes of a specific energy supply chain, particularly the primary-to-secondary conversion processes. However, pursuing energy efficiency in this way leads to sub-optimal results for the energy sector as a whole. Energy efficiency improvements must be pursued in a holistic, coordinated manner from primary fuel extraction or importation right through to end use. For instance, it is probably better to invest a given amount of money to improve the average energy efficiency of electricity end-use devices such as lights, refrigerators, A/Cs, motors, and appliances (that together consume say 80% of electricity supply) by 20%, than to use the same amount of money to undertake projects that improve the efficiency of transmission and distribution lines by only 10%. Likewise, it makes little sense to focus all investment in long-term projects for improving crop yields for the production of ethanol that will be used as vehicle fuel, if the most economic plan is to transform the entire vehicle fleet to electric. In such a case, substantial efforts should be concentrated on making the electricity production and distribution processes more efficient as well.

Energy Recoverability

An oft-overlooked abundant source of energy is the "waste" heat that becomes immediately available as we convert fuels into useful energy form. Waste heat is the most abundant of useful energy forms because on average it accounts for about 60% of the output of all energy conversion processes. With proper planning, coordination and focus, waste heat – when viewed as "recoverable energy" - can be a major source of energy for use in the same process that generates it or it can be transferred to other parts of the system where it can be used by other processes.

Combined cycle gas turbines, co-generation plants and A/Cs with heat recovery are prime examples of systems that harness recoverable energy thus improving overall process (or system) efficiency:

a) Gas turbines generate electricity from the combustion of fuel. In single cycle gas turbines, the heat that is released during the combustion process is simply rejected into the atmosphere through an exhaust system. In combined cycle gas turbines, the heat is captured instead and used to produce steam that in turn drives a steam turbine to generate additional electricity. In this way the overall process efficiency is boosted to as high as 60%; significantly higher than that of single cycle turbines, with efficiencies in the region of 35-45%.

b) Co-generation plants, which are usually found in sugar processing factories, operate on a similar principle to combined cycle gas turbines. Most configurations use a steam turbine to generate electricity. The low pressure exhaust steam is then captured and used in the evaporation and boiling processes of sugar production. Of course, co-generation plants go a step further and use the waste (bagasse) remaining from sugar cane processing to fire the boilers used to make the steam that drive the steam turbines in the first place.

c) Most A/C systems are designed to simply extract heat from the room or building to be cooled and reject it into the atmosphere. A/Cs with heat recovery route this heat into hot water tanks instead of rejecting it into the atmosphere; saving on energy that would have had to be generated separately just to heat water.

These systems all use the energy that would have ordinarily been lost as waste heat, thus improving overall system efficiency and reducing the demand for the additional energy – now being sourced from waste heat - that would have had to be found to fuel the process itself and/or the other processes.

Economic versus Technical Efficiency

Energy efficiency is also not only about the amount of secondary energy produced per unit of primary fuel input (technical efficiency). The fuel itself is only one aspect of the inputs: the capital and the O&M costs of the equipment used to convert the fuel to secondary energy must also be fully taken into consideration. In fact, for some renewable energy sources such as wind energy, there are no fuel inputs: the capital and O&M costs of the wind plant are the only cost inputs. Thus, the true indicator of the efficiency of a process – one that considers all the inputs – is its economic efficiency.

From the perspective of the national energy sector, economic energy efficiency should ideally be measured as the sum of the present value of the energy used for all end-use purposes divided by the sum of the present value of the costs of all the inputs – fuels, materials, equipment, labor etc. - into the energy production and distribution (inc. useful energy conversion) processes. Therefore, given two different plans that both suffice all end-use requirements, the plan that costs less on a *present value basis* is the more efficient one. For Belize, which must import almost all the energy conversion equipment needed to produce secondary energy and useful energy, viewing energy efficiency from this perspective is an imperative that cannot be under-estimated: using a more narrow definition that considers only the primary energy inputs (e.g. fuels) may lead to over-focusing on and thus improvement in technical efficiency, but at the expense of increased quantities and/or costs of the other inputs, which could ultimately result in no improvement or even a reduction in overall economic efficiency.

Economies of Scale

Energy production and distribution is a capital-intensive undertaking, and unit supply costs fall significantly the greater the energy demand. This occurs for two main reasons: Firstly, as demand grows, larger production and distribution equipment can be utilized; and, as a general rule, the larger the equipment, the lower is its unit manufacturing cost and unit O&M cost. Secondly, unit fixed costs of supplying energy will decrease, since total fixed costs are then spread across a larger demand base. The fact of having a low population base dispersed in pockets across a relatively large land area coupled with a low-energy intensive industrial base has in fact been a major structural issue impeding cost reductions in the energy sector in Belize.

Capacity Utilization

Unit costs also fall as capacity utilization increases. Energy planners, particularly in the electricity industry, are therefore always concerned with sizing equipment for maximum lifetime utilization: the smaller the size, the greater the chance of full utilization; but, this has to be weighed against the higher per-unit capital and O&M costs of smaller equipment as discussed above. This is an important consideration especially when the supply mix consists of natural resource-driven variable output generators such as wind turbines, as the economics of such installations are predicated on full utilization of output which waxes and wanes with the availability and intensity of the underlying resource. The ideal situation occurs when demand is so large that equipment capacity utilization is always near 100% and equipment size is not a constraint.

Energy Sustainability

According to the *World Economic Council* (WEC), energy sustainability means “the provision of energy in such a way that it meets the needs of the present without compromising the ability of future generations to meet their needs”.

Sustainability hence has three key dimensions: A process or supply chain for a particular energy form is considered *economically sustainable* if the benefits of the energy it helps to produce, and other spin-off benefits from its constituent activities that accrue to the economy as a whole, outweigh the costs incurred over the long run. It is *environmentally sustainable* if it causes minimal harm or damage to people and the environment over the long run. And, it is *socially sustainable* if it improves - or as a minimum does not degrade - the living conditions of the poor and others living on the margins of society, either by providing them with greater accessibility to and affordability of modern energy forms or by generating economic activity within their communities.

From the perspective of the entire energy ecosystem, the way we *use* energy – that is, the forms and amounts of energy use - also has equally important implications for its sustainability. Switching to less polluting forms of energy lowers GHG emissions, and so reduces harm done to people and the environment. The less energy we use, the less we need to supply it, and the lower are the consequent costs, losses and environmental damage. Beyond this, when we use less storable energy in the present, we retain more for the future.

The link between sustainable energy and climate change

Most of the world's modern energy is sourced from fossil-fuels: coal, oil and natural gas. The burning of fossil fuels - in generators to produce electricity; in vehicles, marine vessels and airplanes for transport; and in industrial motors – releases a slew of gases into the earth's atmosphere: chief amongst them are carbon dioxide, methane and nitrous oxide.

Carbon dioxide occurs naturally in the earth's atmosphere and biosphere. The biosphere's stores of carbon dioxide include plants and animals, soil, oceans, rocks and fossil fuel deposits. Each day, carbon dioxide flows from earth's atmosphere into the biosphere and oceans and out of the biosphere and oceans back into the atmosphere as part of the natural cycle of life. These flows had been in balance over millions of years and so the concentration of carbon dioxide in the atmosphere had remained fairly constant. The flows in and out of the fossil fuel deposits in particular had been negligible as these build up over millions of years … until the Industrial Revolution happened, and we started burning fossil fuels.

This meant that the release of carbon dioxide from fossil fuel deposits (when burned) into the atmosphere increased beyond the natural flow. Some of the "unnatural flow" of carbon dioxide is sucked up by the oceans; but most remain in the atmosphere. So the concentration of carbon dioxide in the atmosphere continues to increase as we continue to burn fossil fuels. In fact, it has been estimated that the carbon dioxide content of the atmosphere has risen from 285 ppm to some 390 ppm - or as much as 430-450 ppm $CO2$ equivalent, if other greenhouse gases are included - as a result of human activity, chiefly the combustion of fossil fuels, deforestation, agricultural practices and emissions of particular gases by industry.

What do higher-than-normal concentrations of carbon dioxide in the atmosphere mean for us? **GLOBAL WARMING!** Carbon dioxide and the other green house gases present in the earth's atmosphere absorb thermal radiation coming from the earth and re-radiate a part of it back to the earth's surface. The higher the concentration of green house gases in the atmosphere, the more is the radiation that is reflected back to earth. This causes an increase in the temperature on the earth's surface. In the 20th century alone, for example, the mean temperature of the earth's surface rose between 0.56 ^{O}C to 0.92 ^{O}C. Scientists predict that, if we continue burning fossil fuels unabated, this temperature will increase by 3-5 ^{O}C above pre-industrial revolution levels before the end of the century.

Though the forecasting models vary - climate change prediction is a complex science – they tend to agree on the following sequence of events: As the earth's surface temperature increases, snow and ice will melt at a higher rate, leading to inundation of coastal areas and habitats; precipitation events and storms will occur more intensely and more frequently; some plant and animal species will become extinct (also caused by oceans becoming more acidic because of increasing carbon dioxide concentrations); and the reverberating cycle of such events can lead to unprecedented catastrophe on a global scale … if something is not done to stop it!

In a 2009 UNDP Report entitled "Belize and Climate Change: The Costs of Inaction", Dr. Robert B. Richardson of Michigan State University predicts that , as a consequence of global warming, Belize's future climate will be characterized by warmer temperatures, declining levels of precipitation, increasing concentrations of carbon-dioxide in its coastal waters and more frequent extreme weather events, resulting in heat stress, water stress, loss of important ecosystems including our coral reefs, changes in agricultural productivity particularly lower yields from maize, physical damage from storms and hurricanes, and greater incidence of infectious diseases (Richardson, 2009). These predictions have significant implications for energy demand patterns and supply infrastructure into the future: Demand for air-conditioning and cooling will increase with hotter days and nights and more frequent heat waves. The output of hydro-electric sources will be curtailed as precipitation levels decrease; and transmission and distribution lines and other structures, such as wind turbines and roof-top mounted solar panels, will need to be built to more stringent structural standards to withstand the more intense weather events.

In order to maintain the global temperature increase below 3 ^{0}C and so prevent this sequence of events from occurring and altering life as we know it, world leaders have finally reached some level of consensus that deliberate action must be taken now to *among other things* severely cut back our use of fossil fuels, to actively engage in reducing or removing altogether the GHG emissions from the fossil fuels that we do (have to) burn, and even to pro-actively capture and sequester GHGs already in the atmosphere due to our actions in the past.

Given the current stage of development of the technologies that we have at hand, it is much more cost-effective to direct our efforts to cutting back on our use of fossil fuels and so cut back on the rate of GHG pollution rather than trying to sequester the emissions we produce as we burn them or after we burn them. The globally accepted target is to cut back GHG emissions to at least 50% of 2005 levels by 2050.

The UNFCCC, the Kyoto Protocol and the Clean Development Mechanism

The ***United Nations Framework Convention on Climate Change*** (UNFCCC or FCCC), is an international environmental treaty, amongst most countries of the United Nations, that is aimed at fighting **global warming.** Its stated goal is achieving "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."

The ***Kyoto Protocol***, which came into force in 2005, is a formal and legally-binding agreement between 191 countries, committing certain members (called *Annex 1* countries) to reducing their emissions of green house gases by specified target levels and all members to other related general commitments. The Annex 1 countries may undertake to reduce their emissions directly or they may use certain innovative “flexibility mechanisms” provided under the protocol. One of these “flexibility mechanisms” is the ***Clean Development Mechanism*** (CDM).

How does the CDM work?

The CDM is cap-and-trade emissions reduction mechanism that is set up to operate on the principle that it is easier to achieve emission reductions in Non-Annex 1 countries, as these countries will likely have a greater potential to upgrade to more efficient and less polluting forms of energy generation. Annex 1 countries can therefore meet their emission targets by participating in clean energy and other energy-saving projects in Non-Annex 1 countries where the quantum of emissions reduced per dollar invested will likely be higher.

A project is awarded a number of CER (certifiable emission reduction) credits based on the degree to which it reduces GHG emissions (relative to a pre-determined baseline). The CER credits earned by a particular project are shared between the participating Annex 1 and Non-Annex 1 countries in proportion to the extent of their investments in the project. The Annex 1 country can use its portion of credits earned to offset its emissions target; the Non-Annex 1 country can sell its portion of credits earned to any Annex 1 country, which can use it to (further) offset its emission targets. In this way, a number of objectives are achieved:

- A global market - and hence a price - for carbon (emissions) is established. Carbon pollution is treated as a global commodity that can be traded on international markets: you purchase the “rights to pollute”.
- Global emissions are reduced (at least relative to the baseline).
- Clean energy technologies are introduced in developing countries, with bi-lateral financing from Annex 1 countries.

Energy Resilience

Energy resilience[4] refers to the capacity of individual parts of the national energy sector or of the sector as a whole to bounce back quickly from or absorb shocks arising from energy price flaring or from disruptions in one or more energy supply processes or chains. It is therefore intimately and inextricably linked to both energy efficiency and

[4] The notion of “resilience in energy” was first introduced back in 1982 in a book *Brittle Power: Energy Strategy for National Security* by Amory B. Lovins and L. Hunter Lovins, and more recently championed – though proposing a different strategy - by Andrew Grove, former Chairman and CEO of Intel Corp, in a 2008 article in *American Magazine*.

sustainability: As we supply and use energy more efficiently, we become less dependent on it and consequently are less affected when disruptions occur. Similarly, shifting our dependence from foreign fossil fuel to renewable energy sources result in greater environmental and social sustainability, but also reduce our vulnerability – and hence boost our resilience - to external price shocks. This makes the task for policy-makers easier. These goals are mutually reinforcing: any action that helps to achieve one of them is likely to help to achieve the other!

The recent experience of over $100 USD per barrel of crude oil that transpired in 2008 exposed the lack of resilience of the world's food production systems - and by extension the world's poor - to oil price shocks. The huge rise in food and energy prices strained family budgets, causing many families to slide deeper into poverty. In the mean time, the small-farmer, faced with sky-rocketing input costs, had to cut back on applications: thus depressing yields and further squeezing farm incomes. It was a clear reminder that the existing agricultural systems, which are heavily dependent on petroleum and petro-derivatives, cannot be sustained in a climate of volatile oil prices.

Besides energy efficiency and energy renewability, there are two other very important components of the portfolio of strategies for pursuing energy resilience: *fuel resource diversity* and *process flexibility*.

Fuel Resource Diversity

In general, the more diverse the fuel resource supply portfolio of a country, the lower the impact of a sudden change in any single supply source, and the more stable the costs over the long run. There are two kinds of fuel resource diversity that are of interest to strategic planners and policy-makers: resource type diversity and resource location diversity.

a) *Resource type diversity*. Having different resource types – such as wind, natural gas, biomass, diesel, and hydro – in the energy supply mix lessens the impact of a sudden rise in cost or a shortage of any single one of them. A single protracted war in the Middle East may cause the cost of diesel for transport or for electricity generation to suddenly sky-rocket, or a particularly dry year may severely impact hydro-electricity supply countrywide, or a low-yield sugar crop season may result in reduced bagasse output and consequently curtail supply of electricity to the grid. But the chances of all three events (a dry year, a low-yield sugar crop season, and a protracted war in the Middle East) occurring at the same time – though seemingly more likely these days – are much less than the chance of any one of them occurring.

   Resource type diversity also comes into play on a much shorter time scale – daily or even hourly – particularly for renewable energy resources whose outputs tend to be largely independent of each other: For instance, the output from solar PV is highest when there is no cloud cover blocking out sunlight and wind power works best on windy days; but an overcast day, while blocking out sunlight, does not stop the wind from blowing, and a windless day does not stop the sun from shining. Having both resources in the resource supply pool "firms up" the supply output potential.

In fact, proposed regional electricity trading schemes are often predicated on exploiting these variations in output between renewable energy source types. Wind and hydro resources, for example, are widely viewed as highly complementary. The Nordic power exchange, Nordpool, is a testament of how having a power system with large amounts of hydropower makes it easier to incorporate wind energy into the supply mix and increase the share of generation from wind. Using a similar strategy, the soon-to-be-commissioned SIEPAC transmission system, spanning Central America, expects to harness the disparate wind energy resources scattered amongst the various member countries on top of the region's large hydro power resources, thus increasing the overall supply of firm energy from variable renewable energy sources (Yepez-García, Johnson, & Andrés, 2010).

b) *Resource location diversity*. Geographic dispersion of resources is as important as diversity in resource type. Simply put, the wind does not suddenly stop blowing everywhere at the same time, and it is highly improbable that a hurricane will hit everywhere in the entire country at the same time (at least not with the same level of intensity). Placing or developing resources in strategic locations throughout the country mitigates the chances of the supply of energy countrywide being affected by a single event confined to a specific geographic area, whether as a windless day in Corozal or a hurricane devastating Stann Creek,.

It stands to reason that the greater the geographic dispersion of resources, the greater the benefits, assuming the incremental benefits gained are not outweighed by the costs of transporting energy from the dispersed locations to where it is ultimately consumed. Regional trading schemes, such as SIEPAC, are further underpinned by this prospect of complementarity between variable resources scattered over a wide geographic expanse, as has been demonstrated in several European countries with large wind systems (Yepez-García, Johnson, & Andrés, 2010).

The benefits arising from pursuing resource location diversity also underlie the increasing momentum towards implementing distributed generation, whether off-grid or grid-connected, such as wind mills or micro-hydro outfits directly powering agricultural irrigation systems, or solar thermal collectors used in residential households for water heating or in remote locations for solar drying, or standalone solar-powered, hydro-powered or wind-powered systems serving individual communities. As opposed to centralized generation, a failure of any single generation source will have little impact on the rest of the system[5].

The original authors of the concept of *energy resilience* had advocated renewable energy development and distributed generation[6] as two key components of a robust strategy aimed at creating a resilient energy sector in the USA. As pointed out by Andrew Grove in his 2008 article in *American Magazine* entitled "Our Electric Future" (Grove, 2008), a reliable and efficient electricity transmission and distribution system is the crucial integrating glue of the strategy: Most renewable energy forms can only be harnessed on a large scale by converting them into electricity; and distributed generation sources, whether occurring as small-scale micro-generation sources within a national energy system or as large-scale deployments in individual countries within a region, can only be connected with each other and to consumption centers through an electrical grid. A robust electricity grid therefore facilitates both resource type diversity and resource location diversity, using inter-connectivity to first aggregate the benefits of diversity and then to distribute them to final energy consumers.

Process Flexibility

Countries that have little control over the cost and availability of inputs to their major production systems or over the demand for and market price of the outputs of these systems must as much as possible install production systems that are flexible: that is, systems comprising processes that can be easily adjusted or reconfigured to use a different feedstock or to produce a different output. Depending on resource availability and market conditions, the outputs of large-scale production systems may at times cost more to produce than the price the market is willing to pay for them. When such conditions occur, flexible systems can be adjusted to use a different lower costing input or produce a different more marketable output.

The modern sugar factory is an example of a flexible-output production system, producing sugar and ethanol in quantities depending on the relative demand – and hence market prices - for them. On the other hand, gas turbines are usually configured as flexible-input production systems and can switch between fuel inputs - natural gas or diesel or HFO or even biodiesel - depending on their relative prices and availability. But process flexibility does not necessarily have to be confined to the production side of things. Brazil has taken process flexibility to another level with its Flex Fuel Vehicles (FFVs), manufactured specifically to suffice the need for flexibility in a volatile fuel

[5] Assuming that effective coordination mechanisms are in place where the sources are grid-connected.

[6] Grove, on the other hand, proposes making electricity the major integrator and carrier of energy – from energy source to end-uses – and argues for strengthening the electrical transmission and distribution networks and transforming the transportation fleet to run on electricity instead of petro-fuels (Grove, 2008).

market. A Brazilian-made FFV can run on any blend of ethanol and gasoline: the engine senses the proportion of ethanol in the mixture and adjusts the internal combustion process for optimal performance. The prescribed fuel blend is determined by the relative prices of gasoline and ethanol, and announced to the public as these relative prices change. In this way, consumers are buffered from the negative effects of volatile oil prices.

Energy Independence ≠ Energy Resilience

Energy resilience encompasses the idea of energy security. However, while policies of the past mistakenly equated energy independence with energy security, pursuing a strategy of energy independence is nowadays viewed as costly and futile.

One of the problems with the old "energy independence equals energy security" paradigm is that it encourages framing the energy security and self-sufficiency problem at the national aggregate level only – treating national demand as a single consumption point at the risk of ignoring the need to ensure that sufficient supplies of energy are available for each population center and key load center at different locations within the national infrastructure. For instance, we may currently produce 65% of our electricity from indigenous sources - a formidable number by any world standard; but, what are our options if Belize is hit by a hurricane that destroys the 69 KV transmission line connecting the Southern districts to the sources of generation further north? Will the isolated areas be self-sufficient? The average energy consumption in the southern load centers of Belize is approximately 165 MWh per day. There is only one functioning energy source in the south, Hydro Maya; and it is only capable of producing 40 MWh per day on average. Hence, although there may be sufficient generation at the national level to meet the electricity needs of the entire country, the generation on hand in the south – once cut off from the national grid - will be far from sufficient to meet the demand in the South.

There is a further even more important corollary to the energy independence mantra. What happens when conditions change in a direction opposite to the one being prepared for? Mexico, for example, has huge reserves of natural gas, as much as Trinidad and Tobago, which is currently the largest exporter of natural gas in the Western Hemisphere. But, Mexico's plans to exploit this potential for local use as well as for export were thwarted when natural gas prices around the world dropped in the wake of the technology breakthroughs for extracting gas from shale rock and the subsequent shale gas revolution now sweeping across North America and even parts of Europe and Asia. If Mexico had kept its head in the sand, pursuing energy independence for the sake of sticking to populist policies, it would probably have persisted with developing its own reserves of conventional natural gas resources and would have been forced to export its natural gas at low prices or use it for its own consumption at a relative loss. Instead, Mexico has put its original plans on hold, made an about-turn and is preparing to import natural gas from its northern neighbor; taking advantage of the new opportunity available to it for driving down the cost of energy that underpins its substantial industrial base. At the same time, it has been making arrangements to sell electricity into the soon-to-be-commissioned SIEPAC grid. The Grand Strategy?: Get cheap natural gas from its neighbor in the north, generate electricity from it, and sell the electricity – at a premium - to its southern neighbors, who face relatively higher electricity costs.

The Dependency Dilemma

The mainstay of past energy security policies has been lowering dependence on foreign fuel supplies. However, this kind of narrow strategic focus is what makes it difficult to solve the energy security conundrum in the first place.

When we speak of indigenous energy, we tend to think "home-grown": we expect our monies to stay at home instead of flowing out abroad to buy tons of oil to fuel diesel generators. But what portion of the cost of generating a unit of electricity from indigenous sources actually stays at home? This is a relevant and important question when we consider energy sustainability and resilience within the broader context of economic security. We need to ensure that the foreign exchange savings gained from weaning ourselves off foreign oil are not negated by the foreign exchange losses incurred in purchasing equipment from abroad to harness our indigenous energy sources: moving from one form of dependency, foreign oil, to another form of dependency, foreign materials and equipment.

For instance, the newer technologies such as solar and wind (and even hydro) are characteristically capital-intensive as opposed to fuel intensive. By shifting from fossil-fuel based conversion technologies to these newer, renewable technologies, we can drastically reduce our dependence on foreign oil: but we are in fact simultaneously increasing our dependence on foreign equipment. In both cases, we pay out scarce foreign exchange to foreign suppliers: in one case, most of the payments go to *foreign suppliers of fuel*; in the other case, most of it goes to *foreign suppliers of equipment*[7].

Another case in point is electric vehicles, which have received much attention as the future of energy-efficient transport, because they offer the promise of reducing our dependence on foreign oil. But, electric vehicles use batteries that are made from metals that are relatively scarce and that are in abundant supply in only a few currently "politically unstable" countries (McConnell & Turrentine, 2010). So in moving to electric vehicles, we may reduce our import dependence on unstable supplies of foreign oil, but at the cost of import dependence on unstable supplies of batteries.

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[7] It is arguable that dependency on foreign oil is not the same as dependency on foreign equipment supplies. They both cause a drain on local FE resources indeed, but the schedule of loan repayments for capital equipment is known in advance as compared with the very uncertain schedule of volatile oil prices; thus making the local economy much less vulnerable to price shocks.

These anecdotal references underscore the need to assess *energy resilience* within a broader context – that of *economic security and economic resilience* – if we are to properly detect and plug the holes. For each energy solution, we need to ask if we are not simply replacing one foreign dependency for another: for example, oil for technology or oil for batteries.

2 WHERE ARE WE NOW?

The Global and Regional Energy Context

Since the beginning of the new century, the global energy arena has been undergoing unprecedented transformation, driven mainly by persistent volatility in world oil prices and growing concerns over climate change.

- Renewables have now gained a solid, though still relatively small, footing in the global energy supply market. Onshore wind energy is now considered a mature technology, and wind now accounts for as much as 20% of generation in some European countries. China and Taiwan are the world's top producers of solar voltaic technology, and China has been investing heavily in bio-energy and renewable energy infrastructure in the LAC. Biofuels has gained traction in the transport fuels market particularly in Europe and South America. Ethanol has emerged as a viable renewable alternative to gasoline, and a number of countries have introduced legislation mandating a minimum percentage of ethanol mix in fuel blends. Additionally, extensive R&D efforts are currently being directed towards making biodiesel cost-competitive with petro-diesel, especially in the LAC.

- Natural gas has emerged as the cleaner and cheaper hydrocarbon alternative to oil and coal. An unexpected technological breakthrough in harnessing natural gas from shale rock has sparked a virtual shale gas revolution in the USA and around the world: "Shale gas" now accounts for 30% of US domestic production of natural gas, and the "discovered" reserves in the US alone are sufficient to supply their local demand for the next 120 years at current consumption rates. This has resulted in an oversupply of natural gas on the world market and a consequent decoupling of natural gas prices from oil prices.

- Over the past decade, Brazil, the most populous country in the Western Hemisphere after the USA, has emerged as the energy powerhouse of the Americas, investing substantially in energy R&D and churning out innovations such as high-yielding sugar cane varieties, mechanized sugar cane harvesting, dual ethanol/sugar production, and flex fuel vehicles. Brazil is now exporting its technological know-how to the rest of the LAC, engaging in "ethanol diplomacy" to exert its influence in the region.

- Venezuela, the country with the second largest petroleum reserves in the world[8] and the second largest natural gas reserves in the Western Hemisphere, has been at the

[8] Wikipedia (Wikipedia - Oil Reserves, 2011) reports the summary of oil reserves from the OPEC website. Saudi Arabia's oil reserves as of 2011 are estimated at 264.52 billion bbls and Venezuela's at 211 billion bbls. According to Wikipedia, many experts believe that Canada's reserves are closer to 2,000 billion bbls.

forefront of the latest wave of resource nationalism that has swept over many countries of the LAC, taking a marked anti-foreign interest stance whilst peddling its influence in the region through initiatives such as Petro-Caribe[9]. As a consequence, Venezuela's oil and gas investments have been markedly outpaced by those of its neighbors who possess only a fraction of its vast fossil fuel resources. For example, Trinidad and Tobago's natural gas reserves are 1/10th of Venezuela's, yet Trinidad and Tobago is currently the largest exporter of natural gas to the United States. This is because, aside from Peru and Alaska in the USA, Trinidad and Tobago is the only country in the Western Hemisphere with LNG liquefaction capability[10].

- Mexico has likewise started to prepare itself to be an important regional player and powerbroker in the hemispheric energy market, given its huge endowment of oil and gas resources and its excellent wind resources, and recognizing its unique position as the sole terrestrial conduit between the USA and Canada above and Central and South America below. Mexico has also made substantial investments, both financial and political, in the Meso-American Project, which started nearly two decades ago, as a plan to link the energy and telecommunication assets of the countries of Central America. This project is about to bear its first fruits: the regional transmission grid, linking the countries of Central America with Colombia in the South and Mexico in the North, is 95% complete and slated for formal commissioning by the end of 2011.

Overview of Belize's Energy Sector in 2010[11]

Energy Supply Sources

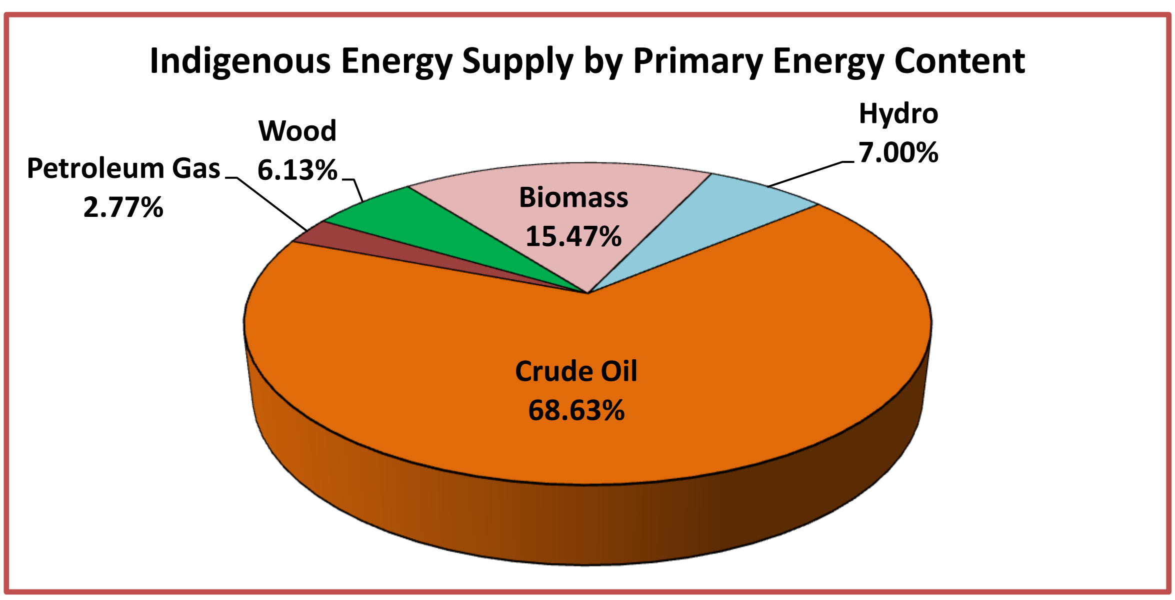

Figure 2.1.1.A: Indigenous Energy Supply by Primary Energy Content for Year 2010

[9] Petro-Caribe is an agreement signed between Venezuela and Caribbean countries (as of 2005) for the sale of petroleum products to these countries from Venezuela's PDVSA under favorable financing terms.

[10] LNG liquefaction capability is the capability to compress natural gas into liquid form (1/600th of its gaseous volume) so that it can be transported over long distances (greater than 2,500 miles).

[11] *Energy Balance 2010* supporting the data provided in this section can be found in **Appendix E**.

A total of 13,538 TJ (or 323,354 TOE) of indigenous primary energy was produced in Belize in 2010: comprising of 1,513,700 barrels of crude oil; 403,675 metric tons of bagasse[12] (for steam and electricity generation); 189,212,500 scf of petroleum gas; 263,150 MWh of hydro-electricity; and 43,253 metric tons of wood fuel (firewood). Crude oil and petroleum gas accounted for 68.63% (9,291 TJ) and 2.77% (375 TJ) of this indigenous energy production respectively on the basis of energy content value; the indigenous renewables made up the remaining 28.6% (3,872 TJ), measured on the basis of energy content value: bagasse (15.47%), hydro (7.00%) and wood fuel (6.13%)[13].

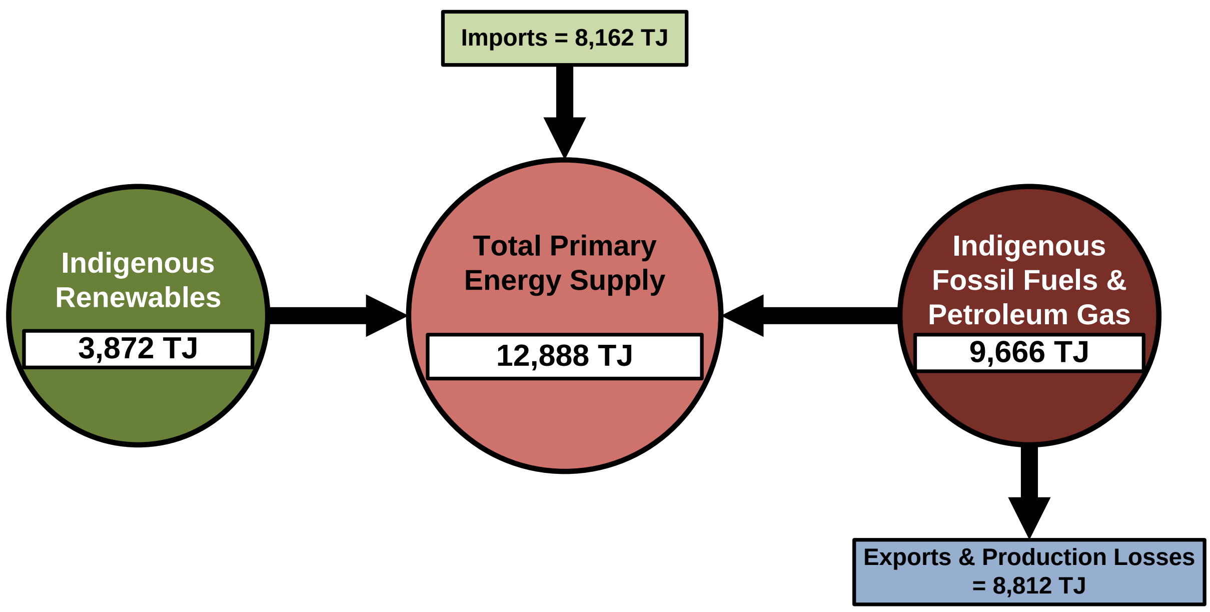

Figure 2.1.1.B: Primary Energy Supply Flows for Year 2010

Of total indigenous energy produced, 8,743 TJ (or 64.6% of total) was exported as crude oil (1,424,540 barrels). However, 8,162 TJ of energy was imported in the form of refined petroleum products (93%) and electricity from CFE (7%). The resultant total primary energy supply (TPES) into the national economy was therefore 12,888 TJ.

Figure 2.1.2 below illustrates the breakdown of TPES by type of fuel supplied to the local energy sector in 2010: 63.3% was imported either as refined petroleum products or as electricity (from CFE), 6.7% was gotten from local petroleum resources, and 30% was harnessed from renewable sources (biomass, wood and hydro). The latter is an especially noteworthy statistic when one considers that the LAC region, which boasts the highest renewable resource usage in the world, had a renewability index[14] of 12% in 2007; and Brazil, the paragon for renewable energy innovation, had a renewability index of 45% in 2007.

[12] However, only about 75% of this was actually used to produce electricity and steam, and hence included as part of the total indigenous energy produced in 2010.

[13] There are a few small wind and solar installations by private generators. But the energy currently provided by these is negligible: less than 0.01% of total primary energy supply, if we extrapolate 2002 results from a 2003 Report by Launchpad Consulting (Launchpad Consulting Belize C.A; , 2003).

[14] RE as a percentage of TPES

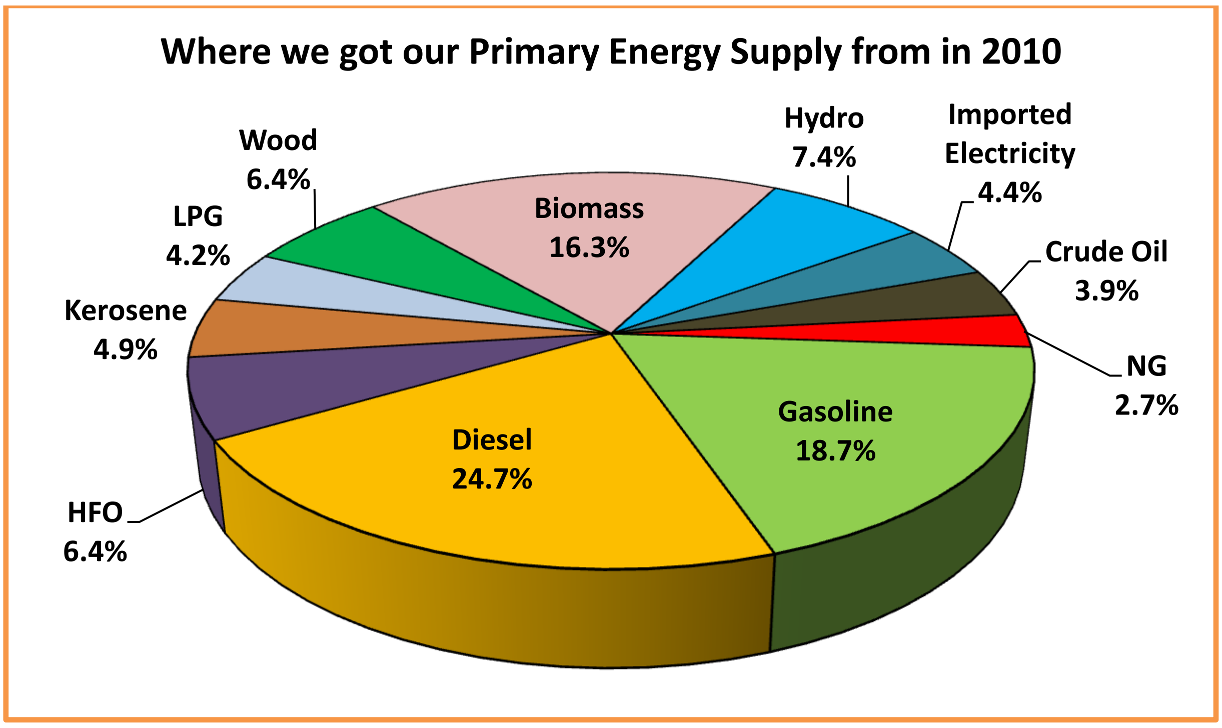

Figure 2.1.2: Primary Energy Supply by Fuel Type for Year 2010[15]

Electricity Supply

In 2010, 28.5% (3,670 TJ) of the total primary energy supply was converted[16] into 573,707 MWh (2,065 TJ) of electricity. Figure 2.1.3 below provides a breakdown *on an energy content basis* of the primary fuel inputs used in generating electricity.

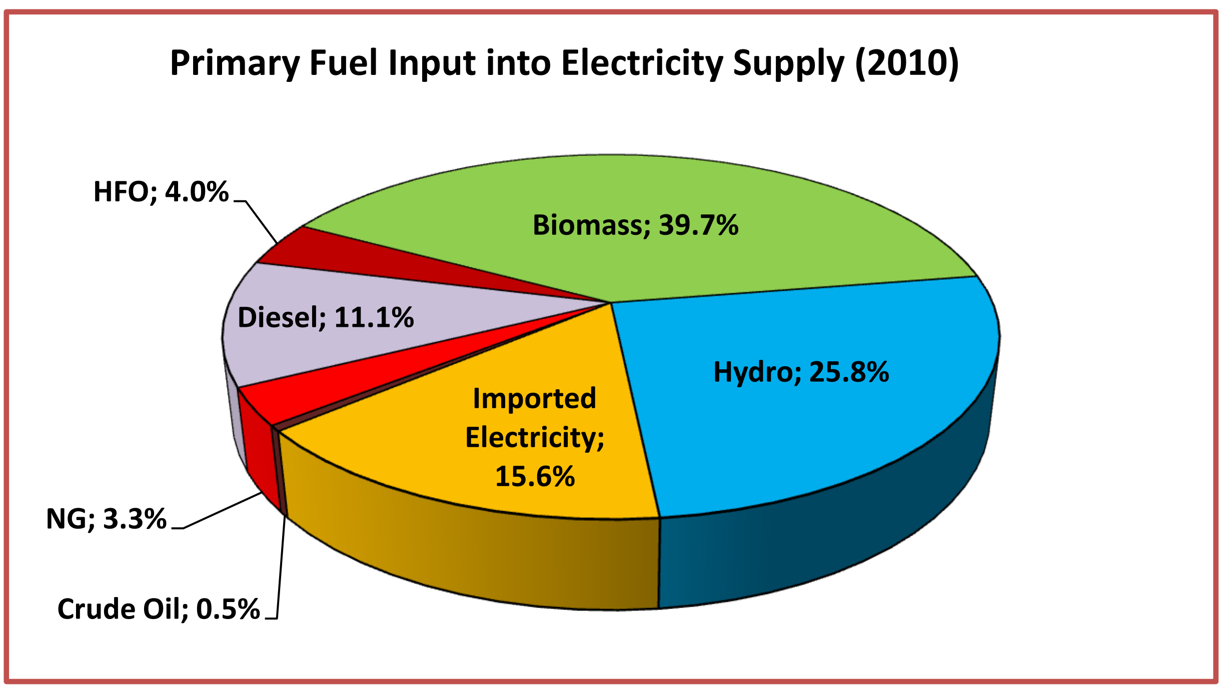

Figure 2.1.3: Breakdown of Primary Fuel Inputs used for Electricity Generation in 2010

Figure 2.1.4 below provides a breakdown of the actual electricity (measured in MWhs) generated from the primary fuel inputs. Approximately 60% of electricity was generated from renewable energy sources, and 27.6% was imported from Mexico. Interestingly,

[15] Expressed as: Total energy content of fuel consumed/Total energy content of ALL fuels consumed.

[16] This includes electricity imports that are not actually converted, but rather 'passed-through' to consumers. Hydro primary energy input is also evaluated as the energy content of the electricity output.

nearly 16% of the total electricity was generated for own use, with the remainder provided by utility sources.

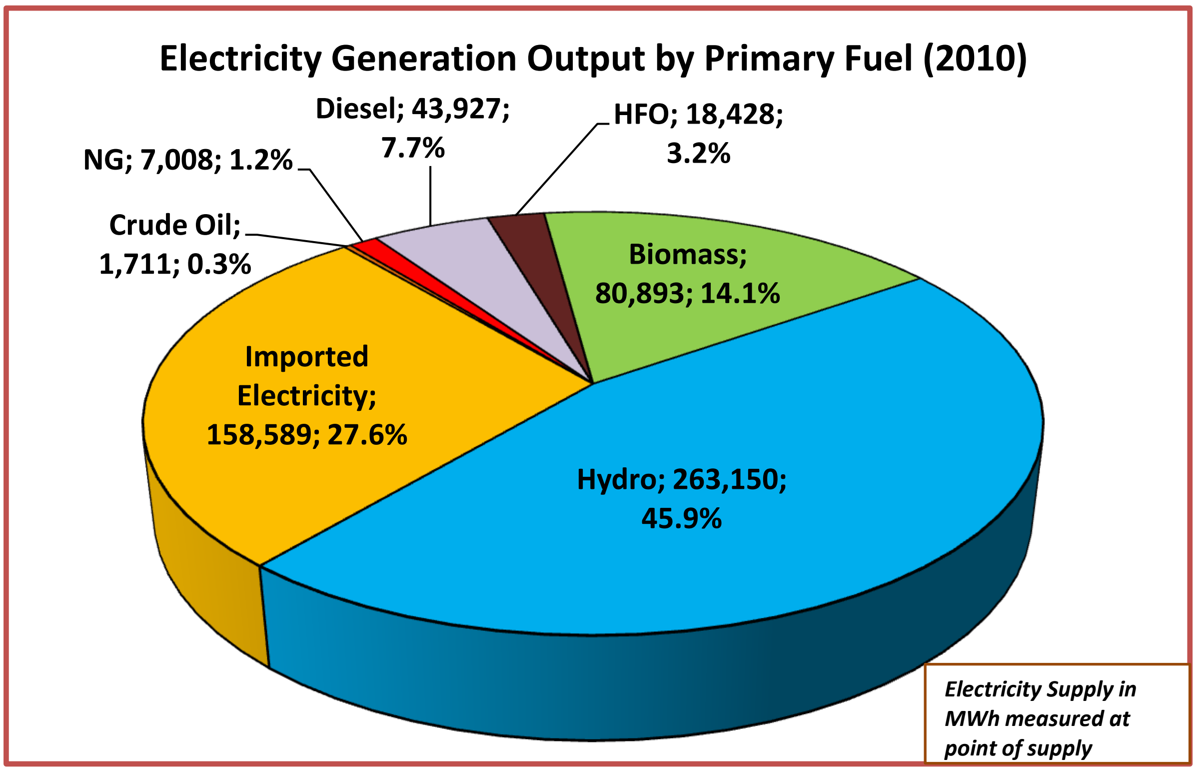

Figure 2.1.4: Breakdown of Electricity Generation Output by Primary Fuel in 2010

Energy Consumption Patterns

Belize consumed 12,888 TJ (or 307,823 TOE) of total primary energy supply[17] from all fuel sources[18] in 2010, costing approximately $206 million US dollars[19] or about 14.4% of GDP[20]. This means that, on the basis of fuel energy content, **we produced more energy than we consumed:** 13,538 TJ versus 12,888 TJ.

The corresponding calculated aggregate energy intensity – that is, the economy-wide primary energy consumed per dollar of GDP – was 8,536 BTU per US dollar of GDP *in 2010 dollars*. For comparison, the estimated energy intensities of the USA, El Salvador, Jamaica and Barbados for 2008 were 7,523, 3,370, 8,555 and 3,360 BTU per US dollar of GDP *in 2005 dollars* respectively (EIA, 2008).

Of the total primary energy supply, 10,946 TJ (or 261,437 TOE) was actually delivered to consumption points as secondary energy (*Ref: Figure 2.1.5 below*). The difference reflects the losses incurred in generating, transmitting and distributing electricity[21].

[17] This is assessed in accordance with EIA convention. In particular, because imports and exports are, so far as any particular country is concerned, equivalent to increments (or decrements) in the primary energy available to it, they are treated as part of the total primary energy supply (TPES).

[18] 'fuel' and 'energy' are used interchangeably here: so imported electricity is a fuel.

[19] This cost does not include the cost of delivery of fuel or electricity to consumption points (within Belize).

[20] Using 2010 GDP of $1.431 billion USD (Belize GDP Data & Country Report, 2011).

[21]It was assumed that negligible losses incurred in distribution of other fuels with Belize.

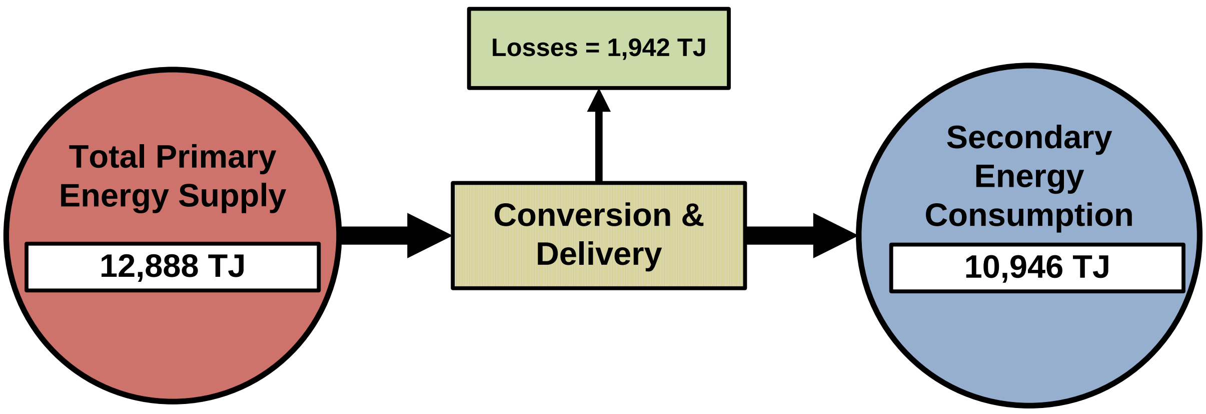

Figure 2.1.5: The TPES-to-Secondary Energy Consumption Pathway for Year 2010

Figure 2.1.6 below illustrates the breakdown of the secondary energy consumption by sector and - within each sector - by type of fuel for 2010, on the basis of the energy content of the fuels consumed.

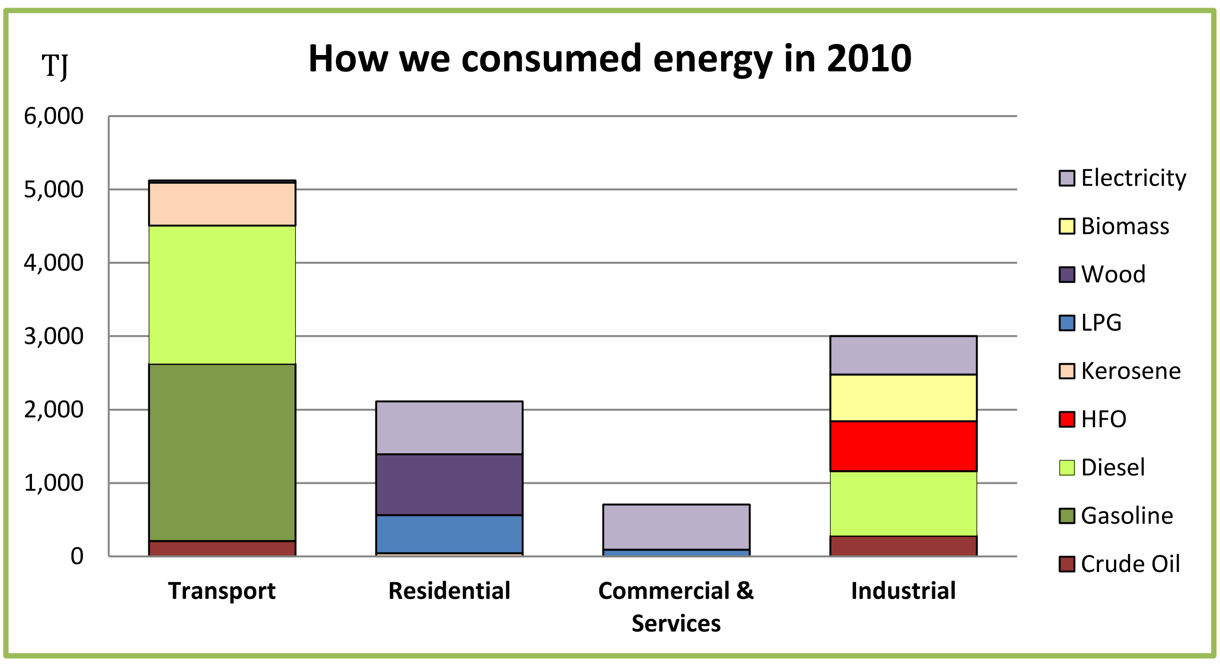

Figure 2.1.6: Secondary Energy Consumption by Sector and Fuel Type for Year 2010

The transportation sector was the biggest consumer of energy in 2010, accounting for 46.8% of total secondary energy consumption. Within this sector, gasoline accounted for 47% of all consumption; diesel for 36.9%; and kerosene (used as aviation fuel), crude oil[22] and LPG[23] for the remaining 16.1%[24].

The industrial sector consumed 27.43% of total secondary energy in 2010: 61.3% of this sector's consumption was due to the use of diesel, HFO and crude oil to run industrial motors and for steam generation; 21.3% was for the use of steam produced from

[22] Local crude oil is used as a substitute for diesel in certain heavy duty vehicles. The crude oil is usually left in drums for a time in order for impurities to settle, and then mixed with diesel in a 50:50 ratio.

[23] About 3% of the current gasoline vehicle stock has also been converted to run on LPG.

[24] Gasoline and diesel purchased in Mexico and Guatemala, and electricity used to charge golf carts in San Pedro and other locations in Belize are not accounted for in these calculations due to lack of data, although the amounts used should not significantly affect our results.

bagasse within the sugar industry; and the remaining 17.4% was due to the direct consumption of electricity.

The remaining 25.77% of total secondary energy consumption in 2010 was due to the residential and commercial & services sectors. Wood, used for cooking mainly in rural areas, accounted for 39.3% of residential energy consumption; while electricity and LPG accounted for 34% and 24.6% of residential energy consumption respectively. The main secondary fuel consumed by the commercial and services sector was electricity (about 87.3%).

GHG Emissions

Belize's energy sector as a whole produced 702,461 tCO2e of GHG emissions in 2010, at a rate of 56 tCO2e per TJ of primary energy supply. The electricity supply sub-sector produced GHG emissions at the lower rate of 52.74 tCO2e per TJ, mainly because of the higher proportion of low carbon energy sources in the supply mix; although this is partly offset by the high emissions rate of imported electricity[25].

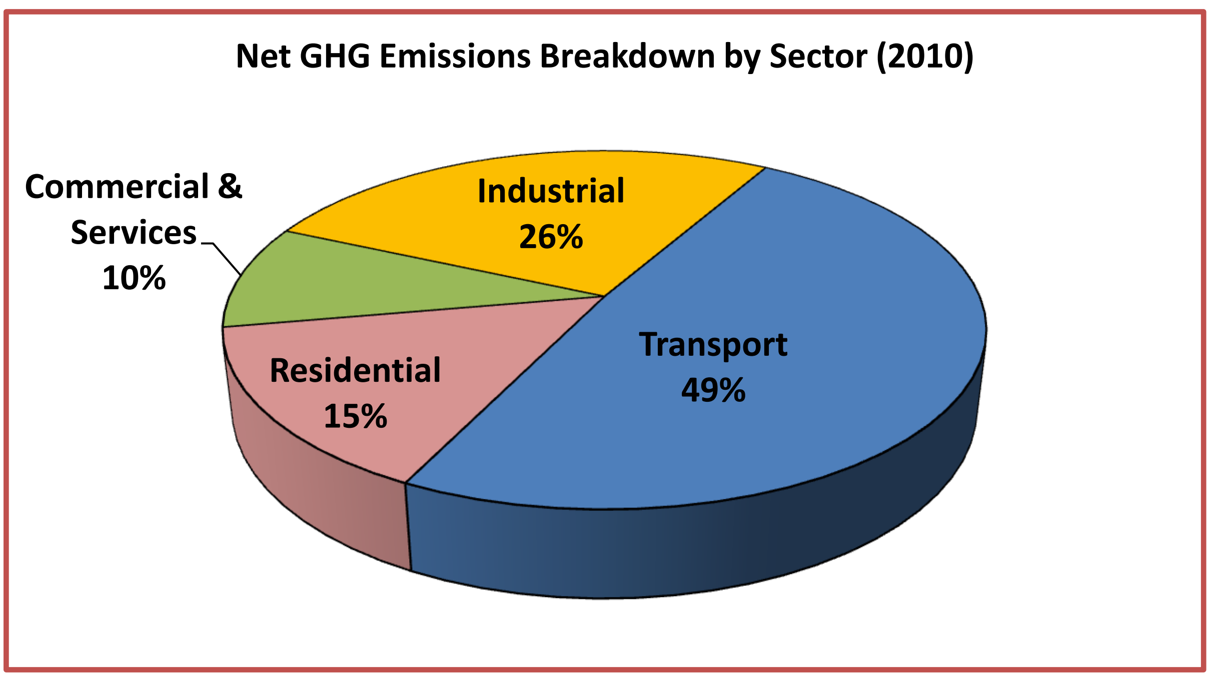

Figure 2.1.7: Net GHG Emissions by Sector for Year 2010

Overall, the transportation sector accounted for 49% of total net GHG emissions in 2010, although it consumed only 46.8% of total energy. This was mainly due to the fact that all the energy used in this sector was fossil fuel-based, compared with the other sectors that used biogenic renewable energy sources directly, or indirectly through electricity[26], to some degree or the other. At a price of $25.00 USD per tCO2e[27], the cost of energy

[25] The emissions rate of imported electricity is at least three times higher than that of any other source because it is assessed at the primary energy supply point (that is, where it enters our national borders).

[26] 81% of electricity supplied in 2010 is generated from renewable energy sources (measured at primary energy level).

[27] This was the nominal price chosen to reflect the cost of carbon in 2010.

sector emissions (the cost of carbon) in 2010 was over $17.5 million USD, or 7.86% of total energy cost *inclusive of the cost of carbon*.

3 WHAT ARE OUR ENERGY SUPPLY OPTIONS?

The purpose of this section is to look at the inventory of energy supply sources/fuels available to us in Belize, both indigenous and foreign-sourced, in order to assess the cost of converting these primary resources into secondary energy resources (again given current available technologies) and to estimate an upper limit for the potential of developable local primary resources, given available technologies.

Costs

Cost is a tricky quantity, as its assessment is always subject to interpretation given the context. In this case, we are assessing the (production) cost of converting primary energy resources into secondary energy resources that are then used directly by final consumers: for example, the cost of capturing solar energy (primary energy resource) and converting it into electricity (secondary energy resource) that is then used for lighting; or the cost of converting sugar cane (primary energy resource) into ethanol (secondary energy resource) that is then used to power a motor vehicle.

This production cost consists of four components:

1. The capital cost of developing plants to convert the primary energy resource into the secondary energy resource.
2. The cost of (supply of) the fuel used as the primary energy resource.
3. The operations and maintenance cost of running the plants. O&M costs also include the costs of preventing and cleaning up some level of environmental pollution; but do not include the cost of GHG emissions.
4. The market-based GHG emissions cost.

The production cost is finally expressed on a per-unit basis (e.g. per KWh of electricity produced) levelized over the life of the plant(s)[28].

"While the levelized cost of energy for *alternative energy* generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located), dispatch characteristics (e.g., baseload and/or dispatchable

[28] One of the difficulties encountered with coming up with true life cycle costs for any of the nascent renewable energy technologies is that reported costs from other countries in which the technologies have been deployed include subsidies and other financial incentives that can distort the picture. On the other hand, these incentives are generally meant to compensate for the historical tendency to exclude externalities, such as pollution, from the cost picture; thus enhancing the case for these cleaner, renewable technologies.

intermediate load vs. peaking or intermittent technologies), and contingencies such as carbon pricing." (Lazard, 2009)

Putting a Price on Carbon

"The market is in many ways an incredible institution. It allocates resources with an efficiency that no central planning body can match and it easily balances supply and demand. The market has some fundamental weaknesses, however. It does not incorporate into prices the indirect costs of producing goods. It does not value nature's services properly. And it does not respect the sustainable yield thresholds of natural systems. It also favors the near term over the long term, showing little concern for future generations." (Brown, Plan B 3.0: Mobilizing to Save Civilization, 2008)

When we emit carbon into the atmosphere beyond the natural flow of the carbon cycle, we impose a cost on future generations either to adapt to a diminished life style caused by global warming (hotter and more humid climates, acid rain, rising sea levels, more violent storms) or to develop innovative technologies for sequestering carbon from the atmosphere until GHG levels are returned to "normal" levels. If this cost is not reflected in the price of the products that are produced by processes that emit carbon into the atmosphere or in the price of products that emit carbon into the atmosphere when consumed, then these products will garner a larger share of the market than is justified by their "true cost" to society, and carbon pollution may well continue unabated.

One of the reasons that carbon pricing has met with much resistance - and why in fact the carbon pollution theory itself has met with some cynicism - is that the more serious effects of global warming on our way of life are projected to occur *too far* into the future: in the latter half of this century or even beyond. Developing countries, with their limited resources and who have had little to do with causing the global warming problem in the first place, have thus had little impetus to take action to cutback emissions. The CDM, though, is setup to reward countries that take action: a country earns money at the rate of the global carbon market price for each metric ton of GHG emissions avoided or removed relative to a pre-determined baseline. Given two options to supply energy, the only difference being that one will emit more GHG pollutants over its lifetime, we are now economically incented to choose the cleaner technology. Choosing the more polluting technology deprives us of earnings at the rate of the carbon price; and this deprivation must therefore be reflected as an added cost (to society) of using the technology itself.

Carbon dioxide and other GHGs are not the only form of environmental pollution affecting us: GHG pollution has probably garnered world-wide attention because of the threat to the way of life of developed countries! There are many other toxic chemicals such as particulate matter, carbon monoxide and mercury that are released into the

environment during the processing of energy that will cause serious illnesses and even death well before 2050. We also need to place a price on these: and we need to do it now.

Governments and parties with vested interests have adopted and proposed various measures for putting a price on carbon: explicitly through carbon taxes and emissions trading (cap-and-trade), and implicitly through emissions standards, best available technology targets, and subsidies. It is not our intention *at this point* to debate the relative merits of each of these measures; but rather to make an initial determination of a price point for carbon, so that we can factor it into our cost calculations and analyses, thus showing how putting even a modest price on carbon affects the relative cost rankings of the various energy supply-side options and demand-side measures available to us.

In his book, "Plan B 3.0 – Mobilizing to Save Civilization", Lester Brown, one of the world's pre-eminent green activists, recommends starting immediately with a carbon tax of $20 USD per ton (of GHG emissions) in 2008 and gradually increasing this to $240 USD per ton by 2020. This price would be $60 USD per metric ton today. Brown argues that this proposed tax regime is necessary to maintain carbon dioxide at environmentally sustainable levels, and moreover that it is not nearly as onerous as many other revenue-raising tax regimes on fossil fuels that are currently in place in Europe. The 2010 Report "Caribbean Regional Electricity Generation, Interconnection, and Fuels Supply Strategy" prepared by *Nexant* consulting firm used a price of $50 USD per metric ton: no explanation was given for how they arrived at this price. Barclays Capital, a world-renown investment firm, recently forecasted a 2012 price for CERs of about $33.00 USD per metric ton. We have decided to conservatively start with a reference price of $25 USD per metric ton (from 2010), and to increase this price by 7% per year over the planning horizon, as shown in Figure 3.1.0 below. This is equivalent to a constant price of $50.00 USD at 10% real discount rate over the planning horizon.

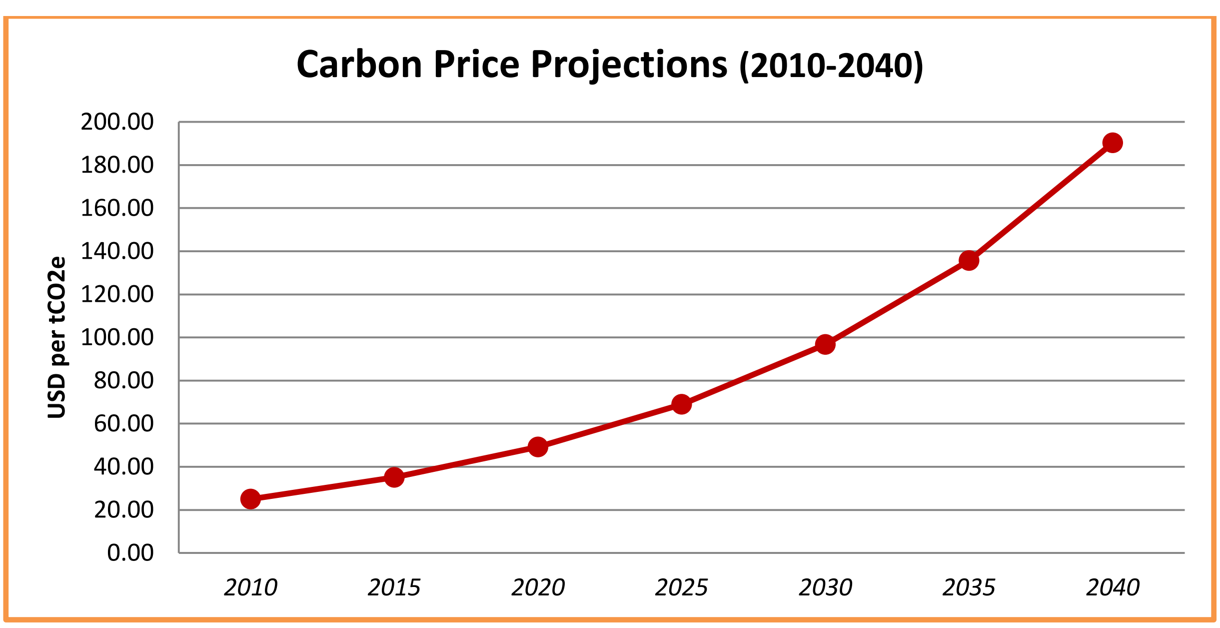

Figure 3.1.0: Carbon Price Projections for the Period 2010-2040

Supply Potential

For each of the indigenous sources, we further assess its full developable potential in terms of KWh of energy producible per year and over the lifetime of the source (if exhaustible).

As we assess each resource, we should keep in mind that the current annual demand for utility-provided electricity in Belize is approximately 485,000 MWhs, and current demand for all energy forms, including electricity and transport fuels, is approximately 12,849 TJ. These should serve as reference points for determining what portion of energy needs can potentially be supplied from the resource.

INDIGENOUS RENEWABLE ENERGY SOURCES

Wind Energy

State of the Technology

Wind is an infinite and abundant source of energy, with a near-zero GHG emissions footprint. Energy from the wind has been harnessed from ancient times to sail ships across the oceans and from pre-industrial times to pump water and mill grains. Today, the focus on wind energy is for the production of electricity.

"The gross (wind) energy production potential from (Belize's) offshore areas with moderate-to-excellent wind resource … is over 140 times our current electricity demand, and sufficient to meet the projected electricity needs of the entire Central American region (excluding Mexico) for the next 10 years."

However, there are two significant challenges to harnessing the full potential of wind energy for electricity production: its intensity (speed) varies widely across (the time of) the day; and the windiest locations tend to occur in the deep offshore areas and on land at higher elevations, which are usually far removed from the main load centers.

Moreover, when assessing wind energy potential, we need to do separate assessments for onshore and offshore wind energy. As the names suggest, onshore wind energy is harnessed from wind blowing over land; offshore wind energy is harnessed from wind blowing over the sea. The latter presents significant engineering challenges during deployment and maintenance – and substantial R&D efforts continue to be dedicated to finding ways to overcome these challenges. But although more complex and hence more costly to deploy and maintain, offshore wind power installations have a number of key advantages over onshore installations. Firstly, wind is more abundant and stable over the sea. Secondly, larger wind turbines – which tend to be more efficient - can be deployed (in shallow) offshore more easily than onshore. Thirdly, onshore installations are more likely to meet with public resistance because of noise, visual impact and displacement/right-of-way issues.

The technologies for producing energy from the wind rely on very basic principles that convert the kinetic energy of the wind into the rotational energy of a turbine that in turn generates electricity. These technologies are now fairly mature and have been deployed widely around the world. The IEA (IEA, 2011) reports that global installed capacity of onshore and offshore wind has been growing at an average rate of around 30% per year since 2000; reaching 121 GW in 2008. Wind energy in 2008 generated about 260 million MWhs of electricity. However, although wind energy comprised 20% of total electricity consumed in 2008 in Denmark, the undisputed world leader in wind energy deployment, it only accounted for 2% of total electricity consumption in the USA.

The power that can be generated from the wind at a particular point in time is directly proportional to the cube of the wind speed at that point in time; but also increases with the rotor diameter of the wind turbines, the height of the turbines above ground and the roughness of the terrain surrounding the wind plant. Theoretically therefore, if, at a certain point in time, the wind speed in a location A is twice that of the wind speed in another location B, then the power output of a wind turbine at location A will be 8 times as much as the power output at location B. Generally speaking, locations with higher wind speeds are therefore more viable for wind development than those with lower wind speeds. In practice, wind turbines are optimized for certain speeds; moreover, they have a cutoff speed range below and above which they shut down. Reliable wind measurements at selected sites are therefore important in order to size turbines for optimal performance.

Wind resources are categorized into seven classes depending on the wind speed and the height of the installation relative to sea level as shown in Table 3.1.1 below.

	10 m (33 ft)		**50 m (164 ft)**	
Wind Class	WPD (W/m^2)	Speed in m/s (mph)	WPD (W/m^2)	Speed in m/s (mph)
1	0 - 100	0 - 4.4 (9.8)	0 - 200	0 - 5.6 (12.5)
2	100 - 150	4.4 (9.8) - 5.1 (11.5)	200 - 300	5.6 (12.5) - 6.4 (14.3)
3	150 - 200	5.1 (11.5) - 5.6 (12.5)	300 - 400	6.4 (14.3) - 7.0 (15.7)
4	200 - 250	5.6 (12.5) - 6.0 (13.4)	400 - 500	7.0 (15.7) - 7.5 (16.8)
5	250 - 300	6.0 (13.4) - 6.4 (14.3)	500 - 600	7.5 (16.8) - 8.0 (17.9)
6	300 - 400	6.4 (14.3) - 7 (15.7)	600 - 800	8.0 (17.9) - 8.8 (19.7)

7	400 - 1,000	7 (15.7) - 9.4 (21)	800 - 2,000	8.8 (19.7) - 11.9 (26.6)

Table 3.1.1: Classes of Wind Power Density (WPD) at Heights of 10 m and 50 m [Source: EIA]

The lowest class (Class 1) has the lowest wind speed and the least energy output per unit land area; the highest class (Class 7) has the highest wind speed and the greatest output per unit land area.

Environmental Benefits/Costs

A typical wind-powered plant emits 0.021 tCO2e GHG per MWh of electricity generated (Wikipedia: Emissions Intensity, 2011). Since this is substantially lower than the current grid GHG emission rate of 0.289 tCO2e GHG per MWh, introducing a wind-powered plant into the supply mix would further lower the grid GHG emission rate.

CDM EARNINGS TRACKER

A 10 MW wind-powered plant would generate 10 MW x 30% capacity factor x 8,760 hours = 26,280 MWhs of electricity per year. Over a ten-year project evaluation period and using the current grid emission rate as the baseline, this would yield 10 x 26,280 x (0.289 – 0.021) = 73,058 CERs. At a price of $25 USD per CER, these can be traded in for $1,826,145 USD (*undiscounted value*): about 10.5% of the initial capital cost of the project (@ $1.7 million USD per MW of installed capacity).

A much-touted disadvantage attributed to wind power generation by some of the more extreme environmentalists is that windmills kill significant amounts of birds. However, data collected in various countries that use wind turbines for energy generation show that the environmental hype is not well supported by the facts: windmills do much less damage to birds than ordinary vehicular traffic. Reported collision rates – between turbines and birds – have been usually low where proper pre-construction investigations are carried out as part of environmental impact assessments to ensure that wind farms are not sited close to the habitats of nesting birds (MacKay, 2009).

Resource Availability and Utility-scale Supply Potential: Onshore Wind

According to the US DOE's National Renewable Energy Laboratory (NREL), Belize has approximately 737 square kilometers (or 284.5 square miles) of onshore terrain with moderate-to-excellent wind resource - that is, Class 3 or higher – distributed as shown in the table below.

This works out to a gross energy production potential of 7,641,580 MWhs from terrain with moderate-to-excellent wind resource at 50 metres above sea level. Most of this windy terrain occurs in the Maya Mountain Range and the northern cayes. If we assume that 80% of this land area is already being used or earmarked for other purposes or is altogether inaccessible or is unusable for wind power generation purposes, then the gross energy production potential of the usable land area is 1,528,316 MWhs.

Wind Class	Terrain area[29] (in sq. km)	Annual Energy Production Potential[30] (MWh per sq. km)	Total Annual Energy Production Potential (MWh)
3	497	9,500	4,721,500
4	234	12,100	2,831,400
5	6	14,780	88,680
6	0	0	0
7	0	0	0
ALL	737		7,641,580

Table 3.1.2: Onshore Energy Production Potential for Wind Class 3 & higher at 50 m above sea level

Assuming a conservative availability factor of 90%, the net energy production from *onshore wind* generation from terrain with moderate-to-excellent wind resource, using today's technologies, is therefore approximately 90% x 1,528,316 MWhs = 1,375,484 MWhs of electricity per year. This is just under 3 times our current annual utility-provided electricity consumption rate.

Resource Availability and Utility-scale Supply Potential: Offshore Wind

According to the NREL wind resource maps, Belize also has approximately 3,500[31] square miles of offshore marine water area with moderate-to-excellent wind resource up to 70 miles off the coastline: this includes about 800[32] square miles of shallow[33] marine area with Class 3 wind resource between the coast and the barrier reef, and 900[34] square miles of marine area with Class 4 wind resource beyond the barrier reef.

This works out to a gross energy production potential of 69,087,590 MWhs (per year) from offshore areas with moderate-to-excellent wind resource at 80 metres above sea level. To put this figure in perspective: this is over 140 times our current electricity demand; and sufficient to meet the projected electricity needs of the entire Central American region, excluding Mexico, for the next 10 years[35]. Of this total amount, the shallow offshore marine area has a gross energy production potential of 14,752,500 MWhs. If we assume that 10% of the shallow marine area can be used for wind power

[29] Terrain areas as provided by the NREL's "Central America Wind Resource Mapping Activity" Report (NREL).

[30] Refer to **Appendix A** for basis of derivation of these numbers.

[31] Approximate measurement derived from Central America wind resource map (NREL).

[32] Ibid.

[33] Shallow offshore for wind energy development purposes is water of depth of less than 30 m (MacKay, 2009). The marine waters between the coast and the Belize Barrier Reef, from the North going southwards to Belize City, are at most 6 m in depth (UNEP, 2009).

[34] Approximate measurement derived from Central America wind resource map (NREL).

[35] The 2020 electricity demand forecast for all of Central America *excluding* Mexico is 67,557,000 MWh (WEC, 2008).

generation, then the gross energy production potential of the usable shallow offshore area is 1,475,250 MWhs per year.

Wind Class	Terrain area (in sq. km)	Annual Energy Production Potential[36] (MWh per sq. km)	Total Annual Energy Production (MWh)
3	6,734	7,120	47,945,622
4	2,331	9,070	21,141,968
5	0	0	0
6	0	0	0
7	0	0	0
ALL	9,065		69,087,590

Table 3.1.3: Offshore Energy Production Potential for Wind Class 3 & higher at 80 m above sea level

Assuming an availability factor of 80% for shallow offshore, the net energy production from shallow *offshore wind* generation, using today's technologies, is therefore approximately 80% x 1,475,250 MWhs = 1,180,200 MWhs of electricity per year. This is over 2 times our current annual utility-provided electricity consumption rate.

If wind energy could be stored with negligible losses and the cost of wind energy plus storage were competitive with other forms of energy, we would be able to meet <u>ALL of our electricity needs from utility-scale onshore and shallow offshore wind energy alone for the next 20 years (assuming a 5.5% growth rate)</u>, using the today's technologies and allocating less than 0.7% of our total land area and less than 3% of our total shallow offshore marine waters to its production.

There is an important caveat that should be inserted here: the potential of energy generation from wind is site-specific, and detailed wind measurements over sufficiently long periods must be done at selected candidate sites in order to come up with more accurate assessments of the feasibility of deploying wind-powered plants at those sites.

Production Costs

According to a 2008 Conference Paper titled 'Wind Energy in Latin America' (Blanco, 2008), the average cost of producing one KWh of gross energy from *onshore wind* in the Latin American and Caribbean region ranges between $0.03 - $0.05 USD per KWh for good onshore sites with low surface roughness and capacity factors greater than 35%[37]. The IEA estimates much higher onshore wind power costs: currently between $0.07 to $0.13 USD per KWh (IEA Technology Roadmap- Wind Energy, 2011). Our calculations give a figure of $0.0895 USD per KWh for a nominal 10 MW onshore wind plant with a

[36] Refer to **Appendix A** for basis of derivation of these numbers.

[37] This estimate appears to be very optimistic: in a Brazilian energy auction in 2009, the average cost for wind power actually contracted was about $0.083 USD per KWh (Yepez-García, Johnson, & Andrés, 2010).

capacity factor of 30%, assuming installation costs of $1,700 USD per KW. The US DOE projects a reduction of 10% in onshore wind LCOE by 2030.

> The cost of wind energy from a particular plant is extremely sensitive to the capacity factor achievable. The capacity factor (expressed as a percentage) is calculated as the actual annual energy output of the plant divided by the maximum annual energy output (that is, the annual energy output if it were running at maximum capacity 100% of the time). As explained further above, wind is an intermittent energy source: the wind speed, and hence the power derivable from the wind, at any time varies widely across the time of the day. This means that there will be times – actually many times – when the wind plant is not running at its maximum capacity. Moreover, if the maximum capacity of the wind plant is greater than the demand during certain periods of the day, then there may be times when all the power derivable from the wind plant cannot be absorbed by the grid. In such cases, not all the wind power that is available will be used, unless it can be stored for later use.
>
> In general therefore, assuming well-planned staging of wind farms so that capacity maintains pace with demand, most utility-scale wind plants that are deployed around the world have capacity factors in the range of 20 to 40%. Although data for the Caribbean available from wind energy installations in Curacao and Jamaica indicate that a 35% capacity factor is achievable, a safer assumption would be a capacity factor of 30% for onshore installations in Belize.

The cost per KW of *offshore wind* power installations can be more than twice the cost of onshore wind power installations: this is because of the higher foundation and cabling costs which increase with distance from the shore (IEA Technology Roadmap- Wind Energy, 2011). Moreover, the O&M cost as a percentage of the turbine cost is usually higher because offshore wind turbines are exposed to high concentrations of salt in the air and therefore deteriorate more quickly and it costs more to do maintenance work in the middle of the sea than on land. Though the higher capital and O&M costs are partially offset by the higher yields of *offshore wind* installations, in general, a KWh of *offshore wind* energy costs 1.5 to 2 times the cost of a KWh of *onshore wind* energy. The IEA reports that the LCOE for offshore wind projects developed between 2005 and 2008 ranged between $0.11 and $0.13 USD per KWh (IEA Technology Roadmap- Wind Energy, 2011). These costs are projected to fall by 25% by 2030[38].

The IEA Technology Roadmap – Wind Energy 2011 estimates that the wind turbine itself constitutes 75% of the initial capital cost of a wind power project for onshore wind, and 50% for offshore wind[39]. O&M cost is shared 50:50 between replacement parts, materials and labor (Morthorst, 2004). If we make the fair assumption that almost all materials and 50% of labor cost used in O&M will be foreign-sourced, then 75% of the O&M cost flows out of the country. On average therefore, about 80% of the cost of generating onshore wind will flow out of our country to pay foreign sources.

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[38] Based on IEA projections that investment costs will decrease by 27% and O&M costs by 25% by 2030.

[39] A 2004 Report 'Wind Energy – The Facts ' estimates that approximately 80% of the initial capital cost of a wind power project is the cost of the wind turbine itself (Morthorst, 2004).

The 2009 Report 'Managing Variability' (Milborrow, 2009) found that the additional cost [40] incurred in integrating wind resources power into supply networks is negligible if the energy supplied by the resource is less than 20% of the total network supply. Table 3.1.4 below provides a summary of the extra costs[41] of integration for different wind penetration levels.

Wind Penetration Level	Lower Level Cost	Upper Level Cost
10%		1.50 USD per MWh
20%	2.25 USD per MWh	3.00 USD per MWh
40%	7.50 USD per MWh	10.50 USD per MWh

Table 3.1.4.1: Summary of Costs of Integration for Different Wind Penetration Levels

Onshore wind with backup firm capacity, assuming a 20% penetration level, therefore currently costs in the range of $0.112 to $0.1195 USD per KWh.

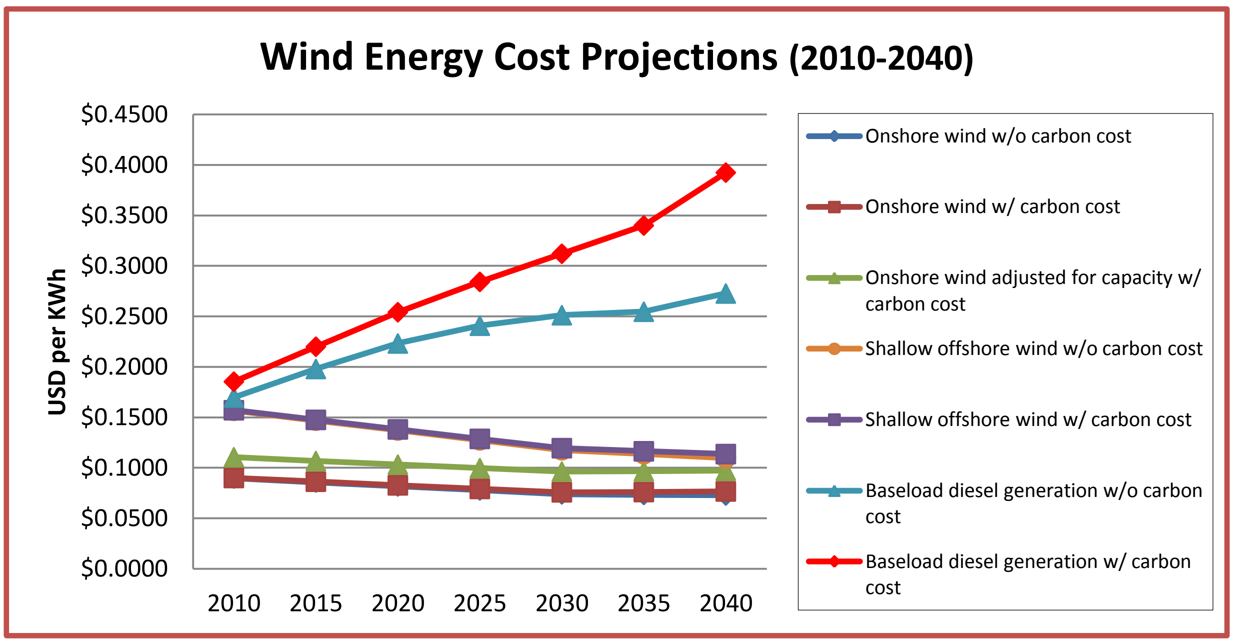

Figure 3.1.5.1: Cost Projections for Wind-Powered vs. Diesel Electricity Generation for 2010-2040

Figure 3.1.5.1 above compares the projected trends in the cost of onshore and shallow offshore wind generation with baseload diesel generation costs over the forecast horizon.

The graphs show that both onshore and shallow offshore wind generation – including onshore wind generation adjusted to provide for firm capacity - will cost less than baseload diesel generation throughout the forecast period, and the cost differential should increase as diesel fuel costs trend upwards over the long run.

[40] This includes the cost of short-term system balancing, backup capacity costs and transmission constraint costs. The latter refers to costs that are incurred when the output of the wind plant is constrained by the capacity of the transmission line connecting it to the grid.

[41] The costs quoted are however based on petroleum prices in 2009.

Solar Energy

State of the Technology

Solar energy is the most abundant energy resource on earth. In fact, if all the energy reaching the earth from the sun could be captured, we would have sufficient energy to serve all our energy needs more than 5,000 times over at current consumption rates! Moreover, like Wind, energy from the Sun has a near-zero GHG emissions footprint.

Figure 3.1.5: A 10 MW Solar Farm Project near Barstow, California (Nexant, 2010)

However, there are some challenges associated with harnessing the vast power of the sun: sunshine is only available during daylight hours; its intensity varies across (the time of) the day; and the amount of sunshine is affected by the degree of cloud cover and other obstructions at any time of the day.

There are two main utility-scale technologies for harnessing the energy of the Sun: solar photovoltaic (PV), and concentrating solar power (CSP).

Solar PV technologies convert sunlight (the light of the sun) into electricity. Solar PV panels are made of semi-conductor material that absorb sunlight and create an electric field that drives electricity through the connected circuit. Some versions of solar PV, called crystalline silicon PV (c-Si), use silicon-based semi-conductors that convert about 12-20% of the energy of the sun into electricity. C-Si PV accounts for 85-90% of the global solar PV market today (IEA - Solar PV Roadmap, 2011). Newer thin-film semiconductors, made of cadmium-telluride and copper indium diselenide , have lower conversion efficiencies, but are much cheaper to make[42]; and, as a result, installations using thin-film PV have lower life cycle costs – about 20% less - for the same output.

[42] This is because of the low consumption of raw materials, higher production efficiency and ease of building integration (IEA, 2011).

Concentrator PV (CPV) is an emerging PV technology that concentrates sunlight on a small high efficiency cell[43].

Figure 3.1.6: (a) The Nellis Solar PV Plant in Nevada, USA (b) A CSP Parabolic Trough Solar Farm

Concentrating Solar Power (CSP) is a class of technologies that concentrates the sun's energy to heat a receiver; the heat collected is then transformed into steam to drive steam turbines for electricity generation or to drive chemical processes. CSP is best deployed in regions with plenty of sunshine (average DNI above 2000 KWh/m^2/year) and clear skies[44]. There are four main types of CSP technologies, categorized by the way they track and focus the sun's rays and whether the receiver is fixed or mobile: parabolic troughs (the most mature of the technologies), parabolic dishes, linear fresnel collectors and solar towers. CSP for electricity generation is used mainly in large-scale applications of 100 MW to 300 MW.

CSP plants have the significant advantage – over their PV counterparts and other non-dispatchable renewable energy technologies – of being able to provide relatively cheap short-term thermal energy storage (TES)[45], and so smooth variability of supply especially during periods of reduced sunlight caused by cloud cover (NREL: The Value of Concentrating Solar Power and Thermal Energy Storage, February 2010).

Environmental Benefits/Costs

Utility-scale Solar PV plants emit 0.106 tCO2e GHG per MWh of electricity generated; while a typical solar-powered CSP plant emits 0.04 tCO2e GHG per MWh of electricity generated (Wikipedia: Emissions Intensity, 2011)[46]. Both of these are lower than the

[43] Solar-to-electric AC efficiencies of 23% have already been demonstrated in tests. IEA forecasts that AC efficiencies of over 30% can be reached in the medium term (IEA, 2011).

[44] That is in regions located between 15 to 40 degrees latitude north or south of the equator (IEA, 2011).

[45] Because CSP receivers first generate heat that is then converted into electricity (and do not generate electricity directly as do Solar PV modules), they can store excess heat - by heating molten salts for instance - that can be converted to electricity at a later time. While this feature may increase upfront investment costs and result in some efficiency losses during the storage cycle, its main benefit is that it improves the firm capacity and hence the dispatchability of the plant (IEA, 2011).

[46] These figures need to be verified by further research.

current grid GHG emission rate of 0.289 tCO2e GHG per MWh. So introducing a Solar PV farm or a CSP plant into the supply mix would further lower the grid GHG emission rate.

However, solar technology is not without its environmental and safety drawbacks, namely: the high water footprint of CSP due to steam production (Lesser & Puga, 2008), the depletion of rare minerals used in PV manufacturing, the dangers inherent in handling gases used for surface treatment of thin films, and the toxicity of some semiconductor components (GCEP, Stanford University, 2006). These issues may take on greater significance - and hence will need to be resolved - as the other more pressing problems related to GHG emissions subside in step with reduction in fossil fuel use.

Resource Availability and Utility-scale Supply Potential

According to the NREL solar map for Central America, about 65% of Belize's land area receives 5.0 to 5.5 KWh per square meter of sunshine[47] per day. This is below the lower level threshold generally required for CSP solar plants, and so Solar CSP is probably not well suited for Belize. If we assume that this solar irradiation is converted to electricity using Solar PV technologies[48] with an average conversion efficiency of 16%, this works out to a gross energy potential of 5.25 KWh/m^2/day x 65% of land area x 23,000,000, 000 m^2 x 365 days x 16% conversion sunlight-to-DC electricity efficiency x 75% DC-to-AC conversion efficiency = 3,437,750,000 MWhs per year. Again, to put this figure in perspective, this is sufficient to meet the projected electricity needs of the entire Central American region, *including* Mexico, for the next 50 years at current growth rates[49].

"(The) gross energy production potential (of Belize's solar energy resource) … is sufficient to meet the projected electricity needs of the entire Central American region, *including* Mexico, for the next 50 years at current growth rates."

If we *very conservatively* assume that only 1% of this land area is available and amenable for solar generation, then the possible annual energy output from *solar* generation, using today's technologies, is therefore equal 1% x 3,437,750,000 MWhs = 34,377,500 MWhs per year. Using an availability factor of 95%[50], the net energy potential is 95% x 34,377,500 = 32,658,625 MWhs. **The exact amount of land area**

[47] Solar irradiation – Flat plate tilted at latitude (south facing)

[48] Solar PV is used here instead of Solar CSP, because CSP requires clear skies and average DNI above 2000 KWh/m^2/ year. The solar map shows few of such areas, if any, in Belize.

[49] Central America's electricity consumption in 2010 was approx. 253,000,000 MWh (Mexico: 210,000,000 and the rest of CA: 43,000,000). At growth rates of 5.5% per year, it would take 49 years for this number to increase to 3,437,750,000 MWh.

[50] This is in keeping with the availability factors used in most of the literature (roughly 97-98%).

available and amenable for *solar generation* needs to be determined in a further and separate study.

This means that if solar energy could be stored with negligible losses and the cost of solar energy plus storage were competitive with other forms of energy, we would be able to meet <u>ALL our electricity needs using utility-scale solar energy alone for the next eighty years[51]</u>, using the today's technologies and allocating less than 0.7% of our total land area to its production.

Production Costs

Despite many years of research and development, solar power has not yet become cost-competitive with other technologies in the energy market; mainly because of its higher capital costs, modest conversion efficiencies, and intermittency. The current cost[52] per KWh of electricity from utility-scale solar PV is about USD $0.32 per KWh: ranging from USD$0.24 per KWh for sites with high DNI to $0.48 per KWh for sites with moderate-to-low DNI (IEA - Solar PV Roadmap, 2011). Solar CSP currently costs between USD$0.20 per KWh and $0.295 per KWh for large parabolic trough plants (IEA, 2011).

However, advances in solar conversion technologies continue to be made as developed countries allocate more monies to research and development in alternative energy in face of the shrinking oil supplies and the ill-effects associated with fossil fuel combustion. The IEA Solar PV Roadmap 2011 projects the efficiency of solar crystalline PV to increase from 16% today to 25% in 2030. Newer thin film technologies are projected to increase from an average of 10% today to 16.5% by 2030.

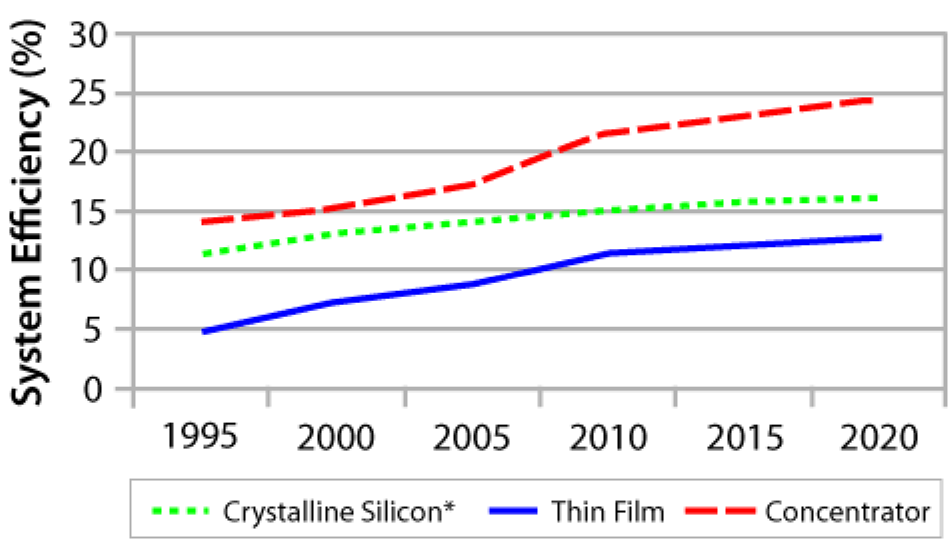

Figure 3.1.7: Projections of Conversion Efficiency of Main Solar PV Energy Technologies (Source: EERE, 2007)

Of particular significance is the recent involvement of China and Taiwan in the solar PV market: China's solar PV market has grown rapidly, experiencing a twenty-fold increase

[51] Current utility-scale electricity generation is 485,000 MWhs. At growth rates of 5.5% per year, it would take 79 years for this number to increase to 32,658,625 MWhs.

[52] 2008 Costs

in capacity in just four years; China and Taiwan together now produce more than 50% of both crystalline silicon cells and modules, with China now leading the world in PV cell exports (Melbourne Energy Institute, 2011). Further innovations – coupled with economies of scale and learning curve effects[53] - are expected to drive down unit capital costs of solar PV conversion technologies to about 60-70% of current levels over the next 10 years, leading to further reductions in life cycle costs (*See figure below*).

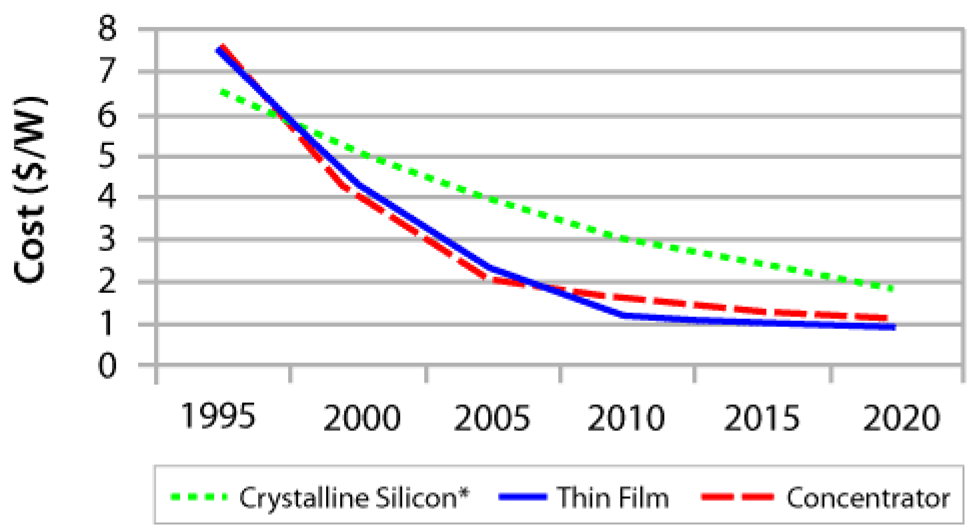

Figure 3.1.8: Unit Capital Cost Projections of Main Solar PV Energy Technologies (Source: EERE, 2007)

The IEA projects that the levelized cost of Solar PV will decrease to a median of $0.14 USD per KWh (in the range $0.105 - $0.210 per KWh) by 2020 and a median of $0.09 USD per KWh (in the range $0.070 - $0.135 per KWh) by 2030 (IEA - Solar PV Roadmap, 2011).

The projections for cost reductions for CSP plants for the period up to 2050 are given below:

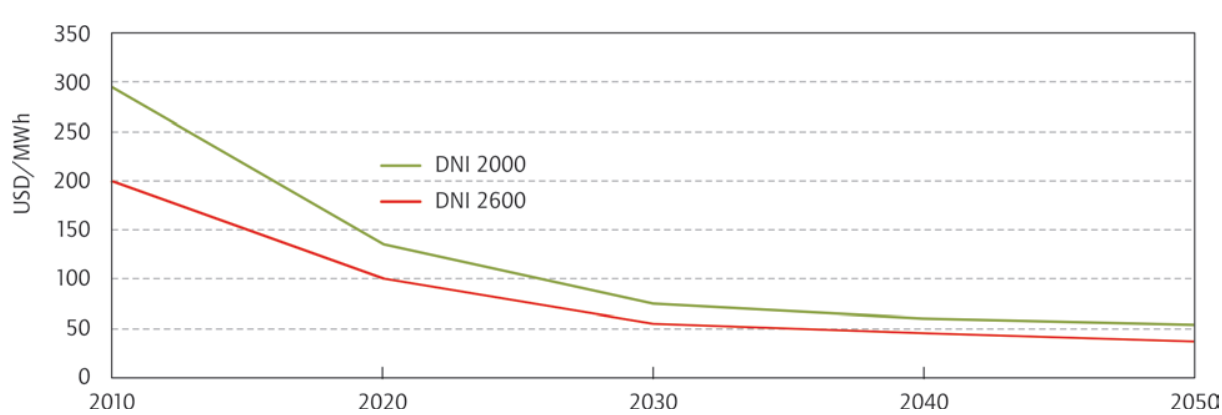

Figure 3.1.9: Projected LCOE from CSP plants under different DNI levels (IEA, 2011)

***Lazard's Levelized Cost of Energy Analysis 3.0*[54] found that while Solar PV technologies have the "potential for significant cost reductions", other conventional energy**

[53] (Borenstein, 2008) argues however that analysis of historical cost and production data over the past 30 years has revealed that learning-by-doing effects on solar PV production costs have been relatively small.

[54] (Lazard, 2009)

generation technologies are experiencing cost inflation. An important trend to track therefore is the path of solar energy to achieving *grid parity*; that is, when its cost will be at least as cheap as the average cost of other sources of supply available to Belize. Predictions abound as to when this will be achieved in developed countries, with most expecting this to happen within the next 10 years (it has already happened in Hawaii and Italy), especially given the upward trend in the price of fossil fuels and the increasing pressures to drastically reduce harmful emissions associated with their use. Given that the capital cost of the solar panels themselves constitute over 90% of the levelized cost of solar energy and assuming continuous improvement along the current technology path, the cost of solar in developing countries like Belize should track closely with those in developed countries.

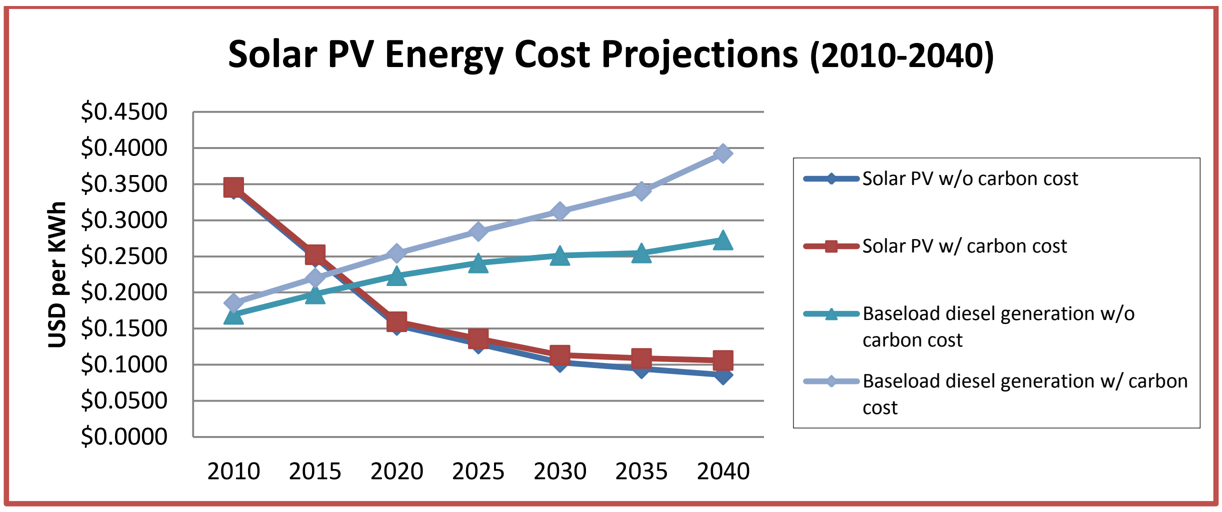

Figure 3.1.9.1: Cost Projections for Solar PV vs. Diesel Electricity Generation for 2010-2040

Figure 3.1.9.1 above compares the projected trends in the cost of solar PV electricity generation with baseload diesel generation costs over the forecast period over the forecast horizon: Solar PV costs are projected to remain higher than diesel electricity generation costs until 2015, and then after should continue to fall even further to as low as 1/3rd of diesel electricity costs by 2040.

Hydro-electricity

State of the Technology

Hydro is the most mature of the renewable energy technologies deployed worldwide: in fact, it was the first renewable energy technology to be deployed on any significant scale in Belize, when the 18 MW Mollejon Hydroelectric Plant was built on the Macal River and commissioned in 1995.

One of the advantages of hydroelectric power is that electrical energy can be stored (as pent-up water in reservoirs) when the energy obtainable from the water flow exceeds the demand, and released when demand increases or as required.

There are three general types of hydro-electric plants:

a) *Run-of-the-river Hydro Plants*: The power output at any time is solely dependent on the current amount of flow and natural "head" in the river

b) *Reservoir Hydro Plants*: These use reservoirs (or dams) to store excess water that is released as needed to produce energy. Reservoir Hydro plants therefore tend to have a higher firm capacity and hence higher capacity factors than run-of-the-river plants. However, the additional cost of the reservoir makes storage plants significantly more costly to build.

c) *Pumped Storage Hydro Plants*: Like Reservoir Hydro Plants, these use reservoirs (or dams) to store water. In addition, however, water released downstream of the reservoir can be pumped back into the reservoir (for later use) when excess energy is available from other sources.

Hydro plants are also categorized, according to their maximum power producible, into: large hydro (> 50 MW), medium hydro (10 MW – 50 MW), small hydro (1 MW – 10 MW), mini hydro (100 KW – 1 MW), micro hydro (10 KW - 100 KW), and pico hydro (10 KW or less). As a general rule, medium and large hydro plants usually feature a reservoir or storage facility, while smaller hydro plants are usually run-of-the-river types.

Environmental Benefits/Costs

Like the Wind and the Sun, Hydro has a near-zero GHG emissions footprint Hydro: about 0.015 tCO2e GHG per MWh of electricity generated (Wikipedia: Emissions Intensity, 2011). This is lower than the current grid GHG emission rate of 0.289 tCO2e GHG per MWh; so introducing another hydro plant into the supply mix would further lower the grid GHG emission rate.

CDM EARNINGS TRACKER

A 5 MW run-of-the-river hydro plant would generate 5 MW x 40% capacity factor x 8,760 hours = 17,520 MWhs of electricity per year.

Over a ten-year project evaluation period and using the current grid emission rate as the baseline, this would yield 10 x 17,520 x (0.289 – 0.015) = 48,005 CERs. At a price of $25 USD per CER, these can be traded in for $1,200,120 USD (*undiscounted value*): about 12% of the initial cost of the project (@ $2 million USD per MW of installed capacity).

However, some Hydro plants, especially those that use storage reservoirs and constrain the natural flow of the river, are considered environmental hazards as the build-up of water behind the dams destroys some terrestrial habitats, whilst the uneven flow downstream of the dam destroys both terrestrial and marine habitats.

The latter issue has been at the heart of numerous, well-publicized public and legal disputes between hydro developers and various interest groups and environmentalists both locally and abroad. The Chalillo Project was delayed by nearly two years mainly because of vigorous opposition from environmental NGOs.

Resource Availability and Utility-scale Supply Potential

In 1990, a comprehensive study of Belize's hydro-electric power potential was commissioned by BEL, and conducted by CIPower, a Canadian consultancy firm. At that time, the consultants found that Belize had approximately 70 MW of developable hydro potential, capable of yielding 330,000 MWh of annual energy, throughout 12 sites countrywide: 60 MW of the total potential was located on the Macal River.

To date, just over 50 MW of hydropower has been developed on the Macal River (in the Cayo District) in a cascading scheme format: the 7 MW Chalillo Hydro Plant, the 25.2 MW Mollejon Hydro Plant, and the 18 MW Vaca Plant. The Chalillo Hydro Plant has a reservoir with a storage capacity of 120 million cubic meters (of water); the Mollejon and Vaca Hydro Plants have minimal storage capacity (approximately one million cubic meters each) [55]. An additional 3.2 MW run-of-the-river hydro plant, Hydro Maya, was also built on the Rio Grande ('Big River') in the Toledo District. Together, all four hydro plants generated 263,500 MWh of electricity in 2010.

Figure 3.1.10: The Chalillo Hydro Plant is part of a 50 MW cascading scheme on the Macal River in Belize

The remaining sites, screened in the 1990 CIPower Report, that have not yet been developed include: Rubber Camp (15 MW), Swasey Branch (3 MW), South Stann Creek (2 MW), Bladen Branch (2 MW), and Rio On (0.6 MW). However, a hydro project at Rubber Camp is no longer possible because its potential output has been substantially reduced as a result of the development of Chalillo; and in any case it would likely have faced similar environmental concerns brought to the fore during the protracted debates over the construction of Chalillo.

[55] Based on data provided by Mr. Joseph Sukhnandan, former Vice President of Energy Supply at BEL.

In 2006, an updated inventory of Belize's hydro-electric potential was carried out by a Finland-based firm Electro-watt Ekono on behalf of BECOL. The study identified a further four projects with good potential for development in addition to other sites named in the CIPower Report: upgrading the Chalillo Plant with an additional 16 MW of capacity by utilizing the unused head between the Chalillo Plant and the Mollejon water intake point; an 8.4 MW cascading scheme on the lower Macal River downstream of the current Vaca Falls Plant; a 15-20 MW cascading scheme of low-head power plants along the Mopan River; and a possible large-scale project at the Chiquibul site near the border with Guatemala with similar project characteristics to the existing cascading scheme on the Macal River[56]. The total undeveloped hydro potential (for small, medium and large hydro plants) of Belize is therefore estimated to be in the region of 75 to 100 MW[57].

Assuming that the full remaining hydro potential is approximately 75 MW with a conservative capacity factor of 40%[58], the usable energy potential of currently undeveloped hydro generation is approximately = 75 x 40% x 8760 = 262,800 MWHs per year. Adding this to the 263,500 MWHs generated from Mollejon, Chalillo, Vaca and Hydro Maya in 2010, the usable energy potential of hydro generation *in totum* countrywide is estimated at 526,300 MWhs per year: sufficient to meet all of our current electrical energy needs.

Production Costs

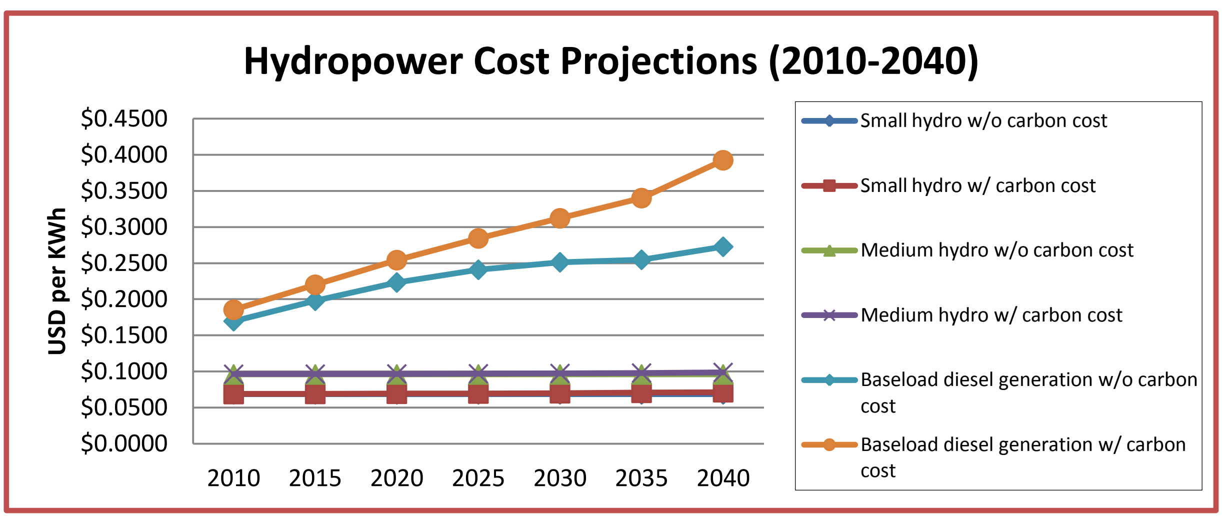

Figure 3.1.10.1: Cost Projections for Hydropower vs. Diesel Generation for 2010-2040

Fortunately, Belize has had experience with commercial scale hydro for over 15 years and the suppliers' prices have been well-documented. The energy produced from the medium-sized hydro schemes (Mollejon/Chalillo/Vaca) costs USD$0.095 to $0.11 per

[56] The report did not provide an estimated output plant capacity: but this has been assumed to be in the region of 25 to 50 MW, since it has similar characteristics to the existing Macal River cascading scheme.

[57] In the 2003 Energy Sector Diagnostic Report by Launchpad Consulting, Dr. Ivan Azurdia-Bravo[57] had estimated that an additional 35 MW of hydro potential exists in Belize: the basis for this estimate was however not provided.

[58] The Hydro Maya Plant has consistently maintained a capacity factor above 50%.

KWh in 2010: this falls at the higher end of the LCOE range for medium-sized hydro plants in countries worldwide. Energy from the only run-of-the-river small hydro plant, Hydro Maya, costs approximately US$0.07 per KWh: this falls at the lower end of the LCOE range for small hydro plants in countries worldwide. This cost will remain fixed for the entire PPA contract period.

Although energy from the Hydro Maya project costs less than energy from the Mollejon/Chalillo/Vaca cascading scheme, it must be borne in mind that the scheme, by virtue of its reservoir in the Chalillo Plant, provides firm capacity and storage throughout a significant portion of the year in addition to energy; the Hydro Maya Plant capacity on the other hand varies directly with water flow in the Rio Grande.

Figure 3.1.10.1 above compares the projected trends in the cost of small and medium hydropower generation with baseload diesel generation costs over the forecast period 2010-2040. The projected increasing cost differential is due principally to the projected increases in the cost of diesel fuel.

Geothermal Energy

State of the Technology

Geothermal energy occurs as a heat streams that rise to the earth's surface from two sources: heat emanating from the radioactive decay of elements within the earth's crust, and heat trickling through the mantle and crust from the earth's core. These heat currents are more intense in areas where the earth's crust is thin; or where natural conduits to the surface - such as volcanoes, geysers and hot springs - occur; or where man-made conduits exist in the form of holes drilled for oil, natural gas and water extraction. As a consequence, geothermal energy developments have historically been limited to these areas. However, recent technological breakthroughs and the rising cost of traditional energy sources have considerably expanded the scope of viable geothermal development. Where natural or pre-existing man-made conduits are in short supply, holes can now be drilled deep below the surface to "pull" the heat from the hot rocks within the earth - much like drilling for oil - via what are called Enhanced Geothermal Systems (EGS).

A very significant advantage of geothermal energy is that it is "always on" and does not suffer from the intermittency problem that plagues both solar and wind generation deployments. This makes geothermal developments extremely suitable for baseload dispatch in electrical power supply systems.

Geothermal resources can also be used to generate electricity; or to supply heat directly, including: for space heating and water heating, for fish farms and commercial greenhouses, and for milk pasteurization.

There are three main technologies used for generating electricity from geothermal resources:

a) **Dry Steam Power Generation**: Naturally-occurring geothermal steam is pulled from the earth's crust and used directly to drive turbines that generate electricity.

b) **Flash Steam Power Generation**: Very hot water is piped from naturally-occurring hydrothermal reservoirs within the earth's crust, depressurized in low-pressure tanks, and the flash steam that is produced as a result is used to drive turbines.

c) **Binary Cycle Power Generation**: Moderately hot water is passed through heat exchangers to heat another "working" fluid (refrigerant) that boils at a lower temperature than water. The working fluid is converted into gaseous form (when heated) that is then used to drive turbines. The hot water may be sourced from naturally-occurring hydrothermal reservoirs within the earth's crust or from the waste hot water produced as a by-product of oil and gas extraction.

Environmental Benefits/Costs

Geothermal systems emit approximately 0.122 tCO2e GHG per MWh of electricity generated (Wikipedia: Emissions Intensity, 2011). These GHGs occur mainly as carbon dioxide and methane which are found dissolved in geothermal water and released into the atmosphere when the water (or steam) is pulled to the earth's surface. Geothermal water also contains trace amounts of toxic chemicals such as arsenic and mercury.

EGS development in particular can also induce seismicity (earthquakes) in the immediate vicinity of the area where the hydrothermal reservoir is being developed[59].

Resource Availability and Utility-scale Supply Potential

There is no record of any comprehensive study of Belize's potential for geothermal energy development being done in the recent past. A part of the reason for this may be that Belize, unlike most of its Central American neighbors, does not fall within any of the major young and active volcanic belts and has been deemed not to possess any viable geothermal resources. However, there is evidence that volcanic activity occurred in the South-West region of Belize in the past and it is likely that low-temperature geothermal resources (that can be exploited using Binary Cycle Power Generation technology) may be found in that area. A 2007 Energy Sector Review commissioned by the IDB briefly noted that an RE expert hired by the GOB had mentioned that there was a "promising" geothermal resource in the South of Belize, but that it was not possible to confirm the claim (Arbeláez, 2007). Given high oil prices, EGS - once commercially rolled out - should therefore be considered an option worthy of further investigation in Belize.

[59] The most notable to date occurred in the City of Basel, Switzerland, when an EGS project had to be canceled in December 2009 after over 10,000 seismic events were recorded during the first 6 days of water injection (Wikipedia: Induced Seismicity in Basel, 2011).

Biomass

State of the Technology

Biomass is often considered the oldest source of renewable energy, going back to the ancient times when it was used to fuel fires for cooking and heating. Biomass refers to agricultural, industrial, animal and human waste: including bagasse (from sugar processing), saw dust (from wood processing), forest and crop residues, manure (from cattle and poultry), liquid waste from sewers and septic tanks, and MSW

Energy is produced from biomass by burning it to produce steam that is used directly for heating, or to drive industrial motors, or to drive steam turbines to generate electricity; it may also be converted to “syngas” that is then used in gas turbines to produce electricity. Most modern biomass-based plants are built as cogeneration facilities, where the biomass is burnt to produce high-pressure steam that drives turbines to produce electricity; the exhaust low pressure steam is then used in one or more heating applications. Recent advances in technology have also created a new opportunity for converting biomass into cellulosic ethanol that can then be used as transport fuel replacement (This will be further discussed under section on “Biofuels” further below). Of course, the conversion of biomass (waste) to electricity and/or cellulosic ethanol has the added benefit - sometimes the primary benefit - of getting rid of the waste at the same time.

However, unlike Wind and Solar, there are significant environmental risks associated with biomass combustion and gasification; mainly, it can use large amounts of water and cause air pollution (and hence damage habitats and ecosystems). The technology and conversion process used to produce secondary energy from biomass must therefore be carefully selected and monitored in order to mitigate the harmful effects of its production.

Environmental Benefits/Costs

Plant-based biomass power plants emit (net) zero tCO2e GHG per MWh of electricity generated: this is because most of the GHGs that are emitted during combustion are biogenic (that is, the emissions are part of a closed carbon loop and are balanced off by the natural uptake of carbon dioxide during plant growth OR are considered part of the natural cycle of CO_2 sequestration and release). Obviously, introducing plant-based biomass power plants into the supply mix will lower the grid GHG emission rate. Beyond this, burning residues as fuel in power plants is disposing of them for free!

MSW-fired (Waste-to-Energy or WTE) plants, on the other hand, emit over 0.6 tCO2e GHG per MWh of electricity generated. However, if the waste source is biogenic, then the net emissions are zero.

Resource Availability and Utility-scale Supply Potential

Bagasse

In 2010, approximately 403,675 tonnes of bagasse was produced by the BSI Factory[60] from 1.167 million tonnes of sugar cane. About 75% of this bagasse, along with 229,420 gallons of heavy fuel oil, was used in steam turbines to generate 97,961 MWh of electricity and 456,270 tonnes of low pressure steam (used in boilers). The electricity generated from the steam turbines was supplemented by an additional 5,748 MWhs of electricity from diesel generators to supply the internal electricity needs of BSI and BELCOGEN (55,077 MWhs), and the remaining 48,632 MWhs was sold into the grid. According to BSI, the output to the grid could have been doubled (to approximately 100,000 MWhs) if all of the bagasse produced was burnt to produce high-pressure steam.

Non-Bagasse Sources

Rough estimates of Belize's biomass potential from other sources were gleaned from a 2009 OAS Cellulosic Biomass Study[61]. This study assessed the quantity of dry biomass obtainable from agricultural and forestry residues (excluding bagasse from sugar cane processing) and MSW[62]. The study estimated that a total of 3 million US tons of biomass was available as possible feedstock for energy production in 2008: 2.42 million tons from agricultural residues, 0.22 million tons from forestry residues, and 0.35 million tons from MSW. The authors concluded that approximately half of this resource can be economically converted into bio-fuels (or electricity), and that maximum available production could easily exceed this with further expected technology developments and a greater focus on optimal land management.

If we assume that one-third of the total 350,000 tons of MSW is generated in the Belize City and surrounding areas and that 50% of this waste can be collected for electricity generation, then we can produce 0.6 MWh/ton x 50% x 1/3 x 350,000 = 35,000 MWh of electricity per year. This is roughly 15% of the current electricity demand of the Belize District.

Using conversion rates from of 0.6 MWh[63] of electrical energy per ton of biomass, and assuming that 50% of this resource can be economically harnessed, we can potentially obtain 0.6 MWh/ton x 50% x 3,000,000 = 900,000 MWh of electricity per year from biomass, not including bagasse and animal and human waste.

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[60] Which currently comprises the entire sugar processing industry.

[61] (Contreras & De Cuba, Cellulosic Ethanol Technology as Waste Management tool – the Belize Potential, 2009)

[62] Biomass from manure and sewage were apparently not taken into account.

[63] Derivation based on: 600 metric tons (660 short tons) of MSW will produce about 400 MWh of electrical energy (Wikipedia: Incineration, 2011).

The total electricity currently producible from available biomass sources, including bagasse but excluding animal and human waste, is therefore 1,000,000 MWh per year. This is roughly twice our current utility-provided electricity consumption.

Production Costs

Electricity from Bagasse, produced at BSI's Tower Hill Factory and sold into Belize's national grid, currently costs approximately $0.117 USD per KWh; and (per contract) is expected to increase by 2% each year. This figure falls at the higher end of the range of costs for electricity produced from solid biomass for utility-scale projects around the world; that is, from $0.05 to $0.12 USD per KWh. We can assume that energy from a plant using forestry and agricultural residues and MSW as the main fuel source will cost in the middle to upper end of this range around $0.010 USD per KWh.

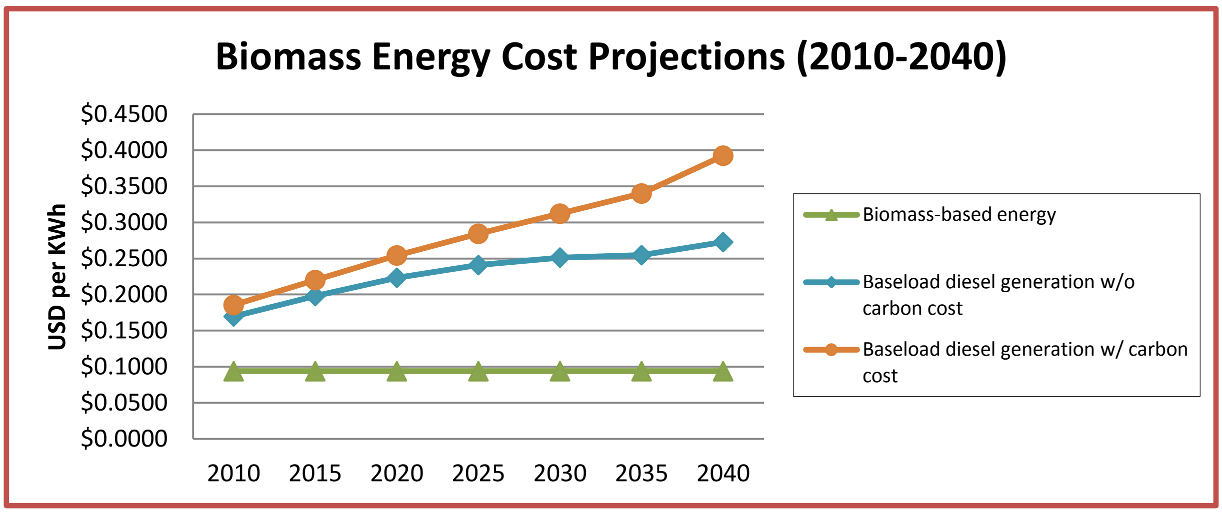

Figure 3.1.11: Cost Projections for Biomass-based vs. Diesel Electricity Generation for 2010-2040

Bio-fuels

Bio-fuels have garnered a lot of attention as a renewable energy source ever since Brazil's huge success with replacing gasoline with ethanol blends in the 1970's, and in more recent times with the emergence of their versions of flex-fuel vehicles that can run on varying blends of gasoline and ethanol. While wood (used mainly for cooking) continues to be the most widely-used biofuel by far, there are three main bio-fuels that hold much promise and which have been the focus of significant R&D efforts worldwide: cane ethanol, cellulosic ethanol and bio-diesel.

Wood Fuel

State of the Technology

Large quantities of wood fuel (firewood) are used mainly for residential cooking and water heating in the rural parts of Belize and for producing lime that is used in fertilizers and for tortilla-making.

The disadvantages of using firewood for cooking and heating are frequently highlighted as:

- Cooking by using firewood to fuel open or semi-closed hearths uses up precious resources in an inefficient way (~10% overall efficiency; that is total energy absorbed by what is being cooked as a % of energy content of wood used to cook it). Modern wood-burning stoves can be over twice as efficient (20-25% on average) *Note these cost approx. $600 to $3,000 USD*. (Biogas Support Program, Nepal - Study Report on 'Efficiency Measurement of Biogas, Kerosene and LPG Stoves, 2001).
- The incomplete burning of firewood causes the emission of particulate matter and other toxic and carcinogenic substances into the air - mainly carbon monoxide, but also benzene, butadiene, formaldehyde, poly-aromatic hydrocarbons and many other compounds (Smith, 2011) - that can cause serious illnesses especially in women and children, who are usually the ones at home when food is being prepared. According to Kirk R. Smith, Professor Environmental Health Sciences at the University of California at Berkeley, health effects caused by continual biomass fuel use in households include "chronic obstructive pulmonary disease, such as chronic bronchitis and emphysema, in adult women who have cooked over unvented solid fuel stoves for many years" and "acute infections of the lower respiratory tract (pneumonia) in young children, the chief killer of children worldwide" (Smith, 2011). Firewood therefore has come to represent an oppressive and discriminatory form of energy.
- Although not definitive, "biomass fuel use has also been found to be associated with tuberculosis, cataracts, low birth weight in babies of exposed expectant mothers, and other health conditions in a number of other studies" (Smith, 2011).

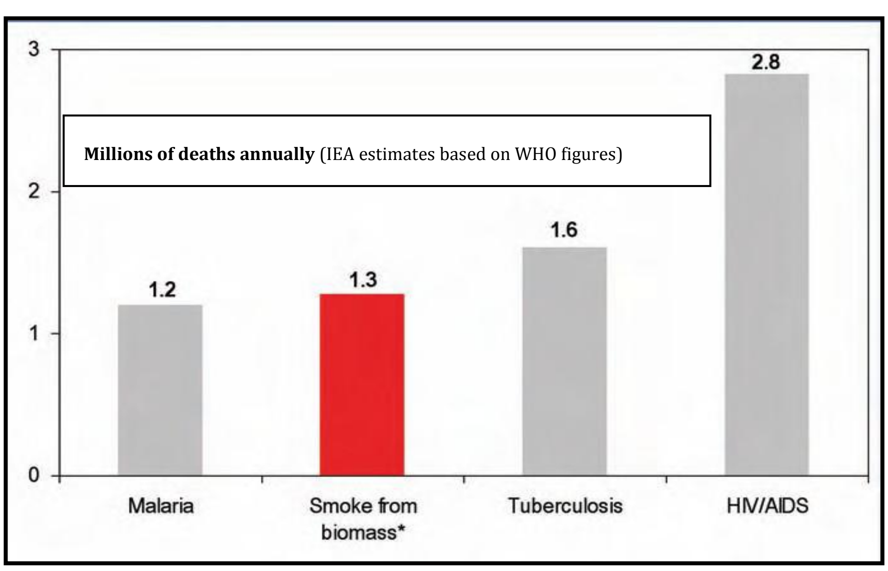

Figure 3.1.12: Premature deaths yearly worldwide due to the use of biomass for cooking compared with other well-known causes (*Source: WEO 2006*)

- Because firewood is retrieved from forests that are not always close to the point of consumption, transportation costs - which for most rural communities occurs in the form of 'person-hours' - are high.

- The use of firewood destroys forests. In addition to being the natural habitat of thousands of species and protecting biodiversity and land integrity, forests are the major terrestrial carbon sink and so play a very important role in maintaining the natural balance of the tenuous carbon cycle.

There are however advantages to using firewood as a fuel source:

- It is indigenous: Unlike LPG, used for cooking by over 80% of households countrywide and that is sourced from Guatemala and Mexico, the use of firewood does not represent a drain on our FX balance, as it is produced locally.
- It is renewable, if used sustainably.
- It is carbon-neutral (the carbon dioxide it releases when burnt is the same amount that was sequestered from the atmosphere when the tree was growing): the net GHG emissions are zero, especially because its preparation incurs minimal use of fossil fuels.
- Wood fuel can burn as cleanly as LPG if wood charcoal is used instead of firewood and improved cooking stoves and vents are used to minimize incomplete combustion and prevent the spreading of smoke within the household.

Environmental Benefits/Costs

Like all plant-based biomass, the combustion of wood fuel (for energy) results in zero net GHG emissions, as the carbon dioxide released during burning is the same carbon dioxide that is absorbed during plant and tree growth. Moreover, because wood collection is mostly done by manual labor, minimal GHG emissions occur as a result of its "production".

However, as referred to earlier, firewood burns incompletely when combustion occurs in traditional fire hearths, thus releasing particulate matter (PM) and other toxic and carcinogenic substances into the air that can cause serious respiratory illnesses especially in women and children, who are usually the ones at home when food is being prepared. Moreover, uncontrolled collection of firewood leads to deforestation which can affect biodiversity and land integrity.

Resource Availability and Supply Potential

No specific indigenous wood fuel consumption data could be obtained from local sources, therefore data provided by international organizations had to be used to estimate total nation-wide consumption. According to FAO estimation, 579 kg (1.127 cubic meters) of wood are consumed per capita for households that use wood fuel (inc. dried wood and charcoal) as the primary means of cooking. OLADE estimates a much higher figure - 1284 kg per capita for dried wood and 536 kg per capita for charcoal - based on data gathered from its members (Hernández, 2011). From the 2000 census, approximately 16% of households in Belize used wood for cooking. Assuming this proportion is the same in 2010, then the total quantity of wood consumed by 16% of the 80,000 households in 2010 = 1284 kg[64] x 16% x 80,000 households x 3.9 persons per household x 19.2 MJ/kg= 1,230 TJ.

There is an alternate method for estimating the quantity of wood fuel consumed. Using wood fuel for cooking is on average approximately four (4) times less efficient than using LPG. The total quantity of LPG used by the 67,200 households that used LPG in 2010 was about estimated at 564 TJ. This works out to approximately 8.39 GJ per household per year[65]. A household using wood for cooking (assuming all households cook on average the same amount of food) will therefore use 33.56 GJ per year; that is, 4 x 8.39 GJ. Using this method, the estimated energy content of wood consumed by households in 2010 was therefore 33.56 x 16% x 80,000 households = 429.57 TJ. This is just over 1/3 of the quantity derived using the OLADE figures.

It could not be determined if either of the derived rates of wood fuel consumption were sustainable. In addition, there is no data available on how firewood is collected and re-distributed to consumers: in particular, the percentage that is collected directly by households and the percentage (if any) that is collected by middlemen and sold to households. This kind of data is needed in order to assess the efficiency of the collection and re-distribution process and so determine if the industry (whether informal or not) could benefit from commercialization.

Production Costs

The collection and distribution of wood fuel is not usually accounted for in the formal energy sector: hence, no price is placed on a given quantity of wood fuel at source. The OAS Report "*Cellulosic Ethanol Technology as Waste Management tool – the Belize Potential*" provides a calculus for determining the cost of supplying wood residues to be used in the production of cellulosic ethanol. Working backwards from the results, this cost was deciphered to be $37.82 USD per dry metric ton of wood residues[66]. It should be borne in mind that this is the cost of collecting wood from de-centralized source sites and transporting it in trucks to a centralized location.

We can reasonably assume that the cost of a single person collecting wood and transporting by foot or horseback to his home will be *at least* $37.82 USD per dry metric ton. On an energy-basis, this is $0.00197 USD per MJ or $0.00709 USD per KWh.

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[64] Using the OLADE figure for wood fuel only (and assuming relatively negligible charcoal use). The reasonableness of this assumption would of course have to be tested via a later more detailed study on actual local wood fuel usage.

[65] This is half the average LPG consumption per household of 15.9 GJ derived from the OLADE statistics (Hernández, 2011).

[66] Based on data contained in the report: (Contreras & De Cuba, Cellulosic Ethanol Technology as Waste Management tool – the Belize Potential, 2009)

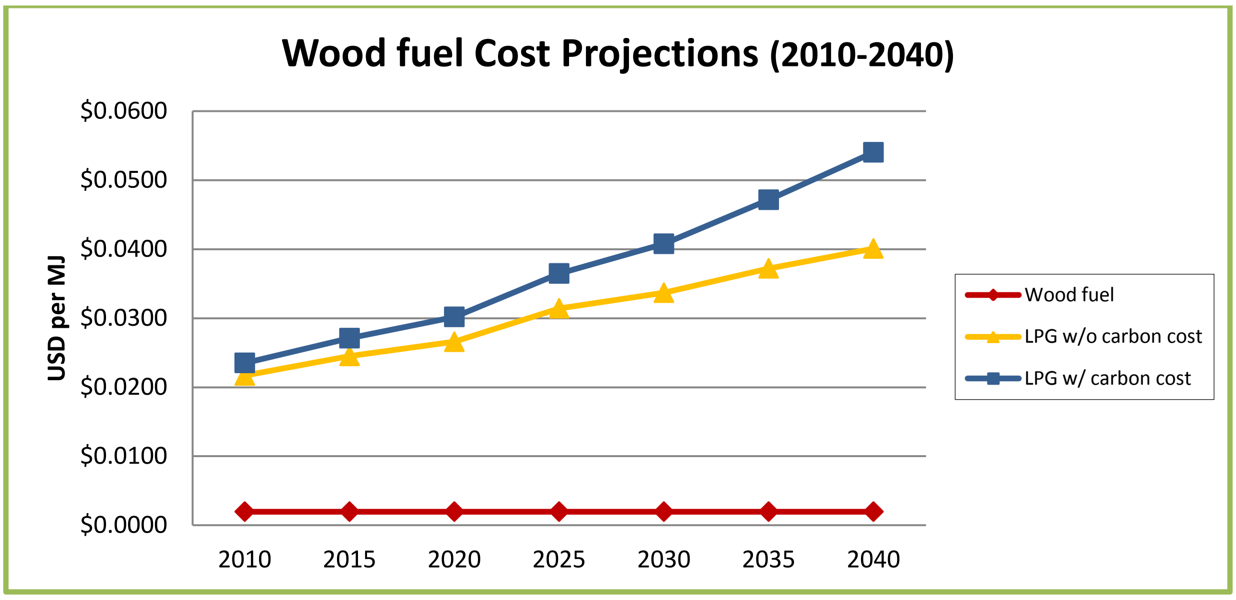

Figure 3.1.13: Cost Projections for Wood Fuel vs. LPG for 2010-2040

Cane Bioethanol

State of the Technology

Bioethanol is ethanol (a high-octane liquid fuel) produced by a process that converts plant starch to alcohol. It can be produced from a variety of plant sources, including sugar cane (Brazil), maize (USA), sugar beet (Europe) and cassava. In Brazil, sugar and ethanol are produced on an integrated basis: the relative amounts of sugar and ethanol produced in any crop period is influenced by the relative market prices of these commodities (Xavier, 2007).

Ethanol is blended with gasoline to produce various combinations of "gasohol": for example, E10 is a blend of 10% ethanol and 90% gasoline; E25 is a blend of 25% ethanol and 75% gasoline. Although the net calorific value of ethanol is lower than that of gasoline, the price differential between the two and the better performance of ethanol conversion engines usually make the cost - per unit of energy produced - cheaper for ethanol blends. Moreover, ethanol has about 20-30% lower carbon emissions per unit of energy output than gasoline.

Environmental Benefits/Costs

7.3 kg of CO_2-equivalent GHGs are emitted for each gallon of bioethanol combusted. However, approximately the same amount of CO_2 is sequestered from the atmosphere during the growth of the sugar cane or corn plant that is used to produce the ethanol. So the net GHGs emitted are zero. In reality, indirect emissions do occur when energy from other sources is used during production, transport, storage and distribution; but this depends on the particular production process used, as well as the plant source.

Ethanol is also used as a substitute for lead additives in vehicle fuel, thus improving air quality especially in urban centers most prone to traffic congestion.

Resource Availability and Utility-scale Supply Potential

While Belize's only active sugar processing plant, BSI, currently has no firm plans to start producing ethanol[67], this possibility is not completely off the table, as the Banco Atlantida Group, the Honduras-based consortium that has been negotiating with GOB and BSI to purchase majority stock in BSI, has expressed its intention to expand operations and explore all profitable growth opportunities if a deal can be consummated.

In the meantime, there are two other major ethanol production projects that are in the planning stages. The first is at the Libertad Sugar Factory, which had been bought over by a Mexican consortium with the stated intention of producing ethanol for export. Little further development has occurred since the purchase however, and, at last report, a change in strategy towards producing sugar was being contemplated, given the trend of favorable prices for sugar on the world market. The second is an ethanol bio-refinery and co-generation plant to be located in the Big Falls area (of the Belize District), and which is to be sourced from sugar cane grown on 30,000 acres of surrounding farmland. The bio-refinery will have the capacity to produce up to 30 million gallons of ethanol per year, and the power plant will be capable of generating 25 MW of electricity, 9 MW of which will be sold into the national grid. The project developers, a USA-based company with experience in biofuel production in Africa and Brazil, are considering building a pipeline from the factory location to the sea port in Big Creek through which the ethanol will be transported for eventual export[68]. This plan is still in its conceptual stages, and negotiations are currently underway to acquire the land in Big Falls.

In any case, most of the required infrastructure for the production of ethanol is already in place at the three distilleries in Belize. The only component missing is the required facility for the dehydration 92-96% aqueous ethanol into 99.5% ethanol. Even so, the blending facility, testing equipment and knowledge required to complete the process was once available in the country, as small quantities of E85 "gasohol" were produced locally in 2009. Aside from market hurdles, one of the concerns noted at the time was the need to carefully manage the introduction of more easily available alcohol in high quantities in the market. These non-technical issues could be addressed with further research.

Production Potential

Brazil gets in the range of 6,800-8,000 litres of ethanol per year from each hectare of land planted[69], and is working on new techniques and technology to ramp this up to

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[67] Per information received from Hon. Godwin Hulse (October 2011).

[68] Ibid

[69] Deduced from data provided in (Wikipedia - Ethanol Fuel, 2011) and (Wikipedia - Ethanol Fuel in Brazil, 2011).

9,000 litres per hectare per year (Wikipedia: Ethanol Fuel in Brazil, 2011). Belize has approximately 809,000 hectares of land suitable for agriculture (just over 35% of total land area), with less than 10% under cultivation or being used as pasture lands (CIA FactBook, 2009). If we assume that 5% of this land, or about 100,000 acres, can be designated for ethanol (from sugar cane) production and that we can get just over one-half the lower end of the current yields that Brazil gets, then we can potentially produce 3,500 x 5% x 809,000 = 141,575,000 litres (or 37,400,000 US gallons) of ethanol per year. This is equivalent to 24,933,333 gallons of gasoline per year on an energy content basis: about 25% more than our current yearly (gasoline) consumption.

Production Costs

Although Brazil produces sugarcane-based ethanol for as low as $0.83 USD per gallon (Wikipedia - Ethanol Fuel in Brazil, 2011), the experience of other countries in the region has not been close to the same: Jamaican ethanol costs over $1.50 USD per gallon to produce and ethanol from Mexico costs about the same. It is likely that Belize's production cost would be closer to that of Jamaica or Mexico, and that cane ethanol can today (or in the near future) be produced in Belize for around $1.60 USD per gallon[70].

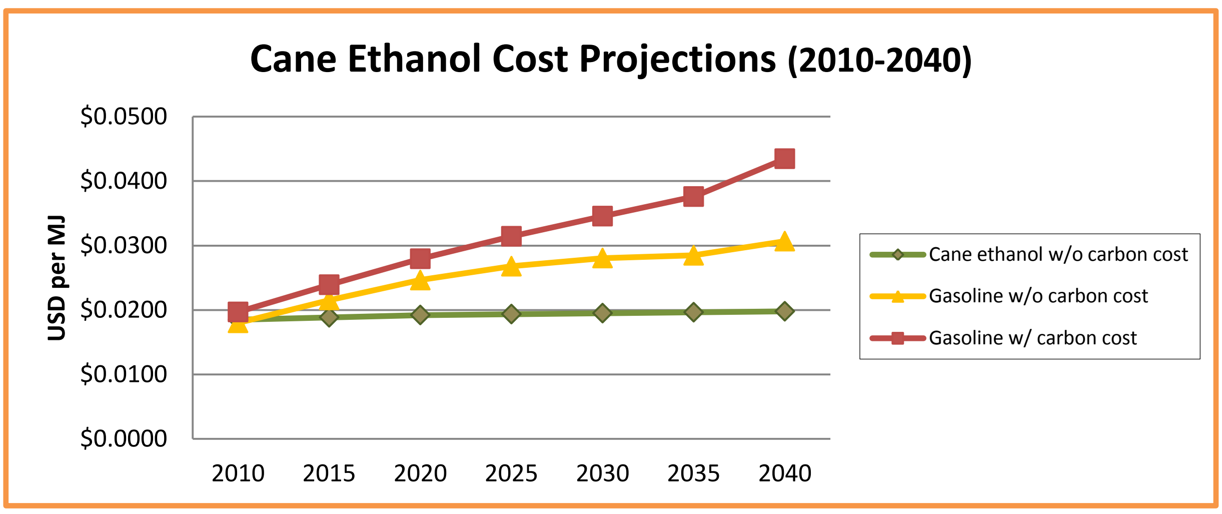

Figure 3.1.14: Cost Projections for Cane Ethanol vs. Gasoline for 2010-2040

Cellulosic Bioethanol

State of the Technology

Cellulosic ethanol, also called second-generation bioethanol, is ethanol that is derived from cellulosic plant fiber found in agricultural and forestry residues; manure and human waste; and the organic component of MSW. Although the technology for producing cellulosic ethanol is still in the pilot and demonstration phase, it is already showing significant advantages over conventional cane ethanol:

[70] This estimation is also based on the cost of $0.63 USD per litre of gasoline equivalent for cane ethanol provided in Figure 13 of the IEA Technology Roadmap – Biofuels for Transport (2011).

a) its sources are abundant;

b) because it can be derived from non-food sources, it does not have to compete with agriculture for land, and can in fact be incorporated into the agricultural production value chain;

c) it has more "energy bounce" (that is, it takes less energy to produce it);

d) it emits less GHG during production;

e) although not yet commercially produced, all indications are that it will be considerably cheaper than gasoline – and conventional ethanol - on a per-gallon basis.

Environmental Benefits/Costs

7.3 kg of CO_2-equivalent GHGs are emitted for each gallon of cellulosic ethanol combusted. However, since cellulosic ethanol is mostly derived from agricultural and forestry residues, the net GHGs emitted during its lifecycle are also near-zero.

Utility-scale Supply Potential

An additional 50,000,000 US gallons of ethanol per year could be produced if available biomass were used to produce cellulosic ethanol instead of electricity (Contreras & De Cuba, Feasibility Study on the Cellulosic Ethanol Market Potential in Belize, 2009), which is equivalent to 33,333,333 US gallons of gasoline per year: this is almost twice Belize's current yearly gasoline requirements.

"If (we use biomass) to produce cellulosic ethanol, we can potentially get … 50,000,000 US gallons of ethanol per year, which is equivalent to 33,333,333 US gallons of gasoline per year: this is almost twice our current gasoline requirements."

Note however that the waste heat from biofuel production can be used to generate electricity, so production of ethanol and electricity from cellulosic biomass are not necessarily mutually exclusive.

Production Costs

The OAS Cellulosic Ethanol Report concludes that cellulosic ethanol can be produced in Belize for between $1.64 to $2.17 USD per gallon using 2008 technology, and between $0.0873 to $1.40 USD per gallon using 2012+ technology (Contreras & De Cuba, Feasibility Study on the Cellulosic Ethanol Market Potential in Belize, 2009). It is therefore reasonable to assume that cellulosic ethanol can be produced for about $1.10 USD per gallon, when the technology becomes available in the near future[71]. These

[71] The mid-point of the $0.0873 to $1.40 USD per gallon cost range.

projections are however far lower than the $2.30 USD per gallon for 2020 provided in Figure 13 of the IEA Technology Roadmap – Biofuels for Transport (2011): This discrepancy may be due to the assumptions made with regard to feedstock costs, which can make a substantial difference in the final cost results, and additional retail marketing and distribution costs.

Based on data used in the OAS Report, it is estimated that roughly 60% of the cost per gallon of cellulosic ethanol flows out of the country to pay for capital, specialized maintenance services and enzymes.

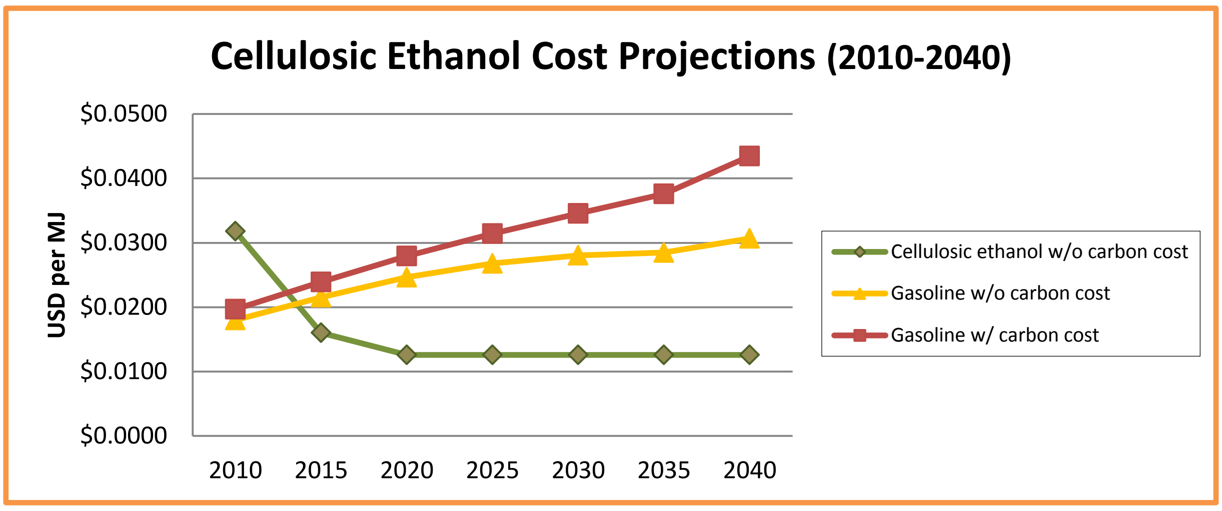

Figure 3.1.15: Cost Projections for Cellulosic Ethanol vs. Gasoline for 2010-2040

Biodiesel

State of the Technology[72]

Biodiesel is diesel produced by mixing ethanol or methanol with vegetable oil, animal fats, or recycled cooking oil in a transesterification process. Vegetable oil sources include palm oil, coconut oil, canola oil, corn oil, jatropha seed oil, cottonseed oil, flex oil, soy oil, peanut oil, sunflower oil, rapeseed oil and algae.

Figure 3.1.16: Fruit coatings and seeds from Jatropha Curcas L. plants grown on Maya Ranch Plantation in Belize (*Courtesy: da Schio, 2010*)

Biodiesel can be used with any diesel engine as a fuel alternative (to petroleum diesel) or as a fuel additive to reduce vehicle emissions.

[72] Much of discussion below based on information gleaned from (Shumaker, McKissick, Ferland, & Doherty).

There are several advantages to using biodiesel over petroleum diesel:

a) its net GHG emissions are negligible[73], when it is produced from plant-based or biogenic sources;

b) it contains negligible amounts of sulphur, thus leading to significant reduction in sulphur-related emissions which are a major cause of acid rain;

c) it burns more cleanly than petroleum diesel, producing lower levels of particulate matter, thus lowering emissions of nitrogen, carbon monoxide and unburned hydrocarbons[74];

d) it behaves similarly to petroleum for engine performance and mileage; in fact, biodiesel usually gives higher mileage than gasoline;

e) it dissipates engine heat better than petroleum diesel;

f) it has a lower flash point than petroleum diesel and thus there is a lower chance of the occurrence of damaging fires;

g) B20 (that is 20% biodiesel and 80% petroleum diesel) and lower-level blends can be used in nearly all diesel equipment, without requiring engine modifications; however blends greater than B20 may require engine modifications; and

h) it is compatible with most existing petroleum diesel storage and distribution equipment.

On the other hand, biodiesel breaks down if stored for extended periods of time; and it may be corrosive to rubber and liner materials and so cannot be stored in concrete lined tanks (Shumaker, McKissick, Ferland, & Doherty).

Environmental Benefits/Costs

According to the National Soydiesel Development Board of the USA, using a B20 biodiesel/petro-diesel blend instead of pure petro-diesel can result in significant reductions in air pollution from diesel engine exhaust emissions: a 31% reduction in particulate matter, 21% reduction in carbon monoxide, and a 47% reduction in total gross hydrocarbon emissions (Ahouissoussi & Wetzstein). Moreover, unlike petroleum-based diesel, bio-diesel combustion produces almost no sulphur emissions (which can cause acid rain).

The net GHG emissions for biodiesel produced using bio-ethanol for transesterification are actually negligible, since both are derived from plant-based sources.

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[73] In practice, the cultivation of plants used to produce biodiesel use up fossil fuels in transportation, fertilizer production and other activities; so the net emissions are in fact not zero.

[74] Some of the literature claim that biodiesel may actually raise the levels of pollutants emitted other than GHGs – *Source: The Pros and Cons of 8 Green Fuels*.

Utility-scale Supply Potential

The production capacity of biodiesel depends on the source of the oil feedstock chosen. Many of the vegetable oil plant sources such as soy, jatropha, oil palm, and peanut can be grown in Belize. The jatropha plant, locally known as 'physic nut', is particularly attractive as an energy crop because of its many remarkable qualities: it is native to Belize and the local variations possess good genetic properties; it is not edible (and so there is no competition with a food source); it is drought-resistant and can be grown on marginally-arable lands or even in saline soils; it improves soil structure thus controlling soil erosion; it responds well in intercropping farming systems with other local crops such as habanero peppers and where it can be used as a boundary hedge; it requires low technology inputs and its cultivation can be easily implemented at the small-farm scale as there is no need to fulfill cyclical agricultural duties such as soil tillage that may require mechanized assistance; and the co-products of its cultivation such as leaves, latex, fruit coatings, and seed cake can be used for the production of fertilizers, insecticides and soap (da Schio, 2010).

In fact, Jatropha projects were started up in Belize as far back as 1997, mainly for purposes of crop rotation and vegetable oil production, by the then Janus Foundation (now called TDSF), an NGO involved with promoting sustainable use of natural resources. The most well-known is probably the 0.5 hectare Jatropha farm at Maya Ranch in the vicinity of the Maya Mountain Northern Foothills Region that has been in operation since 2003. Recently, an American company, Blue Diamond Ventures Inc. acquired about 73 hectares (180 acres) of land in the Stann Creek District with the stated intention of setting up a Jatropha-based biodiesel plant in three stages: a pilot stage with an initial output capacity of 200,000 to 500,000 gallons per year (GPY), followed up with the construction of a 2.5 million GPY commercial demonstration facility, and finally a 50 million GPY facility. *At the time of preparing this report, no further information could be gotten on the progress of the implementation plans for this project*. TSDF is reportedly also conducting a feasibility study of commercial cultivation and management of Jatropha Curcas L. for biodiesel production and land rehabilitation in Belize, using improved high-yielding seeds imported from Guatemala. This study is being done under the auspices of the EEP.

Approximately 194 gallons of plant oil can be gotten from one acre of planted jatropha (Kurki, Hill, & Morris, Updated 2010). The yield of biodiesel from plant oil is in the region of 97%. So, assuming that 5% of our 809,000 hectares (2,000,000 acres) of arable land is designated for jatropha cultivation, then we can potentially produce 97% x 194 x 5% x 2,000,000 = 18,818,000 US gallons of biodiesel per year. This is equivalent to 17,264,220 gallons of diesel per year on an energy content basis: this is slightly less than our current yearly (diesel) consumption for all end-uses and 44% more than our current yearly (diesel) consumption for transport only.

If ethanol is used in the transesterification process, then the total quantity required is 27.38% of the quantity of oil (by volume) = 27.38% x 194 x 5% x 2,000,000 = 5,311,720 gallons of ethanol per year. This can easily be supplied by excess ethanol from local conventional or cellulosic ethanol production (*Refer to discussions on Bioethanol in previous section*).

Production Costs

A 2010 Report titled "Biodiesel: The Sustainability Dimensions" quoted a biodiesel production cost range of $1.50 to $2.50 USD per gallon (Kurki, Hill, & Morris, Updated 2010). The IEA Annual Energy Outlook 2007 quotes a slightly tighter range of $1.80 to $2.40 USD per gallon for biodiesel produced from soybean oil. The IEA projections for reductions in the cost of conventional biodiesel over the horizon to 2050 are not as promising: in fact, conventional biodiesel trends the highest amongst the biofuels. Biodiesel produced using advanced biomass-to-liquids techniques, though currently more costly given the novelty of the technologies, is expected to be much cheaper than conventional biodiesel into the future.

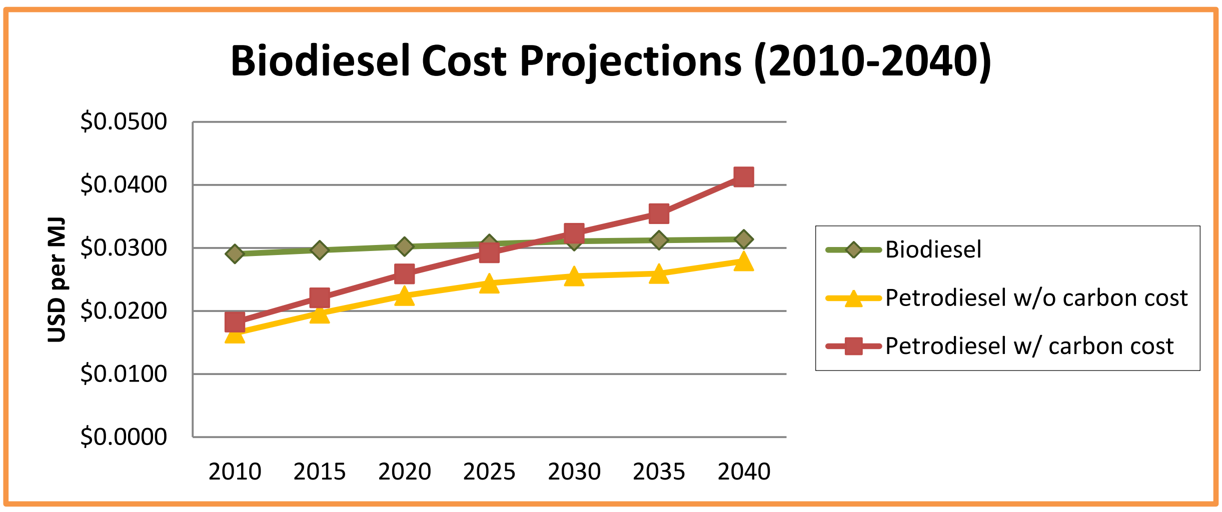

Figure 3.1.17: Cost Projections for Biodiesel vs. Petrodiesel for 2010-2040

NON-RENEWABLE ENERGY SOURCES

Indigenous Crude Oil

State of the Industry

Oil has historically been viewed as an export industry in most countries where it has been discovered in commercial quantities. Even when oil is refined locally, the refined petroleum products are usually sold on the international market. This is no less the case for Belize.

The first discovery of underground formations in Belize with the potential to produce commercial quantities of oil was made by concession-holder, Belize Natural Energy (BNE) in July, 2005 in the Spanish Lookout community in the Cayo District. Since that time, approximately 90% of the oil extracted has been sold directly into the international markets; the rest has been sold directly on the local market.

About 35% of the oil so far sold locally had been taken up by Belize's first local commercial refinery, Blue Sky, which commenced operations in 2007, but abruptly ceased production after being acquired by BNE in early 2010[75]. Blue Sky extracted mainly naphtha and light fuel oil (LFO) from locally-produced crude oil via a single-stage flash-point separator, which is basically a technology that is normally used to strip naphtha from diesel. The residual light fuel oil was blended with imports of diesel and HFO, and sold to local industrial consumers; the naphtha was sold into neighboring Peten, Guatemala. According to Blue Sky, the projected gross savings to the Belize economy from their refinery operations would have been in the region of $12 to $20 BZD per barrel of crude oil, which would have resulted in gross savings of over $14 million BZD per year, and a consequent net reduction of $0.50 BZD per gallon in diesel and HFO fuel costs. The major beneficiary from this initiative was the power generation sector, as the refinery was able to supply HFO to BAL at a price which was 20% below that of other regional suppliers.

The rest of the oil sold on the local market (65%) has been used – without further processing – mainly as a substitute for bunker fuel in boilers by sugar processors, citrus processors, rum distilleries, aquaculture farms, and poultry and meat processors, as well as for electricity generation by Farmers Light and Power Company (FLPC) in Spanish Lookout in the Cayo District[76]. The benefit for local consumers is that the substituting crude oil is cheaper than the substituted refined product: in 2010, the price of locally-produced crude oil was $1.73 USD per gallon, compared to $4.19 USD per gallon at the pump for diesel. However, no study has been done or data collected on the effects of crude oil on the engines and motors in which they are used, and the additional costs borne as a consequence. The latest reports are that, as of late, there has been a significant cutback in the use of crude oil for local transport and other industrial uses because of higher-than-expected incidences of engine and equipment failures.

Resource Availability and Supply Potential

According to the Geology Department in the Ministry of Natural Resources, Belize currently has 15.5 million barrels of recoverable oil reserves from its Spanish Lookout Field[77]. In early 2011, the NEPD received unofficial reports from the GPD that a significant oil find was made by BNE in the vicinity of the Never Delay Village near

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[75] According to BNE, the principal investor, the operation was shut down because it became unprofitable and the business model was unsustainable.

[76] Source: GPD of Belize. GPD also claims that it is not aware that crude oil is being used directly in heavy-duty vehicles as a substitute for diesel.

[77] Based on data provided by the GPD. BNE's estimate is 18.1 million barrels.

Belmopan in the Cayo District. The field reportedly has 5-6 million barrels of proven oil reserves. It is currently in the development phase and is producing 425 barrels per day. For purposes of ensuing analyses done in this report, the total recoverable reserves at this juncture will be estimated at 20 million barrels (15.5 million from the Spanish Lookout site plus 4.5 million from the Never Delay site).

"The electricity that we can produce in a little over four (4) months from using less than 0.7% of our total land area for solar energy generation (not including micro-generation opportunities) is about the same as the electricity we can get from extracting and burning ALL of the oil from our proven reserves."

BNE was extracting roughly 4,130 barrels of crude oil per day from its Spanish Lookout field in 2010; this has fallen to 3,500-4,000 barrels per day in 2011 so far[78]. So, the annual rate of production is expected to be 1,539,000 barrels per year. This gives us roughly 13 years of indigenous oil remaining, if no further finds are made.

While widespread speculation and optimism abound amongst the Belizean public and Government that large oil fields exist beyond the Spanish Lookout area, no further major finds have been officially reported to date. In the meantime, the Government has parceled out the entire country, including the offshore, into oil exploration areas; and has awarded concessions to various companies to conduct exploratory testing for oil.

Can we supply all of our transport and industrial fuel needs from our indigenous oil supplies?

A barrel (42 US gallons) of crude oil yields 44.2 US gallons of finished products distributed in the amounts as follows: gasoline, 19.5 gallons; distillate fuel oil, 9.2 gallons; kerosene-type jet fuel, 4.1 gallons; residual fuel oil, 2.3 gallons; liquefied refinery gasses, 1.9 gallons; still gas, 1.9 gallons; coke, 1.8 gallons; asphalt and road oil, 1.3 gallons; petrochemical feedstocks, 1.2 gallons; lubricants, 0.5 gallons; kerosene, 0.2 gallons; and other, 0.3 gallons.

If we refine – instead of sell - all our crude oil, either locally or by arrangements with refineries in the region, then we can produce the following quantities of finished products each year.

Product	Quantity Producible (gals)	Quantity Required Locally (gals)	% of Local Needs Met
Gasoline	30,010,500	18,823,140	100%
Distillate fuel oil (Diesel)	14,158,800	17,898,888	79%
Kerosene-type jet fuel	6,309,900	499,800	100%

[78] Source: GPD of Belize and BNE.

Residual fuel oil	3,539,700	5,860,974	60%
Liquefied refinery gasses	2,924,100	N/A	
Still gas	2,924,100	N/A	
Coke	2,770,200	N/A	
Asphalt and road oil	2,000,700	N/A	
Petrochemical feedstocks	1,846,800	N/A	
Lubricants	769,500	N/A	
Kerosene	307,800	3,265,290	9%
Other	461,700	N/A	

Table 3.2.1: Quantity of Products producible from Refined Local Oil versus Quantity Required[79]

We would be self-sufficient in gasoline (in fact we could export gasoline) and most of the diesel needed; but would still need to import 91% of our kerosene needs (for lighting and cooking) and 40% of our residual fuel oil needs at today's consumption rates. Of course, the oil refining process can be tweaked to produce more or less of the different products listed above; and it is likely that all of Belize's demand for refined oil products can be met from its own crude oil sources based on 2010 production rates.

Indigenous Oil versus Indigenous Ethanol

Using a gasoline equivalent of 0.9 for the finished products derivable from one barrel of crude oil, the total gallons of gasoline (equivalent) that can be gotten from our 20 million barrels of proven oil reserves is 42 gallons per bbl x 20,000,000/0.9 = 933,333,000 US gallons.

How does this compare with ethanol? We can potentially produce 87,400,000 US gallons of ethanol per year (= 58,266,666 US gallons of gasoline-equivalent per year).

So our total oil reserves can be replicated by producing cellulosic ethanol (from all our organic wastes) and conventional ethanol (from sugar cane grown on 1.75% of our total land area) for the next 16 years.

Can we supply all of our electricity needs from our indigenous oil supplies?

From another (electricity) perspective: The total energy content of the finished products produced from 1 barrel of crude oil is 5.8154 MMBtu or 1,705 KWh. At a conversion efficiency of 33%, this yields 568 KWh of net electricity generation per barrel of crude oil. So, 1,539,000 bbls of crude oil per year should give us 568 x 1,539,000 = 874,512,000 KWh = 874,512 MWh of electricity per year, for 13 years, from all our proven oil reserves. This is just less than twice our current utility-provided electricity consumption!

Electricity from Indigenous Oil versus Wind-Powered Generation

[79] Source: EIA (2001)

All our oil reserves of 20 million barrels of crude oil should give us 568 x 20,000,000 = 11,360,000,000 KWh = 11,360,000 MWh of electricity, since each barrel of crude oil can potentially produce 568 KWh of electricity.

We can get wind energy in quantities of 1,375,484 MWh per year from onshore wind, using less than 0.7% of our total land area; and 1,180,200 MWh per year from shallow offshore wind, using less than 3% of our shallow offshore marine waters: for a total of 2,555,684 MWh per year. This means that the electricity that we can produce in four and a half years from using less than 0.7% of our total land area and less than 3% of our total shallow offshore marine waters for wind energy generation (not including micro-generation opportunities) is about the same as the electricity we can produce from extracting and burning all of the oil from our current proven reserves.

Electricity from Indigenous Oil versus Solar-Powered Generation

We can also get about 32,658,625 MWh per year from solar generation. So, the electricity that we can produce in a little over four (4) months from using less than 0.7% of our total land area for solar energy generation (not including micro-generation opportunities) is about the same as the electricity we can get from extracting and burning ALL of the oil from our proven reserves.

Projected Prices and Costs

Since operations started in 2005, about 90% of the crude oil produced locally is exported for sale on the international market, where its price at any point in time is determined by the international market price, independent of the local production cost. In 2010, 1,424,542 barrels of crude oil was sold on the international markets for total revenues of $113,836,348.25 USD: the average price was therefore $79.91 USD per barrel. The average reported spot price for WTI crude oil in 2010 was $78.70 USD per barrel.

In 2010, 82,338 barrels of oil were sold directly on the local market for total revenues of $5,992,507.78 USD: the average price was therefore $72.78 USD per barrel. The difference between the international and local market price is the cost of transportation and other logistical arrangements involved with shipping abroad.

Indigenous Petroleum Gas

State of the Technology

"Flare gas" or "associated gas" is natural gas occurring as a mixture of gaseous hydrocarbons that are released during crude oil production. It is usually made up primarily of methane, propane and butane. Most drilling companies flare the gas just before release into the atmosphere, mainly to convert the methane in it to carbon dioxide in order to reduce the impact of its GHG emissions footprint, since methane is 21 times more potent a GHG than carbon dioxide (Carbon Trust - Resources: Conversion Factors).. However, in doing so, valuable energy is simply lost.

Technologies exist that can extract 90% or more of the content from the associated gas by passing it through a series of processes, including compression, cooling, filtering and fractionation in a gas processing plant. The extracted gases and liquefied gases can then be delivered by pipeline directly to points of use, used on site to generate electricity or stored for later delivery to end users.

The gas associated with crude oil extraction at the Spanish Lookout site has a significantly different composition from gas usually found in natural gas fields. While "raw" natural gas normally has high levels of methane content (above 50%), the composition of the associated gas from the Spanish Lookout field is closer to that of a petroleum gas: containing methane (15%), ethane (30%), propane (30%), butane (15%) and other gases (10%)[80]. The gas-oil ratio of the associated gas has recently fallen to 125 scf per barrel of crude oil – or 500,000 scf per day - compared with 200 scf per barrel during the earlier years[81].

BNE processes the associated gas by passing it through a gas processing plant capable of processing up to 10 million scf per day. It uses a two step process (of compression and cooling) to separate the associated gas into three output streams: a natural gas mixture of methane and ethane, LPG (propane and butane), and heavier hydro-carbons. The natural gas mixture is used to fuel a 1 MW gas turbine that generates about 60% of BNE's electricity needs[82]. LPG is stored and sold in the local market as cooking fuel. The heavier hydrocarbons (occurring mainly as pentane, hexane, heptane and octane) are re-injected back into the crude oil production train.

LPG is a mixture of two gases – propane and butane – that is used throughout the world for cooking, water and space heating, power generation, and transport. More recently, it is being used increasingly used as an aerosol propellant and a refrigerant, replacing chlorofluorocarbons in an effort to reduce damage to the ozone layer. In Belize, LPG has historically been used mainly for cooking (80% of households) and transport (approx. 3% of vehicles). All LPG used in Belize was sourced from Mexico and El Salvador until BNE started supplying LPG into the local market in early 2011.

Resource Availability and Supply Potential

LPG

[80] Per information received from Mr. John Cooper, Technical Manager at BNE (October 24, 2011).

[81] The gas-oil ratio of sweet crude oil is usually 320 scf per barrel. However, in such cases, the methane content of the gas is normally as high as 70% by volume.

[82] According to BNE, small quantities of the gas are flared from time to time.

Approximately 3.25 kg of LPG can be extracted from the associated gas of each barrel of sweet crude oil produced at the Spanish Lookout site, assuming an extraction efficiency of 90% and given that about 125 standard cubic feet (scf) of associated gas on average can be gotten from each barrel of crude oil. If we produce crude oil at the rate of 1,460,000 bbls per year (4,000 bbls per day), the total LPG extractable from the associated gas of current local crude oil extraction operations is equal to 4,268,750 kg (or 2,042,500 US gallons) of LPG per year[83]. This is just over 30% of current LPG consumption for cooking in Belize[84].

If the extractable LPG is used to generate electricity instead, we can potentially produce 14,760 MWh per year of electricity (or about 3% of our current electricity demand) from indigenous LPG, assuming LPG electricity generation efficiencies of 27% on average. This is slightly more than the total electricity being produced by the Hydro Maya Project alone (14,400 MWh per year), which is currently BEL's smallest bulk energy supplier.

Natural Gas

Approximately 1.63 kg of the natural gas mixture of methane and ethane can be extracted from the associated gas of each barrel of sweet crude oil produced at the Spanish Lookout site, assuming an extraction efficiency of 90% and given that about 125 standard cubic feet (scf) of associated gas on average can be gotten from each barrel of crude oil. At a crude oil production rate of 1,460,000 bbls per year (4,000 bbls per day), the total natural gas mixture extractable from the associated gas of current local crude oil extraction operations is equal to 2,143,285 kg per year.

The energy content of the natural gas mixture is 49 MJ per kg x 2,143,285= 105,020,970 MJ = 105 TJ. If the natural gas is used as fuel to power a gas turbine at 30% efficiency, the electricity producible is 30% x 105,020,970 /3.6 = 8,752 MWh per year. This is about 1.8% of BEL's annual electricity generation, and significantly less than the amount of electricity generated by the Hydro Maya project.

Production Costs

According to the Bureau of Standards, in 2010, BNE produced 4,541,968 lbs (2,060,200 kg) of LPG at a cost[85] of $2,025,880.00 BZD ($1,004,153.00 USD), yielding a per-unit cost of $0.4875 USD per kg. BNE wholesales LPG for $67.00 BZD per 100-lb cylinder ($0.7312 USD per kg) to retailers, resulting in a mark-up of $0.2437 USD per kg; but

[83] Data provided by the Belize Bureau of Standards show that BNE sold 2,060,784 kg of LPG in the local market. This is less than 50% of the calculated potential output of the plant based on the data received from BNE.

[84] 34.9% if we use 12,234,273 kg as the total annual demand. This result supports BNE's claims that it can produce over 30% of national demand for LPG.

[85] It could not be ascertained if this was the full cost inclusive of capital costs or if it only included operational expenses.

mandates a cap on price to final consumers of $92.00 BZD per 100-lb cylinder ($1.005 USD per kg)[86].

No detailed cost data could be obtained on the operations of the LPG plant and no data was forthcoming on the cost of operating the 1 MW BNE-owned gas turbine at Spanish Lookout.

Downstream Refined Oil Products Industry

State of the Industry

All refined oil products (gasoline, diesel, kerosene and aviation gasoline) are imported from either the USA or Venezuela under the Petro-Caribe Agreement (discussed further below) and transported to Belize via ocean tankers[87]. Gasoline and diesel are also indirectly "imported" into Belize when local vehicles travel across to the border cities/towns (particularly, Chetumal in Mexico and Melchor de Mencos in Guatemala) for the expressed – or collateral - purpose of "filling up".

Except for oil sourced from Venezuela under the Petro-Caribe arrangement, Esso Belize, a local subsidiary of multinational Exxon-Mobil, is the sole bulk importer of refined oil products into Belize: 29 shipments totaling 44,384,091 gallons of refined oil products - 1,530,485 gallons per shipment on average - were imported in 2010. These imports are then distributed to retail fuel stations overland via trucks or over sea to the cayes via barges through three wholesalers: Esso, Sol and Texaco.

There are two storage depots for refined petroleum products in Belize: the Esso depot in Belize City with a total storage capacity of 166,000 barrels, and the depot at Big Creek with a total storage capacity of 60,000 barrels. The Big Creek depot was originally built to service receipts under the Petro-Caribe agreement, but is now being used exclusively to store locally-produced crude oil (from BNE) earmarked for exportation. Based on the 2010 rate of consumption of 121,600[88] gallons of refined oil products per day, the storage facilities at the Belize City depot has a capacity of approximately 57.34 days of fuel supply.

Retail Fuel Prices

Final consumer fuel prices are regulated by the Government using a fuel pricing formula that covers the full landed fuel cost and commercial charges plus taxes. The landed fuel cost is the CIF fuel cost plus port and storage fees and foreign exchange stamp duty. Taxes include import duty, an environmental tax and GST. Commercial charges include

[86] Per data provided by Mr. Daniel Gutierez, BNE Marketing Manager (October 2011).

[87] Except for oil products refined locally in Belize up to early 2010.

[88] Calculated as the total consumption in 2010 of 44,384,091 gallons divided by 365 days

wholesaler and dealer (service station) margins and delivery charges. In 2003, the retail dealer margins on imported refined oil products were adjusted from a flat dollar amount per gallon to a fixed percentage of the per-gallon CIF fuel cost. The justification for this change in the pricing formula was to compensate the dealers for the increase in the cost of doing business when pump prices increase. This revision has resulted in dealers being grossly over-compensated: whilst operating expenses rose by an estimated 20% over the last eight years, their margins have increased by 90% – peaking at $0.90 BZD per US gallon in 2008 versus an average of $0.41 BZD per US gallon in 2002.

In 2010, the average per-gallon prices of refined fuel products sold in Belize City were $9.56 for premium gasoline, $9.27 for regular gasoline, $8.38 for diesel and $6.75 for kerosene. The price of a gallon of gasoline was broken down as follows: 52% CIF cost, 34% Taxes and 14% Commercial Charges; while the price of a gallon of diesel was 58% CIF cost, 28% Taxes and 14% Commercial Charges. The average tax on the CIF cost of gasoline was 67% compared to 47.3% for diesel. The average tax on the CIF cost of gasoline was therefore 40% higher than the tax on diesel.

One of the criticisms with the current fuel pricing regulation is that the way in which new prices are put into effect opens it up to price manipulation. Under the current regulation, once a new shipment is received by Esso, all fuel sold thenceforth, including fuel received from previous shipments and held in stock at the main depots or at retail stations, is charged at the prices calculated per the latest shipment. If, for instance, the FOB cost of diesel fuel in stock was $4.75 per gallon and the FOB cost of diesel in the new shipment is $5.00, then the supplier gets a windfall of $0.25 on every gallon of diesel fuel being sold from the original stock until another shipment arrives. While, it is arguable that supplier loses when the opposite scenario occurs, the decision of when to order a new shipment is largely left to the supplier's discretion. This provides an opportunity for the supplier to "game the system" [89] by simply choosing to bring in a small shipment of oil products when prices – and hence FOB costs - are high compared to the FOB costs of the fuel in stock, resulting in an immediate change in petroleum product prices country-wide including those in inventory that were purchased at the lower price.

The Petro-Caribe Agreement[90]: *The Venezuelan Connection*

In 2005, the Government of the Bolivarian Republic of Venezuela (hereinafter, Venezuela) and the Governments of 14 countries in the LAC region, including Belize, signed the Petro-Caribe Agreement for the direct sale of petroleum products, on concessionary terms, from Venezuela's PDVSA to the respective countries. The stated

[89] A cursory analysis of data for 2010 revealed no obvious indications of any such "gaming of the system".

[90] Refer to **Appendix B** for details of the Agreement.

objective of the initiative remains: to foster regional solidarity and alleviate financial hardship endured by countries in the target region in the face of rising oil prices.

Through this agreement, PDVSA provides soft financing for the fuel purchases of the LAC countries that are a party to the agreement on the basis of a bilateral fixed quota[91]; *but with no price concessions*, since Venezuela, as a member of OPEC, is obligated to sell its oil at market price. A portion of each invoice (for fuel purchases), called the 'Financed Portion', is to be paid over 25 years at 1% interest rate with a two-year grace period[92], as long as the weighted average FOB price of the basket of products being purchased is higher than $40 USD per barrel. If the price of the basket of petroleum products purchased falls below $40 USD per barrel, then the financing period falls to 15 years and the interest rate increases to 2%. The remaining portion of the invoice, called the 'Cash Portion', is payable within 90 days, with a financing charge of 2% per annum levied after 30 days.

Average purchase price (FOB-VZLA) per barrel (USD)	% of FOB Purchase Value eligible for Long-term Financing	Financing period (years)
$15.00	5%	15
$20.00	10%	15
$22.00	15%	15
$24.00	20%	15
$30.00	25%	15
$40.00	30%	25
$50.00	40%	25
$80.00	50%	25
$100.00	60%	25
$150.00	70%	25

Table 3.2.2.1: Petro-Caribe Long-Term Financing Schedule

As shown in Schedule I above, the level of the 'Financed Portion' increases as the price per barrel of the basket of petroleum products purchased increases[93]. For instance, the 'Financed Portion' is set at 40% of the total bill, when the price of the basket of petroleum products being purchased is higher than $50 USD per barrel; 50%, when the price of the basket is higher than $80 USD per barrel increase; and 60%, when the price of the basket is higher than $100 USD per barrel.

There are four other important provisos of the Agreement: Firstly, only the FOB component of the invoice is available for financing: the cost of freight and insurance must be paid immediately on delivery. Secondly, under the agreement, PDVSA arranges all delivery of the fuel to Belize. Thirdly, Venezuela may agree to repayment in-kind,

[91] Up to a monthly average of four thousand barrels per day in Belize's case.

[92] Interest is capitalized (simple interest method) during the grace period.

[93] It has been widely misconstrued that the basis for changes in the level of the portion eligible for long-term financing is the change in **crude oil prices**. However, we have conclusively confirmed that this is not so and the basis is in fact the per-barrel FOB price of the basket of goods being purchased.

such as agricultural products, but at preferential prices. Lastly, and importantly, Venezuela may terminate the agreement at anytime by giving 30 days notice.

As of the time of the writing of this report, 18 countries[94] had signed unto the Petro-Caribe Agreement with Venezuela, namely: Antigua and Barbuda, Bahamas, Belize, Cuba, Dominica, Dominican Republic, El Salvador[95], Guatemala, Guyana, Grenada, Haiti, Honduras, Jamaica, Nicaragua, St. Lucia, St. Kitts and Nevis, St. Vincent and the Grenadines, and Suriname.

Current Status of the Petro-Caribe Initiative

In June 2007, Government, through a specially-formed company, Belize Petroelum and Energy Limited (hereinafter, BPEL)[96], signed a contract with Petro Fuels Belize Limited (hereinafter, PFBL), a subsidiary of the Big Creek Group[97], to supply refined petroleum products, lubricants and LPG (delivered under the Petro-Caribe Agreement) to PFBL through BPEL for selling and distribution into the local market. PFBL would import the products through the port at Big Creek, which was also owned by PFBL's parent company, the Big Creek Group, and would be responsible for all costs related to receipt, storage, distribution, marketing and retailing of the products. GOB would obtain the full benefit from the earnings due to the discount on the long-term financing charges; while the full short-term financing benefits would be passed on to PFBL

During the period 2007 to 2009, PVDSA delivered 457,680 barrels (19,222,560 gallons) of refined petroleum products, valuing over $41 million USD (FOB), in fifteen (15) shipments to Belize through the Big Creek Port under the terms of the agreement. These products were sold almost exclusively in Southern Belize, mainly to industrial consumers, as it was not viable to compete with ESSO further north due to the difference in transportation charges between the two areas. Even so, according to PFBL, this business model could not be sustained because the landed cost of the PDSVA supply was higher than the supply from ESSO, due to higher freight and insurance charges for transporting from Venezuela which were out of the PFBL's control. This situation was further complicated because fuel price changes were triggered only when shipments were received by ESSO: PFBL was therefore left open to competitive price manipulation tactics, especially given its inability to dictate its own petroleum products delivery

[94] This number may have increased or may soon increase to 19, as the *Latin American Herald Tribune* reported on June 15, 2012 that President Martin Torrijos of Panama announced that his country would be joining the Petro-Caribe Program.

[95] There is some confusion as to the nature of the Agreement with El Salvador, and that it is in fact an informal agreement through which Venezuela helps to finance an opposition political party in the country.

[96] BPEL was formed with the sole purpose of contractually engaging with Venezuela's PDVSA as required under the terms and conditions of Petro-Caribe.

[97] A company operating out of the Stann Creek District, which was also the owner and manager of the big Creek Port through which supplies from Petro-Caribe would be channeled.

schedule. Moreover, PFBL frequently complained of receiving invoices late from PDVSA and having to price their products on the basis of previous shipments, which caused them at times to under-price their products (relative to their actual costs) to the market.

PFBL formally closed down its Petro-Caribe-related operations in 2009 because of the high cost and unreliability of the PDVSA supply, and because they were unable to work out an agreement with PDVSA to arrange their own shipping. At the same time, PDVSA apparently made a unilateral decision, applicable to all Petro-Caribe member countries, that the local Government-owned party to the contracts - BPEL in Belize's case – should be replaced by a joint venture of state-owned companies of both Venezuela and the recipient country. It appears that the authorities in Venezuela were not satisfied with the supply business model being utilized amid feedback from other countries that the benefits of Petro-Caribe were being channeled away from the intended beneficiaries of the program, the Government and People of the recipient countries, towards a coterie of private interests; and hence sought to exert tighter control over the program. A planned visit by PDVSA officials to Belize since 2009 to setup this new arrangement never materialized; and no serious effort was made by any of the parties to revive the program since that time until March 2012.

Potential Earnings by GOB from the Petro-Caribe Initiative

The main benefit of Petro-Caribe is the concessionary financing terms and resultant financing space provided. The net inflows from the long-term financing arrangements could be used to cover 100% of the current SuperBond debt obligation repayments from 2012 through to 2019, and hence to drastically reduce the total public sector financing gap (through to 2019) by almost half on average (Mencias, What Petro-Caribe can do for BELIZE, 2012).

Figures in US$ Millions	*2013*	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*
A. Super Bond Debt Service Payments	(46)	(46)	(46)	(46)	(46)	(46)	(74)
B. Inflows from PetroCaribe ('Financed Portion')	67	50	50	50	50	50	50
C. Debt Service Payments due to PetroCaribe	0.00	0.00	(0.84)	(3.36)	(5.87)	(8.39)	(10.91)
D. Carry Forward (accrues at 7.5% interest rate)	23	29	35	38	39	38	3
E. **Resultant Financing Gap on Super Bond**[1]	**0**	**0**	**0**	**0**	**0**	**0**	**0**
% of Debt Service covered by PetroCaribe	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Table 3.2.2.2: Potential Effect of Projected Future Inflows from Petro-Caribe on SuperBond Repayment Schedule[98]

An assessment[99] of the actual savings achievable from the long-term financing afforded by Venezuela has shown that the present value of the savings[100] possible on each year's supply of petroleum products would amount to approximately $27,000,000 USD or

98 Taken from (Mencias, What Petro-Caribe can do for BELIZE, 2012)

99 Ibid.

100 Using a *conservative* cost of capital of 7.5% per annum (2012); also ignoring any difference between the landed cost of Petro-Caribe fuel and fuel from traditional supply sources.

$0.63 USD per gallon, if 100% of our gasoline and diesel needs are supplied via Petro-Caribe, assuming imports of 42,500,000 US gallons per year at an average FOB cost of $2.50 USD per gallon[101]. These results show that Government would be able to afford to take $0.25 USD per gallon out of its annual savings from Petro-Caribe to lower fuel pump prices and still manage to funnel $0.38 USD per gallon into its coffers to pay debt obligations and invest in public-sector projects, or, alternatively, allot all the savings to directly lowering pump prices by more than $1.25 BZD per gallon!

The Downside of the Petro-Caribe Initiative

Despite its touted objectives, Petro-Caribe has been widely criticized as simply another prong of Venezuela's "oil diplomacy" strategy aimed at making countries in the region more beholden to and dependent on a single supplier, Venezuela, at the expense of cutting commercial ties with the U.S companies who currently supply most of their refined petroleum demand (Noriega, 2006). Opponents of Petro-Caribe have argued that, instead of making adjustments and re-directing efforts and resources to wean themselves off oil, these countries are fooled by a false sense of low cost oil, which is in fact a discount on the market cost, which must still be eventually paid over time. In 2006, Trinidad and Tobago's then Prime Minister, Patrick Manning, had forewarned that Petro-Caribe "represents a retreat from market principles" and would leave Caribbean countries "high and dry if private companies abandoned the region" (Noriega, 2006).

Despite Trinidad and Tobago's obvious self-interested stance, there is much to suggest that participating countries should heed this forewarning. Petro-Caribe is largely viewed as a cornerstone of a Chavismo foreign policy of hegemonic outreach in the LAC region; and, given its relative unpopularity[102] at home in Venezuela, it is widely felt that Petro-Caribe may well come to an end when Chavez is no longer President. There is increasing pressure on the Chavez regime at home in Venezuela to revisit agreements such as Petro-Caribe, which are viewed by many as controversial export deals to supply oil under preferential terms, such as the low cost financing concessions and the barter program. This perception is backed up by a sharp reality: According to a recent Reuters report (2012), the proportion of PDVSA's sales not directly paid for in cash rose from 32% in 2009 to 36.5% in 2010 to 43% at the end of 2011. PDVSA's resulting, record-high debt levels have left the company struggling to make payments to suppliers and having to put its investment plans on hold, including its much-touted project to develop the huge petroleum deposits in the country's Orinoco Belt. To make up for its cash

[101] This would result in long-term financing proceeds from Petro-Caribe of just over $50 million USD per year.

[102] "If an opposition candidate defeats Chavez next year and ends the former soldier's 13 years in power, they would all be expected to review these deals. The majority of the agreements are unpopular with Venezuelans, according to opinion polls" (Excerpt from Reuter's website, Article: "*Venezuela's Perez would revise Cuba oil deal*" by *Diego Ore*, *November 10, 2011*)

shortfall, PDVSA was forced to issue $10 billion USD worth of bonds in 2011. (Parraga & Daniel Walli, 2012). The pressures – both real and political – should, as a minimum, force participating, countries like Belize to put Petro-Caribe in as realistic a perspective as possible: to confine projected inflows and other benefits from the program to our short and medium-term plans only, and to consider ways how they might build a more reciprocal relationship with Venezuela that can potentially thrive much further into the future!

Projected Prices and Costs

International Crude Oil Prices

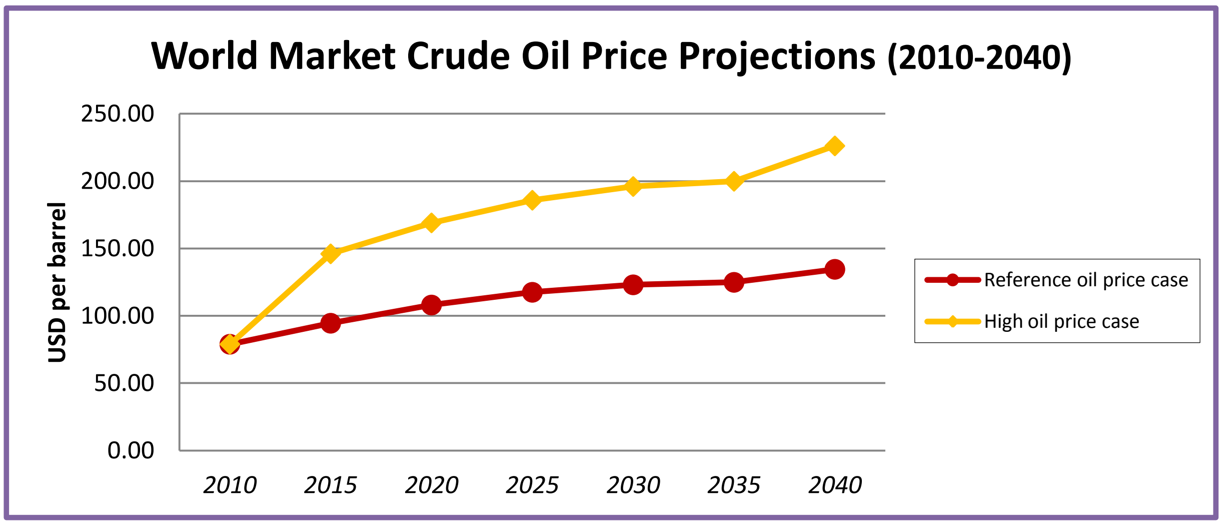

Figure 3.2.3.1: World market prices for Crude Oil for 2010-2040 (*Source: EIA*)

Transport Fuel

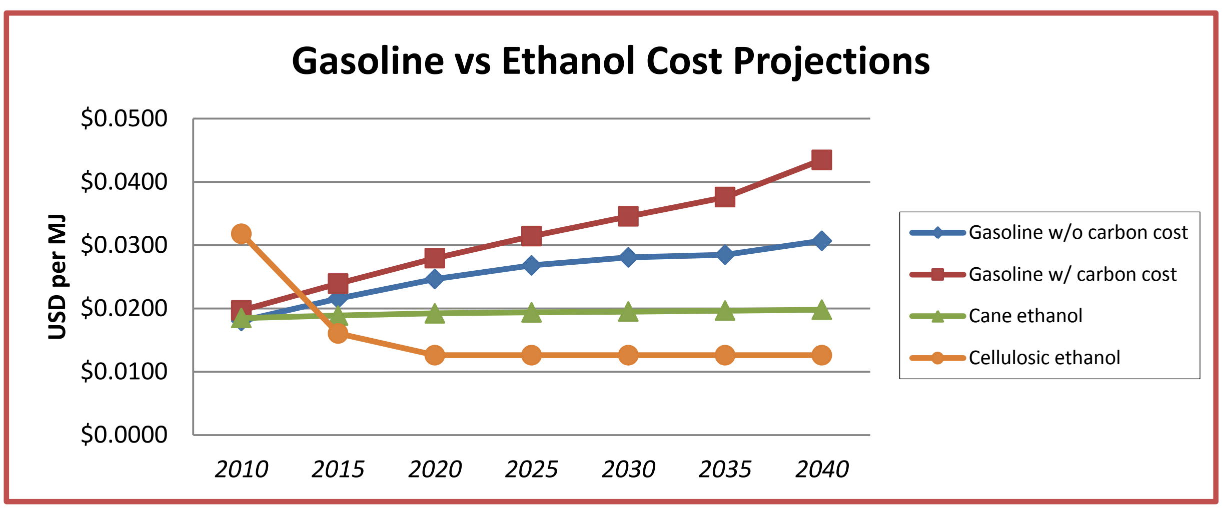

Figure 3.2.3.2: Gasoline vs. Ethanol Cost Projections (in USD per MJ) for 2010-2040

Figure 3.2.3.2 illustrates the projected rise in the local cost of gasoline[103] relative to ethanol biofuels over the period 2010 to 2040. Gasoline costs are projected to increase as a direct function of crude oil prices. The costs of ethanol biofuels are based on the

[103] Projections of landed cost of gasoline based on AEO crude oil market price projections. This cost does not include local transportation and distribution costs and taxes.

local production costs discussed under the relevant sub-sections in the *Biofuels* section further above. These costs are assumed to remain constant (2010 prices) for most of the forecast period. Even without taking into consideration the cost of carbon, gasoline costs are projected to be significantly higher than ethanol costs over the long run.

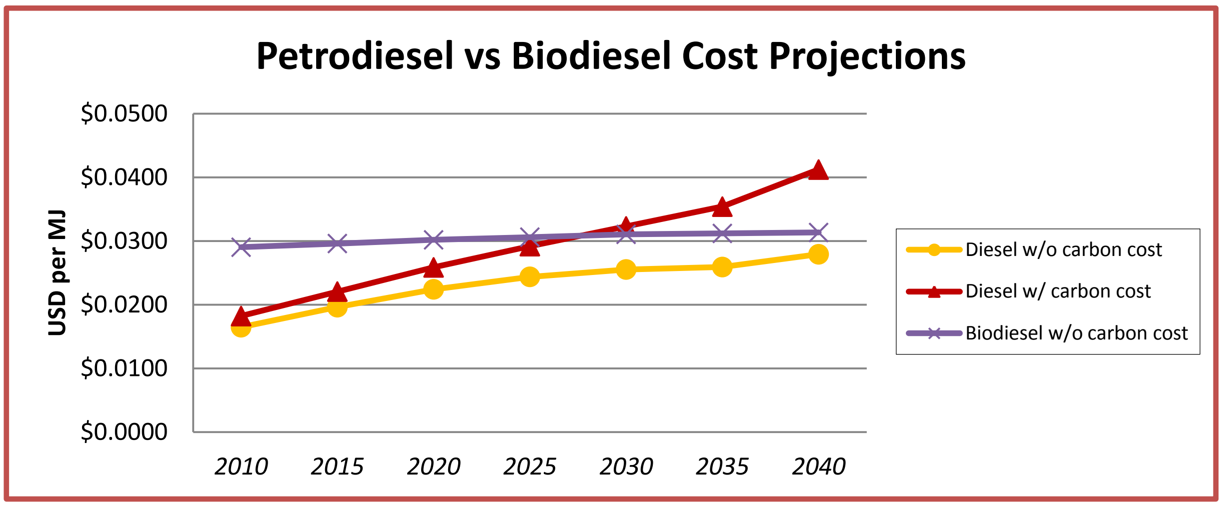

Figure 3.2.4: Petrodiesel vs. Biodiesel Cost Projections (in USD per MJ) for 2010-2040

From the projections in Figure 3.2.4 above, it can be seen that (petro-)diesel is expected to cost less than biodiesel throughout the forecast period unless the carbon cost of diesel is taken into account, in which case the cost of diesel is projected to be higher than that of biodiesel after 2025. These projections are of course highly dependent on long-term trends in crude oil prices[104] and technology innovations in biodiesel production.

Carbon Costs

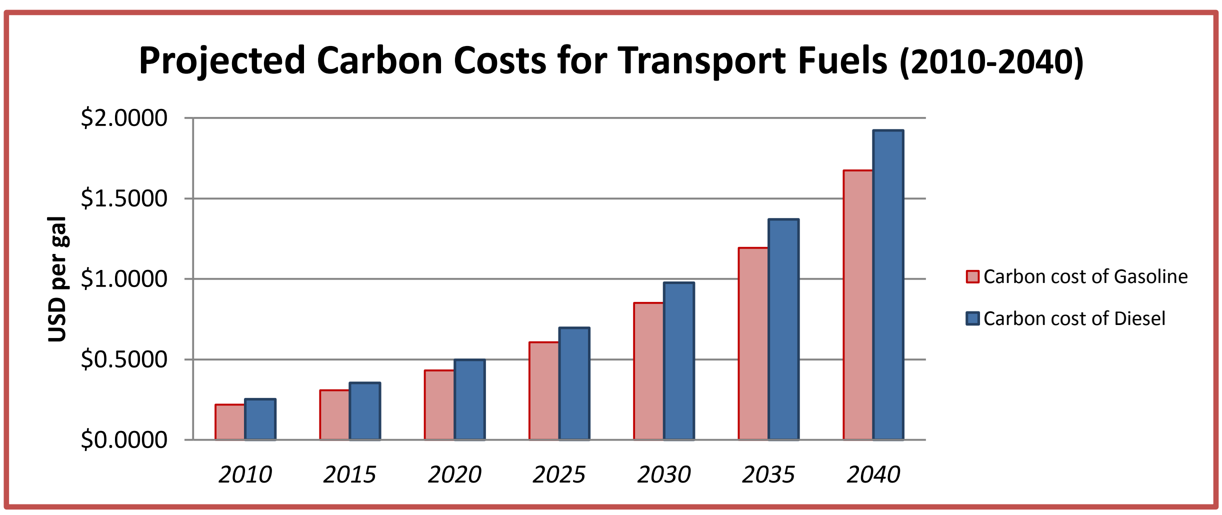

Figure 3.2.4.1: Carbon Cost Projections for Transport Fuels for 2010-2040

Gasoline and diesel emit 0.0088 and 0.0101 tCO2e of carbon (per gallon) on combustion respectively. Figure 3.2.4.1 above illustrates the projected trends in the cost of carbon for these two main transport fuel types, based on the estimated projections of the carbon price over the planning horizon given in Figure 3.1.0 at the beginning of the

[104] Diesel costs are projected to increase as a direct function of crude oil prices (per the 'Reference oil price case' provided in the previous sub-section).

chapter. Carbon costs of gasoline are projected to increase from $0.22 to $1.675 USD per gallon, or from 8.5% to nearly 30% of total fuel cost, over the planning horizon. Carbon costs of diesel are projected to increase from $0.2525 to $1.922 USD per gallon, or from 9.58% to 32.26% of total fuel cost, over the planning horizon.

Electricity Generation from Diesel and HFO

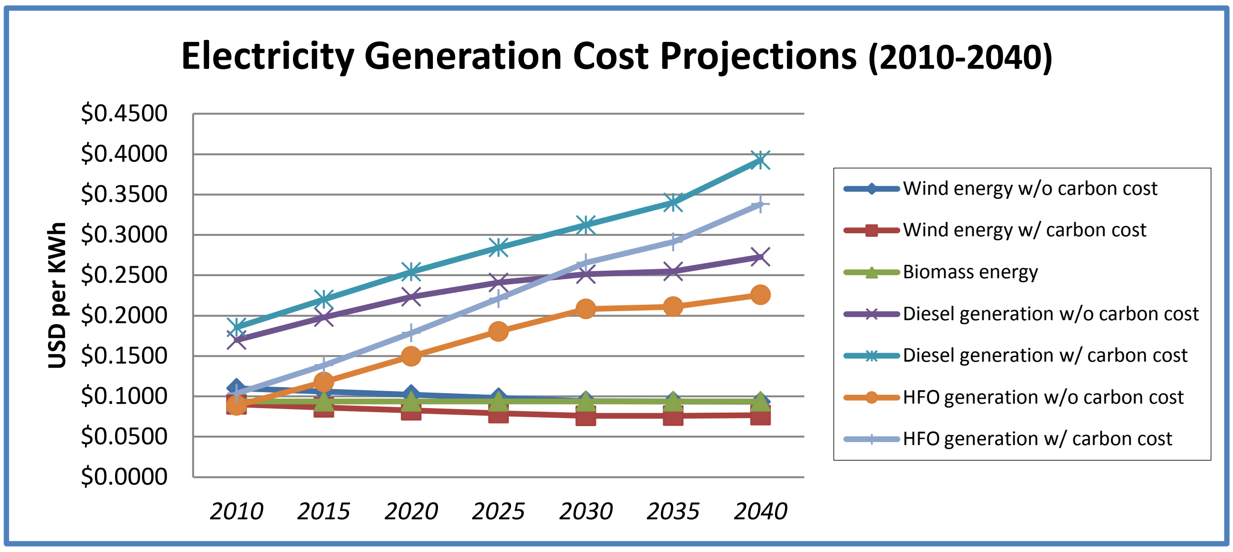

Figure 3.2.5: Electricity Generation Cost Projections for 2010-2040

During the short time of preparing this report alone, the world market price for WTI crude oil fluctuated between a high of nearly $115 USD per barrel and a low of $80 USD per barrel, corresponding to a landed cost (Belize) for diesel of $3.25 USD per gallon (high) and $2.25 USD per gallon (low) respectively. The levelized cost of generating electricity from medium-speed diesel generators would therefore have fluctuated between $0.25 USD per KWh and $0.18 USD per KWh. The graph above projects the cost of electricity generation from various fossil-fuel based sources versus biomass-fired generation and wind generation[105] over the next 30 years. Both HFO generation and diesel generation will cost significantly more than either biomass-fired generation or wind generation over the next 30 years.

How low would crude oil prices have to be for baseload diesel generation to be comparable with biomass-fired or wind electricity generation in say 2015?

In 2015, the costs of biomass-fired and wind-generated electricity are projected to be $0.0939 and $0.1068 respectively. Crude oil prices are projected to be $94.59 per barrel on average in that year, resulting in diesel generation costs of $0.2589 USD per KWh *without accounting for carbon costs*: that is, over twice the cost of biomass and wind electricity. In order for diesel generation costs to fall to $0.1068 USD per KWh, diesel

[105] The cost of wind generation includes the cost of capacity based on the latest quotation of $4.50 USD per KW-month provided by CFE during the latest round of negotiations with GOB/BEL in June 2011. The cost of capacity so derived is also in agreement with Table 3.1.4 further above, which provides the cost of integrating wind resources into the supply mix at different wind penetration levels.

fuel costs would have to fall to $1.20 USD per gallon. Based on historical correlations, this would mean crude oil prices would have to fall to about $35.00 USD per barrel!

Carbon Costs

Wind and solar (PV) generation produce 0.021 and 0.106 tCO2e GHG emissions per MWh of electricity generated respectively. On the other hand, baseload diesel and HFO generation (at 60% capacity factor) produce 0.6293 and 0.5909 tCO2e GHG emissions per MWh of electricity produced respectively; while diesel generation used for peaking produces as much as 0.839 tCO2e GHG emissions per MWh of electricity. Thus, oil-based electricity generation can emit in the range of 30 to 40 times more carbon than wind generation and 6 to 8 times more carbon than solar (PV) generation.

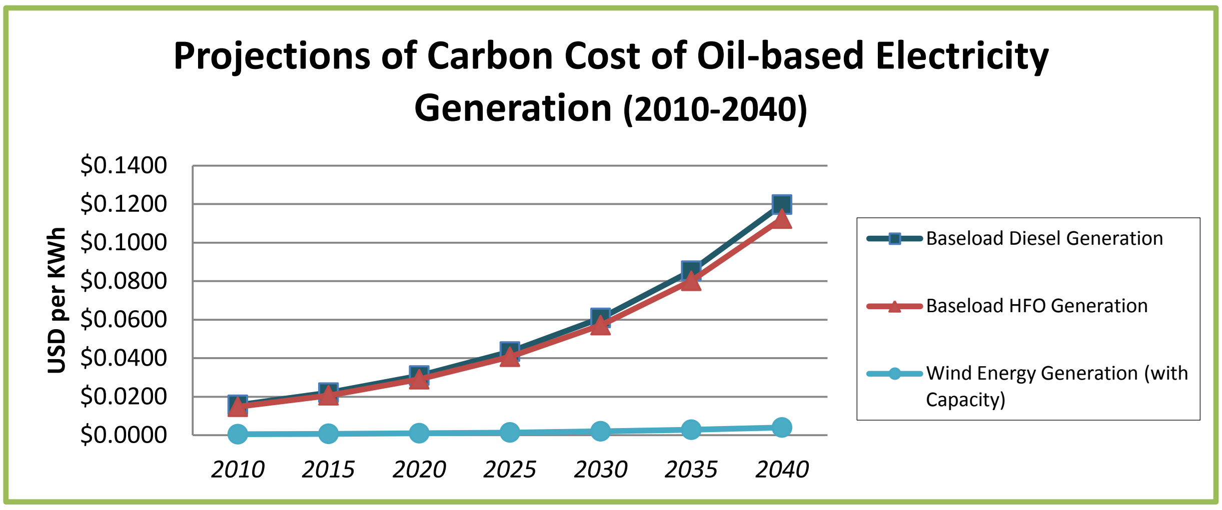

Figure 3.2.5.1: Carbon Cost Projections for Oil-based Electricity Generation for 2010-2040

Figure 3.2.5.1 above compares the projected trends in the cost of carbon for diesel and HFO with that of wind generation, based on the estimated projections of the carbon price over the planning horizon given in Figure 3.1.0 at the beginning of the chapter.

Downstream LPG Industry

The State of the Industry

Most of the liquefied petroleum gases used in Belize – primarily propane and butane - is imported by independent suppliers from either Mexico or from the USA or Venezuela by way of El Salvador. The fuel is hauled overland from supply sources in Mexico and El Salvador and delivered to depots belonging to the various importers, from which point they are delivered by truck and barge to distribution points on the mainland and in the cayes respectively. BNE began supplying locally-produced LPG in early 2010.

The constituent propane and butane are delivered (from the foreign supply sources) separately and mixed in country at the main depots. The mixtures provided by different wholesalers vary widely from 60% propane by volume to over 90% propane by volume. The amount and the content of the LPG sold to final consumers have been the subject of much controversy recently, resulting in the enactment of government legislation requiring retailers to provide weighing instruments at points of sale, including delivery trucks, so that consumers can verify on the spot the quantities of LPG being received. Government also revised base prices charged by the various distributors to reflect the proportion of propane/butane in the mixture.

In 2010, a total of 5,021,385 lbs (2,277,660 kg) of liquefied butane gas was imported into Belize at a cost of $3,807,461 BZD ($1,887,217 USD); and a total of 21,119,008 lbs (9,579,413 kg) of liquefied propane gas was imported at a cost of $16,720,659 BZD ($8,287,811 USD)[106]. The average importation cost of butane and propane in 2010 was therefore $0.8286 USD per kg and $0.8652 USD per kg respectively. These were on average 15.82% higher than the wholesale cost of $0.7312 USD per kg charged by BNE for the 4,541,968 lbs (2,060,200 kg) of LPG produced locally in 2010.

Retail Fuel Prices

Similar to refined oil products, LPG prices to consumers are regulated by the Government using a pricing formula that covers the CIF cost (delivered to the Belize), commercial charges for transportation and distribution within Belize and a 2% environmental tax. In 2010, commercial charges were approximately 40% of FOB cost. Transportation charges vary according to the retail distribution area (and hence the distance from the supplier's main depots).In September 2011, a premium charge of approximately $8.00 BZD per 100-lb tank (or $0.0874 USD per kg) was allowed on the sale of LPG with a 60:40 propane-to-butane gas ratio (by volume) in order to rationalize prices in light of reported significant discrepancies in the content of the LPG mixtures provided by the different suppliers.

Projected Prices and Costs

International Natural Gas Prices

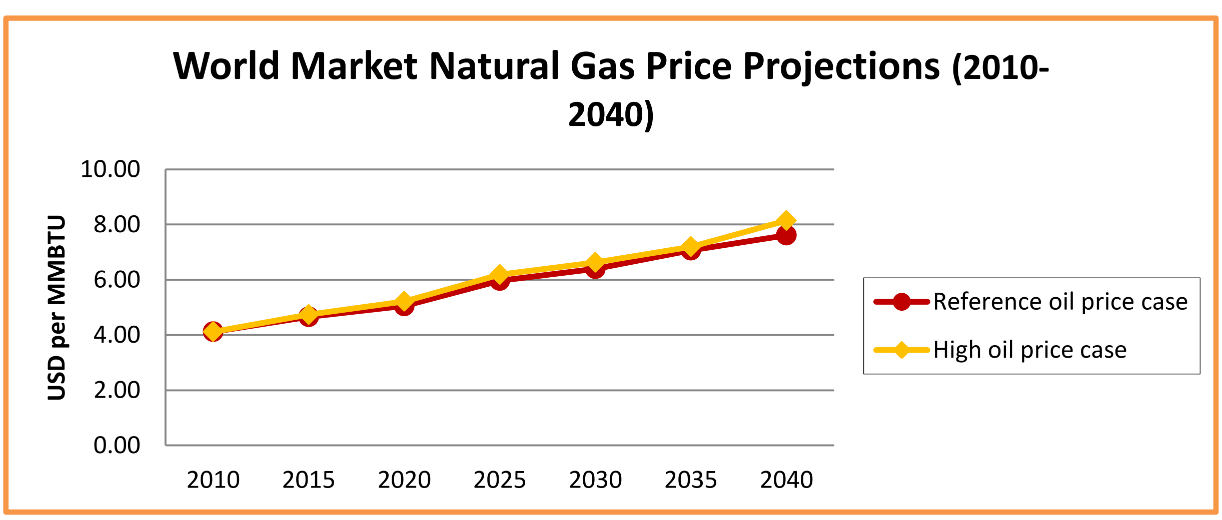

Figure 3.2.6: World market prices for Natural Gas for 2010-2040 (*Source: EIA*)

[106] Source: Bureau of Standards of Belize (2011)

Research conducted by the NEP team has shown that LPG prices (landed in Belize) are tied to international natural gas prices.

Figure 3.2.6 above provides forecasts of natural gas prices (Henry Hub) for a reference oil price scenario and a high oil price scenario[107].

Cost of LPG delivered to Belize

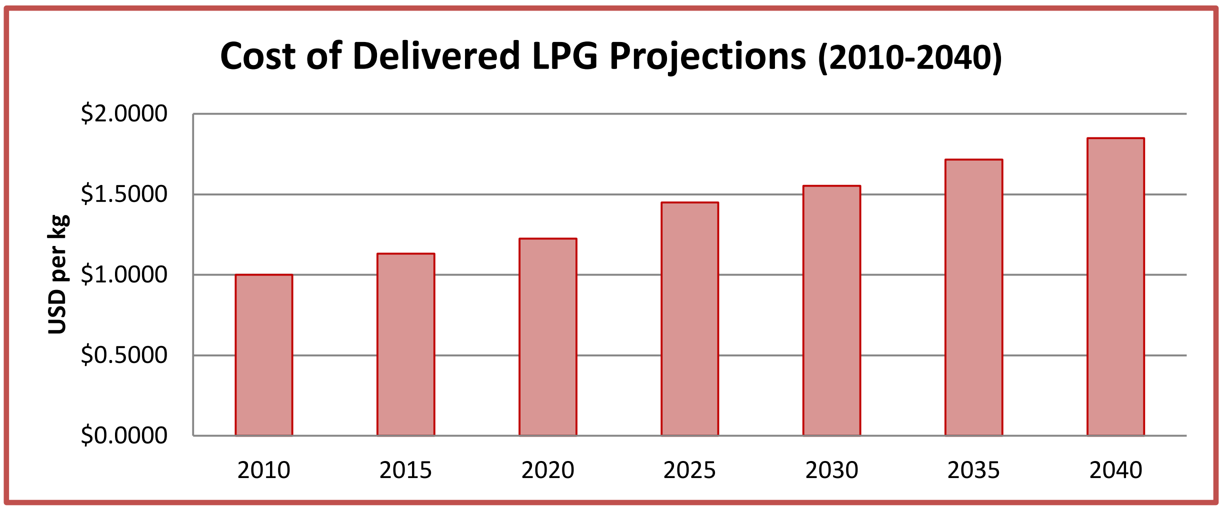

Figure 3.2.7: Cost of Delivered LPG Projections for 2010-2040

Figure 3.2.7 above shows the forecasted costs of LPG delivered to Belize for the period up to 2040. These costs were derived by projecting the historical correlation between LPG costs delivered to Belize and international natural gas prices.

Environmental Benefits/Costs

LPG is a relatively clean gaseous mixture that burns with little soot or sulphur emissions. It does however produce 5.65 kg of CO2-equivalent GHGs per US gallon during combustion[108]. On an energy content basis (net calorific value), this is 0.211 kg of CO2-equivalent GHGs per KWh, which is 13% and 16% lower than the emissions rate for gasoline (0.242) and diesel (0.253) respectively.

Downstream Natural Gas Industry

State of the Technology

Natural gas is quickly emerging as the fossil fuel of choice for electricity generation - and in some cases for transport - in countries seeking to diversify away from their dependence on oil. It is currently over four times cheaper than oil on an energy equivalent basis (using 2011 prices to date); is less toxic; burns more cleanly than both

[107] That is the forecasted prices of NG if the reference oil price scenario occurs and the forecasted prices if the high oil price scenario occurs.

[108] This number increases as the proportion of propane in the butane-propane mixture increases.

oil and coal; and produces 12.1% less emissions than LPG, 26.8% less than diesel, and 45% less than coal (when burned) respectively.

Natural gas is mixture of gaseous hydrocarbons, made up mainly of methane with the heavier hydrocarbons (primarily ethane) making up the remaining portion. It can be found in natural gas fields occurring deep within the earth; in coal beds; in shale rock as shale gas; or "associated" with crude oil, either existing as a gas cap above the crude oil in the underground formation or dissolved in the crude oil itself. It is also produced biogenically in marshlands or landfills (Wikipedia: Natural Gas Processing, 2011).

***Shale Gas* is natural gas trapped in shale rock. Although, it has been long known that impermeable shale contains natural gas, the technologies available for releasing the trapped gas were not economically feasible. Breakthrough research and the rising cost of competing energy sources are however changing the playing field. Shale gas now accounts for 30% of US domestic production of natural gas, and the "discovered" reserves in the US alone are sufficient to supply their local demand for the next 120 years at current consumption rates. Two of the major concerns at the outset are that the hydrocarbons and chemicals used to extract the gas from shale will contaminate aquifers that supply drinking water and that the extraction process uses up large quantities of water. (WEC, 2010)**

Processed natural gas is stored and/or transported either as pipeline gas, compressed natural gas (CNG) or liquefied natural gas (LNG). Pipeline gas is natural gas in its normal gaseous form that is delivered via pipelines from source to where it is consumed. Pipeline gas is economical within a radius of a maximum distance of 4,000 km or 2,500 miles (Wikipedia - Natural Gas, 2011). For longer distances and in other cases where it is cost-prohibitive to run pipelines through harsh environments such as mountainous terrain or deep undersea, it is more cost-effective to transport natural gas as CNG or LNG.

CNG is natural gas in gaseous form, compressed to 1/250th of its volume at standard temperature and pressure. LNG is natural gas in liquid form, compressed to 1/600th of its volume at standard temperature and pressure. While it is less costly to transport LNG (since its volume is less than half that of the same mass of CNG), the facilities needed to liquefy the gas (before transporting) and re-gasify it (after delivery) are usually very high[109], making LNG economically viable only for delivery distances of over 2,500 miles (Economides, Sun, & Subero, 2006).

[109] A typical liquefaction plant costs in the region of USD$750 million to $1.25 billion: about 50% of total investment costs. Re-gasification facilities typically cost US $500-550 million depending on terminal capacity. (Economides, Sun, & Subero, 2006)

Supply Potential

While no proven reserves of natural gas (fields) have been found in Belize as yet, there are a number of opportunities available or that might soon be available for accessing natural gas within the LAC region: directly from Mexico, by way of the Central American Gasification Project which will be underpinned by supplies from Mexico and Colombia, from Trinidad and Tobago through membership in CARICOM, and from Venezuela under the Petro-Caribe Agreement. It is assumed that natural gas so imported would be used for electricity generation, and should be in sufficient quantities to support at least a 25 MW baseload gas turbine operating at a plant capacity factor of 80%.

Sourcing from Mexico

Mexico’s natural gas pipeline distribution system runs as far south-east as Valladolid in the state of Yucatán (about 200 miles from Belize’s northern border), and terminates in Guatemala less than 100 miles from Belize’s southern border. As far back as 2003, a plan was under consideration by Mexico’s Energy Secretariat to extend the supply of natural gas to the state of Quintana Roo (as far south as Chetumal) in order to supply the local LPG demand and to fuel a 550 MW gas-fired power plant programmed for deployment by CFE. The plan entailed deploying 310-410 miles of additional pipelines to link the targeted consumption centers to the existing network and building an LNG re-gasification terminal (from which the supply would be sourced) in one of four locations: Puerto Campeche on the western side of the Yucatán peninsula, Puerto Progreso near Mérida at the top of the peninsula, Puerto Morelos at Xel-Há near Cancún and Puerto Chetumal (Portes Mascorro, 2003). If this plan were to be implemented, it would open up an opportunity for Belize to source low-cost natural gas for a new gas-fired power plant and for other industrial purposes in the north simply by extending the natural gas pipeline a few miles further from Chetumal into Belize.

Very near to the time of finalizing this Report, Mexico’s Energy Secretariat confirmed that the foregoing plans had changed drastically since the time of their initial conception in 2003 and that further development of LNG re-gasification terminals had been put on hold. Instead, Mexico was planning to invest in extending its gas pipelines northward into Mexico to source cheap shale gas in the USA. Moreover, there were no plans to run pipelines into Quintana Roo; instead CNG would be transported overland by truck from Yucatán to specific customers.

Central American Gasification Project

A 2010 Report titled “Central American Electric Interconnection System (SIEPAC): Transmission and Trading Case Study” by Economic Consulting Associates noted that a Central American gasification project is being considered as part of the wider Meso-American Project to build a natural gas transmission system through the region, connecting the Central American countries to gas supplies from Mexico and Colombia, as well as the building of an LNG re-gasification terminal in the region to serve the area (Economic Consulting Associates, 2010). This would present an opportunity to source natural gas, assuming extension of existing NG distribution systems (from Mexico or Guatemala) to Belize or arrangement for overland transportation (as CNG) from the nearest terminals.

Sourcing from Trinidad and Tobago

Trinidad and Tobago is one of the largest natural gas exporters in the world and the largest exporter to the United States. It also exports natural gas to the Dominican Republic and Puerto Rico. As of 2002, plans were being proposed to construct a 500-mile pipeline from Trinidad to supply the islands of Barbados, Martinique, Guadeloupe and St. Lucia (Nexant, 2010); Jamaica is also entering the bidding phase of a project to construct an LNG terminal which was originally to be supplied by LNG sourced from Trinidad at preferential prices[110].

Even if natural gas could be purchased from Trinidad and Tobago at preferential prices, the demand in Belize is much too low to justify the cost of transportation and of investing in a local LNG re-gasification terminal. Any supply from Trinidad would therefore have to be arranged as part of economically-sized shipments to Mexico and/or Central America as a whole through a future LNG terminal in Mexico or another part of Central America. This would also entail extending the existing NG distribution systems of our neighbors (Mexico or Guatemala) to Belize or arranging for overland transportation (as CNG) from their nearest CNG terminals.

The Petro-Caribe Agreement

The Petro-Caribe Agreement also provides for purchase of natural gas from Venezuela; although it is not clear if the low-cost financing afforded under this agreement is applicable to natural gas products. Venezuela has no LNG liquefaction facilities and there are no firm plans in place to build any of such facilities (Nexant, 2010), so any natural gas supplied under Petro-Caribe would have to be supplied by ship as CNG or via pipeline under a future Central American Gasification Project.

Although shipping natural gas as CNG from Venezuela more than 1,500 miles overseas to Belize may not be justifiable on its own given the relatively small quantities involved, a cost effective solution could probably be found through a system of coordinated purchases and deliveries to countries in the LAC who are signatories to Petro-Caribe, as proposed by Nexant in their 2010 Report "Caribbean Regional Electricity Generation,

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[110] However, the countries have not been able to reach any agreement on these prices at the commercial level and supply of LNG will be based on competitive bids. It is uncertain if any other country would be capable of supplying Jamaica's NG demand since Trinidad is the only country in the region with developed LNG production capability.

Interconnection, and Fuels Supply Strategy" (Nexant, 2010). That proposal envisions a large vessel starting off from Venezuela with a full payload and delivering sufficient products to fill each country's storage along its route; each delivery round may have different stops along the way, depending on the current inventory levels and storage capacities of the participating countries along the route.

Projected Prices and Costs

Cost of Natural Gas delivered to Belize

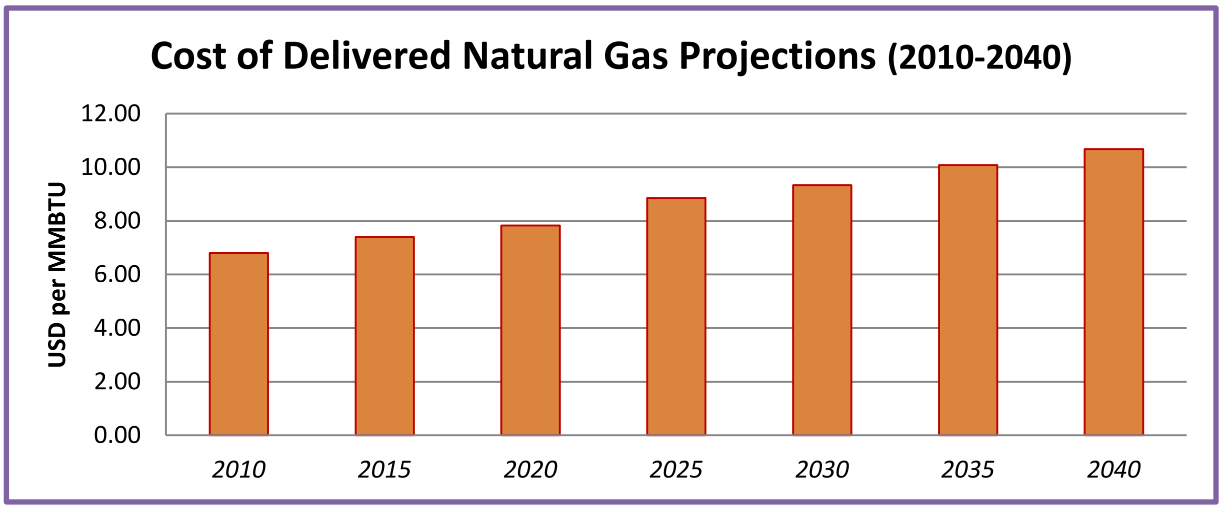

Figure 3.2.8: Cost of Delivered Natural Gas Projections for 2010-2040

Figure 3.2.8 above shows the forecasted costs of natural gas delivered to Belize for the period up to 2040. These costs were derived by employing the methodology used by Nexant in their 2010 Report "Caribbean Regional Electricity Generation, Interconnection, and Fuels Supply Strategy" (Nexant, 2010): the international price of natural gas (Henry Hub) was used as the base (*See Figure 3.2.6 in the previous sub-section above*), transport and re-gasification costs of $2.00 USD per MMBTU were added[111], and the final cost was adjusted for expected losses of 10%[112] during transport and re-gasification.

It is assumed that actual delivery could occur through a number of options: including via pipeline linked to Mexico, or as CNG shipped from Venezuela.

Electricity Generation from Natural Gas

The levelized cost of generating electricity from low-speed generators using natural gas for fuel is projected to be competitive with wind energy and biomass-fuelled electricity generation throughout the forecast horizon. However, if carbon costs are taken into

[111] Nexant uses $1.50 USD per MMBTU (Nexant, 2010). According to Economides et al (2006), transporting NG costs between $1.50 and $2.50 per MMBTU depending on actual distance.

[112] Nexant uses 9.1% (Nexant, 2010).

account, NG generation costs are projected to increase above both biomass-fired generation and wind generation costs after 2020.

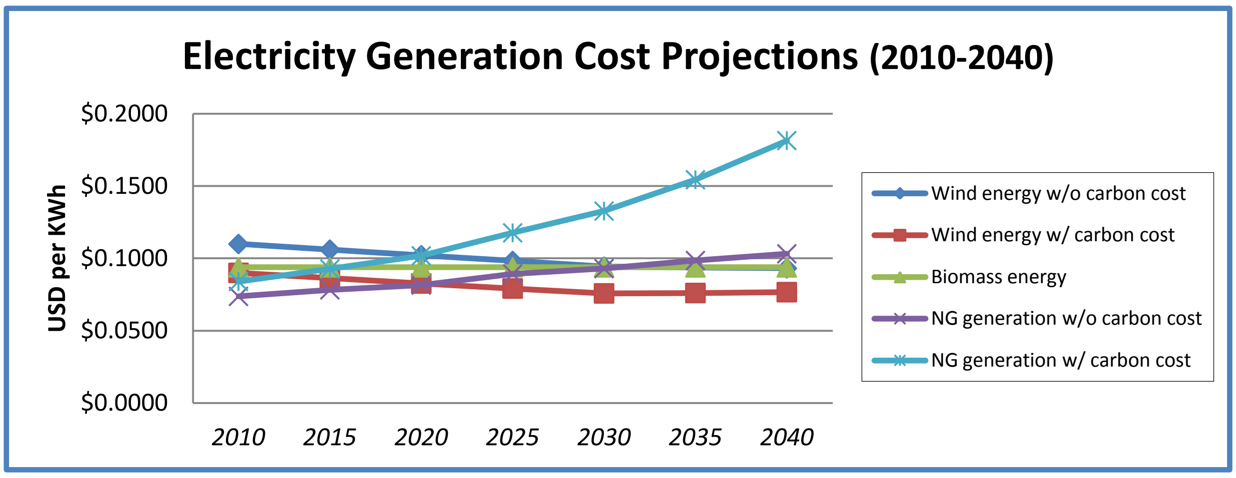

Figure 3.2.9: Electricity Generation Cost Projections for 2010-2040

Carbon Costs

Wind and solar (PV) generation produce 0.021 and 0.106 tCO2e GHG emissions per MWh of electricity generated respectively. On the other hand, baseload diesel and HFO generation (at 60% capacity factor) produce 0.6293 and 0.5909 tCO2e GHG emissions per MWh of electricity produced respectively; while diesel generation used for peaking produces as much as 0.839 tCO2e GHG emissions per MWh of electricity.

Thus, oil-based electricity generation can emit in the range of 30 to 40 times more carbon than wind generation and 6 to 8 times more carbon than solar (PV) generation.

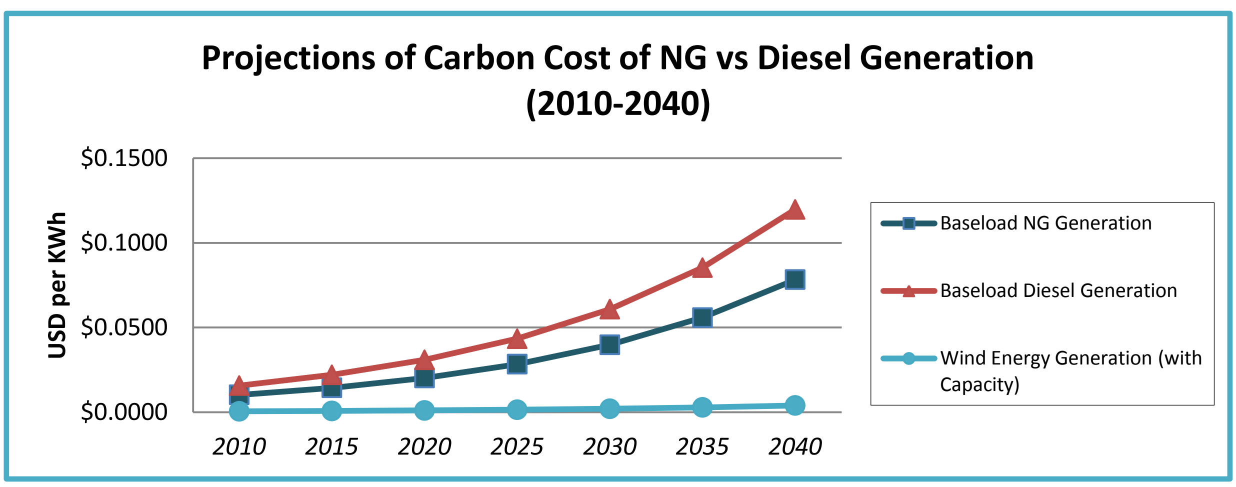

Figure 3.2.9.1: Carbon Cost Projections for NG vs. Diesel Electricity Generation for 2010-2040

As can be seen from Figure 3.2.9.1 above, carbon costs due to natural gas-based electricity generation are projected to be significantly lower than carbon costs due to diesel generation over the planning horizon, although still much higher than the carbon costs attributable to wind generation.

Electricity Imports

Interconnection with Mexico

Background

Belize currently receives up to 50 MW of electrical power from the national utility of Mexico, Comision Federal De Electricidad (CFE), via a 115 KV transmission link that interconnects the national grids of both countries.

The supply of electricity from Mexico has been underpinned by four contracts made directly between CFE and BEL: a Framework agreement, an Emergency Assistance agreement, an agreement for Firm Capacity and Associated Energy Supply, and an Economic Energy Purchase agreement: The *Framework Agreement* sets out the general conditions that govern the other contracts, including the communication protocol, operating procedures and regulation of the energy transactions between the two parties. The *Emergency Assistance Agreement* sets out the terms and transactional arrangements for the exchange of power between the parties during times of emergency, including hurricanes and other natural disasters. The *Firm Capacity and Associated Energy Supply* agreement and the *Economic Energy Purchase* agreement together stipulate the terms and conditions, particularly the charges, for the purchase of capacity and energy under normal conditions.

The interconnection with Mexico has served Belize well over the years since its inception in the early 1990s. For many years, it was Belize's lowest cost supply source and, up to this time, the most reliable source (with an availability of over 99.5%). Moreover, during times of disaster, particularly when local generation sources and transmission links have failed, the supply from CFE – provided under the Emergency Assistance Agreement – have proven invaluable. Since the oil spikes of 2007 however, the cost of electricity supply from CFE has increased significantly; to the point where it is no longer BEL's lowest cost supplier. Starting in 2008, BEL enlisted the support of GOB to intervene on its behalf to secure more favorable prices and terms of supply from CFE. While these efforts have yielded a number of concessions from CFE, success in garnering substantial and lasting reductions in CFE's prices has been limited as CFE itself has been experiencing an increasing marginal cost[113] of supply due to rising oil prices and greater local demand in Mexico.

More recently, talks with CFE have been initiated by BEL to consider the possibility of exporting electricity (from Belize) to Mexico during periods of excess energy from the hydroelectric plants on the Macal River. The amounts of excess energy that can be sold

[113] CFE's price floor for energy to BEL is set equal to the marginal cost of electricity supply at its Chetumal node, plus a markup.

and consequent revenues obtainable via this arrangement are not known at this time. Importantly, this would signal a new dawn in Belize’s relationship with Mexico, and an opportunity to give start to a new export industry.

Supply Potential

The supply from CFE is constrained, by the maximum transfer capacity of the 115 KV transmission line linking the two national systems, to 60 MW. BEL is currently unable to take more than 50 MW of power from Mexico without experiencing voltage regulation problems at certain load center bus bars. CFE has indicated that it is prepared to supply up to the 60 MW limit as long as certain power flow conditions are met. This could potentially lead to savings of over $3,000,000 USD per year, as Belize will be able to take more “economic” or “opportunity cost” energy at times when it is cheaper (Mencias & Esquivel, 2008).

Projected Prices and Costs[114]

As earlier stated, the cost of the supply of electricity from CFE is determined by two agreements, a Firm Capacity and Associated Energy Agreement and an Economic Energy Purchase Agreement.

a) *Firm Capacity and Associated Energy Agreement*: In the previous incarnation of this agreement[115], BEL paid a capacity charge - on a take-or-pay basis - for definite levels of capacity taken in periodic intervals over the life of the agreement. The price of the energy associated with the firm capacity was indexed to world market prices for heavy fuel oil, natural gas and diesel via a formula provided by CFE. *This agreement was unilaterally cancelled by CFE in early 2010*.

   During a new round of negotiations held in July 2011, CFE proposed to reinstate the Firm Capacity Agreement under a new pricing regime. Like the previous agreement, the price of energy supply under the proposed new agreement has an energy charge component and a capacity charge component. However, it is structured differently from the previous agreement. The capacity charge component is to be reduced by almost half to $4.50 USD per KW per month; and energy charge is now CFE’s actual marginal cost of energy supply at its Chetumal node plus a service charge of $0.015 USD per KWh.

b) *Economic Energy Purchase Agreement*: This agreement provides for the purchase of excess levels of interruptible capacity and energy that is available from CFE on an hourly basis over each 24-hour period. The price of energy in each hour is directly tied to the marginal cost of production - that is itself dependent on demand and

[114] Most of the discussion in this section based on 2011 “Report on Outcome of Negotiations held in Mexico City from July 4th to 5th, 2011 between Government of Belize, BEL and CFE” (Mencias, 2011).

[115] The agreement was unilaterally cancelled by CFE in early 2010.

supply conditions in Mexico's electricity market - and may vary widely from hour to hour. In general, however, "economic energy" prices are usually significantly lower than the price from all other sources of supply in the early morning from midnight to 6:00 am; but on average higher during the rest of the day.

According to CFE, the price of energy under the existing agreement is set as the projected marginal cost of energy at the Chetumal supply point plus a variable percentage mark-up[116]. During the round of negotiations held in July 2011, CFE proposed to replace the existing agreement with a new 'Opportunity Cost Energy Purchase Agreement': which is - for all intents and purposes - identical to the existing agreement which it is to replace, but with the price set as the actual incurred marginal cost of energy at the Chetumal supply point plus a fixed percentage mark-up of 20%. BEL has estimated that these new terms could reduce its cost of power by as much as $1.5 million USD per year[117].

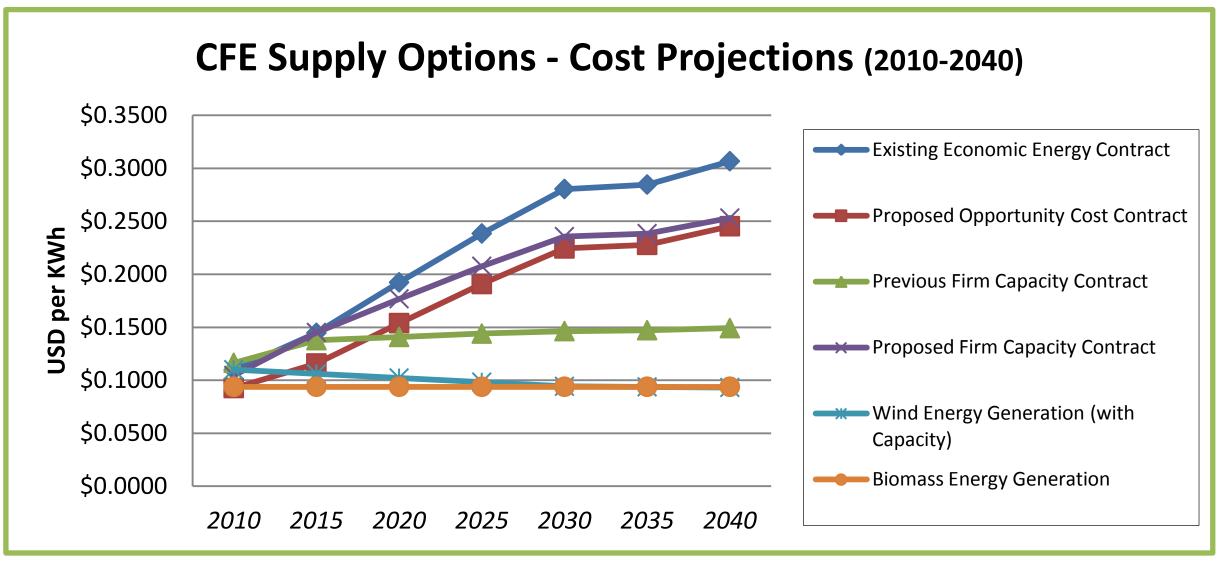

Figure 3.2.10: Costs of CFE Electricity Supply Options vs. Wind and Biomass Energy for 2010-2040

Figure 3.2.10 above provides projections of the cost of energy (and capacity) from CFE under the four different scenarios: the previous firm capacity agreement, the proposed firm capacity agreement, the existing economic energy purchase agreement and the proposed opportunity cost energy agreement[118].

With time, all these supply options will become increasingly costlier when compared with onshore wind and biomass-fuelled electricity generation. The previous Firm Capacity Agreement is included for historical reference only, and serves to show that

[116] This was calculated as 63.9% in 2010 and 47.3% for 2011 up to May.

[117] During the negotiations, CFE agreed to consider a further proposed change made by BEL: if the price of energy from CFE surpasses the average cost of energy from BEL's other supply sources, then the mark-up should be reduced to 10%, otherwise it remains at 20%.BEL has estimated that, if accepted, the proposed change could potentially reduce the cost of energy by a further USD $1 million per year (Mencias, 2011).

[118] The projected energy cost for the existing Economic Energy Agreement, the proposed Opportunity Cost Agreement and the proposed Firm Capacity Agreement are all based on using projected HFO fuel-only costs as a proxy for CFE's projected marginal cost.

even if this previous favorable arrangement were to be restored, it would still be costlier than wind and biomass energy.

Environmental Benefits/Costs

Although the environmental effects of CFE's electricity generation processes may not be felt directly in Belize, it is important to account for the effects of our energy use at the global level particularly for GHG emissions, since, whether the emissions occur in Belize or in Mexico, the eventual consequences – global warming and its attendant ills - for all of us are the same. For these purposes therefore, the indirect emissions rate due to electricity imports[119] from CFE (Mexico) is 0.889 tCO_2e per MWh (US DOE, 2007). This number takes into account the losses incurred in transmitting the energy to Belize.

SIEPAC

Background

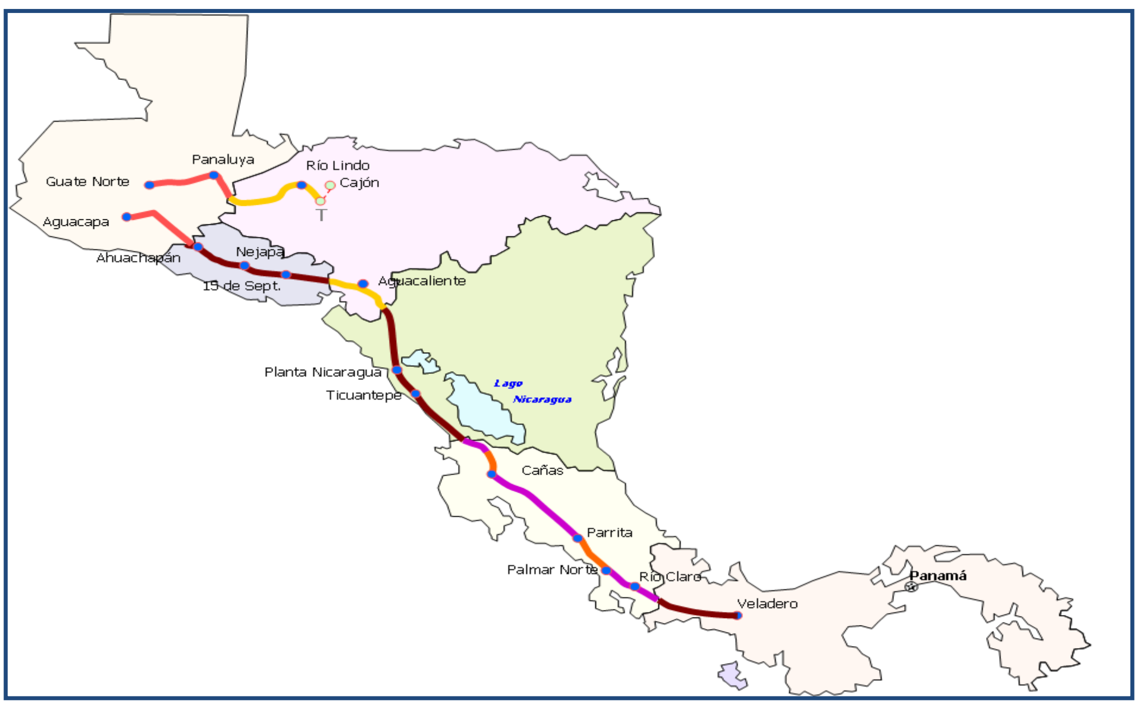

Figure 3.2.11: The SIEPAC Transmission Line Route

The SIEPAC component of the Meso-American Project[120] provides for the establishment of a regional electricity market (MER)[121] spanning the countries of Central America and

[119] Strictly speaking, for carbon accounting purposes, emissions due to electricity imports are "charged" to the country generating the electricity. Practically, these emissions are caused because of demand for energy in the consuming country, and should not be ignored in any energy-related carbon mitigation plan.

[120] Formerly the Plan Puebla-Panama Project.

[121] The MER will be superimposed upon, but operate independently of, national electricity markets; and managed by a supra-national authority.

underpinned by a 1,100 mile long 230 KV transmission line from Puebla in Southern Mexico to Panama[122] with a final link to Colombia[123], budgeted to cost USD $494 million.

According to the latest progress report, as of December 2010, all of the required institutional structures have been created and are now operational, and 95% of the transmission lines have been constructed.

The main objectives of SIEPAC are to improve regional energy security and reliability and decrease cost. Energy security and reliability are enhanced in two ways: a) by having ready access to other sources of energy when local sources fail or become unavailable b) by having access to a diversified energy mix – thus cushioning individual national markets from price shocks affecting fuels used by local sources.

The prospect for decreased costs is predicated on opportunities to exploit economies of scale in generation given access to a much larger market[124] and to sell and purchase excess energy and capacity. The region already has significant unused thermal capacity (an average capacity factor of 10%) and it is estimated it has over 22,000 MW of hydro electric potential: more of which can now be developed given the access to a regional market. Moreover, large-scale projects, such as a coal-fired plant in El Salvador are already being planned. Importantly, projects based on intermittent renewable sources such as Solar and Wind could become more economically feasible because the effect of their intermittency would be absorbed within a much larger supply matrix.

The SIEPAC project is not without its detractors who claim that the negative impacts of building a regional transmission grid, such as deforestation, environmental damage and indigenous population dislocation, will outweigh the benefits; and furthermore that the benefits will accrue disproportionately to the foreign investors involved with the project. Environmentalists and NGOs have also expressed concern over the push towards further large hydro development, which is highly disfavored given the claimed negative impacts on natural habitats and indigenous populations.

Belize has not formally signed unto the SIEPAC plan; and it is unclear whether it can be involved at this late stage, especially because participating countries must purchase shares in the venture and are required to commit to repaying a USD$40 million loan from the IDB that was used to jumpstart the project. CFE of Mexico has offered to support any request made by Belize for inclusion into the SIEPAC pact. In the meantime, while it may be cost-prohibitive for Belize to join SIEPAC at this time, it can probably

[122] Strictly speaking, the connection between Southern Mexico and Guatemala is not a part of the SIEPAC plan: however, this line has already been built under separate arrangements and is currently in operation.
[123] A southern connection of the SIEPAC line with Colombia is presently under development. Colombia has a significant electricity production cost advantage over Central America – of the order of 2 to 1 – due to its large resources of hydropower, natural gas and coal (Economic Consulting Associates, 2010).
[124] The line will have an estimated 300 MW of transfer capacity at border points (Economic Consulting Associates, 2010).

pursue an arrangement to sell excess energy to Mexico and/or Guatemala, who can then sell to SIEPAC.

Supply Potential

The supply potential of SIEPAC is highly dependent on eventual regional participation. The transmission line itself is being planned and designed for a maximum transfer capacity of 300 MW at border points, with a provision to be able to add a second circuit and so increase the transfer capacity by a further 30 to 100%. Even so, because Belize is not a party to SIEPAC, and our only foreseeable tie is through the existing transmission interconnection with Mexico; in the short term, the SIEPAC supply should be considered the same as – but mutually exclusive to - the CFE supply in terms of availability and reliability.

Projected Prices and Costs

A 1995 pre-feasibility study had indicated that SIEPAC could potentially lower costs of electricity supply in the region from the then 1995 cost of $0.11 USD per KWh to $0.09 USD per KWh (Martin, 2010). Although, it is not known how these projections have changed more than 15 years later, it would have been expected that the cost of energy available to Belize from SIEPAC would on the average be lower than the cost of Belize's own energy supply, given the possibilities for regional-scaled projects, including low-cost hydro-power, that exploit economies of scale.

This does not appear to be the case however. During the July 2011 negotiations between GOB and CFE, CFE confirmed that they were invited to join SIEPAC as a supplier of electricity to the region and had subsequently bought approximately 11% of the shares in SIEPAC. The fact that CFE paid millions of dollars to accept this invitation is an indication that their research shows that their cost of excess energy is or will be lower than that of at least a portion of the energy being supplied or that will be supplied by the other providers in the SIEPAC supply network.

Moreover, historically, the cost of CFE's excess energy is often higher than the cost of energy supply from Belize's hydro and biomass sources during certain hours of the day and particularly during the "wet season". In fact, Figure 3.2.10 further above projects that CFE's prices will become increasingly costlier than biomass energy over the planning horizon.

This means that excess energy from Belize could many times be lower than that of at least a portion of the energy being supplied or that will be supplied by the other providers in the SIEPAC supply network.

Given these considerations, it is probably best to assume that the cost of energy from SIEPAC will be at least equal to the cost of excess energy available to Belize from CFE.

Environmental Benefits/Costs

Similar to the discussion for *Interconnection with Mexico* further above, it is important to account for the effects of our energy use at a regional level. For these purposes therefore, the indirect emissions rate due to electricity imports from SIEPAC is projected to be 0.940 tCO_2e per MWh (US DOE, 2007). This number takes into account the losses incurred in transmitting the energy to Belize.

The “Intermittency Problem” of Wind and Solar Energy Resources

Let us say that a particular load has a daily profile as follows: 2 MW for the first 6 hours, 1 MW for the next 6 hours, 3 MW for the last 12 hours; and that we have two available sources from which to serve the load: a biomass-powered plant and a wind-powered plant. The biomass-powered plant has a maximum rated capacity of 4 MW: so its output can be varied as required to match the load level as it changes throughout the day. The wind-powered plant also has a maximum rated capacity of 4 MW, but the power output at any time is not fully under the control of the operator. On a particular day, the wind speed may be such that at most 2 MW of power can be generated from the wind plant for the entire day: this means that it will not be able to meet the full demand requirement of the 3 MW load for the last 12 hours of the day. The situation can become more complex: the wind plant may be able to produce 3 MW of output during the first 12 hours, but only 2 MW of power during the last 12 hours. In this case, the 3 MW power is producible, but not at the time needed. If it were possible to store some of the extra power produced in the first 12 hours and then re-generate it as needed, then the 3 MW of demand would be met during the last 12 hours of the day.

The problem described above is the **intermittency problem**; and is the reason that intermittent energy sources, such as Wind and Solar, present a problem to system planners and dispatchers. Generally speaking, intermittent energy sources are on their own not sufficiently reliable to meet peak loads. On the other hand, if the maximum power producible from the intermittent source is a small part of a supply mix, then the intermittent source can be dispatched when available and the other sources can supply demand when the intermittent source is not available.

A number of options are currently being exploited and explored to overcome the problem of intermittency and so take full advantage of the benefits offered by intermittent sources. These include:

Geographic dispersion: This involves strategically siting intermittent energy sources in dispersed locations relative to each other to take advantage of the variability of the weather across these locations.

Weather Forecasting: Forecasting the weather to plan for capacity even if one or a few days in advance.

Interconnection: Interconnecting to larger networks reduces the impact of supply variability from intermittent sources.

Hydro Reservoirs: Supply from hydro plants can be cut back when supply from intermittent sources is available: the scaled-back water flow is stored in hydro reservoirs until needed.

Storage: The excess energy generated during times of high availability is stored in batteries, pumped storage hydro reservoirs, thermal storage facilities (e.g. molten salt), hydrogen gas, flywheels, compressed air and super-conducting magnetic energy; and released when needed. Except for batteries and pumped storage hydro, none of these storage technologies have been proven commercially viable as yet.

Over-sizing of installed capacity: The installed capacity of plants are over-sized so that as much power as possible is gotten from the source when it becomes available.

Smart Grid Management: See discussion at the very end of this chapter.

MICRO-GENERATION

Micro-generation, for purposes of this report, refers to non-utility-scale energy generation by households or even small businesses for self-use (off-grid) and/or to export to the grid (on-grid). It is treated separately from the other utility-scale supply options because - although the underlying supply technologies are mostly the same - the complexity of the technical and institutional arrangements required to bring it to fruition and integrate it into the supply matrix, such as metering and settlement, are very different from the norm in "ordinary" utility-provided energy supply and because some of the technologies, such as geothermal pumps, are currently applicable only to non-utility scale deployments.

Benefits of Micro-Generation

The suite of micro-generation technologies includes solar PV, solar thermal for water heating and cooling, micro-wind turbines, micro- and pico-hydro, biomass, geothermal pumps for cooling and water heating, micro combined heat and power (micro CHP) and small-scale fuel cells. These technologies enable us to tackle the problems of energy supply constraints, energy security, GHG emissions reduction and energy poverty at the point of use; thus representing a 180-degree shift from the centralized supply-side control paradigm that have come to be accepted as the norm. Furthermore, a study by the "Sustainable Consumption Roundtable" (DTI, 2006) found that households that engaged in even modest levels of micro-generation showed a considerable increase in the level of their energy awareness and subsequent conservation activities.

Barriers to Micro-Generation Penetration

However, a number of constraints must be overcome in order to foster a viable micro-generation market in Belize. High initial costs, lack of technical know-how, and regulatory uncertainty are the major hurdles facing micro-generators in getting micro-generation off the ground. Clear, upfront policies and procedures are necessary to stimulate the development of the micro-generation market. Micro-generators need to know that they can recover their investments and make a profit, and that they cannot be arbitrarily denied the opportunity to sell electricity to the grid once the interconnection procedures are properly followed. Electricity providers must be assured that the connection of micro-generation sources to the grid will not undermine safety and system security or impair quality of service in the immediate vicinity or beyond and result in loss of control on their part, but will rather increase system reliability and help to manage demand.

Energy Buyback, Gross Metering and Net Metering

Energy buyback is simply an arrangement where micro-generators sell back a part or all of the electricity they produce into the grid. There are two main metering configurations for implementing energy buyback: the two-meter arrangement (gross metering) and the single meter (net metering) arrangement. In gross metering, one meter is used to register the quantity of electricity purchased (imported) from the grid, and the other is used to register the quantity of electricity sold (exported) to the grid. In net metering, on the other hand, energy exported is directly set off against energy imported. Thus, a single meter - which turns backward when energy is exported - is used, instead of having to use two separate meters.

Net metering is easier and less costly to install and maintain, and is considered more appealing to micro-generators. However, one of the cited disadvantages of net metering from the electricity provider's standpoint is that, *on the basis of cost*, a unit of energy imported from the grid to the micro-generator's premises is not the same as a unit of energy exported to the grid from the micro-generator's premises. The electricity provider is paid *the retail price of energy* for each unit of energy that it provides to the micro-generator and therefore pays back *the retail price* for each unit of energy that is exported from the micro-generator into the grid. Accordingly, if this exported unit of energy would have been provided instead from the bulk energy supply sources, the electricity provider would have had to pay at most the cost of power from its most expensive source (its marginal cost of energy supply): which is usually significantly less than its retail price. On average, therefore, the electricity provider loses *the difference between its retail price and average marginal cost of energy supply* for each unit of electricity that is set off by net metering.

However, a contradicting argument is that a unit of energy supplied from a micro-generator is not the same as a unit of energy supplied by a bulk energy supplier, because the unit of energy from the micro-generator is used up in the immediate vicinity while the unit of energy from the bulk supplier incurs transmission and distribution costs on its way to the final consumer. In such a case, the electricity provider's loss – on the basis of long run marginal costs – is minimal.

The Economics of Micro-Generation

From a consumer's point of view, micro-generation is preferable to grid electricity if the LCOE of the technology being used is less than $0.22 USD per KWh - the average retail price of grid electricity in Belize - *all other things being equal*. However, when deciding if micro-generation makes economic sense, policy-makers must view things from the broader national perspective. The relevant question is: would the electricity needs of the consumer be best served by micro-generating at the consumer's end or by expanding grid supply? The cost (LCOE) of micro-generation must therefore be compared with the long-run marginal cost (LRMC) of supply from the grid, so as to ensure that as a society we are using the least cost option to serve our energy needs. This LRMC includes the generation cost, plus the capital and O&M cost of the infrastructure[125] for transmitting and distributing the energy to the consumption point, plus the cost of the energy lost in transmission and distribution (T&D).

When calculating the LCOE of a utility-scale wind plant, the point of supply (where energy delivered is measured) is the border between the plant and the utility's transmission and distribution (T&D) network: so the LCOE is the cost of the supply up to that point, divided by the quantity of energy delivered up to that point. By the time the energy supplied reaches a consumer, it would have incurred both losses (of energy) and costs (of usage) as a result of passing through the utility's T&D network. The unit cost *up to the point of delivery to the consumer* will therefore be higher than the LCOE of the plant (on its own) due to both the additional cost (of T&D usage) and the decrease in energy delivered. It is this cost *up to the point of delivery to the consumer* that must be compared to the cost of micro-generation; as the micro-generated energy is delivered directly to the consumer (at the source).

For applications where a significant portion of the micro-generated electricity is sold into the grid, the applicable reference metric is not the full LRMC; because, for the most part, the electricity exported to the grid is used up in the general vicinity of the source and would incur only the low voltage distribution portion[126] of the T&D-related costs included in the full LRMC. Additionally, if the micro-generated supply provides little or no firm capacity (as is the case with solar and wind without battery storage or backup power), then the full LRMC is no longer the appropriate reference metric against which the LCOE is to be compared. There are then two possible solutions: use the LRMC *without* its generation capacity-related cost component as the new reference metric; or, alternatively, add an additional cost (of firm capacity) component to the LCOE , so that it is comparable with the full LRMC.

Unfortunately, the LRMC of electricity supply in Belize is not known. It must be emphasized that the LRMC is not the same as the retail electricity price, which is determined via an accounting-based calculus over a very limited time horizon. Although

[125] Infrastructure in this sense encompasses the physical transmission and distribution lines, transformers and accessories, as well as the entire organizational support structure required for supplying electricity.

[126] This is supported by the findings of a 2008 research paper "The Market Value and Cost of Solar Photovoltaic Electricity Production" (Borenstein, 2008) on solar PV installations in California, which found that PV installations have had negligible impact in reducing distribution infrastructure costs for either new or existing neighborhoods, but could lead to transmission infrastructure cost reductions.

we may have to use this retail electricity price as a proxy for the LRMC in the meantime, it is critical that the true LRMC and its various components are calculated – and revised each year - so that investment decisions can be made on the basis of sound economic analysis.

Micro-Generation Technologies

There are four micro-generation technologies in particular that we consider below: micro-wind turbines, domestic roof-mounted solar panels, solar water heaters and geothermal pumps. While wind and solar technologies have already been discussed before, we focus our discussion on the particular challenges and opportunities presented in rolling these out on a small scale at the level of households and communities.

The concept of a world powered by micro-generation is an appealing one – except of course for electric utilities. One UK study projects that 30% to 40% of the UK’s annual energy needs could be supplied from micro-generation sources by the year 2050. More optimistic enthusiasts feel that micro-generation will eventually be to the energy industry what the Internet is to the information industry.

Before the advent of the Internet, information was controlled and disseminated by a few. Today, millions of consumers of information have access to millions of producers of information. In the same way, micro-generation holds the promise of connecting millions of producers of energy to millions of consumers of energy: literally, generating “power by the people”, “for the people”. Electric utilities – already entrenched in the ways of centralized command and control of energy supply – may well find it hard to fathom managing what appears will be a dizzying and chaotic array of supply fluctuations, voltage spikes, brownouts and every other power system aberration imaginable. But new concepts such as the smart grid – already being tested and rolled out in some countries – are fast closing the gap between what is only now a promise and what could soon be a reality!

Small-scale Wind Turbines

State of the Technology

The NREL 2007 Technical Report ‘Distributed Market Wind Applications’ (Forsyth & Baring-Gould, 2007) segments the US and international non-utility scale wind market (<= 1 MW installed capacity) into seven different market segments for purposes of investigation. These are: small-scale remote or off-grid power of less than 100 KW per installation (residential or village); residential on-grid power; farm, business or small industrial applications of 100 – 500 KW per installation; community grid-connected power to schools, public buildings or for municipal services of 500-1000 KW per installation; wind/diesel hybrid systems for rural communities; stand-alone wind or hybrid systems for water irrigation; and stand-alone wind or hybrid systems for water desalination. The applicability of this level of segmentation to Belize cannot be known for sure until a similar investigation is done locally. However, it does provide an initial reasonable starting point for assessing the different needs and challenges facing different categories of consumers.

Although utility-scale wind energy is already cost-competitive with most other forms of energy, there are a number of technical and market barriers stymieing widespread use of wind turbines for non-utility scale applications. The major barrier is the higher cost of non-utility-scale installations compared with utility-scale installations. This higher cost is driven by four main factors: small and mid-sized turbines used in non-utility scale installations are relatively more costly to manufacture than the larger turbines used in utility-scale installations given the manufacturing technologies currently available; their low market penetration means that costs are slow to benefit from learning curve effects and economies of scale of volume production; their limited hub heights (due to safety and aesthetic requirements etc) result in lower energy production compared to a similar-sized turbine used in a utility-scale operation; and equipment, particularly inverters, needed for grid-connection adds another layer of costs. Other barriers include: high noise levels and negative visual impacts especially in residential neighborhoods, increased risk of lightning strikes and other dangers associated with having tall and unplanned-for structures atop residential rooftops or near residences, product reliability issues especially in corrosive coastal environments and particularly related to the integrity of turbine blade coatings, lack of trained maintenance support which in turn further affects product reliability and energy output, lack of performance standards, and perceived poor performance in practice relative to expectations (Forsyth & Baring-Gould, 2007).

Moreover, for on-grid installations currently in operation in the United States and the UK, micro-generators have complained of difficulties in meeting "unreasonable" interconnection standards imposed by utilities; utilities, on the other hand, have expressed serious concerns about safety issues, such as those related to "islanding"[127] that could cause serious injury and even death to linemen (Johnson, 2003).

Supply Potential

The power output of residential rooftop micro-wind turbines range in size from 1-50 KW. The energy obtainable from a 5 KW rooftop installation, assuming a capacity factor of 20% = 5 KW x 20% x 8760 = 8,760 KWh per year. A typical middle class household in Belize uses approximately 450 KWh of electricity per month or 5,400 KWh per year: so

[127]"Islanding" occurs when an electric generator fails to immediately disconnect from the grid during a fault condition or other event during which there would otherwise be no energy on that portion of the local electric power system. (Johnson, 2003)

it would be able to easily meet all of its electricity needs from a 5 KW rooftop micro-wind turbine, assuming energy storage is available if off-grid or some energy buyback arrangement is in place if on grid; so that excess energy from the installation can be stored (traded) until needed in times of low energy output.

What if we were to consider the residential wind-powered micro-generation potential from a national perspective? About 25,000 of the roughly 80,000 households in Belize are located along the coast or on the cayes, where they are exposed to Class 2 to 3 wind speeds suitable for small wind applications. If we assume that we can install a 10 KW micro-wind turbine (with capacity factor of 20%) on the rooftops or in the surrounding yard of 50% of these households, then the total energy obtainable from ***residential wind-powered micro-generation*** is 50% x 25,000 x 10 KW x 20% x 8760 = 219,000 MWh per year. This is roughly equal to all of our current residential electrical energy needs: so, we can meet all of our current residential electricity needs by micro-generating wind-powered electricity from 10 KW micro-wind turbines placed on the rooftops of 16% of our households *assuming that wind energy can be stored or traded*!

There of course various other configurations for small-scale wind generation that may be more efficient and cost-effective than distributing wind generation over so many households. For example, it probably makes more sense to put a single 100 KW turbine in an area with moderate wind resource than to put a 50 KW turbine in an area with moderate wind resource and another 50 KW turbine in an area with poor wind resource: not only would we benefit from the higher speeds but we would also benefit from the lower costs of interconnection and O&M of one as opposed to two wind turbines. So, community wind projects featuring larger turbines (up to 1 MW) and turbine clusters may be the more viable way to go in the immediate future. On the other hand, concentrating micro-generation in fewer locations undermines some of the key benefits sought from micro-generation in the first place; namely, locating turbines in different geographic locations is sometimes a part of a wider strategy to smooth the variability of intermittent resources, and generating energy at the point where it is needed eliminates the energy losses and circuit failure risks associated with transmitting and distributing it from centralized sources.

Production Costs

The cost of small non-utility-scale wind energy varies over a wide range as a result of the diverse and site-specific reported experiences. A 2007 NREL Report (Forsyth & Baring-Gould, 2007) quotes various installed costs: $3,200 USD per KW; $4,000 - $7,000 USD per KW; and even $1,000 - $1,200 USD per KW. It may be that some of these costs take incentives into account. In any case, a cost range of approximately $2,000 - $5,000 USD per KW (excluding incentives) appears a reasonable average for small-scale installations in low to moderate wind regimes. This works out to a levelized cost range of $0.0976 to $0.224 USD per KWh, including operations and maintenance costs, but excluding any provisions for energy storage or backup power facilities to mitigate intermittency effects.

Environmental Benefits/Costs

For all practical purposes, non-utility wind generation using small and mid-sized turbines produces zero GHG emissions, and so the emissions savings are 0.3359 tCO2e GHG per MWh (or 0.3359 kg of CO_2-equivalent GHG per KWh) of micro-generated electricity. At a GHG emissions price of $25.00 USD per metric ton, this works out to savings of $0.0084 USD per KWh.

Small-scale Solar PV Panels

State of the Technology

Small-scale PV systems are divided into two broad categories: residential systems, typically up to 20 KW on individual dwellings; and commercial systems, typically up to 1 MW for commercial office buildings, schools, hospitals, and retail (IEA, 2011). These PV modules are available as roof-mounted panels or roof tiles and conservatory or atrium roof systems.

Supply Potential

Residential Solar PV Electricity Generation

A typical residential building in Belize with a roof made of sheet metal, concrete, rubber rye or shingles has roughly 100 m^2 of total rooftop area (excluding overhang). However, due to factors such as shading from nearby houses and trees and other rooftop obstructions, we assume a 30% rooftop availability factor; that is, usable area (hit directly by solar radiation) as a percentage of total roof area[128]. Most urban locations in Belize are exposed to solar radiation of 5.25 KWh per m^2 per day on average. So the amount of solar energy that can be generated by putting 10%-efficient solar panels on the rooftop of a typical solar-capable residence is 30% x 100 m^2 of usable roofing area x 10% conversion sunlight-to-DC electricity efficiency x 75% DC-to-AC conversion efficiency x 5.25 x 365 days = 4,311 KWh per year. This is just

Figure 3.3.1: Solar PV panels atop a roof in Spain

[128] A 2008 NREL study (Denholm & Margolis, 2008) on roof-top solar installations uses an availability factor of 27% for warm/arid climates.

sufficient to meet approximately 75% of the annual electrical energy consumption of 5,400 KWh per year of a typical middle-class household in Belize.

Again, we can consider the solar-powered micro-generation potential from a national perspective. Belize has about 80,000 houses of which approximately one half are made concrete. If we assume that all concrete houses are capable of supporting solar roof panels and that we can place solar PV panels on the rooftops of 50% of these concrete residential houses, then the total energy obtainable from residential roof-top solar PV installations countrywide is 50% x 80,000 houses x 4,311 KWh = 172,440 MWh per year. This is roughly 85% of our current residential electrical energy needs: so, we can meet most of our current residential electricity needs by micro-generating solar electricity from 50% of our households *assuming that solar energy can be stored or traded*!

Solar PV Electricity Generation in Hotel Industry

Although no official statistics are available on commercial building sizes and layouts, we can consider the case of a typical major hotel in Belize: such a building would have around 500 m^2 of available rooftop area (Duffy-Mayers, Loreto, 2010). The amount of solar energy that can be generated by putting 15%-efficient solar panels on the rooftop of such a hotel is therefore 500 m^2 x 15% conversion efficiency x 5.25 x 365 days =71,859 KWh per year. This is about 15% of the average annual consumption of a typical large hotel in Belize[129]. So rooftop solar PV generation alone cannot supply all of the electrical energy needs of a typical major hotel in Belize.

Production Costs

According to the IEA's Technology Roadmap for Solar Photovoltaic Energy, the average installed cost of residential solar PV systems in 2008 was $6,000 USD per KW, yielding an LCOE of $0.48 USD per KWh; and the average installed cost of commercial solar PV systems in 2008 was $5,000 USD per KW, yielding an LCOE of $0.40 USD per KWh. Although currently substantially higher than the $0.22 USD per KWh retail price of electricity in Belize, these costs are expected to fall to $0.21 USD per KWh and $0.175 USD per KWh respectively by 2020 and $0.135 USD per KWh and $0.115 USD per KWh respectively by 2030.

Environmental Benefits/Costs

For all practical purposes, small-scale solar PV electricity generation produces zero GHG emissions; and so the emissions savings are 0.3359 tCO2e GHG per MWh (or 0.3359 kg

[129] Largest hotels in Belize have consumption of 40,000 KWh per month or 480,000 KWh per year. (Source: BEL)

of CO_2-equivalent GHG per KWh) of micro-generated electricity, which works out to savings of $0.0084 USD per KWh.

Active Solar Thermal for Water Heating

State of the Technology

Active solar thermal (AST) technologies refer to solar thermal collectors that collect sunshine (the heat of the sun) that is then used to heat or cool water and building spaces in residential or small-scale applications. Although China boasts the highest installed solar thermal capacity - by a wide margin - world-wide, Israel and Cyprus are the world leaders in per capita solar water heating use; roughly 85% of Israeli households now use solar water heaters after the Israeli Government mandated their use in response to the oil crisis of the 1970s (Wikipedia - Solar Water Heating, 2011).

Active Solar Thermal Design

There are two basic design principles underlying all AST configurations: whether the sink (or intended target) is heated directly or indirectly, and whether the heat transfer fluid (HTF) is passed through the thermal collectors *passively* by natural convection currents or *actively* (by pumping).

Figure 3.3.2: A flat plate solar thermal water heating system

Direct versus Indirect Systems

In direct or open-loop systems, the sink (heating target) is heated directly: cold water (or air) passes in through one side of a solar thermal collector, incoming radiation is captured by the collector and transferred to heat the water (or air) directly, and hot water (or air) passes out through the other end. In indirect or closed-loop systems, the HTF and the heating target flow through separate circuits: the HTF (usually water) is heated by passing it through the thermal collector, the heated fluid is then circulated through a heat exchanger, where the heat is transferred to the sink (water or air) circulating in a separate circuit. Though open loop systems are cheaper (upfront investment cost), they have two main drawbacks: they usually have no overheat protection and they suffer from scale build-up in the thermal collectors due to the hardness of the water. In closed-loop systems, the quality of the water (used as HTF) in the heating circuit can be controlled.

Passive versus Active Systems

Active AST systems have a number of advantages compared with passive AST systems deriving mainly from having control over the HTF flow and not being constrained to having the storage tank placed above the thermal collectors as required in the passive system configuration. As a result, active systems have better efficiency and can be easily integrated with back-up gas or electric pumps. In addition, the storage tank can be hidden from view or placed in a conditioned environment to improve insulation from heat loss.

Supply Potential

If we assume that all concrete houses are capable of supporting solar water heating systems, then almost all of the water heating needs of 50% of the households in Belize can be met by using solar water heaters[130], particularly during the warmer and sunnier days of the year.

Geothermal Pumps

State of the Technology

Geothermal pumps or ground source heat pumps (GSHP) are used mainly in commercial applications – and to a lesser extent in residential applications - to heat buildings during cold weather and cool them during hot weather. Although geothermal pumps account for only a small portion of the space cooling and heating market worldwide, implementation of the technology has been growing at a 10% and represents the largest exploitation of direct geothermal resources to date (Le Feuvre, 2007).

How GSHPs work

The upper region of the earth's crust in the band 5 to 15 m (15 to 45 feet) below the surface maintains a constant temperature in the range of 50 °F to 60 °F (10 °C to 16 °C) throughout the year – regardless of the temperature on and above the earth's surface. When the temperature on or above the earth's surface is hot, this constant temperature zone below the surface is a potential heat sink. When the temperature on or above the earth's surface is cold, the zone becomes a potential heat source. Geothermal pump technology is designed to exploit this observed property of the earth.

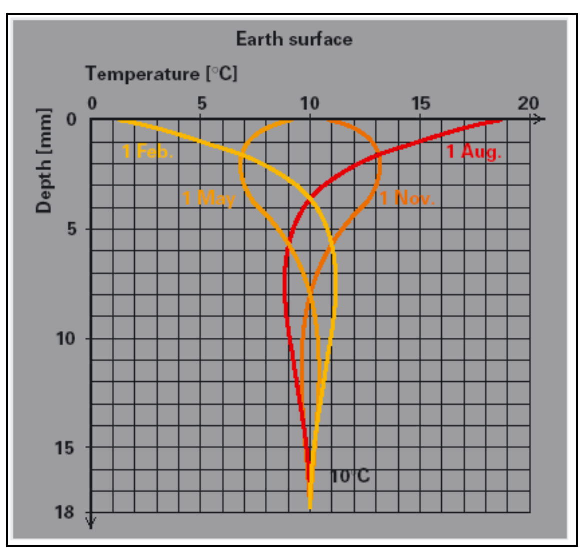

Figure 3.3.3: Typical Ground Temperature Profile   Source: (Le Feuvre, 2007)

[130] This is conclusion is drawn from that insights gotten from IEA Buildings Technology Roadmap 2010 which reports that "solar water-heating systems for single-family dwellings are relatively small, with collector areas of 4 m2 to 6 m2, and meet 20% to 70% of average domestic hot water needs". (IEA, 2011)

A typical GSHP installation connects the building, whose temperature is to be conditioned, to a network of tubes or pipes that is buried underground in the constant-temperature zone (CTZ). The GSHP circulates refrigerant fluid (or water) through the piping network; rejecting heat from the building to the CTZ when the temperature in the building is relatively hot, and absorbing heat from the CTZ into the building when the temperature in the building is relatively cold.

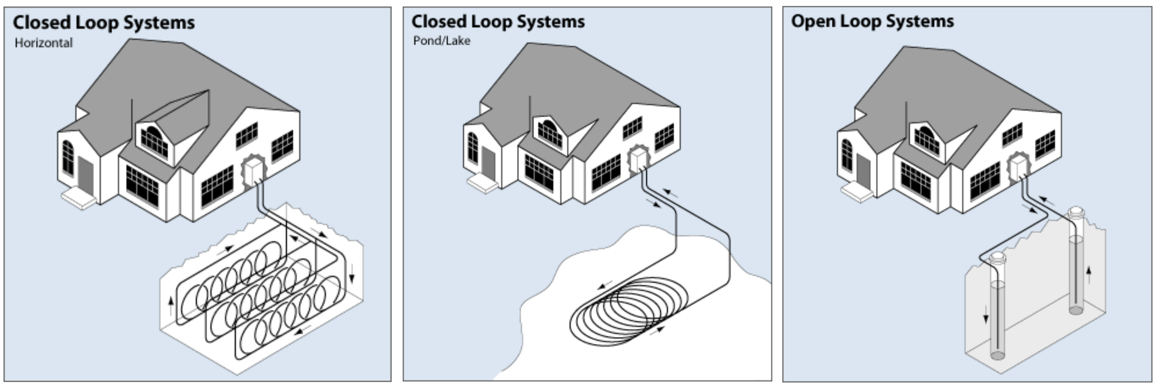

Figure 3.3.4: Types of Residential Geothermal Heating/Cooling Systems (*Source: US DOE*)

There are two main configurations for GSHP installations: closed-loop and open-loop.

- **Closed-loop** systems circulate the refrigerant within a closed pipe circuit. The part of the circuit external to the building being conditioned may be placed underground or in a pond or lake. Closed-loop in a pond or lake is cheaper than closed loop underground – since there is no need to dig into the earth - if there is a pond or lake nearby and if there are no adverse environmental effects resulting from the rejection of heat into the pond or lake.
- In **Open loop** systems, the part of the circuit external to the building being conditioned connects into water in a well or deep pond/lake: this body of water forms a part of the circuit, and provides the refrigerant fluid (in this case groundwater) that conducts heat between the CTZ and the building. Open loop systems usually have lower installation and maintenance costs because there is no need for a huge network of pipes. They are suitable in areas where there is plenty of groundwater or a nearby pond or lake. However, the heat exchanger can be subject to fouling, corrosion and blockage since it is directly exposed to the groundwater (Le Feuvre, 2007); in addition, stringent controls must be in place to ensure that there are no adverse environmental effects resulting from rejecting heat into the groundwater or pond.

GSHP works best though where the total quantity of heat rejected to the earth (during cooling) is balanced off by an equal quantity of heat absorbed from the earth in order to maintain the constant temperature of the zone in the immediate vicinity of the ground heat exchanger; if not, the ground temperature will increase over time causing system performance deterioration. One way to maintain the required balance is to use the GSHP for both space cooling and water heating; so that the heat rejected to the ground in one 'cooling' cycle is used to produce hot water that is stored in a tank (for later use) in an alternate 'heating' cycle. GSHP technology is therefore excellent for supplying the space cooling and water heating needs of hospitals, schools, hotels, and certain small-scale commercial operations.

Where heating needs are relatively small compared with cooling loads, increasing the size of the ground heat exchanger or the distance between adjacent boreholes can help to stem the ground temperature rise resulting from the load imbalance: but this will incur higher initial investment costs. A more economical alternative is to use a hybrid GSHP design, where an auxiliary heat rejecter (e.g. a cooling tower) is used to handle the excess heat rejection loads during cooling: the ground heat exchanger size and hence investment cost is reduced at the - much lower - expense of adding a cooling tower. Case studies conducted by Oak Ridge National Laboratory confirm that both the initial costs and lifecycle costs of GSHP systems using cooling towers are significantly lower than equivalent GSHP systems that depend on increased ground heat exchanger size. (Oak Ridge National Laboratory, 2001)

GSHP Efficiency

The efficiency of a heat pump is its coefficient of performance (COP) and is measured as the amount of useful energy or heat transferred by the pump divided by the amount of input energy used to enable the transfer. Unlike traditional air-source heaters and A/C's, GSHPs require energy only to move heat – not to generate it; and as a consequence tend to have higher efficiencies. A 2007 IEA-commissioned survey of heat pumps used in single family dwellings found that GSHP's deployed in North American residences had COPs in the range 280-500% compared to air source heat pumps that had efficiencies in the range 250-440% (IEA, 2011).

The main factor affecting the COP of GSHPs is the temperature lift (or drop) that is being sought: the greater the lift or drop, the lower the efficiency. The performance of a GSHP system is therefore largely dependent on the average temperature of the CTZ and the thermal properties of the ground in which the ground heat exchanger is laid. Heat exchange between the ground heat exchanger and the surrounding earth occurs through two natural processes: thermal conduction in the ground material and thermal convection in the intervening fluid (whether water or air). In general, the higher the thermal conductivity and the lower the porosity[131] of the ground material (rocks and soil), the more efficient is the heat exchange. Groundwater flow facilitates heat exchange; so low-permeability ground material that impede ground water flow will negatively affect heat exchange. (Le Feuvre, 2007)

[131] Lower porosity implies less space for intervening air, which is a poor thermal conductor.

Supply Potential

For all the reasons discussed in the foregoing section, an assessment of the potential for using geothermal cooling (and heating) in Belize can only be determined after investigating local weather conditions (temperature and humidity) and conducting proper hydro-geological studies of the earth in target areas. In Belize City and other coastal areas for instance, the saline environment will corrode copper pipes ordinarily used for direct heat exchangers, so indirect heat exchangers with polyethylene or polybutylene pipes may have to be used. Using sea water source heat pumps might be a more sensible option for buildings on the coastline, or river water source pumps for buildings situated inland along river courses or ponds. The amount of ground area available is also an important factor to take into consideration: if ground space is limited, as would be the case in Belize City, then vertical closed-loop systems will have to be implemented.

Projected Costs

A 2006 NREL Report[132] documented the results of a life-cycle cost analysis of various HVAC systems for a proposed new office building on the Winnebago Reservation in Nebraska. The analysis took into consideration three different types of HVAC system: rooftop units with gas heat and direct expansion cooling (air-cooled condensers), air-source heat pumps, and geothermal heat pumps. The study found that although the GSHP system had the highest installation costs, it had the lowest O&M costs and the lowest NPV: 18% lower than the other two alternatives. The applicability of these results to Belize was not investigated in detail. However, it should be noted that the cooling-to-heating load ratio for the HVAC systems would be much higher for Belize, and the electricity prices in Belize are much higher – at least twice as high - than the electricity prices used in the study. The former consideration would tend to favor the other two options as greater cooling/heating load imbalances lead to higher GSHP investment costs, while the latter would tend to favor the GSHP installation since GSHP technology uses energy to transfer heat only.

Environmental Benefits/Costs

The net environmental benefit from using GSHP-driven HVACs for supplying cooling and heating needs depends on what technology/source it is replacing. For example, if it is being used to replace HVACs that are powered from the electricity grid, then the net GHG emissions will be reduced, because the total electricity used by the GSHP-driven system will be less than that used by an all-electric system. However, if it is replacing a solar PV or solar thermal-driven HVAC, then the GHG emissions might likely be higher.

[132] (Chiasson, 2006)

A greenhouse gas analysis was conducted as part of the 2006 NREL Study referred to in the foregoing section. The study found that the use of a GSHP system could reduce annual GHG emissions by 15 tCO2e compared with the rooftop units, and by 33 tCO2e compared with air source heat pumps. However, the major share of the electricity supply modeled under the study was from high-carbon coal-fired plants, and the results would therefore be less dramatic in Belize's case where 70% of electricity supply is from low-carbon renewable energy sources.

EMERGING TECHNOLOGIES

Research and development of technologies that can tap into other forms of renewable energy and improve energy efficiency and sustainability as a whole have intensified in this century. Some promising innovations that should be kept on our radar are:

- **Algae Fuel**[133] refers to bio-fuels such as biodiesel, bioethanol, biobutanol, biogasoline and biohydrogen that are sourced from algae. Most of the research being conducted today is focused on the production of biodiesel from algae. Algae have always been of interest to researchers as a potential source of fuel because of their high lipid content (anywhere from 2% to 40% by weight) and high harvesting rates: typical algae harvesting cycles last from 1 to 10 days compared to the yearly crop cycles for most competing alternatives such as palm oil, soybean and jatropha. Researchers involved in algae biodiesel pilot and demonstration projects are claiming per-acre yields of 5,000 to 20,000 US gallons per year: 7 to 31 times that of the conventional biodiesel feedstocks. Moreover, because algae thrive best in saline ponds and marshes, they do not compete with agricultural crops for land or for freshwater. (Wikipedia - Algae Fuel, 2011)

  Like all plants, algae need sunlight, water and carbon dioxide to grow and thrive. However, algae are not particularly hardy organisms and yields are very dependent on environmental conditions: overcrowding and overexposure to sunlight or high concentrations of oxygen – that they produce as they grow - can kill them; the temperature, salinity and pH of the growth medium must be maintained fairly constant; and the algae crop must be continually fed with carbon dioxide.

  There are three main harvesting environments for algaculture that are currently being researched and tested: open ponds, closed loop systems and closed-tank bio-reactors. Open ponds require the least upfront capital investment; however, they are the most risky, as this is the environment in which algae are most exposed to the vagaries of weather, disease and contamination. In closed loop systems, the algae are cultivated in clear plastic bags which are stacked high and shielded from rain by cover: this arrangement simultaneously exposes them to sunlight on all sides, while

133 Most of the information provided here is based on (Newman, 2011).

providing protection from weather, contamination and disease. In closed-tank bioreactors, the algae are placed in round drums in an indoor environment, where their growth conditions are carefully controlled and managed. Although the most costly, this arrangement yields the highest algal growth rates.

Algae biofuel production can yield further savings from pursuing synergies with other processes. For instance, bioreactors can be strategically placed in the vicinity of carbon dioxide effluent sources such as power stations and industrial plants. The carbon dioxide effluent of the power plants can be "sequestered" by feeding it directly into the bioreactors, thus closing the carbon loop and saving costs: reducing the need to invest in carbon dioxide producing sources on the algae production end and reducing the need to invest in carbon dioxide sequestration equipment on the power production end. Similarly, algae biodiesel production can be combined with wastewater treatment, where the wastewater provides the nutrients for algae growth and the wastewater is "treated" by the algae in the process: that is, the wastewater is cleaned when the "nutrients" are consumed – and so removed - by the algae, and the water so treated is recycled for use, thus continuing the cycle.

- **Hydrogen Fuel Cells**[134] produce DC electricity from hydrogen and oxygen via a simple electro-chemical process - similarly to how batteries work - with very high conversion efficiency and with zero carbon emissions. The DC electricity can then be converted to AC electricity to power motors (including, motors used in electric vehicles) and electrical appliances. The four main types of fuel cell are molten carbonate fuel cells (MCFC), solid oxide fuel cells (SOFC), phosphoric acid fuel cells (PAFC) and polymer electrolyte membrane fuel cells (PEMFC). The fuel cell is "recharged" by simply refilling it with hydrogen. Hydrogen fuel cells therefore have the potential to replace batteries in EVs, and thus putting to rest fears about future scarcity of the metals currently used in EV battery production.

  There are two significant hurdles that first need to be overcome in order to realize the touted benefits of a "hydrogen economy" built around hydrogen fuel cells: cost-efficient production and storage. Firstly, hydrogen does not occur freely in nature: most of it occurs bonded with oxygen as water, or with carbon as hydro-carbons. The current methods available for hydrogen extraction (from its sources) are all cost prohibitive. The main method used for extricating hydrogen from hydrocarbons is called steam reformation. Like hydrocarbon combustion processes, this process also releases carbon dioxide into the atmosphere unless it is sequestered. Hydrogen can also be extracted from water ("water splitting") via a number of processes: electrolysis, where electricity is passed through water; thermo-chemical processes using solar PV or CSP; and other photo-electrochemical and photo-electrocatalytic

[134] Discussion and information based on (Wikipedia - Hydrogen Economy, 2011).

processes. The advantage of water-splitting is that no carbon dioxide is released directly into the atmosphere and the carbon polluting effects of the entire process is therefore dependent on the source of energy used in splitting the water: if the electricity used to split the water is produced from clean renewable energy sources then there will be zero carbon emissions associated with the process. Hydrogen can also be produced biologically in fermentative processes using bacteria or by algae in algae bioreactors.

Hydrogen at normal temperature and pressure occurs as a low density gas. It therefore has to be pressurized or liquefied to reduce its volume so that sufficient quantities can be stored on board vehicles (to feed fuel cells) to provide comparable driving ranges with gasoline counterparts. A number of challenges arise as a consequence of having to store hydrogen in liquefied or pressurized form on board vehicles: the hydrogen liquefaction technologies currently available are very energy intensive; the mass of the storage tanks adds to the overall vehicle mass and hence reduces fuel economy; liquid hydrogen tanks have to be well insulated to prevent boil off; and, because hydrogen is a small molecule, it seeps through storage tank liners causing leakage and liner weakening. In order to overcome the challenges of storing compressed or liquefied hydrogen, scientists have been experimenting with other methods of storage; including physical absorption into solid storage material, and chemical conversion to a hydrogen-containing compound (hydride) from which it can be easily released when needed.

If these hurdles can be overcome, hydrogen may well emerge as the ultimate storable energy carrier: Renewable electricity production spikes which exceed grid demand can be used to generate hydrogen, which is then stored and later used to re-generate electricity to meet demand during later production lulls or as needed.

- **Enhanced Geothermal Systems** (EGS), also called Engineered Geothermal Systems or Hot Dry Rock Geothermal Systems (HDR), are a nascent technology that artificially reproduces the conditions of naturally-occurring geothermal systems that is then used to generate electricity. While naturally-occurring geothermal steam or geothermal hot water resources occur under only about 10% of the earth’s surface area, dry hot rocks are almost everywhere deep below the earth’s surface. In EGS, highly pressurized water is injected into an area containing these hot dry rocks until the rocks are fractured to a point sufficient to create a hydrothermal reservoir. Once this hydrothermal reservoir is created, then it can be used in the same way that Binary Cycle Power Generation uses a naturally-occurring hydrothermal reservoir.

  The cost of EGS is difficult to estimate because only a few projects have been launched commercially and because it is site-specific: the cost varies widely depending on the drilling depth of the injection well, the composition of the rocks through which the well is drilled, and the nature of the geological formations in the area where the hydrothermal reservoir is created. Studies conducted by MIT estimate the LCOE of EGS at an ideal site in the USA to be in the range of $0.175 - 0.295 USD per KWh[135], given today's technologies; however, this cost could be as high as $0.747 USD per KWh in less suitable locations that require deeper drilling through hard rock formations (Massachusetts Institute of Technology, 2006). Over time, EGS is expected to produce electricity at a much lower LCOE of $0.036 – 0.092 USD per KWh (EERE - Geothermal Technologies Program, 2008). One of the touted advantages of EGS is that they can be sited closer to load centers[136] thus reducing electricity transmission costs.

- **Smart Grids** use digital technology and communications to match supply with demand - and vice versa - on electricity networks and to "increase connectivity, automation and coordination" between suppliers and consumers (Wikipedia - Smart Grid, 2011). On the demand-side this may involve rescheduling flexible loads, dropping interruptible loads, or automatically lowering or ramping up demand as required: this may be done at the level of an individual factory, commercial establishment or household; or a section of an individual factory, commercial establishment or household; or even an individual equipment or appliance within a factory, commercial establishment or household. On the supply side, smart grids enable integration of micro-generation sources and variable power sources such as wind and solar energy as well as battery-based systems such as EVs and PHEVs, which may serve as sources or sinks depending on the state of the connected power system. These result in energy savings from peak load management, accelerated deployment of energy efficiency programmes, reduced line losses and direct feedback on energy usage. (IEA, 2011)

  Additionally, the capacity to self-heal and mitigate system-wide disruptions is an inherent quality of most smart grid designs as the system can automatically serve deprived or stranded loads from other parts of the network and redirect energy flows around damaged equipment when a supply path fails or, on the other hand, isolate and maintain individual sub-networks intact and energized even when the national grid as a whole fails.

  Although smart grid technology is still in its infancy stages, a number of countries, including Canada, USA, Italy and Germany have commissioned smart grid projects, which are currently at various stages of development.

- **Solar Air-conditioning** uses the heat of the sun to cool buildings. It is an attractive proposition because the need for cooling usually coincides with the occurrence of

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[135] (Sanyal, Morrow, Butler, & and Robertson-Tait, 2007) gives a much lower estimated cost of $0.054 USD per KWh.

[136] However, Tester et al 2006 claim that most of the promising EGS sites actually occur at distances far removed from loads centers.

solar radiation (IEA, 2011). The main solar cooling technologies currently in use are *thermally-driven chillers* and *desiccant evaporative cooling systems* (IEA, 2011).

A 2010 study titled "Solar Cooling in Australia: The Future of Air-conditioning?" concluded that solar thermal cooling is still not as cost effective an option as electric-driven cooling given the climate and electricity prices in Australia, and that the cost of electricity would have to be higher than $0.47 AUD (approximately $0.47 USD) for solar thermal cooling to achieve grid parity in the sunnier parts of Australia, which have similar climate conditions to Belize's (Kohlenbach & Dennis, 2010). The IEA similarly concludes that the costs of solar cooling would have to fall if it is to become competitive with current conventional cooling technologies (IEA, 2011).

4 HOW CAN WE CHANGE OUR ENERGY USE PATTERNS?

"Policymakers should devote as many resources to managing their demand for energy as their supply .... Energy efficiency programs have been proven to be the cheapest, fastest, and cleanest way for utilities to meet customers' energy needs. Instead of incurring economic costs, nations gain immediate economic benefits and savings when businesses and individuals simply begin to conserve energy."

John Drzik, Chief Executive Officer, Oliver Wyman Group

How can we change our way of life – the things we do and the way we do things – in order to reduce our energy footprint? Rather than thinking of how we can supply our ever-growing energy wants and needs, what can we do to curb them?

Reducing the amount of energy we use to support our way of life can be done in two general ways: we can maintain our lifestyle but do things more efficiently – that is, do things in a different way that uses less energy to achieve the same result – or we can change to a less energy-intensive lifestyle. The same holds true for a business or an industrial factory: reductions in energy consumption can be made by maintaining the same level of output or service but adopting more energy-efficient practices and processes, or by phasing out energy-intensive products or services as much as possible.

The following sections proffer various ways in which energy demand and hence energy costs in the various sectors can be reduced – in some cases drastically – with a mix of time-proven measures and newer innovations. In keeping with our focus on practicality and efficiency, most of these measures are aimed at reducing consumption in the Transport Sector, as this is the sector that is responsible for most of our energy demand (over 40%) and most of our GHG emissions (nearly 50%).

TRANSPORT

The amount of energy that is consumed by a typical vehicle depends on a number of factors:

a) For short-distance (urban) travel, where starts and stops are frequent, most of the energy goes into speeding up the vehicle. The energy consumed in speeding up is a direct function of the total mass of the vehicle (and its contents) multiplied by the cube of its speed.

So to save energy, we need to:

i. Use cars that weigh less and move at slower speeds.

ii. Decrease the number of stops and starts we make by maintaining steady traffic flow (e.g. by reducing traffic congestion).

iii. Capture and re-use the energy released during the frequent braking.

b) For long-distance travel, most of the energy goes into the swirling 'air tunnel' (drag) that is created behind the moving vehicle. This energy consumed by the drag is a direct function of the frontal area of the vehicle multiplied by the cube of its speed. So to save energy, we need to use cars with sleeker and thinner build and move at slower speeds.

c) A typical fossil-fuel vehicle consumes more energy per minute when it is idling than when it is moving.

d) The rolling resistance is a function of the vehicle's mass and the condition of its tires.

e) The efficiency of the energy-conversion chain of the vehicle determines the percentage of the fuel that is converted to motive power. For most fossil-fuel cars, this efficiency is about 20-35%; the rest is lost as heat. To save energy, we need to use vehicles with more efficient energy-conversion chains.

f) Finally, it goes without saying: the less we use vehicles, the less energy we use.

Below, we investigate a number of measures that can be taken to reduce our transport energy demand, bearing in mind the factors discussed above.

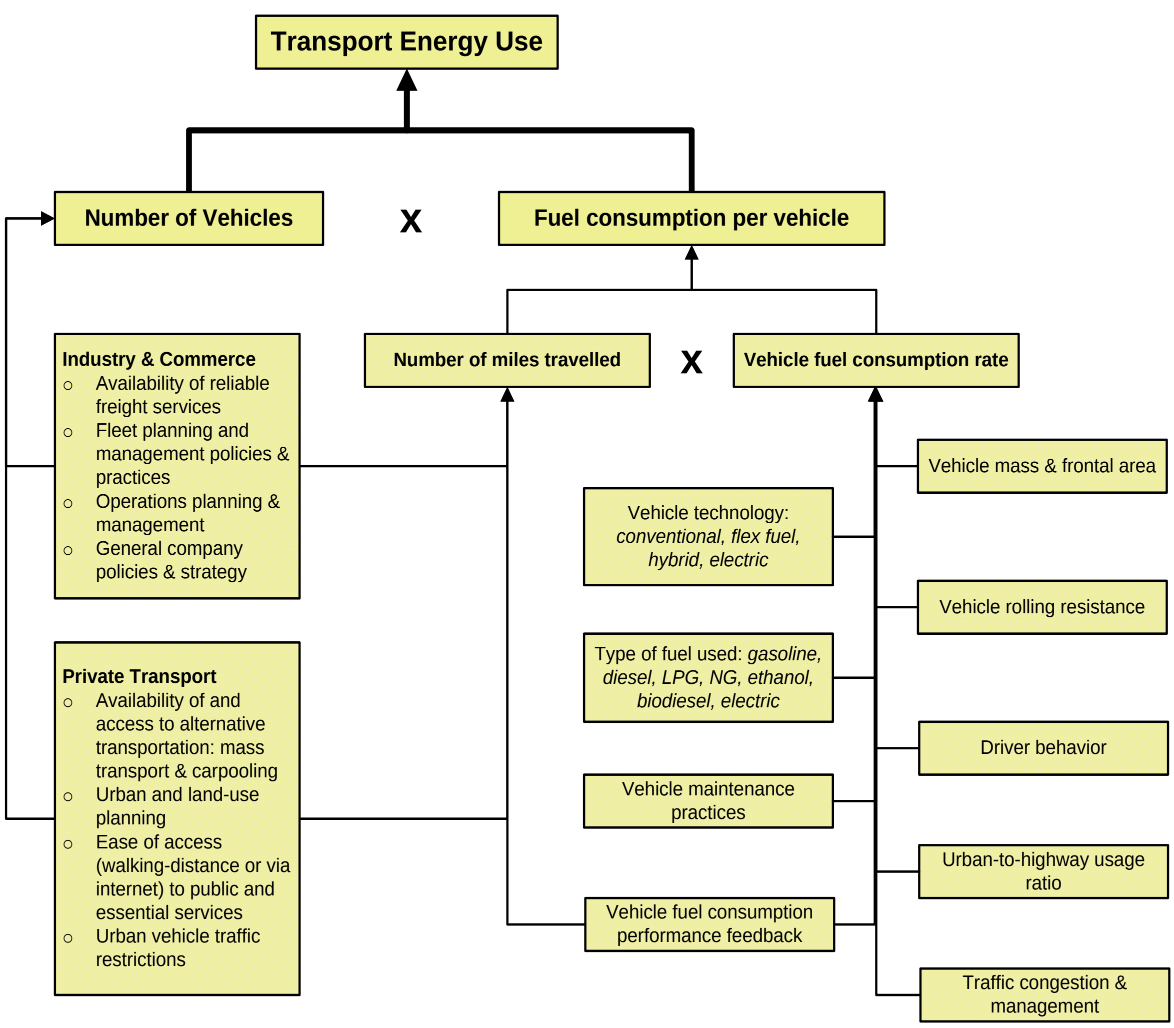

Figure 4.1.1: Factors influencing Transport Energy End-Use

New Vehicle Technology

Small Cars

State of the Technology

As our introductory discussions above show, energy savings can be gotten from using vehicles that weigh less and vehicles that have a smaller frontal area: that is, using smaller vehicles.

Potential for Energy Demand Reduction and Cost Savings

Gasoline Vehicles

Approximately 18,410,200 US gallons of gasoline is consumed in Belize each year[137]. If we assume that 14,000,000 US gallons of this is used in vehicles (the rest taken up by marine vessels and for other non-transport applications), then the accompanying import bill is $42,000,000 USD (*using an average landed cost of regular and premium gasoline of $3.00 USD per gallon*). Assuming an average mileage of 16 miles per gallon, the cumulative total gasoline-powered vehicle miles traveled in a year is therefore 224,000,000 miles.

If we replace say 25% of our gasoline-powered vehicle fleet with smaller vehicles, we will improve fuel efficiency of the replaced gasoline-powered vehicles by about 25% to 20 miles per gallon (since smaller vehicles are 20-30% more fuel efficient). The total quantity of gasoline used by the 25% of the fleet before replacement is 25% x 14,000,000 = 3,500,000 gallons. Working backwards, the total quantity of gasoline used after replacement is: 25% x 224,000,000/20 = 2,800,000 gallons. This is a reduction of 700,000 gallons or about 3.8% of the total gasoline imports, ***and a consequent savings of $2,100,000 USD per year***.

Potential for GHG Pollution Reduction and CDM Earnings

Due to the improved fuel economy of small cars, we avoid burning 700,000 gallons of gasoline per year. For each gallon of gasoline combusted, 8.8 kg of CO_2-equivalent GHG are emitted. So avoided emissions due to migrating 25% of our vehicle fleet to smaller vehicles are: 8.8 x 700,000 = 6,160,000 kg = 6,160 tCO2e GHG emissions.

Over a 10-year evaluation period, this amounts to 61,600 tCO2e GHG emissions (= 61,600 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $1,540,000 (*undiscounted value*). This should be sufficient monies to finance the promotional and educational campaign needed to jumpstart the project.

[137] Based on 2010 results provided by Ministry of Finance.

Diesel Vehicles

State of the Technology

Diesel vehicles use a compression-ignition internal combustion engine (ICE). They exhibit a number of key advantages over their spark-ignition ICE gasoline-powered counterparts. Diesel engines are more fuel-efficient, due to the engine's higher temperature of combustion and greater expansion ratio: they typically convert 45% of fuel energy into mechanical energy compared to 30% at most for gasoline engines. They also have longer lives and emit less GHG emissions per mile travelled.

Potential for Energy Demand Reduction and Cost Savings

If we replace 25% of our gasoline vehicles with diesel vehicles, and assuming the same output (i.e. total number of miles travelled), then the total consumption of diesel = 25% x 224,000,000/20mpg = 2,800,000 gallons of diesel.

The total cost of gasoline imports for 25% of fleet is $10,500,000 USD per year. Thus, if these are replaced by diesel vehicles, the total cost of diesel imports will be 3.00 USD per gallon x 2,800,000 gallons = $8,400,000 USD per year. So the total savings is $2,100,000 USD per year.

From another perspective, it costs $3.00/20 mpg = $0.15 USD per mile to run a diesel vehicle, compared to $3.00/16 = $0.19 USD per mile to run an equivalent gasoline vehicle at current average prices for both types of fuel.

The purchase price tag of diesel vehicles is on average $2,500 USD more than that for a similar-sized gasoline-powered vehicle. Using an average vehicle life of 8 years, this amounts to $500 USD per year over the life of the vehicle (*using a 12% discount rate*). One-quarter of Belize's gasoline-powered vehicle fleet is about 4,000 vehicles maximum: so this is $2,000,000 USD per year of additional costs to migrate 25% of the gasoline vehicle fleet to diesel. The net savings is therefore 2,100,000 – 2,000,000 = $100,000 USD per year[138]. These savings are negligible!

There is another possible obstacle in the way of migration to diesel. Local auto mechanics have a preference for working with gasoline vehicles and actively dissuade consumers from making the switch to diesel. Any promotional effort will have to take into consideration the fact that auto dealers, auto mechanics and auto parts stores are major opinion leaders in the motor vehicle industry, who presently have very little incentive to support any policy decision to encourage the switch to a more efficient fuel.

[138] This cursory analysis is supported by a recent study done by Carnegie Mellon University which concluded that the lifetime cost of ownership and operation of a diesel vehicle is less than that of a gasoline vehicle in spite of the higher initial costs.

Potential for GHG Pollution Reduction and CDM Earnings

25% of our gasoline vehicle fleet uses 3,500,000 US gallons of gasoline per year. So the total yearly emissions are 8.8 kg of CO_2-equivalent GHGs per gallon x 3,500,000 gallons = 30,800 tCO2e GHGs. The total yearly emissions due to the replacement fleet of diesel vehicles are 10.1 kg of CO_2-equivalent GHGs per gallon x 2,800,000 gallons = 28,280 tCO2e GHGs. The avoided emissions are therefore 30,800 – 28,280 = 2,520 tCO2e GHGs.

From a mileage perspective, gasoline vehicles emit 8.8/16 = 0.55 kg of CO_2-equivalent GHGs per mile travelled; while diesel vehicles emit 10.1/20 = 0.505 kg of CO_2-equivalent GHGs per mile travelled. So diesel vehicles emit marginally less GHGs per mile travelled than gasoline vehicles do.

Over a 10-year evaluation period, this amounts to 25,200 tCO2e GHG emissions (= 25,200 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $630,000 (*undiscounted value*).

LPG Fuel-Converted Vehicles

State of the Technology

LPG is the third most used motor fuel in the world, after gasoline and diesel, and is most popular in the EU, Australia, Hong Kong, India, South Korea, Serbia, the Philippines, Turkey and Armenia. Its major advantage as a motor fuel alternative, other than lower cost per vehicle mile traveled, is that it is "cleaner". It also burns with negligible particulate and smoke emissions. Moreover, because it contains fewer additives and is less corrosive compared to gasoline, it causes less engine wear and tear, thus increasing service intervals and decreasing maintenance costs. According to the IEA ETSAP, the high octane rating coupled with the lower carbon and other oil-based emission characteristics of LPG have resulted in longer engine lifetimes, up to twice that of the normal lifetime of gasoline engines (IEA Energy Technology Network, April 2010).

However, factory-made LPG vehicles are not readily available in most developed countries. The last LPG models commercially produced in the USA are from 2004. As a consequence, some countries, such as Australia, actively promote conversion of vehicles to LPG. Most spark-ignition vehicles that run on gasoline can be converted to run on LPG also, without major modifications. Converting a vehicle to LPG may mean either of two things: replacing the vehicle's fuel supply system with an LPG supply system or installing the LPG supply system as an alternative fuel supply, alongside the existing fuel supply. In the latter case, the driving range of the vehicle is automatically extended (as the vehicle will have two fuel supply sources instead of one). The cost of conversion is largely dependent on the size of the LPG tank needed and hence the vehicle duty (light versus medium versus heavy). In Belize, the reported cost of conversion of light-to-medium duty vehicles for bi-fuel use (gasoline/butane) by mechanics in Spanish

Lookout, Cayo is in the region of $750 to $1,250 USD[139]. In the US, the average cost of converting a light-duty vehicle from gasoline to propane ranges from €2,990 (USD $4,350) to €8,960 (USD $13,000)[140]. The huge discrepancy in the costs is likely due to differences in quality and safety standards for retrofitting such vehicles between the two countries.

A vehicle running on LPG consumes on average 30% to 40% more fuel than one running on gasoline; so the fuel economy is around 10.76 mpg of LPG. This lower fuel economy is due to the lower energy density of LPG. However, LPG emits less GHGs upon combustion: 5.65 kg of CO_2-equivalent GHGs per gallon of LPG, compared to 8.8 kg of CO_2-equivalent GHGs per gallon for gasoline.

Potential for Energy Demand Reduction and Cost Savings

The total cost of gasoline imports for 25% of fleet is $10,500,000 USD per year. If we convert 25% of our gasoline vehicle fleet to LPG, and assuming the same output (i.e. total number of miles travelled), then the total consumption of LPG = 25% x 224,000,000/10.76 mpg[141] = 5,205,912 gallons of LPG. The cost per gallon of imported LPG (not including transportation, marketing and tax; so as to ensure that we are doing an apples-to-apples comparison) is approximately $2.10 USD per gallon. The total cost of LPG imports for the 25% of the fleet replaced is therefore equal to 2.10 x 5,205,912 gallons = $10,932,415 USD per year. So the total savings (loss) is 10,500,000 – 10,932,415 = ($432,415) USD per year.

The cost of converting a gasoline vehicle to gasoline/LPG is on average about $1,000 USD. Using an average vehicle life of 8 years, this amounts to $200 USD per year over the life of the vehicle (*using a 12% discount rate*). One-quarter of Belize's gasoline-powered vehicle fleet is about 4,000 vehicles: so this is $800,000 USD per year of additional costs to convert 25% of the gasoline vehicle fleet to LPG. The net loss is therefore (432,415) - 800,000 = ($1,232,415) USD per year.

The cursory analysis done above does not even take into account the cost of upgrading the refueling infrastructure for LPG use, which is most likely a substantial figure[142]. Of course, maintenance costs tend to be lower for an LPG-converted vehicle; but, *viewed from the national perspective*, the economics seem to be clearly against mass conversion of gasoline vehicles to LPG.

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[139] Based on discussions with local vehicle experts: Eccleston Irving, CEO of Eugene Zabaneh Enterprises, and Gerald Simmons Jr, owner/operator of Simmons Welding Shop operating out of San Ignacio, Cayo.

[140] Source: (IEA Energy Technology Network, April 2010)

[141] This number was calculated using the ratio of the energy content of LPG and that of gasoline = (88.051/131)*16 mpg, and therefore assumes that the fuel-to-mechanical power conversion technology for LPG is as efficient as that for gasoline.

[142] The cost of upgrading a single refueling station for NG use in the EU is about $350,000 USD (IEA Energy Technology Network, April 2010)

Potential for GHG Pollution Reduction and CDM Earnings

25% of our gasoline vehicle fleet will produce 30,800 tCO2e GHG emissions per year. The total yearly emissions due to the converted vehicles are 5.65 kg of CO_2-equivalent GHGs per gallon x 5,205,912 gallons = 29,413 tCO2e GHGs. The avoided emissions are therefore 30,800 – 29,413 = 1,387 tCO2e GHGs.

Over a 10-year evaluation period, this amounts to 13,870 tCO2e GHG emissions (= 13,870 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $346,750.

Flex Fuel Vehicles

State of the Technology

Flex fuel vehicles (FFVs) are a Brazilian innovation[143] that was triggered by the need for flexibility in a volatile fuel market. FFVs produced in Brazil can run on any blend of ethanol and gasoline between E0 and E100 (that is, any mixture of ethanol gasoline in the range of 100% gasoline to 100% ethanol), while most US versions can only run on blends between E0 and E85. The engine senses the proportion of ethanol in the mixture and adjusts the internal combustion process for optimal performance. A typical FFV, sold in the US, costs the same as its gasoline engine counterpart (for the same power output)!

All spark-ignition vehicles manufactured in the US since 1978 can run on E10[144] and most manufactured since 2001 can run on E15[145]. This means that almost all of the vehicles we have in Belize can run on E10 today, and a few can run on E15. The exact amounts would have to be certified via a data-mining analysis conducted on vehicle registration and licensing records.

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[143] Actually, the idea was first drawn up by Henry Ford in 1920's.

[144] According to a 2010 CRS Report (Yacobucci, 2010), no automaker or small engine manufacturer currently warranties its vehicles to use ethanol blends above E10. The report noted that while some fuel distribution systems are rated to dispense up to E10, some may be able to operate effectively on E15 or higher.

[145] The verdict is still outstanding on the compatibility of higher-level ethanol blends with engine materials, the general effects on vehicle operability and performance, and the health effects on human beings (inhalation exposure). The long-term effects on emissions and engine durability for small non-road engines such as lawnmowers are of particular concern. Unlike modern vehicles which have complex fuel systems that can adjust fuel/air ratios in real time, most small non-road engines have carburetor systems with set fuel/air ratios. Ethanol contains oxygen. The oxygen content of the fuel (blend) increases as the proportion of ethanol in the blend increases while the amount of air coming into the engine remains constant. This could cause the engine to misfire and/or overheat, especially in the case of air-cooled engines. (Yacobucci, 2010)

Figure 4.1.2: Flex-Fuel Vehicles: Pickup truck and Motorcycles

About seven million FFVs are currently used in the US that can run on an 85% ethanol blend (E85). US auto companies have committed to manufacturing a larger number of FFVs, in a wide variety of models, to be available at prices competitive with conventional vehicles.

Potential for Energy Demand Reduction and Cost Savings

Let us assume migration of the entire gasoline vehicle fleet to E10. The E10 equivalent of 14,000,000 US gallons of gasoline is 14,482,759 US gallons. More of the E10 is needed because 1 gallon of ethanol has only 2/3 the energy content of a gallon of gasoline (*that is, energy in 1.5 gallons of ethanol = energy in 1 gallon of gasoline*). This 14,482,759 gallons of E10 comprises 1,448,276 gallons of ethanol and 13,034,483 gallons of gasoline. The total import bill is therefore: $1.60 x 1,448,276 + $3.00 x 13,034,483 = $41,420,689 USD.

So based on the simplified analysis above and assuming that CIF gasoline costs are $3.00 USD and that ethanol can be produced locally for $1.60 per US gallon, replacing gasoline with E10 will reduce costs – although only marginally – by about ½ million USD per year. However, there are other key considerations:

a) As the price of gasoline rises relative to that of locally produced ethanol, the cost of using E10 will reduce even further relative to that of using gasoline only; on the other hand, if the price of gasoline falls relative to that of locally produced ethanol, the opposite will occur.

   i. If, for instance, we use a price of $1.10 per US gallon instead (for cellulosic ethanol), then the total cost of the blend is: $1.10 x 1,448,276 + $3.00 x 13,034,483 = $40,696,551 USD. The savings are then 42,000,000 – 40,696,551 = $1,303,449 USD per year.

b) Once the price of gasoline is higher than that of ethanol *on a per-gasoline equivalent basis*, it makes more sense to use a greater percentage of ethanol in the blend. If the price of ethanol is higher, then it makes sense to use less ethanol in the blend. Of course, the extent to which this can be done is dependent on the capabilities of the vehicle fleet.

   i. If, for instance, we switch all our gasoline vehicles to E85 instead and use an ethanol price of $1.10 per US gallon (for cellulosic ethanol), then the total cost of the blend is: \$1.10 x 16,604,651 + \$3.00 x 2,930,233 = \$27,055,814 USD. A 36% reduction in cost and consequent savings of nearly \$15 million USD per year!

c) The difference in fuel costs is only one part of the picture:

   i. First of all, locally-produced ethanol uses local feedstock, local labor and other local services: so only about 60% of these costs (for capital equipment, parts, specialized maintenance services and enzymes) actually flow out of the country, as opposed to 100% for gasoline.

   ii. Secondly there is a marked reduction in our dependence on foreign oil: a 7% reduction in the quantity of gasoline imported if we switch all gasoline-powered vehicles to E10, 18% reduction if we switch to E25, 40% reduction if we switch to E50 and 80% reduction if we switch to E85.

   iii. When the previous two points are taken together, the net foreign exchange savings is nearly \$2 million USD per year if we switch to E10, over \$5 million USD per year if we switch to E25, over \$11 million USD per year if we switch to E50, and over \$22 million USD per year if we switch to E85!

   iv. Lastly and as importantly, higher utilization of local labor and services means increased employment, less poverty, and higher economic growth!

d) While most light-duty conventional vehicles manufactured in the US can use ethanol blends up to E15 without needing any engine modifications, modifications to both the engine and fuel system are required for conventional vehicles that run on blends with higher proportions of ethanol in the fuel mixture.

e) The cost of retrofitting refueling stations for ethanol storage and dispensing have to be evaluated and included in the cost-benefit analysis.

Potential for GHG Pollution Reduction and CDM Earnings

Combustion of pure bioethanol (E100) in vehicles produces no net GHGs: since the CO_2 emitted is the same CO_2 sequestered from the atmosphere during growth of the sugar cane or corn plant used to produce the ethanol (*In reality, emissions do occur during production and distribution, and these would have to be taken into account when a CDM Project is being assessed*). As a consequence, E10 emits 8.02 kg of CO_2-equivalent GHGs per gallon; while E85 – with a higher proportion of bioethanol – emits a mere 1.34 kg of CO_2-equivalent GHGs per gallon.

For migration of all our gasoline vehicles to E10, we would therefore avoid 8.8 x 14,000,000 – 8.02 x 14,482,759 =7,048,276 kg or 7,048 tCO2e GHG emissions, yielding CDM earnings of \$1,762,069 USD over a ten-year evaluation period.

For migration of all our gasoline vehicles to E85, we would avoid 8.8 x 14,000,000 – 1.34 x 19,534,884 = 97,023,256 kg or 97,023 tCO2e GHG emissions, yielding CDM earnings of \$24,255,814 USD over a ten-year evaluation period! One way to look at this is that the

CDM earnings could be used to offset the cost of purchasing 16,000 flex-fuel vehicles (that is the total amount of gasoline vehicles being replaced) by $24,948,800/16,000 = $1,516 USD per vehicle, for the initial rollout.

Hybrid Electric Vehicles

State of the Technology

A hybrid electric vehicle (HEV) combines a conventional internal combustion engine (ICE) propulsion system with an electric propulsion system to provide motive power. The electric power train has better energy conversion efficiency than the ICE: 80% compared to 20% (Brown, Larsen, Dorn, & Moore, 2008). Hybrids are therefore usually 30-40% more fuel efficient *overall* than equivalent conventional gasoline-powered vehicles.

There are two general categories of hybrid vehicles: "plain" hybrid vehicles (HEVs) and plug-in hybrid vehicles (PHEVs). An HEV generates electricity during operation (from the ICE), which is then used to directly power the electric motors or recharge its batteries. HEVs have limited all-electric range and their batteries cannot be recharged from the grid. A plug-in hybrid electric vehicle, on the other hand, is a hybrid vehicle with rechargeable batteries that can be charged by connecting a plug to an external electric power source. They have a longer all-electric range (about 10-40 miles) than HEVs.

Modern HEVs and PHEVs typically employ a number of efficiency-improving technologies to varying degrees:

1) They conserve energy and reduce emissions by using the ICE for propulsion where it performs more efficiently and switching to electric motors only when the vehicle is idling, that is when the ICE performs most inefficiently. However, some versions use only the electric motors to power the wheels; others use both the ICE and the electric motors.

2) When brakes are applied on a conventional vehicle, the kinetic energy released is lost as heat. However, regenerative braking technology used in some HEVs and PHEVs captures this kinetic energy and converts it to electric energy that is used to replenish the rechargeable batteries that power the electric motors.

3) Some hybrids also capture energy when the vehicle is in downhill mode or coasting, which is then used to recharge the batteries.

4) Hybrids use a computer-guided control system to manage the complex relationship between the ICE, electric motors, drive trains and battery systems throughout both the driving and idling cycles, so as to maximize fuel economy.

HEVs and PHEVs are best suited for private passenger transport in urban areas[146]. Hybrid-electric technology is also well-suited for stop-and-go driving by buses and delivery vehicles in urban areas. Studies have found that fuel economy improvements ranging from 10 to 57 percent are achievable using hybrid technology in these applications. Electric or hybrid-electric drive-train technologies are not considered practical for heavy-duty vehicle applications (InterAcademy Council, 2007).

Potential for Energy Demand Reduction and Cost Savings

Replacing gasoline-powered vehicle fleet with hybrids will improve the fuel efficiency of the replaced vehicles by about 40% to 22.4 miles per gallon since Hybrids are about 40% more fuel efficient (McConnell & Turrentine, 2010). The total quantity of gasoline used by 25% of the gasoline vehicle fleet before replacement is 3,500,000 gallons. Working backwards, the total quantity of gasoline used after replacement is: 25% x 224,000,000/22.4 = 2,500,000 gallons.

This is a reduction of 1,000,000 gallons or 5.34% of the total gasoline imports, and a consequent <u>fuel savings of $3,000,000 USD per year</u> by replacing 25% of our gasoline vehicles with hybrids.

However, hybrids currently cost on average anywhere from $4,750 USD (McConnell & Turrentine, 2010) to $7,000 USD (Valdes-Dapena, 2009) more than conventional gasoline cars: this difference is expected to disappear as HEVs and PHEVs take up more market share. Using an average vehicle life of 8 years, this amounts to $1,200 USD per year on average over the life of the vehicle (*using a 12% discount rate*). One-quarter of Belize's gasoline-powered vehicle fleet is about 4,000 vehicles: so this is $4,800,000 USD per year of additional FX outflows to pay towards the purchase cost of imported hybrids. This results in a net loss of $3,000,000 – 4,800,000 = (1,800,000) USD per year. So, switching to hybrids – on the basis of fuel savings alone – is not viable at the current price tag differential between hybrids and conventional vehicles and the current price level of oil. Obviously, if the price tag differential falls or oil prices continue to trend upward, the case for switching will become more favorable.

Potential for GHG Pollution Reduction and CDM Earnings

Apart from the energy savings, and as a consequence of both the improved fuel economy and the use of electric motors to power the vehicle during idling, hybrids produce significantly lower emissions than equivalent gasoline-powered vehicles.

Following from the results obtained in the foregoing section, we can obtain reductions of 5.34% of total gasoline imports (or 1,000,000 gallons of gasoline) by switching 25% of our gasoline-powered vehicle fleet to hybrids. Since 8.8 kg of CO_2-equivalent GHG are

[146] The Mayors of both New York and San Francisco in the USA have announced that all taxis in their cities will be hybrids by 2012, a move designed to reduce CO2 emissions, fuel use, and local air pollution.

emitted for each gallon of gasoline combusted, avoided emissions are equal to: 8.8 x 1,000,000 =8,800 tCO_2e GHG emissions.

Over a 10-year evaluation period, this amounts to 88,000 tCO_2e GHG emissions (=88,000 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $2,200,000.

Electric Vehicles

State of the Technology

Electric vehicles (EVs) use one or more electric motors for propulsion. Since electric drive trains are 3 to 4 times more efficient than ICE driven trains, EVs usually operate much more efficiently than conventional vehicles. They can be charged from any ordinary outlet (adding about 5 miles of driving range per hour of charging), from special wall- or pedestal-mounted charging stations (adding 15-30 miles of driving range per hour of charging) or at industrial-scale DC charging stations (adding about 160 miles of driving range per hour of charging). Some EVs use swappable batteries; this reduces charging time.

Figure 4.1.3: Electric Car charging in France

The driving range of an EV (the maximum distance travelled without needing to "refill") varies between 50 to 200 miles depending on the size (and number) and type of its batteries. In general, the larger the batteries, the heavier is the vehicle and the more is the space taken up within the vehicle – factors which work against better fuel economy.

On the other hand, with smaller batteries, the driving range is reduced[147]. For this reason, the logical target markets for current versions of EVs are niche groups of urban and suburban drivers.

EVs are not a new technology: the first EV was built in 1835; and electric-powered trains and trams have been rolling within cities and across countries all over the world, for over a century, as some of the most economical modes of transport. The recent oil shocks have however sparked a renewed interest in EVs for private transport.

Potential for Energy Demand Reduction and Cost Savings

The average mileage (efficiency) of an electric vehicle is 3.33 mpk (3.33 miles per KWh). Again, if we – sometime in the future - replace say 25% of our gasoline-powered vehicle fleet with EVs, the total KWh used in traveling 56,000,000 vehicle-miles is therefore 16,816,817 KWh. The cost per KWh of electricity is approximately $0.22 USD. About $0.12 USD of this cost flows back to foreign sources to pay for electricity imports (from CFE), fuel, capital investments, consultancies etc[148]. The total FX-component of operating the EVs will therefore = $0.12 x 16,816,817 = $2,018,018 USD annually. So the total FX savings is $10,500,000 USD (the portion of the gasoline import bill due to the 25% portion of gasoline vehicles being replaced) less $2,018,018 USD = $8,481,982 USD per year. If we replaced all gasoline vehicles (100%), the savings would be four times as much: $33,927,928 USD per year.

However, electric cars currently cost well over $10,000 USD more than conventional gasoline cars, though this difference is expected to disappear as EVs take up more market share. Using an average vehicle life of 8 years, this amounts to over $2,000 USD per year over the life of the car (*using a 12% discount rate*). One-quarter of Belize's gasoline-powered vehicle fleet is about 4,000 vehicles: so this is $8,000,000 USD per year of additional FX outflows to pay towards the purchase cost of imported EVs. Even so, there still remains a small net savings of $481,982 USD per year (8,481,982 – 8,000,000).

On the other hand, EVs have much lower maintenance costs than comparable conventional vehicles. Their electric motors have only a small number of moving parts compared to the thousands of moving parts of an ICE; they have no emissions equipment because there is no need to burn fuel; and they have no transmission: consequently there is no need for oil or transmission fluid changes and no expenses to be borne as a result of catastrophic and costly engine failures. These savings in

[147] EV drivers can suffer "range anxiety" much more so than drivers of conventional vehicles because of the reduced driving range exacerbated by the sparsity of refueling stations due to the low market penetration of EVs at this point in time.

[148] Rough calculation from BEL financials 2008-2010.

maintenance costs are partly offset by the cost of batteries, which can be very expensive and need to be replaced every 6-10 years[149]. (Chambers, 2011)

There is also another substantial potential benefit to be gained from bringing EVs into the picture. The price of electricity imports (from CFE) falls to very low levels – to as low as $0.05 USD - during the early morning period, when there is little demand for it and when most cars are parked at home or in a workplace garage. This affords an opportunity to charge up EVs when prices are low; and so further increase FX savings. Again, if 50% of total charging can be done during these off-peak periods, the further savings are: 0.05 x 50% x 16,816,817 = $420,420 USD per year. The extent of these off-peak savings increases even further if wind-powered plants are introduced in the supply mix, as these can now be dispatched to a greater degree (backed-up by other non-intermittent sources such as imported electricity from CFE) when previously they could not, due to low demand at night time. Migrating to EVs thus makes the case for renewable-source generation even stronger!

Potential for GHG Pollution Reduction and CDM Earnings

Like HEVs, EVs emit far less GHG pollutants than their conventional gasoline counterparts: in fact, less than HEVs. The extent of the difference is dependent on the GHG footprint of the combined generation sources making up the electricity supply mix.

The total yearly emissions due to 25% of our gasoline-powered vehicle fleet are 30,800 tCO2e GHG. The total yearly emissions when these are replaced by equivalent EVs equal the indirect emissions rate of the electricity supply source multiplied by the total electricity consumption = 0.336 metric tons per MWh x 16,817 MWh = 5,651 tCO2e GHG emissions. The reduction in emissions is therefore 30,800 – 5,651 = 25,149 tCO2e GHG per year.

Over a 10-year evaluation period, this amounts to 251,490 tCO2e GHG emissions (=251,490 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $6,287,250. These earnings could be used to offset the cost of purchasing 4,000 electric vehicles (that is the total amount of gasoline vehicles being replaced) by $6,287,250/4,000 = $1,572 USD per vehicle, for the initial rollout.

Behavioral Changes

Mass Transport

State of the Technology

Mass transport – buses, trains, trams and trolleys – makes sense as long as there are sufficient people to move around and as long as it is being used as an alternative to

[149] However this spans the average economic life of gasoline vehicles anyway.

private vehicles and taxis (as opposed to walking and bicycles). Studies have shown that the efficiency of mass transport versus private transport is in the order of 5 to 1. However this assumes high capacity factors (usage), which in turn is dependent on the population density of the area. Furthermore, there are other secondary benefits (to energy savings) from using mass transport: reduced traffic congestion in the city, lower parking costs, fewer accidents, lower stress levels amongst drivers, less air and noise pollution.

There are only two forms of land-based mass transport in Belize: buses and vans. Smaller buses are used for inner city transport; larger buses for cross-country transport; and vans for transferring and transporting tourists. Additionally, there are two other options that merit serious consideration and study: bus rapid transit and electric-powered trams for inner city travel. Although trams are inherently more efficient than buses and cause far less pollution, the required investment needed for a tram transport infrastructure may be cost-prohibitive. In any case, however, deploying either of these solutions requires significant investment in infrastructure and a total paradigm shift in the way we plan and develop our urban areas.

Potential for Energy Demand Reduction and Cost Savings

For fossil-fuel powered vehicles, a bus with a fuel efficiency of 10 mpg and carrying 50 passengers consumes 0.002 gallons of fuel per passenger-mile; while a small car with a fuel efficiency of 30 mpg and carrying 4 passengers consumes 0.0083 gallons of fuel per passenger-mile. So, on the basis of operating cost alone, it costs four times less to use fossil-fuel powered mass transport than private transport. However, this operating cost advantage is partly offset by the fact that a 50-passenger capacity bus costs USD $100,000 while a small car costs USD $30,000.

What savings can be had by substituting highway travel using private vehicles with mass transport?

We start off with the following assumptions:

1) 50% of all non-mass transport, non-freight vehicle fuel consumption is due to highway travel.
2) 90% of all gasoline consumption is due to non-mass transport, non-freight vehicles.
3) On average, 2 persons at a time are travelling in a private vehicle during highway travel.
4) One half of current work-bound highway travel by private vehicle can be migrated to mass transport.

The total gasoline used up in private vehicles is therefore 50% x 90% x 14,000,000 = 6,300,000 gallons per year, at a total cost of $18,900,000 USD per year. The total passenger-miles travelled in gasoline vehicles = 2 passengers x 16mpg x 6,300,000 = 216,000,000 passenger-miles per year.

Now if we were able to shift ½ of this amount of travel to mass transport on diesel-powered buses with a fuel economy of 0.002 gallons per passenger-mile (*See calculation in first paragraph of this section*); the total diesel used would be: ½ x 216,000,000 x 0.002 = 216,000 gallons per year, at a cost of $648,000 USD per year.

This yields total yearly fuel savings of ½ x (18,900,000) – 648,000 = $8,802,000 USD per year by substituting ½ of highway travel in private vehicles with mass transport. Even if we manage to shift over only ¼ of the current highway travel by private vehicles to mass transport, the fuel savings would still be $4,401,000 USD per year.

There are other related questions that need to be answered at a micro-level. Some of these are:

- Would Belize City be better served by an electric-powered public tram transport system as opposed to small bus service routes?
- Would inter-urban travel (between Belize City, Belmopan, the Western Towns and the Northern Towns) be better served by an electric train service?
- Would sugar cane delivery transport be better served by an electric train system that transports cane from fields to factory?

These questions are not to be lightly regarded and dismissed without doing the proper technical and economic analyses. If there is one thing that has been shown from the other cursory analyses that have been done under previous sections, it is that there are many opportunities for substantial savings that have so far not been further explored and/or exploited either due to apathy or simple ignorance of the facts!

Potential for GHG Pollution Reduction and CDM Earnings

The total yearly emissions due to highway travel by gasoline-powered private vehicles = 8.8 x 6,300,000 = 55,440 tCO2e GHG. We shift half of this to mass transport, then the reduction in emissions due to highway travel by private vehicles = 27,720 tCO2e GHG per year. However, the added emissions due to the increase in mass transport travel = 10.1 x 216,000 = 2,182 tCO2e GHG per year. The net reduction in GHG emissions due to shifting ½ of all highway travel by private transport to mass transport is therefore 25, 538 tCO2e GHG per year.

Over a 10-year evaluation period, this amounts to 255,380 tCO2e GHG emissions (=255,380 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $6,384,500.

Carpooling

Carpooling is an easy and effective energy-saving transport option for a group of people who all live in one place and all work in another place.

Potential for Energy Demand Reduction and Cost Savings

What savings can be had by substituting work-bound highway travel using private vehicles with carpooling?

We start off with the following assumptions:

1) 25% of all private vehicle fuel consumption is due to work-bound highway travel.
2) 90% of all vehicle gasoline consumption is due to private vehicles.
3) Without carpooling: on average, 2 persons at a time are travelling in a private vehicle during work-bound highway travel.
4) With carpooling: on average, 4 persons at a time are travelling in a private vehicle during work-bound highway travel.
5) One quarter of current work-bound highway travel by private vehicle can be migrated to carpooling.

Gasoline Vehicles

If 4 persons travel to work – say between Belize City and Belmopan – in two separate gasoline-powered vehicles (2 persons per vehicle), each vehicle consumes 1/16 = 0.0625 gpm/2 passengers = 0.03125 g/p-m (gallons of gasoline per passenger-mile).

If these 4 persons now carpool into one vehicle, the vehicle consumes 0.0625 gpm/4 passengers = 0.015625 gallons of gasoline per passenger-mile. Let us up this by 20% to 0.01875 g/p-m in order to account for the increased consumption due to the additional passenger weight and maybe multiple pick-ups or stops within a small locale.

The total gasoline used up in private vehicles for work-bound highway travel is therefore 25% x 90% x 14,000,000 = 3,150,000 gallons per year, at a total cost of $9,450,000 USD per year. The total passenger-miles travelled = 2 passengers x 16mpg x 3,150,000 = 100,800,000 passenger-miles per year.

Now if we were able to shift ¼ of this amount of travel to carpooling with a fuel economy of 0.01875 gallons per passenger-mile, the total gasoline used would be: ¼ x 100,800,000 x 0.01875 = 472,500 gallons per year, at a cost of $1,417,500 USD per year. So the savings = (¼ x 9,450,000) - 1, 417,500 = 945,000 USD per year.

This yields total yearly fuel savings of <u>945,000 USD</u> <u>per year</u> by substituting 25% of work-bound highway travel in private gasoline-powered transport by carpooling.

Carpooling will obviously also reduce total vehicle wear and tear and so lower maintenance costs. If it also reduces vehicle ownership (one or more of the carpoolers may choose to forgo getting a new car when the old one no longer works), then there are other benefits to be factored into the savings calculation.

Potential for GHG Pollution Reduction and CDM Earnings

The total yearly emissions due to work-bound highway travel by private vehicles = 8.8 x 3,150,000 = 27,720 tCO2e GHG. We shift ¼ of this to carpooling, then the reduction in emissions due to highway travel by private vehicles = 6,930 tCO2e GHG per year. However, the added emissions due to the increase in carpooling = 8.8 x 472,500 = 4,158 tCO2e GHG per year. The net reduction in GHG emissions due to shifting ¼ of all work-bound highway travel by private transport to carpooling is therefore 6, 930 – 4,158 = 2,772 tCO2e GHG per year.

Over a 10-year evaluation period, this amounts to 27,720 tCO2e GHG emissions (=27,720 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $693,000.

Walking and Bicycles

"The bicycle, a form of personal transportation, has many attractions. It alleviates congestion, lowers air pollution, reduces obesity, increases physical fitness, does not emit climate-disrupting carbon dioxide, and has a price within reach for the billions of people who cannot afford an automobile. Bicycles increase mobility while reducing congestion and the area of land paved over. Six bicycles can typically fit into the road space used by one car. For parking, the advantage is even greater, with 20 bicycles occupying the space required to park a car." (Brown, Plan B 3.0: Mobilizing to Save Civilization, 2008)

Potential for Energy Demand Reduction and Cost Savings

What if we were to replace urban travel with bicycles and walking: how much could we save?

The data on how much fuel is used moving by vehicle within our towns and cities are not readily available. If it is conservatively assumed that 50% of fuel consumption is used up in urban vehicle travel, and that 10% of this vehicle travel (using gasoline-powered vehicles) could be replaced with walking or bicycles; then savings of 10% x 50% x 14,000,000 = 700,000 gallons of imported fuel can be made, resulting in FX savings of $2,100,000 USD per year.

The cost of the additional bicycles and of provisions for bicycle parking that would be needed, as well as the cost of marketing and promoting the benefits of walking and cycling, would have to be factored into the calculations. There are of course other benefits to be gained from replacing vehicles with walking and bicycles: such as reduced traffic accidents and better health!

Potential for GHG Pollution Reduction and CDM Earnings

The total yearly emissions due to urban vehicle travel of 10% of our gasoline-powered vehicle fleet are 8.8 kg of CO_2-equivalent GHG per gallon x 10% x 50% x 14,000,000 = 6,160 tCO2e GHG.

The total yearly emissions reduction possible from replacing 10% of urban vehicle travel with walking and bicycling is therefore 6,160 tCO2e GHG. Over a 10-year evaluation period, this amounts to 61,600 tCO2e GHG emissions (=61,600 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $1,540,000.

Highway Driving Behaviors

The faster a vehicle is driven, the higher is the fuel consumption rate: that is, the amount of fuel consumed per mile travelled. If a vehicle increases its average highway driving speed from 60 mph to 72 mph (a 20% increase) for instance, it will increase fuel consumption by 20%. Quick starts and hard stops can burn up an additional 39% more fuel. In total, speeding and aggressive driving can cost about 50% more in fuel consumption than driving at a moderate constant speed, or - put another way - moderating driving behavior can reduce fuel consumption by 33%.

Potential for Energy Demand Reduction and Cost Savings

Assuming that highway travel accounts for about 50% of fuel consumption in Belize, the reduction in gasoline and diesel imports possible from putting measures into effect to curb aggressive driving and speeding (assuming they affect 10% of all highway travel) is 33% x 50% x 10% x 14,000,000= 233,333 US gallons per year for gasoline vehicles. This translates into FX savings of 3.00 x 233,333 = $700,000 USD per year. These savings would have to be weighed against the costs of instituting highway traffic patrols and other measures required to curb aggressive driving and speeding on highways, which has been worked out to be in the range of $240,000 to $355,000 USD per year (See Appendix C). So, we will be just at or above the breakeven point, even if we achieve only 1/2 of our target (of 10% of all highway travel). Of course, there are other benefits to be obtained from efficient highway driving: lower costs of vehicle maintenance due to less wear and tear and fewer accidents.

Urban Driving Behaviors

Intra-urban driving is a form of short-distance travel. Energy savings can be made by reducing congestion and harmonizing traffic flow in order to decrease the number of starts and stops and reduce idling time. Overall these measures can reduce fuel consumption by 3-4% (Friedrich).

Potential for Energy Demand Reduction and Cost Savings

Assuming that urban travel accounts for about 50% of fuel consumption in Belize, the reduction in gasoline imports possible from putting these measures into effect (assuming they affect 25% of all vehicles) is 3.5% x 25% x 50% x 14,000,000 = 61,250 US gallons per year for gasoline vehicles. This translates into FX savings of 3.00 x 61,250 = $183,750 USD per year. These savings would have to be weighed against the costs of instituting additional urban traffic patrols and other measures required to remove bottlenecks especially during rush hour traffic.

Vehicle Maintenance

Using better lubricants improves engine performance and increases the efficiency of the energy-conversion chain. Maintaining proper tire inflation reduces rolling resistance. Together, these measures alone can reduce fuel consumption by a further 5% (Friedrich).

Potential for Energy Demand Reduction and Cost Savings

The reduction in gasoline and diesel imports possible from putting these measures into effect (assuming they affect 25% of all vehicles) is 5% x 25% x 14,000,000 = 175,000 US gallons per year for gasoline vehicles. This translates into FX savings of 3.00 x 175,000 = $525,000 USD per year.

Re-engineering the Mobility Paradigm with Information Technology

State of the Technology

Most interventions so far considered focus on improving the efficiency of the current technology or changing to a different and more efficient technology altogether. For instance, we have proposed moving to smaller vehicles (which improves fuel economy without changing out the underlying ICE configuration) and replacing the current gasoline vehicle stock with electric cars (which completely changes out the ICE with an electric drive train). *But what about eliminating the need for transportation altogether in certain situations?*

A case in point is how tertiary education is delivered in Belize. Students regularly commute back and forth to attend classes in Belize City and Belmopan. Some use private transport; others car-pool and most use public transport. There is an alternative though. Instead of them going to classes, the classes can come to them - via the internet! Energy is then used to carry weightless digital packets over communication links at the speed of a thought instead of tons of fuel-guzzling vehicles moving in relative slow motion across miles of highway and through congested city streets.

While these energy savings alone are substantial, there is another significant benefit: removing the need for delivering education in traditional classroom settings means removing the need for as many physical classrooms, resulting in smaller buildings, smaller and fewer physical campuses, and an overall lower cost of service. Similarly, instead of using scarce funds to build a huge physical library to house thousands of books, it would probably make more sense to build an electronic library and serve up data and information to students wherever and whenever they are needed.

Of course changing the way we have done things for the last 100 years is never an easy task. The inertia is often insurmountable. Many of the savings from reduced energy consumption will initially have to be channeled into campaigns to overcome entrenched barriers and fight cultural resistance. **But policymakers must be guided by numbers and facts. If there is a new technology and innovation that offers a less costly and more effective way of accomplishing the same thing, then ways must be found to encourage its uptake!**

RESIDENTIAL & COMMERCIAL ENERGY USE

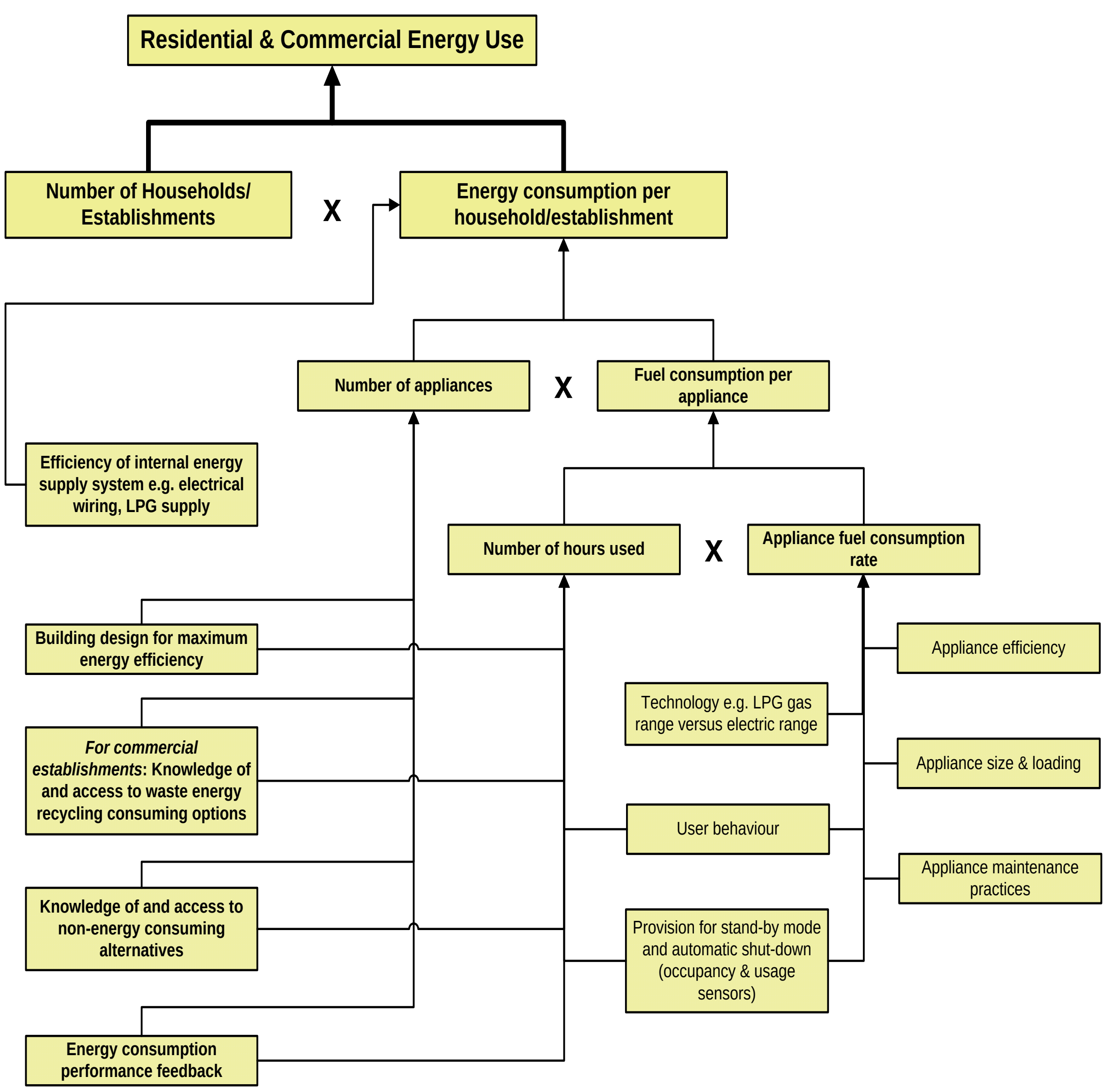

Figure 4.1.4: Factors influencing Residential & Commercial Energy End-Use

Building Design

State of the Technology

"Energy-efficient building design implemented together with efficient heating and cooling systems/equipment represents the largest technical potential for energy savings in residential, commercial, and public service buildings." (Liu, Meyer, & Hogan, 2010)

Energy-Efficient Buildings

Buildings account for 40% of energy use world-wide. The design and quality (of the construction) of the building envelope are the major determinants of how much natural light and air flow into and through the building's interior, how much heat is gained or lost through "thermal bridges" (which allow heat to flow in or out through insulation short-circuits), and hence of the quantity of energy required to heat, cool and ventilate a building (WBCSD, 2007).

Over the last two decades, developing countries, following in the footsteps of Europe and the USA, have become keenly aware of the need to design energy efficiency into buildings from the get-go so as to avoid locking in unduly high life cycle energy costs – particularly energy costs related to space cooling, heating and lighting - when investing in new buildings and associated energy systems. The more recent emphasis on sustainable development and greater awareness of the adverse environmental consequences of our economic activities have led to the propagation of the new energy-efficient building design concepts such as low-carbon buildings, zero-energy buildings, energy-plus buildings and green buildings.

Zero-energy buildings are designed so that the total energy used by the building over its lifetime is equal to the energy supplied by renewable and recoverable energy sources installed in the building. In energy-plus buildings, the energy supplied from renewable and recoverable energy sources exceed the energy used, with the excess energy fed into the public electricity grid or some other energy sink. Both concepts ardently proffer designing buildings on the basis of passive building design principles to lower total energy requirements in the first place before resorting to renewable and recoverable energy sources to provide the remaining requirements. Importantly, a zero-energy or energy-plus building does not necessarily mean that energy is not obtained from sources external to the building (such as the public electricity grid), it simply means that over the building's lifetime, any inflow of energy is netted out by outflows from the building's own energy sources.

The process of "green" or integrated building design involves the application of bio-climatic architectural principles, conservation of materials and resources, selection of energy efficient appliances for providing building services, use of clean and renewable energies, and adoption of ways and means for water and waste management. Green buildings ensure better comfort for the occupants, improved productivity and reduced operating and maintenance costs, while minimizing negative environmental impacts. It is estimated that, while suitable energy saving retrofits in existing buildings can reduce the energy bill by about 20 per cent, if the buildings are designed from the start with an integrated approach, the energy savings can be as high as 50 per cent.

Building Energy Efficiency Codes (BEECs)[150]

BEECs lay out the rules and minimum requirements that regulate the energy performance of building designs and their compliance during construction. They were first introduced in Europe and North America in the late 1970s with significant success, and the idea has since been adopted by many developing countries over the last two decades. BECCs are largely regarded as the most effective policy instrument available to government for removing the market barriers to upgrading to a more energy-efficient building stock.

The biggest challenge to implementing BECCs has been compliance enforcement, mainly because of lack of government commitment to EE efforts as a whole, poor oversight of the construction sector by government, low level of compliance capacity on the part of the construction sector mainly due to the complexity of having to deal with various service providers with non-aligned objectives, and financing constraints. In fact, compliance enforcement in developing countries has been either "seriously lacking or nonexistent" mainly due to budgetary constraints, lack of political will and corruption.[151]

Voluntary Building Certification Programs

Numerous voluntary certification programs have been launched world-wide promulgating the "Green Building" concept. The most well-known are perhaps the US Government's Energy Star certification program for buildings, the USGBC's voluntary certification and rating program called Leadership in Energy and Environmental Design (LEED) and the EU's Energy Performance in Building Directive (EPBD).

LEED, for example, has four certification levels for new buildings: Certified, Silver, Gold, and Platinum. Certification points are awarded for how well a building's characteristics match up with pre-determined criteria in specific areas of energy efficiency and resource conservation such as site selection, materials used, indoor environmental quality and renewable energy use. For instance, more points are awarded for locating a building within walking distance of public transport, or for illuminating a building's occupied space by sunlight as opposed to artificial light. (Brown, Larsen, Dorn, & Moore, 2008)

[150] Discussion based largely on information and data gleaned from (Liu, Meyer, & Hogan, 2010).

[151] Most BEECs in developing countries are "often only on paper due to insufficient implementation and enforcement, corruption and other problems" and are usually doomed if sponsoring agencies do not provide for follow-up support (Iwaro & Mwasha, 2010).

Energy Efficient and Alternative Lighting Technologies

The following energy efficient and alternative lighting technologies currently have much potential for reducing electricity use and, in some cases, displacing the use of all-electric lighting altogether in residential and commercial buildings:

a) ***More efficient lighting components***: more efficient bulbs, more efficient ballasts, luminaires with a high light output ratio and innovative new LED light sources. Replacing incandescent lamps with compact fluorescent lamps (CFLs) or linear fluorescent lamps (LFLs) in residential homes has the greatest energy savings potential: more than 70%.

Figure 4.1.5: LED-lit Kitchen in Modern Home

Fluorescent bulbs can last up to ten times longer than incandescent bulbs. Also, as much as 35% savings can be gotten by upgrading to a T5 fluorescent lamp luminaire using a mirror louvre fixture from an equivalent T8 mirror louvre fixture while using high-frequency ballast and a standard aluminum reflector (Bhusal, 2009).

On the downside, fluorescent lamps contain mercury, which can cause serious damage to the brain and liver especially of fetuses and children. For this reason, proper procedures must be followed for the cleanup upon breakage and proper disposal of spent lamps.

b) ***Properly-designed lighting systems*** that provide "the right amount of light when it is needed and where it is needed is" can also yield substantial energy savings (Bhusal, 2009). Studies have shown that occupancy sensors (that turn lights off in a room after a certain amount of time of no occupancy and on again when someone enters) can cut energy consumption by 20-26% compared to manual switching (Bhusal, 2009). Similarly, sensors that switch off artificial light upon detection of sufficient light intensity from natural light can save up to 20%. Further studies of the relationship between lighting quality and energy efficiency have confirmed that people prefer low-energy illumination levels. In fact, local experience in the Caribbean hotels sector found that "over-lighting" was a common problem.

c) ***Passive day-lighting*** is a component of efficient building design, usually applied in commercial building design. It uses non-moving, static elements of a building such as skylights, windows and sliding glasses to collect and funnel sunlight into the building; and lighting shelves, walls and other elements to reflect the sunlight deeper inside (the building): thus reducing the need for artificial light.

d) A ***Solar lamp*** is a CFL or LED lamp that is powered by a rechargeable battery connected to a photovoltaic solar panel. The battery is charged via the solar panel during sunlight hours and automatically discharges at night. In countries where they are deployed, solar lamps have mainly been used for rural household lighting and in the tourism industry as pathway night lights. Solar lighting technology is ideal for street lights for both off-grid and on-grid applications. Innovative on-grid solutions are now available where the solar energy captured is used to charge the battery and thereafter sent into the grid (the exported energy is metered at the point of generation).

   Until recently, the state-of-the-art in solar lighting had been solar PV panels powering relatively efficient compact fluorescent lamps CFLs. However, recent breakthroughs in light-emitting diode (LED) technology have resulted in LEDs requiring far less power per lumen of output, thus requiring smaller solar panels and storage batteries. This coupled with the longer lifetimes of LEDs compared with CFLs have made them become a much more economical alternative. Moreover, unlike CFL technology that is already considered mature, LED technology is still in its early growth phase and improvements in efficiencies are almost guaranteed to continue.

   One of the only disadvantages of LEDs compared with CFLs is that studies have shown that users generally prefer the more diffused nature of CFL lighting compared with the strong directional nature of LEDs for most lighting purposes, except for task lighting. This disadvantage can be rectified by incorporating simple diffusers into a configuration of smaller LED bulbs - though resulting in higher costs. (Jones, Du, Gentry, Gur, & Mills, 2005)

e) ***Hybrid solar lighting*** is an innovative technology (not yet commercially launched) that uses a combination of sunlight and electric light to illuminate buildings. Sunlight is funneled into the building via fiber optic bundles. The fiber optic bundles join with an electric "artificial" light source in a lighting luminaire that uses photo-sensors to determine how much artificial light is needed to supplement the sunlight in order to maintain a certain illumination level in the room.

Alternative Heating & Cooling Technologies

Examples of the application of alternative heating and cooling technologies that are currently being implemented as part of the low energy-intensity building design concepts – some of which are applicable to retrofits - include:

a) Designing and refurbishing buildings on the basis of passive cooling principles.

b) Installing solar water heaters using solar thermal technology. This – as opposed to solar PV - makes sense in Belize's context because the per-KWh cost of solar thermal ($0.11 USD per KWh on average) is lower than grid electricity ($0.12 USD per KWh) ; but the cost of solar PV is much higher than grid electricity.

c) Installing geothermal pumps for both space cooling and water heating (Refer to section on Geothermal Pumps).

d) Installing water to refrigerant heat exchangers on cooling systems and upgrading to high energy efficiency ratio (EER) A/Cs with heat recovery for supplying hot water.

e) Retrofitting air conditioners with hydrocarbon refrigerant. This lowers maintenance cost, extends equipment life, reduces ozone-depletion impacts (of using CFC and HCFC alternatives), and utilizes our indigenous materials[152].

f) Installing motion sensors to automatically turn off A/Cs in empty rooms.

Potential for Energy Demand Reduction and Cost Savings

Retrofitting the Existing Building Stock with More Efficient Lighting

Lighting accounts for approximately 40% of total residential electricity consumption and 15% of total commercial electricity consumption in most developing countries. The total residential electricity consumption in Belize is about 200,000,000 KWh per year and the total commercial electricity consumption is about 150,000,000 KWh per year: so lighting accounts for 40% x 200,000,000 + 15% x 150,000,000 = 80,000,000 + 22,500,000 = 102,500,000 KWh of electricity use per year.

Assuming that 50% of residential lighting in Belize is provided by incandescent lamps, then replacing 80% of these with CFL or LFL lamps, which can reduce consumption by 70%, could result in a reduction in total electricity used for lighting of 70% x 80% x 50% x 80,000,000 = 22,400,000 KWh per year.

Further assuming that 50% of commercial lighting can be replaced with more efficient fluorescent lamps and LEDs; and that further savings can be gained by putting in place occupancy sensors, natural light sensors and reducing over-lighting (for a total reduction in consumption of about 35% overall); the total consumption reduction attainable is 35% x 22,500,000 = 7,875,000 KWh per year. At electricity generation costs of $0.12 USD per KWh, the possible savings are a substantial $3,633,000 USD per year [= 0.12 x (22,400,000 + 7,875,000)]. The incremental (annualized) cost of the fluorescent and LED lamps and lighting systems would have to be taken into account when conducting a complete analysis.

Potential for GHG Pollution Reduction and CDM Earnings

If changing to more efficient lamps and lighting systems cuts electricity use by 30,275,000 KWh per year, the total yearly emissions avoided equal the indirect emissions rate of the electricity supply source multiplied by the total avoided electricity

[152] If the hydro-carbon is say NG harnessed as a by-product of local oil extraction.

consumption = 0.336 metric tons per MWh x 30,275 MWh = 10,1725 tCO2e GHG emissions per year.

Over a 10-year evaluation period, this amounts to 101,725 tCO2e GHG emissions (=101,725 CERs). At a market price of $25 USD per CER, the potential earnings through the CDM are USD $2,543,125.

Retrofitting the Existing Commercial Building Stock with More Efficient Cooling

Cooling demand accounts for approximately 40% of total commercial electricity consumption in the Caribbean. The total commercial electricity consumption in Belize is about 150,000,000 KWh per year: so cooling uses up 60,000,000 KWh of electricity per year. If retrofits and upgrades can reduce consumption by 40%, the total consumption reduction attainable is 40% x 60,000,000 = 24,000,000 KWh per year. At electricity generation costs of $0.12 USD per KWh, the possible savings are $2,880,000 USD per year.

The cost of the retrofits and upgrades would have to be taken into account when conducting a complete analysis.

Refrigeration

State of the Technology

With recent technological advances, including better insulation, use of more efficient compressors and microchip-controlled defrost cycle; new refrigerators are about 20% more efficient than older models. The size of the refrigerator – more than the quantity of its food and beverage contents - is the major factor determining the amount of energy consumed. Other important factors include the condition of the door seals or gaskets; the thermostat settings; and how often the refrigerator is defrosted.

Most refrigerators use CFCs, HFCs and HCFCs as refrigerants and foaming agents (to foam the insulation used within the refrigerator walls). HFCs and HCFCs emerged as the de facto standard in the US after scientists discovered that CFCs were a major cause of ozone-layer depletion. HCFCs, which were always considered a temporary solution because they still contribute to ozone depletion although to a lesser extent than CFCs, are now being phased out. HFCs, though ozone-friendly, have lately come under greater scrutiny because they are potent green-house gases and are incompatible with common materials and lubricants. Greenpeace and other eco-organizations are promoting the use of hydro-carbons such as propane and iso-butane in place of HFCs and HCFCs as refrigerants and foaming agents especially in developing countries where CFC-technology refrigerators are still allowed and where it is more likely that hydrocarbons will be indigenously available.

Potential for Energy Demand Reduction and Cost Savings

Refrigeration typically account for 20% of residential energy consumption. If we assume that 80% of residential customers (with electricity supply) have refrigerators, and that a further 50% of these can benefit from more efficient refrigerators, then the potential savings are: 20% x 50% x 80% x 20% x 200,000,000 = 3,200,000 KWh. At electricity generation costs of $0.12 USD per KWh, the possible savings are $384,000 USD per year. *The incremental (annualized) cost of the improved-efficiency refrigerators would have to be taken into account when conducting a complete analysis.*

Stand-by Electricity Usage

State of the Technology

“In an analysis of potential energy savings by 2030 by type of appliance, the Organisation for Economic Co-operation and Development (OECD) put the potential savings from reducing electricity for standby use—that consumed when the appliance is not being used—at the top of the list.” (Brown, Larsen, Dorn, & Moore, 2008)

Electricity usage by appliances in stand-by mode worldwide together adds up to as much as 10% of residential electricity use. In OECD countries, the power consumed by devices in standby mode ranged from a low of 30 W to a high of over 100 W. Though relatively small, the cumulative effect is substantial because this power is used around the clock. Countries are responding by mandating maximum power consumption for appliances and devices when in stand-by mode and by recommending the use of “smart” power strips that cut off electricity supply to the device completely when it senses that an appliance goes into stand-by mode.

Energy Use Monitors

State of the Technology

Imagine arriving at home and mounted on the wall at the entrance of your home, just as you let yourself in, is an LED display of your energy consumption since the start of the month (in KWh and dollars): not only for the entire house; but for individual areas of the house or individual rooms or individual appliances! What if you were able to press a button and view a comparison bar chart of how this month’s consumption compares with last month’s? Better yet, what if you didn’t have to come home to see this, and that you could view it all from your computer at work or on your cell phone?

This is not a far-fetched futuristic scene. Most of it is already a reality today. **Energy Monitors** are devices that provide instantaneous feedback on energy consumption in households and small businesses. They are nowadays being distributed under a number of brand names, including ‘The Energy Detective’, ‘PowerCost Monitor’, ‘WiSmart’, ‘The Green Eye’. Various municipalities and utilities are rolling out home energy monitoring programs to help customers make informed choices to reduce their consumption levels: these programs are predicated on the reasonable assumption that action is engendered by information.

Tests conducted in California some years ago and other studies have shown that customers reduced their consumption by 4-15% as a result of using home energy monitors. Another study using the 'PowerCost Monitor' deployed in 500 homes in Ontario, Canada showed an average 6.5% drop in total electricity use (Wikipedia: Home Energy Monitors, 2011). However, a study of 3,000 participants enrolled in a demand-management program conducted by Connecticut Light & Power found that while smart thermostats and other automatic control devices reduced peak energy use by 7%, information devices like power cost monitors had almost no effect on reducing *peak energy usage* (Martin M. , 2010).

Potential for Energy Demand Reduction and Cost Savings

If energy monitors can be distributed to 25% of the residential customer base, then the annual energy savings possible (conservatively assuming a 5% reduction per residential customer) are: 5% x 25% x 200,000,000 = 2,000,000 KWh.

At electricity generation costs of $0.12 USD per KWh, the savings are $240,000 USD per year. These savings would of course have to be weighed against the costs of procuring, installing and maintaining the monitors, as well as the costs involved in retrieving and processing the data.

Cooking

State of the Technology

There are two main cooking fuels/technologies used in Belize: LPG gas ranges, used by over 80% of all households in Belize; and fire hearths and wood-burning stoves, used by 15% of all households (equal to 28% of rural households). Electric ranges are a new entrant in the local market, and it is safe to say that less than 1% of households are using these (2000 Census reported 0.6% of households used electricity for cooking).

Figure 4.1.6: Rural household cooking using wood fuel in traditional biomass stoves

Table 4.1.7 below compares the efficiency and fuel cost of the three main cooking fuels/technologies[153].

Fuel / Technology	Energy Use (MJ)	Efficiency (%)	Fuel Cost (USD)
LP Gas Standard: Local	0.84	40%	$0.0141
LP Gas Standard: Imported	0.84	40%	$0.0246
LP Gas Single Burner: Local	0.62	54%	$0.0104
LP Gas Single Burner: Imported	0.62	54%	$0.0182
Electric: Coil	0.97	35%	$0.0536
Electric: Induction	1.02	33%	$0.0567
Wood: Lorena Stove/Fire Hearth	3.72	9%	$0.0073
Wood: Traditional Stove	1.52	22%	$0.0030

Table 4.1.7: Comparison of Efficiencies and Fuel Costs of Main Cooking Fuels/technologies

The comparison shows that cooking using wood fuel is by far the cheapest option: costing over 4 times less – 2 times less in the case of the fire hearth - than the next closest competitor: locally-produced LPG gas. As mentioned in Chapter 3: Section 4, cooking using wood fuel is considered harmful to human health; and so, in spite of its low cost, it is strongly discouraged by health authorities.

Cooking using electric stoves (whether induction or coil) is also more than two times as costly as cooking using Imported LPG, and between four and six times as costly as cooking using Local LPG.

The case for migrating from LPG to electric is not helped when GHG emissions are factored into the picture. LPG produces 0.24 kg of CO2-equivalent GHGs per KWh = 0.05854 kg of CO2-equivalent GHGs per MJ. Therefore, at a cooking efficiency of 40%, the net emissions = 0.05854/40% = 0.14635 kg of CO2-equivalent GHGs per MJ (used in cooking).

On the other hand, 0.3359 kg of CO2-equivalent GHGs is produced for every KWh of electricity delivered to a consumer's home. This is equal to 0.09331 kg of CO2-equivalent GHGs per MJ of electricity delivered to the consumer's home. At a cooking efficiency of 35%, the net emissions = 0.09331/35% = 0.2666 kg of CO2-equivalent GHGs per MJ (used in cooking); which is nearly twice as much as the GHG emissions due to cooking with LPG.

153 Based on results of standardized tests which involved heating a litre of water from 20 °C to 100 °C, documented in 2009 report entitled 'LP Gas: Efficient Energy for a Modern World' by (Energetics Incorporated, 2009). *The total energy transferred to the water in each case is 0.335 MJ*.

Potential for Energy Demand Reduction and Cost Savings

What would it cost to move completely away from wood fuel to LPG for cooking?

The total energy content of wood fuel used in 2009 was 1,102,000,000 MJ. The cost of the fuel therefore = $0.00197/MJ x 1,102,000,000 = $2,170,606 USD.

Assuming that all the wood fuel is used for cooking or heating water and an average overall efficiency of 12.25% (assuming wood stove market in Belize between fire hearths and traditional stoves are shared 75% and 25% respectively), the useful energy content extracted for cooking = 12.25% x 1,102,000,000 = 135,000,000 MJ.

If we replaced all these wood-fuel stoves with LPG Standard Ranges: Working backwards, the total energy content of LPG needed to achieve this same cooking output = 135,000,000/40% = 337,500,000 MJ. This additional LPG requirement will have to be met from Imported LPG as Local LPG can only serve less than 30% of the current market demand. So, the cost of LPG to replace wood fuel = $0.0293/MJ x 337,500,000 = $9,888,750 USD.

Migrating completely away from wood fuels for cooking to using LPG Standard Ranges would therefore cost $9,888,750 - $2,170,606 = $7,718,144 USD per year. Since 75% of the Imported LPG cost is paid to foreign suppliers and almost no foreign exchange is paid out for wood fuel, the loss in foreign exchange = 0.75 x $9,888,750 = $7,416,562.50 USD per year. There is also the additional capital cost and consequent FX loss in replacing fire hearths and wood stoves with LPG ranges.

If we replaced all these wood-fuel stoves with LPG Single Burner Stoves: Working backwards, the total energy content of LPG needed to achieve this same cooking output = 135,000,000/54% = 250,000,000 MJ. This additional LPG requirement will have to be met from Imported LPG as Local LPG can only serve at most 30% of the current market demand. So, the cost of LPG to replace wood fuel = $0.0293/MJ x 250,000,000 = $7,325,000 USD.

Migrating completely away from wood fuels for cooking to using LPG Single Burner Stoves would therefore cost $7,325,000 - $2,170,606 = $5,154,394 USD per year. Since 75% of the Imported LPG cost is paid to foreign suppliers and almost no foreign exchange is paid out for wood fuel, the loss in foreign exchange = 0.75 x $7,325,000 = $5,493,750 USD per year.

What would it cost to upgrade to higher efficiency wood stoves?

Let us assume that we upgraded all Lorena stoves and fire hearths to higher efficiency traditional wood stoves: The total energy content of wood fuel burned in Lorena Stoves and fire hearths in 2009 was 0.75% x 1,102,000,000 MJ = 826,500,000 MJ.

The useful energy content extracted for cooking = 9% x 826,500,000 = 74,385,000 MJ.

If we replaced all these wood-fuel stoves with higher efficiency wood stoves: Working backwards, the total energy content of wood fuel needed to achieve this same cooking output = 74,385,000/22% = 338,113,636 MJ. The reduction in wood fuel needed = 826,500,000 – 338,113,636 = 488,386,364 MJ and the fuel cost reduction therefore = $0.00197/MJ x 488,386,364 = $962,121 USD per year.

The real savings however will not be monetary because the price of wood fuel is not a market price but a representative “calculated” one. The real savings is the reduction in deforestation (assuming that the wood used as wood fuel for domestic purposes is not a by-product of some other operation).

Energy Service Companies

Myriad reports have lamented the relatively slow take-up of energy efficiency improvement measures by the various energy consumption sectors, given the enormous potential for cost savings that they hold. The barriers to the adoption of EE improvement measures that are often cited include: a lack of information about the EE improvement possibilities on the part of both consumers and potential service companies, the relatively high upfront investment costs associated with EE projects, the requirement for fast payback times, lack of access to capital needed or competition for scarce financial resources from other non-EE core business projects, and the absence of a formal financial services structure targeting this (EE) market. Households in developing countries such as Belize face particular barriers to accessing capital (credit) needed for energy performance improvement projects; mainly due to high loan interest rates (which is partly due to higher transaction costs), lack of information (which is itself due to lending institutions not targeting this market segment), and overly bureaucratic loan approval processes. Formal lending institutions on the other hand are discouraged from targeting this market (households) because of the high cost of credit distribution caused by the diffused nature of demand and the low amount of loans. (WEC, 2010)

Energy Service Companies (ESCOs) are companies that provide management, technical and financial support to households and enterprises, engaging in the implementation of energy efficiency measures or renewable and recoverable energy projects for their own use or on a small scale. This support usually involves designing and developing the project; arranging the required financing; installing and maintaining the EE equipment necessary; measuring, monitoring, and verifying the energy savings; and generally assuming all the risks associated with the project. These ESCO support services are normally rendered via energy performance contracts (EPCs), wherein the ESCO commits to a certain level of energy savings for the client (consumer) and is compensated based on how well the EE project performs.

There are two general EPC models underlying most EPCs: a *shared savings* model and a *guaranteed savings* model[154]. In the shared savings model, the ESCO and the client share the cost savings from the project in a pre-determined proportion for a fixed number of years. The ESCO usually funds the project wholly and thus assumes both the project performance and credit risks: if the applicable savings realized over the project lifetime are not sufficient to cover its costs, then the ESCO loses. Under the guaranteed savings model, the ESCO guarantees a certain level of cost savings to the client - for example, a 10% drop in energy bills; however, the client is usually responsible for arranging the financing for the project and thus assuming full credit risk. If the guaranteed outcome is not achieved, the ESCO makes up the difference to the client; but any savings over and above this guaranteed level redounds to the ESCO. The ESCO thus earns the residual project benefits or incurs the residual losses.

Barriers to the Proliferation of EPC Undertakings and ESCO Development

The barriers to EPC undertakings and ESCO development are different from sector to sector. In the public sector, the long-term, incremental, low visual impact nature of EPC projects tends to be at odds with the goals of public officials and politicians who prefer to engage in high visual impact projects like roads, bridges, hospitals and schools that will have significant visible payoffs within the shorter-term election cycle. Moreover, EPC-based projects will have to be subject to the rules of the public procurement process, which generally skew the focus towards the initial investment outlay required but does not take long-term lifecycle costs and payoffs into consideration. In the industrial sector, which along with the public sector stands to benefit the most from EPCs, uptake of EPCs is generally low because most industrial companies - especially energy intensive companies - tend to feel that they have the capacity - and are in fact in a better position - than an ESCO to undertake EE projects in-house.

The barriers to EPC and ESCO proliferation are basically the same for both the residential and commercial sectors. Savings recoverable from residential projects in particular are small and so the transaction costs of undertaking these projects are usually too high to justify ESCO intervention. Additionally, both sectors suffer from the “split-incentives” problem arising between landlords and tenants. Most landlords build to minimize the initial cost of the building, not its lifecycle cost; the costs of operating and maintaining the building are left to the tenant. Landlords are therefore generally reluctant to spend on EE improvements that ultimately reduce O&M cost borne by the tenant. Tenants on the other hand are concerned that, if they make the investment on their own, they stand to lose when the rental contract comes to an end. This leads to inaction on the part of both parties and stymies EE improvement take-up, which can

[154] Source: (Ürge-Vorsatz, Köppel, Liang, Kiss, Goopalan Nair, & Celikyilmaz, March 2007)

only be overcome by resolving the legal uncertainty issues surrounding EE project ownership and post-rental obligations arising in tenancy situations.

INDUSTRIAL ENERGY USE

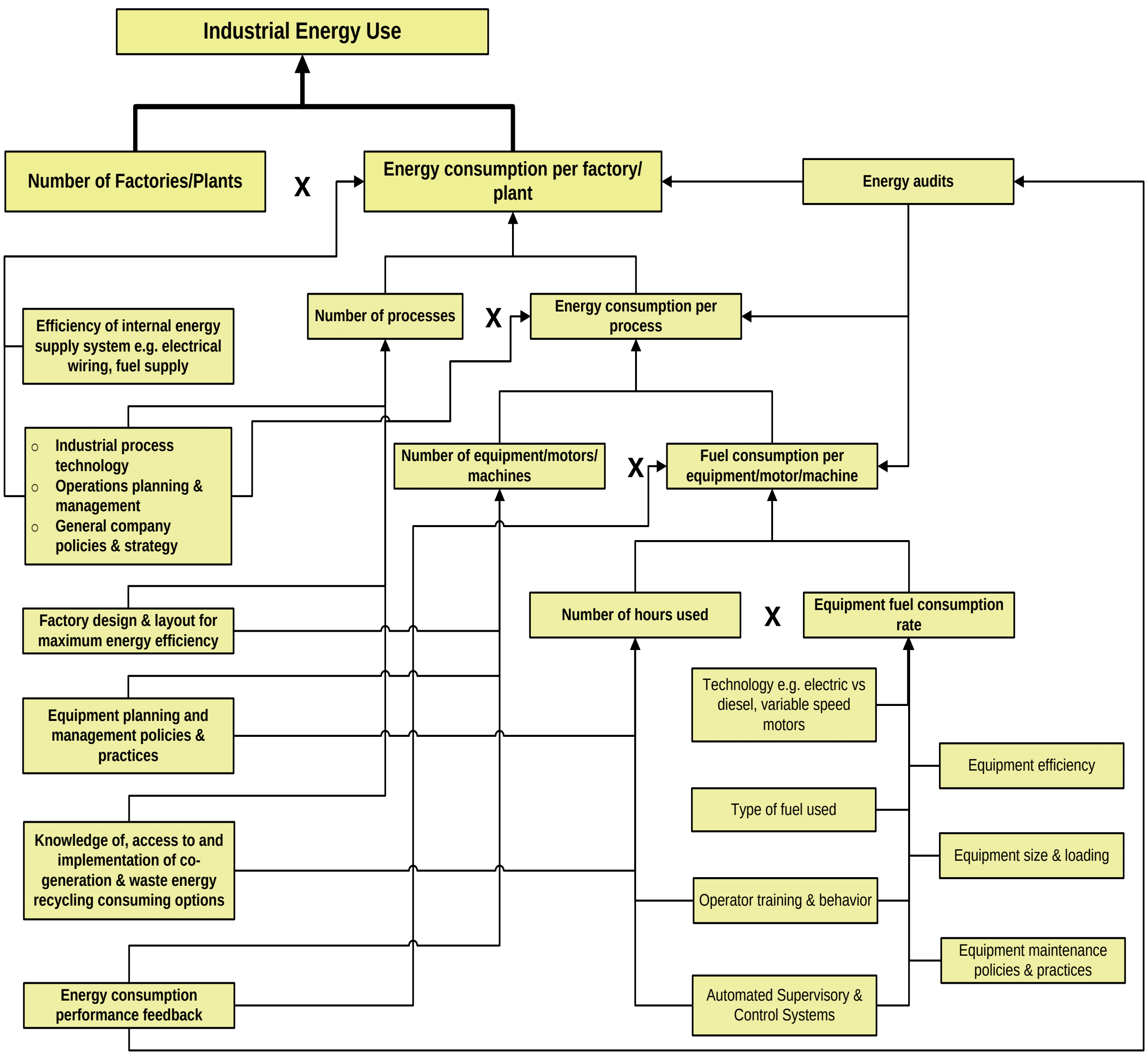

Figure 4.1.8: Factors influencing Industrial Energy End-Use

Agriculture

State of the Technology

Mainstreaming sustainable agricultural practices builds on Belize's forestry and agrarian past, but turns it toward a more sustainable, sophisticated future. It enlists the local farmer to be part of the solution in what is probably the world's most urgent tasks: to move into the post-oil era, to improve the healthiness of our people and to mitigate climate change.

Modern farm practices are heavily dependent on petroleum by-products for fuel, fertilizer and pest management. Renewable energy—such as solar, wind, and biofuels—can play a key role in creating a sustainable future in agriculture. However, weaning the modern agricultural production systems off its heavy dependence fossil fuel requires a radical shift to managing the farm as an ecosystem, rather than as an industrial enterprise, in the same way as the more advanced civilizations did from the beginning of time. Such "ancient" farm practices need to be rediscovered and refined by incorporating the latest scientific advances. Elements of good agricultural practices (GAP) may include inter alia: abandoning mono-cropping in favor of crop rotations, intercropping, and companion planting; planting a portion of land in trees and other perennial crops in permanent plantings or long-term rotations; where possible integrating crop and livestock production; using hedgerows, insectary plants, cover crops, and water reservoirs to attract and support populations of beneficial insects, bats, and birds; and planting off-season cover crops. How quickly we transition to these sustainable agricultural practices will be the critical determining factor of whether our Agriculture Industry can remain viable in an era of rapidly-increasing oil prices!

Agricultural Biomass for Energy

Beyond preventing the obvious hugely consequential repercussions of having to deal with the fallout from a failed Agriculture Industry, the urgent need to transition agriculture into the post-oil era is driven by another arguably equally-as-important need: agriculture and agro-processing are the main producers of high-carbon, energy-rich biomass! It is the carbon content of this biomass and its applicability to many uses that make it the valuable feedstock of the future. The fuels, fiber and chemicals industries have long recognized the importance of carbon and carbon-based materials to their activities, competitiveness and profitability. These industries take basic materials (like crude oil, natural gas, and forest and agricultural matter) and convert and transform them into commodities and intermediate chemicals for distribution to other industrial sectors, or into final products for consumer use. But high energy-intensive sectors, particularly the transport sector and to a lesser extent the electricity sector, can benefit even more. Biomass produced as the waste products or by-products from agricultural activities has the potential to substantially displace petroleum in these sectors. The quicker and more drastic the transition of agriculture away from petroleum and the concomitant transition of these energy-intensive sectors towards using biomass feedstocks, the greater will be the displacement of petroleum - and consequent mitigation of its detrimental effects - out of Belize's economy.

Energy Audits

State of the Art

Energy audits or assessments are conducted to determine how energy is being used within a particular system (a building, an office, a commercial establishment, a factory etc.), and identifying opportunities for energy efficiency improvement and conservation. Such audits involve collecting data on all of the major energy-consuming processes and equipment in a system as well as documenting specific technologies used in the production process (McKane, Price, & De La Rue Du Can, 2006). In developed countries, energy audits are usually conducted by the public utilities, private sector companies or state energy offices.

There are usually four levels of energy audits:

a) *Level 0* - **Benchmarking**: where results of a detailed analysis of historic energy use are compared with that of similar systems. The assessment at this level will simply give an idea of whether the system is performing according to expectations; and, if it is not, the degree to which it is under-performing.

b) *Level 1* - **Walk-through assessment**: This is usually conducted to detect – with a minimum of time and effort - the main cause(s) of a system’s under-performance as assessed by the Level 0 audit. It usually involves a visual inspection of the main elements of the system and an analysis of installed equipment data and operational logs in order to detect leakages in the current internal energy delivery system, inefficiencies in the current delivery system due to design or use of inefficient carriers or converters, and redundant and unnecessary processes.

c) *Level 2* - **Detailed Audit**: At this level, the elements of system are investigated in greater detail. On-site measurements using energy monitors and other devices may be conducted to further investigate anomalies. It may also involve preparation of an energy balance for the plant with a detailed breakdown of energy consumption by processes and a description of on-going and planned energy-efficiency projects.

d) *Level 3* - **Investment-Grade Audit**: This level involves cost-benefit analyses of high-cost investment options to enhance efficiencies mainly by exploiting synergistic opportunities for reuse of waste energy, co-generation and changing feedstock.

The savings that are obtainable from measures implemented in response to the recommendations from energy audits vary according to the type of business/industry, the individual business itself and level of the audit carried out. In Barbados for example, walk-through energy audits of 35 hotels, conducted in 2010 under the Caribbean Hotel Energy Efficiency Action Program (CHENACT), estimated that there was potential for savings of nearly 40% of energy consumption (Duffy-Mayers, Loreto, 2010).

Potential for Energy Demand Reduction and Cost Savings

It is reasonable to assume that if energy audits could detect potential savings of nearly 40% of current energy consumption in the hotel sector in Barbados (which is likely more advanced than Belize’s), then at least the same level of opportunities for savings can be detected through energy audits in Belize’s hotel sector, and to some extent the other non-hotel commercial establishments, since most of the potential savings were related to two sub-systems: air-conditioning and lighting.

These potential savings have, however, already been accounted for under previous sections: *Buildings*. The energy audits are therefore to be viewed as a trigger for action on such energy-saving opportunities.

Energy Management Standards

State of the Art

An energy management standard is a management framework that provides guidance for industrial facilities to integrate energy efficiency into their management practices, including optimizing production and service systems and processes. Energy management standards are applicable to a range of facilities: industrial, commercial, and government facilities.

The main features of an energy management standard include[155]:

a) a strategic plan that requires measurement, management, and documentation for continuous improvement for energy efficiency;

b) a cross-divisional management team led by an Energy Coordinator who reports directly to management and is responsible for overseeing the implementation of the strategic plan;

c) policies and procedures to address all aspects of energy purchase, use, and disposal;

d) an assessment of the major energy uses in the facility to develop a baseline of energy use and set goals for continuous improvement;

e) a list of projects designed to achieve continuous improvement in energy efficiency;

f) creation of an Energy Manual, that is immediately updated as additional energy efficiency projects and policies are undertaken and documented;

g) identification of key performance indicators, to facilitate benchmark comparisons as well as unique to the company, that are tracked to measure progress; and

h) periodic reporting of progress to management based on these measurements.

Bilateral Voluntary Target-Setting Agreements

State of the Art

Voluntary target-setting agreements are negotiated agreements between the Government or an authorized energy agency and an individual company whereby the company agrees to achieve certain energy efficiency targets within a specific time frame, in return for receiving technical and financial support and other economic incentives

[155] Adapted directly from (McKane, Price, & De La Rue Du Can, 2006)

from the Government. A company may, for example, agree to reduce the energy intensity of its production process by 20% within 5 years.

The key elements of such a program would be: the initial negotiating and setting of the targets; identifying energy-efficiency improvement technologies and measures; benchmarking current energy efficiency practices; establishing an energy management standard; conducting energy-efficiency audits; formulating an energy-savings action plan; developing incentives and supporting policies; measuring and monitoring progress toward targets, and program evaluation. (McKane, Price, & De La Rue Du Can, 2006)

Voluntary target-setting agreements have been used mainly in developed countries such as the USA and Japan and in Europe, and have become one of the main tools for getting industrial corporations to participate in GHG emissions reduction initiatives.

Unilateral Voluntary Certification Programs

State of the Art

Voluntary Certification Programs are based on commitments to standards prescribed by the ISO and other management systems such as Six Sigma, Total Quality Management and Lean Manufacturing. Standards such as the ISO-9000 and ISO-14000 series are becoming the de facto codes of practice even though they are not legally binding. ISO-14001 certification in particular does not require commitment to any externally-set targets or performance measures; rather it stresses continuous improvement by letting a company set its own goals and objectives and prescribing the management processes that can be used by the company to achieve the goals and targets.

The uptake of ISO standards in Asia particularly has been rapid, with Asian corporations now comprising approximately 40% of the world's ISO-14000 certified companies.

5 GOALS, STRATEGIES AND MASTER PLANS

> **"Make sure your energy policies include a plan that adds up"**
>
> *David JC MacKay, Author of 'Sustainable Energy – Without the Hot Air'*

GOALS & STRATEGIES

The following goals and strategies have been developed to put Belize firmly on a path to greater energy efficiency, sustainability and resilience over the next 30 years. They reflect the foregoing findings of the assessment of the energy supply options and demand-side energy efficiency and conservation measures currently or soon to be at our disposal, as well as the opportunities, threats and constraints emanating from our study of the local, regional and global energy contexts presented earlier.

Goals

- To foster the sustainable production, distribution and use of energy as a critical resource needed to achieve the overarching national goals of economic growth and long-term prosperity, security, poverty reduction and social equity.
- To minimize the cost of energy in the local economy[156]:
  - The *cost of energy* referred to is the net present cost of energy use by final end-users, and should take into account all capital, O&M and fuel costs of primary energy capture and conversion, including conversion losses and costs of environmental impacts; all capital and O&M costs of secondary energy distribution, including distribution losses and costs of environmental impacts; and all capital and O&M costs of secondary energy conversion to end-use energy, including conversion losses and costs of environmental impacts.
  - The benchmark for this goal could be the average *cost of energy* in those emerging economies with similar socio-economic structure to Belize or countries who are our major competitors. However, this may be too low or too high depending on our own unique circumstances relative to theirs, and it is best that energy cost minimization be subject only to availability of resources and technologies and other uncontrollable factors. Moreover, the cost of energy is very dependent on

[156] While minimizing energy cost will usually automatically redound to economic growth, this does not necessarily have to be the case. Energy cost can for instance be reduced by compromising reliability of supply; which may be detrimental particularly for the industrial sector and thus negatively affect economic growth.

the nature and composition of a nation's produce. Countries like Belize that feature mainly light industries such as Tourism generally consume less energy per dollar of GDP than energy-intensive countries that engage in heavy industries like cement making and steel production. For this reason, the *energy intensity*, which is the total primary energy supply per dollar of GDP, may also used as a reliable indicator of the cost of energy[157].

- To mitigate the impacts of uncontrollable events such as external market price and supply shocks and natural disasters on the cost of energy and on the reliability of energy supply.
- To create a national energy-efficiency-focused culture that is fully aware of how its actions (or inactions) affect energy use and that is pro-active about the conservation and efficient use of energy.

Strategies

1) Elevate and promote the importance of planning for energy efficiency in all sectors of the economy.
2) Promote and support the production of energy from indigenous renewable resources in order to promote sustainability, increase resilience and engender local participation in the energy industry
3) Preserve, develop and manage the Agriculture, Agro-Processing and Forestry Sectors as a major source of biomass feedstock for energy production.
4) Pursue both resource and geographic *diversity* of the supply mix in order to maximize the *resilience* of the energy sector.
5) Develop an *energy-for-export industry* aimed at supplying the regional and other foreign markets over the long term.
6) Build a modern and robust electricity distribution infrastructure to foster greater energy efficiency and resilience and provide infrastructural support for the electricity-for-export industry.
7) Nurture the crude oil industry as a for-export industry.
8) Put in place measures to maximize the production of non-crude oil products from petroleum extraction activities.

[157] The authors believe that the *cost* of energy use divided by GDP is actually a better indicator of energy intensity. However, it may be that it is more difficult to assess cost of energy use than quantity of energy supply especially for purposes of comparing across countries, and hence energy intensity is defined in terms of the quantity of primary energy supply.

9) Develop a local electricity micro-generation market where small producers, such as individual households, communities, commercial establishments and even small industrial participants, can sell electricity into local distributions systems and the national grid.

10) Promote and support *local participation* in the energy supply industry in order to build support for renewable energy initiatives, increase local input and control over the local petroleum industry, and generate employment and economic opportunities locally.

11) Provide access to *cleaner and more versatile energy carriers* in rural areas and populations living on the margins of the socio-economic fabric *as part of broader initiatives of the GOB and NGOs* to improve the standard of living and productivity in these areas.

12) Promote the adoption of energy efficiency and conservation measures in energy applications throughout all sectors of the economy.

13) Promote the adoption of energy efficient equipment and devices throughout all sectors of the economy.

14) Institute a price on carbon in line with binding covenants such as the Kyoto Protocol and in harmony with the evolution of the global carbon market.

Three of the above-mentioned strategies require further discussion:

Development of an Energy-for-Export Industry[158]

Electricity demand in the LAC is projected to double over the next 20 years, with growth in Central America progressing at 5.3% per annum, slightly faster than in other sub-regions. A 2010 World Bank Report forecasts that the major portion of the total electricity generation mix in the LAC in 2030 will be supplied from hydroelectricity (50%) and natural gas (30%) with renewable energy sources, such as wind and geothermal energy, making up only about 7 percent (Yepez-García, Johnson, & Andrés, 2010). The bulk of Mexico's additional generation capacity is expected to be sourced from integrated gasification combined cycle (IGCC) technologies using natural gas for fuel; while most of Central America's additional generation capacity (45%) is projected to be met from hydropower sources.

Concerns have been raised as to the feasibility and sustainability of the projected electricity generation supply scenario described above, in light of the fact that some countries have committed to reducing carbon emissions over the period. Total carbon emissions from electricity generation in the LAC "would more than double by 2030"

[158] Most of the discussion in this section based directly on 2010 ESAMP (World Bank) Report entitled "Meeting the Electricity Demand/Supply Balance in Latin America and the Caribbean" (Yepez-García, Johnson, & Andrés, 2010).

under the scenario (Yepez-García, Johnson, & Andrés, 2010), and emissions intensity (per unit of electricity generated) is actually projected to increase in both Mexico and Brazil. Moreover, it is deemed highly improbable that the full remaining hydropower potential in the LAC could be developed over the next 20 years, given the trajectory of the region’s history of hydropower development, current policies in some of the countries and the expected pushback from environmental groups. Colombia, Peru and Ecuador, for instance, together possess more than half of the total remaining hydro potential in the LAC, but have developed less than 10 percent of their full potential over the past 40 years since the initial spurt of hydropower development that started in the 1970s.

Given the huge disparity between the indigenous energy supply potential and local demand for energy in Belize (due to our small population and low energy-intensive economic structure) and the burgeoning energy demands of countries in Mexico and Central America as discussed above, a substantial opportunity exists for Belize to become a net supplier of electricity to these countries. Similarly, given the comparative advantages of our large tracts of land and subtropical climate conditions, a substantial opportunity also exists for Belize to become a net supplier of bio-energy to countries through the world.

The development of an energy-for-export market will have a number of positive impacts on the energy sector and our local economy as a whole:

- ✓ Create a brand new revenue stream for the Government and People of Belize.
- ✓ Spur the further development of the renewable energy sector and the micro-generation market; giving rise to a host of spinoff business opportunities locally, and redounding in higher employment levels and greater economic development throughout Belize and particularly in rural areas.
- ✓ Provide more opportunities to exploit economies of scale in energy production and distribution, since supply equipment can be sized to serve a larger market.
- ✓ Enable greater capacity utilization of supply equipment, especially variable energy generation equipment such as wind turbines, since any “excess energy” can be readily exported.
- ✓ Instill a new paradigm of viewing and treating energy as a revenue opportunity instead of a cost burden, and giving rise to greater discipline in seeking out ways to reduce energy costs and cut local usage so that profits from the sale of energy can be maximized.

Nurturing of Crude Oil Industry for Export Only

Belize has an abundance of renewable energy resources to suffice all our energy needs for many years to come, given our small population and the fact that our main industries - agriculture, tourism and sugar – are by nature either low energy-intensive or can be readily supplied from local renewable or recoverable energy sources. This is different from the case of many industrialized countries that have sunken investments in traditional high energy-intensive industries whose entrenched and inflexible technologies depend heavily on fossil-fuel supply sources. So while we are in a position to "make the switch", they are not. Moreover, petroleum can be shipped to anywhere in the world: renewable energy *at this time* cannot. To maximize the overall returns from all our indigenous energy sources therefore, it is best to use up our less marketable renewable energy sources locally and export the more marketable petroleum resource internationally.

Furthermore, any objective that promotes the local use of our own (processed) crude oil would inevitably result in sub-optimal returns for the country as a whole. For instance, there would be immense public pressure on the Government to keep oil prices low, even and especially at times when international oil prices are highest – that is, when we could have been gaining the most if we were exporting all our oil. This would not matter as much if the petroleum resources were being utilized largely by businesses and industries for productive purposes; but will surely lead to inefficient behavior amongst the general public, where most of the petroleum is used for personal transport. Thus, promoting local use of our own oil resources would have the effect of shielding us from the proper (international) oil price signals hence leading to inefficient consumption patterns locally and stymieing energy efficiency and alternative energy innovations.

Finally, any strategy that specifically promotes the use of petroleum resources would likely conflict with strategies that promote the use of indigenous alternative low-carbon renewable resources: which would in turn undermine the pursuit of the goals of greater energy sustainability and resilience.

Providing Access to Cleaner and More Versatile Energy Carriers in Rural Areas

This particular strategy must be approached within the context of the broader national goals of promoting economic growth and social equity; since when assessed from the standpoint of the energy sector on its own, it may not be economically feasible to undertake rural electrification and other energy projects aimed at ameliorating the living conditions of the poor and marginalized. Simply making modern energy forms accessible by rural populations and others living on the margins will not solve a single problem if, for instance, other programs are not put in place to upgrade households for receiving these modern energy forms, or if not accompanied by a plan to upgrade local production processes to use more efficient technologies.

PLAN PROPOSALS

The team formulated three plans designed to follow the path directed by the strategies introduced above. Only strategies 2, 4 and 11-14 could be taken into account at this juncture, due to lack of adequate data needed to assess the impacts of the other strategies. **These plans are not optimal but are rather indicative and can serve as starting points for further *more optimal* variations that can be explored in a future study if so required**.

- An '**end-use-centric**' plan that seeks to reduce demand via the least-cost mix of end-use efficiency and conservation measures *without* further development of any of our renewable energy resources.
- A '**supply-centric**' plan that seeks to put in place the least-cost supply mix to meet all our energy demands *without* concern for end-use efficiency or conservation.
- A '**comprehensive**' plan that uses *both* the least-cost mix of end-use efficiency and conservation measures to minimize energy use, and the least-cost supply mix, with further renewable energy development.

Each plan was formulated to achieve the following measurable objectives, which are for the most part derived directly from the strategies above, subject to the constraints already imposed on the plan itself and the other constraints mentioned below.

Plan Objectives

- ✓ Minimize the cost of energy use
- ✓ Minimize the amount of GHG emissions
- ✓ Maximize the renewability index (RI); that is, the percentage of indigenous renewable energy in the total primary energy supply mix
- ✓ Maximize production of energy from indigenous sources (Minimize dependence on foreign energy sources)
- ✓ Maximize the diversity of the energy supply mix
- ✓ Maximize the use of electricity in the secondary energy supply mix

Plan Constraints

- o Meet all projected energy demand
- o Electricity capacity supply must exceed peak demand for electricity
- o Electricity from wind generation cannot exceed 20% of total supply
- o Planning horizon: 30 years

Assessment of the Efficacy of Plans

The extent to which each of the plan objectives were met was assessed against a baseline 'Continue with business as usual' plan (hereinafter called, Plan-0 or the Baseline Plan). The measured results are intended to be used as achievable targets. In this way, targets, such as 'Increase electricity production from renewable sources to

20% of supply portfolio by 2030', will not be set arbitrarily or in isolation, but *after* confirmation, through careful analyses, that they can be achieved. Policies will then be designed and developed to achieve these targets (*See following Chapter*); and, in fact, the efficacy of these policies can in the future be measured by how well the targets are eventually achieved.

How will the achievement of the individual plan objectives be measured?

- The achievement of the first objective will be measured as the net present cost of energy use by final end-users, excluding any emissions-related costs. This energy use will be assessed at the point of supply, and so will not include any local distribution costs[159].
- The achievement of the second objective will be measured as the net present cost accruing from increase of GHG emissions above the emissions of the baseline plan (or minus the net present benefit accruing from reduction of GHG emissions below the emissions of the baseline plan).
- The achievement of the third objective will be measured as the average of *renewable energy as a percentage of total primary energy supply* over the planning horizon.
- The achievement of the fourth objective will be measured as a) the average of degree of dependence on foreign sources over the planning horizon (that is, the percentage of total primary energy supply provided by foreign sources), and b) the percentage reduction in the quantity of foreign oil and foreign electricity imports used over the life of the plan[160] compared with the quantity used under the baseline plan.
- The achievement of the fifth objective will be measured as the average *Simpson Diversity Index*[161] for resource types over the planning horizon.
- The achievement of the sixth objective will be measured as the average of *electricity as a percentage of total secondary energy consumption* over the planning horizon.

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[159] Distribution and final energy conversion costs were not assessed at this juncture given the time limitations of the study. However, it is important that they are included at some point in the near future or in a follow-up study.

[160] No discount factors will be applied in aggregating quantities from different years: as, contrary to the effect of discounting, a reduction in use of a barrel of oil 20 years from today might have more impact than a reduction in a barrel of oil today; because at that time - 20 years from today - it is likely to be even more urgent to reduce our dependence on oil.

[161] This is equivalent to the *Herfindahl Index* and takes into account both the number of supply sources, as well as the relative share of each source in the total supply mix. The greater the diversity, the lower is the calculated index; and conversely, the lower the diversity, the higher is the calculated index. So, the index will be lower for three supply sources with equal shares (33.3% each) than for two supply sources with equal shares (50% each), and lower for three supply sources with equal shares (33.3% each) than for three supply sources with unequal shares (e.g. 40%, 40%, 20%).

Methodology: Simplified Energy Model

In order to assess the efficacy of the plans proposed above, we first constructed a simplified model of Belize’s energy sector. Each of the major sectors (transport, residential, commercial & services, and industrial) was broken down into consumption categories. For example, the transport sector was broken down into the following consumption categories: gasoline vehicles, light-duty diesel vehicles, mass transport diesel vehicles, heavy duty vehicles, other diesel transport, kerosene transport, and LPG transport. Certain consumption categories were further broken down into sub-categories; for example, gasoline vehicles into typical vehicles, small vehicles, flex fuel vehicles, HEVs (hybrids), PHEVs (plug-in hybrids), and EVs (all-electric vehicles).

Starting from the 2010 levels of energy consumption, projections of consumption were made for each consumption category or sub-category in 5-year increments over the next 30 years, based on an assumed growth rate of 4% per annum in the quantum of the drivers of demand in each consumption category or sub-category, and an average efficiency improvement of 1% per annum in the underlying technologies used in the category or sub-category.

Calculation of Energy Supply

For each of the anchor years – 2015, 2020, 2025, 2030, 2035 and 2040 – we aggregated consumption by type of fuel (required to supply the demand), and then worked backwards to determine the level of supply needed. For imported refined fuels and locally-produced fuels, including crude oil, used directly in the transport sector, and wood fuel used for cooking, the level of the supply was set equal to the level of consumption, because we assumed there was no further conversion and no losses incurred during distribution. The energy content of each of the fuel types was then calculated from the quantities required multiplied by their specific energy content (LCV).

For electricity, supply was set equal to consumption demand plus distribution losses. Once the total quantity of electricity supply required was calculated in this manner, we then first dispatched supply from amongst the existing PPAs according to their minimum energy purchase terms and projected availabilities. Amounts required above the total supply from existing PPAs were then allocated, on the basis of cost and availability[162], from a combination of new renewable energy-fuelled plants, new oil or NG-fuelled plants, and electricity imports. In all cases, power plants were dispatched in order to ensure that *as a minimum* total firm capacity[163] exceeded peak demand. Finally, the quantity of petroleum or renewable fuel needed to generate the electricity

[162] Availability here refers to availability of the technology on a commercial scale, with further consideration of the lead time needed to develop the projects.

[163] The firm capacity of wind-powered plants was assumed to be zero.

requirements of each of the existing PPAs and planned new projects was determined by working backwards, taking into account conversion losses. The energy content of each of the fuel types was then calculated from the quantities required multiplied by their specific energy content (LCV).

Calculation of Energy Cost

The cost of energy supply for each plan was calculated under the ‘Reference Oil Price’ scenario only (*See Figure 3.2.2 in Chapter 3*). These costs are based on the quantity of energy supply required for each fuel type multiplied by its respective LCOE as given in **Appendix F**, and therefore include the costs of equipment, O&M and fuel. *The cost of distributing/transporting energy and the cost of the energy end-use devices and equipment were not taken into consideration in the calculations*.

Specifically, the costs of imported refined fuels used *without further conversion* by any of the consumption sectors are the costs of the fuels at the point of importation. The costs of locally-produced fuels (such as bioethanol) used *without further conversion* by any of the consumption sectors are the costs (LCOEs) of producing the fuels only. The costs of electricity are based on the LCOEs of the various electricity supply technologies. In all cases, these costs include no further downstream costs such as storage, in-country transportation and distribution costs.

Plan 0 – “Baseline Plan”

The **Baseline Plan** is the forecasted energy consumption and supply requirements for the energy sector over the next 30 years, if we continue with business-as-usual; that is, without making any further investments in developing our renewable energy sources and taking no initiatives to reduce and change our energy consumption patterns. Full plan details are provided in **Appendix D.1**.

Plan Parameters

- Projections of consumption growth in this baseline case were based on an assumed growth rate of 4% per annum in the quantum of the drivers of demand in each consumption category, and a technical efficiency improvement of 1% per annum; starting from 2010 consumption levels and technical efficiency levels.
- On the supply side, existing electricity supply contracts and new additions were programmed as follows:
  - Maximum energy obtainable under the BECOL, Hydro Maya, and BELCOGEN PPAs would be fully dispatched after 2010. All of BELCOGEN’s energy would be sourced from bagasse.

- Maximum energy obtainable under the BAL PPA would be fully dispatched after 2015 (approximately 111,150 MWhs). In 2015, only 10 MW of capacity (about 66,576 MWhs) would be dispatched from BAL.
- Where existing PPAs were not sufficient to meet required supply, it was assumed that the additional supply would be provided by a combination of new HFO-fuelled plants and imported electricity, since it was assumed that there would be no further renewable technology development under this plan. HFO-fuelled plants were chosen as these are the cheapest of the petroleum-based[164] generation plants over the planning horizon.
- ***Self-Generation***: Electricity produced by self-generators for their own use would continue to be supplied at the same level (except for BSI/BELCOGEN) throughout the planning period, as follows:
  a) 1,711 MWh by CPBL: 75% using crude oil and 25% using diesel.
  b) 7,008 MWh by BNE using locally-produced natural gas[165].
  c) 26,705 MWh by BAL: 75% using diesel and 25% using HFO.
  d) 55,077 MWh by BSI/BELCOGEN using bagasse, HFO and diesel[166] as of 2010, and increasing for the remainder of the period on the basis of the projected 4% annual growth rate and the 1% annual improvement in technical efficiency: *All of BELCOGEN's energy would be sourced from bagasse*.

- No changes were projected for the quantities of indigenous crude oil produced or the quantities exported or indigenous petroleum gas produced or converted to electricity or LPG.

Plan A – "End use-centric Plan"

This plan assumes that we will reduce demand via the least-cost mix of end-use efficiency and conservation measures without further development of any of our renewable energy resources. Additional energy supply requirements over and above existing PPA provisions will be met by adding HFO-fuelled plants or from electricity imports. Full plan details are provided in **Appendix D.2**.

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[164] NG-fuelled plants were not considered a technically feasible option under the Baseline Plan as there are no facilities currently available in Belize for receiving pipeline-NG, CNG or LNG.

[165] This estimate based on assumption that BNE's 1-MW NG-fuelled turbine runs at approx. 80% capacity factor.

[166] A small portion of HFO is used in the boilers to produce the HP steam that is in turn used to produce electricity for both internal use and for export. A small portion of diesel is also used directly in diesel engines to supply electricity to the grid. It is assumed that these practices will cease after 2010 as BELCOGEN improves its operations to use almost 100% bagasse for steam and electricity production.

Plan Parameters

- As in the Baseline Plan, projections of consumption growth in this case were based on an assumed growth rate of 4% per annum in the quantum of the drivers of demand in each consumption category, and a technical efficiency improvement of 1% per annum; starting from 2010 consumption levels and technical efficiency levels.
- Further efficiency improvements and consumption level reduction measures beyond the baseline of 1% per annum were programmed as follows:
  - Transport Sector:
    a) Shift from private gasoline vehicle transport to mass transport: starting at 5% (of transport by gasoline vehicles) in 2015 to 30% at end of 2040.

    b) Shift away from typical gasoline vehicles to mix of lower energy-consuming alternatives. By 2040: smaller vehicles (20%), ethanol flex fuel vehicles (10%), HEVs (40%), EVs (30%). *It is assumed that purchase prices for both HEVs and EVs will be comparable with those of gasoline counterparts at the time of their introduction into the local market in 2020 and 2025 respectively*.

    c) Shift away from typical light-duty diesel vehicle transport to mix of lower energy-consuming alternatives. By 2040: typical diesel vehicle (50%), smaller vehicles (10%), biodiesel flex fuel vehicles (40%).

    d) Shift away from typical mass transport and heavy duty diesel vehicles to mix of lower energy-consuming alternatives. By 2040: typical diesel vehicle (60%), biodiesel flex fuel vehicles (40%).

    e) In all cases above:
       - It is assumed that in any shift from using private transport to using mass transport, 80% of highway travel is substituted while the degree of substitution of urban travel increases gradually from 10% in 2020 to 50% in 2040.
       - Percentage of ethanol in blend for ethanol flex fuel vehicles was assumed to increase from 10% in 2015 to 25% in 2040.
       - Percentage of biodiesel in blend for biodiesel flex fuel vehicles was assumed to increase from 20% in 2015 to 70% in 2040.
  - Residential Sector:
    a) Phasing out of kerosene and candle lighting by 2025, starting from 18% of households in 2010.

    b) Shift away from electric to solar lighting. By 2040: electric lighting (60%) and solar lighting (40%).

    c) Slow phasing out of firewood for cooking: from 16% of households in 2010 to 5% of households in 2040. *This shift actually increases energy costs!*

- Commercial & Services Sector:
  a) Shift away from electric to solar lighting. By 2040: electric lighting (75%) and solar lighting (25%).
  b) Shift towards using solar and geothermal technologies for cooling. By 2040: electric cooling (50%), geothermal cooling (25%) and solar cooling (25%).
  c) Total phasing out of electric water heating. By 2040: LPG water heating (10%), solar water heating (70%) and geothermal water heating (20%).
  d) Shift towards using solar technologies for streetlighting. By 2040: electric lighting (60%) and solar lighting (40%).
  e) Implementation of energy audit recommendations (which are assumed would improve energy use efficiency by 20%). It is assumed that these measures would immediately affect 10% of sector in 2020, increasing to 25% of sector by 2040.
- Industrial Sector:
  a) Phasing out of crude oil usage and gradual shift away from usage of diesel and HFO towards natural gas for industrial applications: starting from 45% diesel, 39% HFO and 16% crude oil in 2010 to 80% NG, 10% diesel and 10% HFO by 2040.
  b) Implementation of energy audit recommendations (which are assumed would improve energy use efficiency by 20%). It is assumed that these measures would affect 10% of sector in 2020 and 25% by 2040.

- On the supply side, existing electricity energy supply contracts and new additions were programmed *similarly to those of the Baseline Plan* as follows:
  - Maximum energy obtainable under the BECOL, Hydro Maya, and BELCOGEN PPAs would be fully dispatched after 2010. All of BELCOGEN's energy would be sourced from bagasse.
  - Maximum energy obtainable under the BAL PPA would be fully dispatched after 2015 (approximately 111,150 MWhs). In 2015, only 10 MW of capacity (about 66,576 MWhs) would be dispatched from BAL.
  - Where existing PPAs were not sufficient to meet required supply, it was assumed that the additional supply would be provided by a combination of new HFO-fuelled plants and imported electricity, since it was assumed that there would be no further renewable technology development under this plan. HFO-fuelled plants

were chosen as these are the cheapest of the petroleum-based[167] generation plants over the planning horizon.

- ***Self-Generation***: Electricity produced by self-generators for their own use would continue to be supplied throughout the planning period as given in the Baseline Plan.

- No changes were projected for the quantities of indigenous crude oil produced or the quantities exported or indigenous petroleum gas produced or converted to electricity or LPG.

Plan B – "Supply-centric Plan"

This plan assumes that we will put in place the least-cost supply mix to meet all our energy demands without implementing any end-use efficiency or conservation measures to curb demand: we will simply consume more of the energy we now consume as our economy and population grows. Full plan details are provided in **Appendix D.3**.

Plan Parameters

- As in the Baseline Plan, projections of consumption growth in this case were based on an assumed growth rate of 4% per annum in the quantum of the drivers of demand in each consumption category, and a technical efficiency improvement of 1% per annum; starting from 2010 consumption levels and technical efficiency levels.
- On the supply side, existing electricity energy supply contracts and new additions were programmed as follows:
  - Maximum energy obtainable under the BECOL, Hydro Maya, and BELCOGEN PPAs would be fully dispatched after 2010. All of BELCOGEN's energy would be sourced from bagasse.
  - BELCOGEN's electricity output would increase to 153,900 MWh per year by 2020.
  - In 2015, only 10 MW of capacity (about 66,576 MWhs) would be dispatched from BAL. The supply of electricity to the grid from BAL would be not be used beyond 2015 due to the high cost of the supply.
  - Around 85% of our remaining hydro potential would be developed by 2040.
  - Additional biomass-fuelled plants would be installed according to the following schedule: a 20 MW plant before 2020, a 10 MW plant before 2035 and a 20 MW plant before 2040.

[167] NG-fuelled plants were not considered a technically feasible option under the Baseline Plan as there are no facilities currently available in Belize for receiving pipeline-NG, CNG or LNG.

- Additional wind energy plants *with capacity factors between 25% and 30%* would be installed according to the following schedule: a 20 MW plant before 2020, a 5 MW plant before 2025, a 20 MW plant before 2030, and another 15 MW plant before 2035.
- ***Self-Generation***: Electricity produced by BAL and CPBL for their own use would continue to be supplied as given in the Baseline Plan *only up to 2015*. After 2015, BAL and CPBL would cease to self-generate and only the supplies from BNE and BSI/BELCOGEN would continue to be provided as given in the Baseline Plan.

- No changes were projected for the quantities of indigenous crude oil produced or the quantities exported or indigenous petroleum gas produced or converted to electricity or LPG.

Plan C – "Comprehensive Plan"

This plan assumes that we will put in place both the least-cost mix of end-use efficiency and conservation measures to minimize energy use and the least-cost supply mix, with further renewable energy development. However, the least-cost supply mix will only be formulated after taking into account the reduction in demand and hence the required supply due to the implementation of the efficiency measures. Full plan details are provided in **Appendix D.4**.

Plan Parameters

- As in the Baseline Plan, projections of consumption growth in this case were based on an assumed growth rate of 4% per annum in the quantum of the drivers of demand in each consumption category, and a technical efficiency improvement of 1% per annum; starting from 2010 consumption levels and technical efficiency levels.
- Further efficiency improvements and consumption level reduction measures beyond the baseline of 1% per annum were programmed exactly as detailed under Plan A above.
- On the supply side, existing electricity energy supply contracts and new additions were programmed following the schedule provided under Plan B, but with a few changes to cater for the lower demand levels due to the demand-side efficiency improvements:
  - Additional biomass-fuelled plants would be installed according to the following schedule: a 20 MW plant before 2020, a 9 MW plant before 2035 and a 15 MW plant before 2040.
  - Additional wind energy plants *with capacity factors between 25% and 30%* would be installed according to the following schedule: a 12 MW plant before 2020, a 5 MW plant before 2030, and another 15 MW plant before 2035.

- No changes were projected for the quantities of indigenous crude oil produced or the quantities exported or indigenous petroleum gas produced or converted to electricity or LPG.

Comparison of Plans[168]

Overview of Results – *Plan Performance*

Table 5.22 below gives the results of key aggregated performance indicators for the various plans over the 30-year planning horizon.

It should be borne in mind that these plans are *fairly conservative* and do not take into consideration any possible gains from energy exports or other spinoff effects on the energy sector or the wider economy or society as a whole.

PERFORMANCE INDICATORS	Baseline Plan	Plan A	Plan B	Plan C
Net Present Cost of Energy Supply (USD)	$3,206,418,586	$3,073,966,847	$2,961,116,791	$2,798,608,329
Net Present Cost of Emissions (USD)	$468,891,516	$433,438,097	$414,976,848	$340,433,237
Net Present Cost of Energy Supply inc. Emissions (USD)	$3,675,310,102	$3,507,404,944	$3,376,093,638	$3,139,041,565
Total Foreign Oil and Electricity Imports (BOE)	17,226,531	15,449,375	15,161,820	12,106,393
Average Dependence on Foreign Imports	68.72%	67.17%	55.78%	52.72%
Average Renewability Index	28.57%	31.67%	40.1%	46.15%
Average Resource Diversity Index	42.67%	38.52%	35.66%	33.7%
Average Electricity as % of Secondary Energy Consumption	16.74%	17.79%	17.45%	17.79%

Table 5.1: ***Comparison of Plans*** **- Results of Key Aggregated Performance Indicators**

Comparisons of the projected outcomes of the plans, given in 5-year intervals, are illustrated in the graphs given further below.

The results clearly show that all three alternative paths – Plan A, Plan B and Plan C – are improvements on the 'Continue-Business-As-Usual' (Baseline) Plan.

Plan C for instance would yield the following improvements over the Baseline Plan:

- A 14.6% reduction in net present cost, which works out to nearly $57 million USD per year or nearly 4% of GDP.
- 30% reduction in foreign imports of fuel (including electricity imports).
- Over 60% increase in use of renewable energy.

[168] Details of each of the Plans can be found in **Appendix D.1 to D.4**.

- 21% increase in the diversity of energy supply sources.
- Just over 6% increase in the permeation of electricity within the secondary energy supply mix.

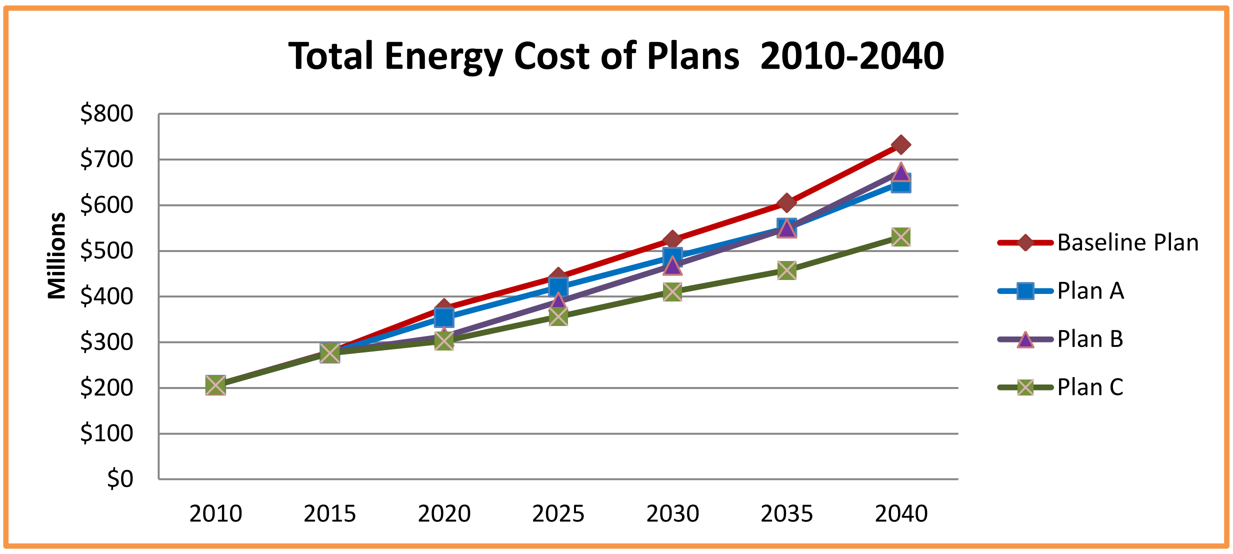

Figure 5.2: ***Comparison of Plans*** **- Total Cost of Energy without Carbon Pricing for 2010-2040**

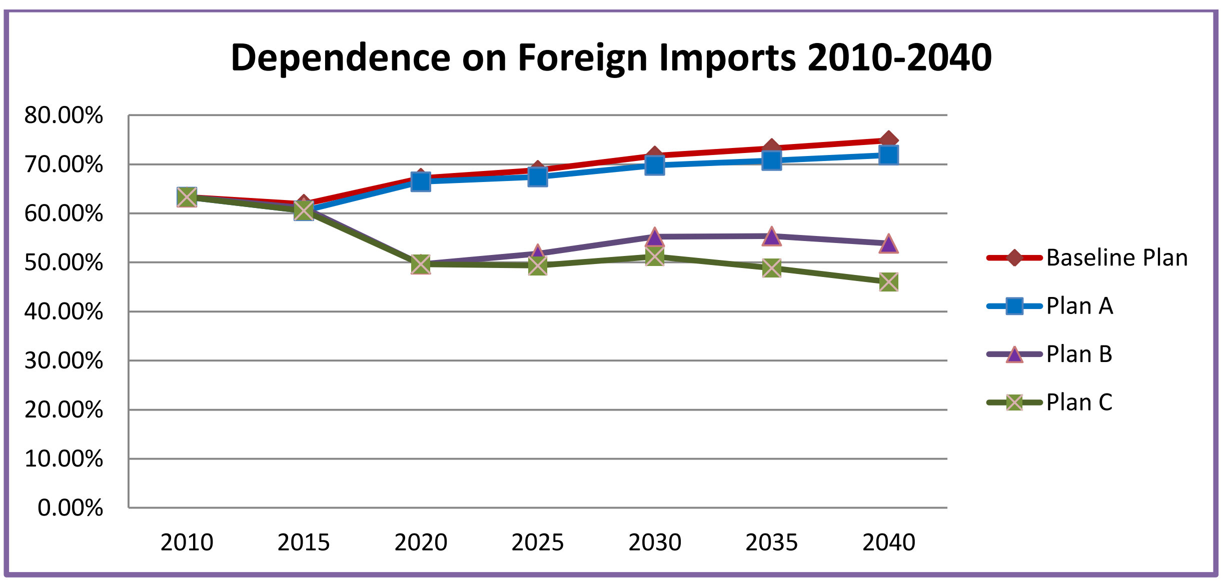

Figure 5.3: ***Comparison of Plans*** **– Degree of Dependence on Foreign Imports for 2010-2040**

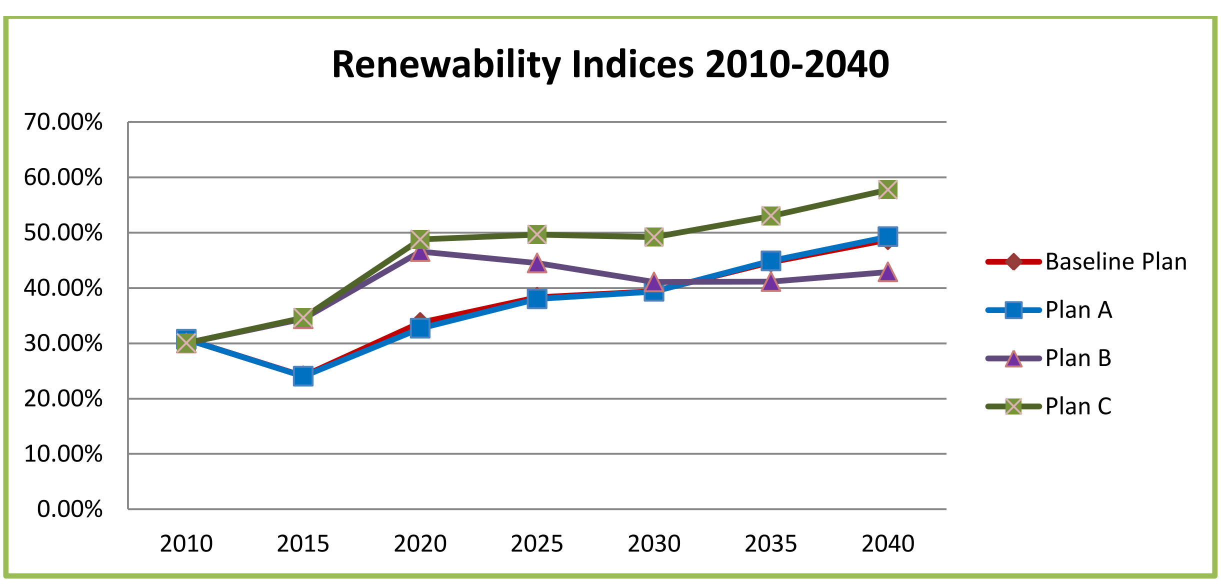

Figure 5.4: ***Comparison of Plans*** **– Percentage of Renewables in Energy Supply Mix for 2010-2040**

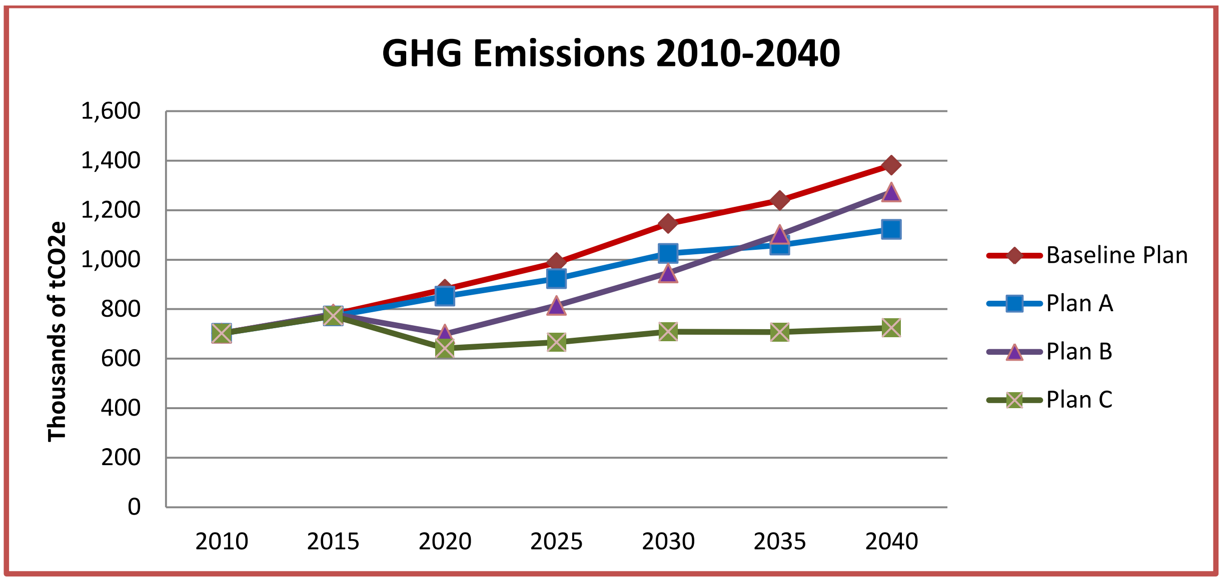

Figure 5.5: ***Comparison of Plans*** **– GHG Emissions due to the Energy Sector for 2010-2040**

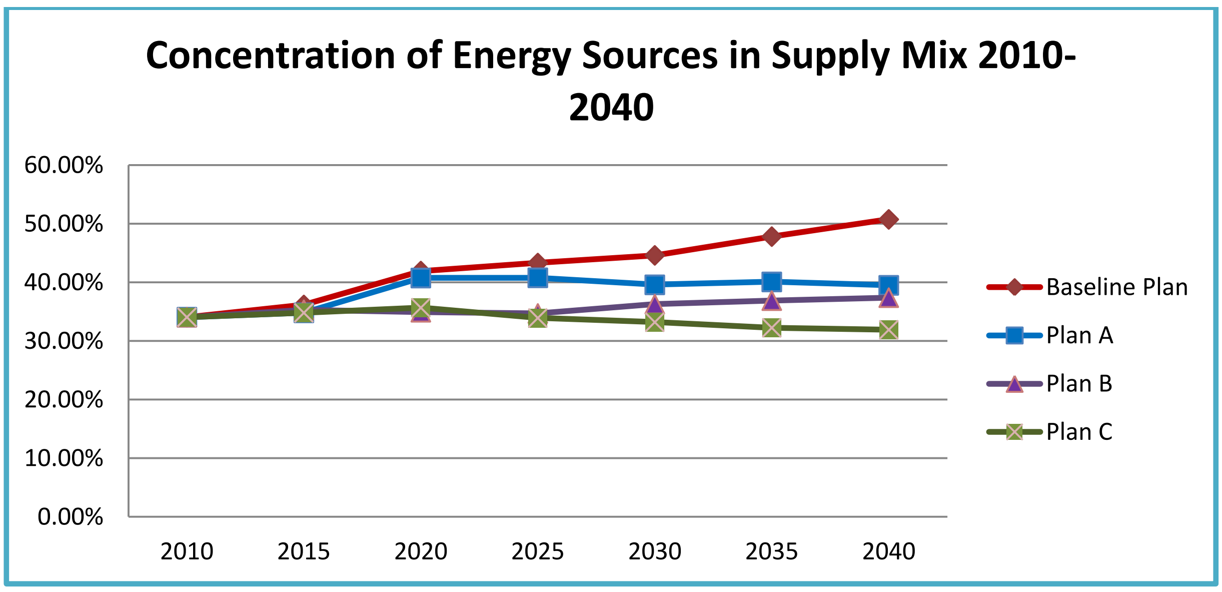

Figure 5.6: ***Comparison of Plans*** **– Concentration of Energy Sources in Supply Mix for 2010-2040**

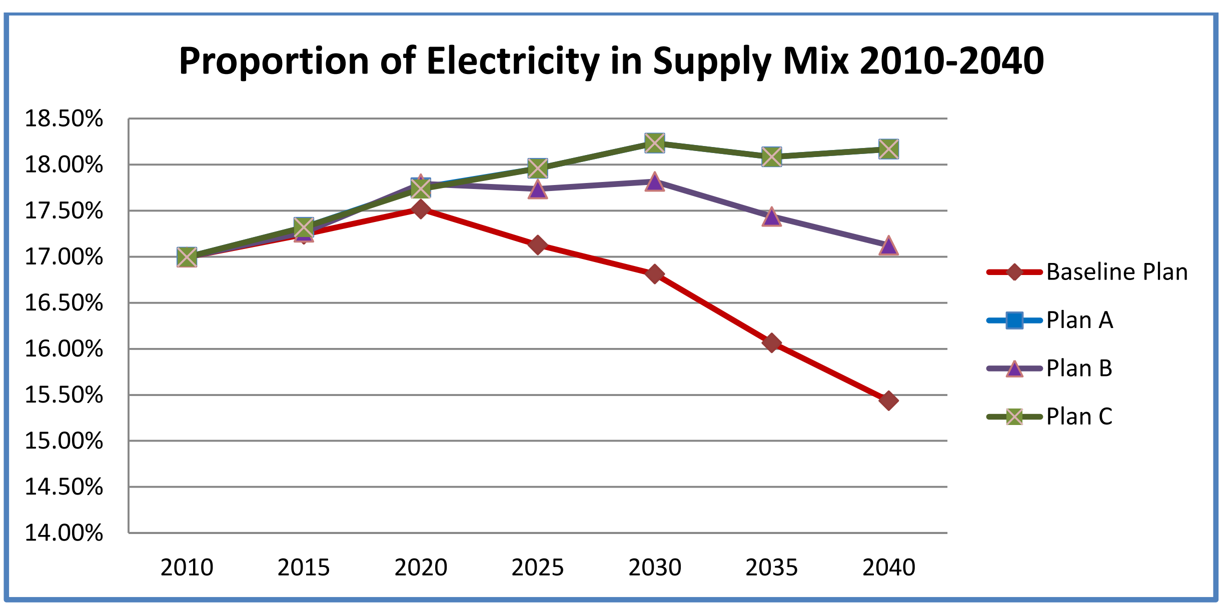

Figure 5.7: ***Comparison of Plans*** **– Proportion of Electricity in Energy Supply Mix for 2010-2040**

6 WHAT TO DO TO MAKE OUR PLANS HAPPEN

> **"We need effective rules and smart policy frameworks … to ensure that the right resources and technologies are available in the right place, at the right time … and at the 'right' price."**
>
> *Pierre Gadonneix, Chairman, World Energy Council*

POLICY RECOMMENDATIONS

The plans formulated in the previous chapter chart possible courses forward, given the data and information on hand, that should enable us to realize our goals for Belize's energy sector over the planning horizon. Plans, especially, of such a broad scope and which potentially involve hundreds of projects distributed over a wide cross-section of the economy, can only be brought to fruition if proper policies are in place to stimulate, guide and coordinate action.

The policy recommendations presented in the sections below are intended to serve two main purposes:

- To give life to the plans formulated in the previous chapter or subsequent iterations of or updates to these plans;
- To generally administer and guide the development of Belize's energy sector along the path of efficiency, sustainability and resilience and towards meeting the goals and supporting the strategies proposed in the previous chapter.

It is important to note that these policies are in most cases co-dependent and mutually-reinforcing; and so the effectiveness of any individual policy will largely depend on how it fits into the entire portfolio of policies being put forward.

Energy Planning

Building an efficient, sustainable and resilient energy supply and services infrastructure cannot happen by chance, and it cannot happen overnight. It must be planned; then built. This does not mean that once built, there is no longer any need for planning. Building an energy infrastructure is an incremental and on-going process, and the planning process must accordingly be on-going.

Plans are commitments to a specified course of action(s); designed to achieve one's objectives. They are formulated only after a thorough analysis of the uncontrollable events and factors that may occur in the future; so that one can take the path of least resistance – and hence maximum efficiency and lowest cost - to realizing one's objectives. Once these commitments are publicized, the marketplace can respond with confidence and in an efficient coordinated way to provide the goods and services required by these plans. For example, if Government mandates that by 2015 all gasoline sold at fuel stations must be mixed with at least 20% of bioethanol by volume: then entrepreneurs can direct their energies towards bioethanol production projects; financiers can provide reasonable financing terms for bioethanol projects knowing that entrepreneurs will have a market for their products; fuel filling stations can begin the process of retrofitting storage and filling facilities to accommodate bioethanol; and vehicle dealerships can make arrangements so that new gasoline vehicle stocks can run on E20.

On the other hand, plans are not static. The underlying drivers of demand may change or the availability and cost of current and emerging technologies and fuels may change. A stark instance of this is when oil prices suddenly sky-rocketed in late 2007, or when oil was found (in quantities sufficient for commercial production) in Belize in 2005. When events such as these occur, plans must change to take them into account. However, the marketplace would have already made commitments based on the previously enunciated plans. In such cases, the costs of switching to the new plan would have to be taken into consideration when deciding on the way forward.

Establish a National Energy and Electricity Planning Institute

The NEP Team recommends that GOB set *as its first and immediate priority* the establishment of a *National Energy and Electricity Planning Institute (NEEPI)*, with responsibility for formulating energy plans and policies in coordination with relevant stakeholders, for disseminating these plans and policies to relevant stakeholders (after the requisite approvals have been gotten), and for monitoring and enforcing – where applicable – adherence to these plans and policies by the bodies charged with administering them. One of the key functions of the Institute will be the collection and compilation of data on all relevant areas and activities in the energy sector to support energy planning and policy analysis, for providing information feedback to stakeholders, and for monitoring activities.

The Role of NEEPI *vis-a-vis* the Role of the PUC

The NEEPI is responsible for planning and policy-making for the *entire energy sector* in fulfillment of its mission to develop the energy sector along the path of efficiency, sustainability and resilience. The NEEPI retains this role regardless of the industry market structure.

The PUC, on the other hand, is the regulator of the electricity sub-sector *amongst other things;* acting in lieu of the ultimate regulator, competition, because of the monopoly status afforded the public utility. Its mandate is circumscribed to ensuring that electricity supply is available, accessible, reliable and affordable to *consumers in the* *electricity sub-sector* specifically. Thus, the PUC is responsible for ensuring compliance with the policies issued by NEEPI and for managing the relationships, overseeing the transactions, monitoring and enforcing contracts and other informal arrangements - whether explicit or implicit - and resolving disputes between the various parties in order to maintain and even enhance the viability of the sub-sector in accordance with the plans and policies prepared and disseminated by the NEEPI.

Setup an Energy Sector Planning Framework

The NEP Team recommends that a robust standardized planning framework be setup and adopted by the NEEPI to guide the process of formulating a least-cost long-term plan(s) for the further development of Belize's Energy Sector along the path of sustainability and resilience. The major output of this plan will be a demand-supply balance of energy flows, evaluated in terms of physical quantity and cost, and broken down by energy form for each year or other suitable constituent period of the planning horizon. *These outputs will inform the policy-formulation process*.

This least-cost long-term plan will be selected from an initial list of candidate plans: Each candidate plan will feature a mix of energy efficiency and conservation measures aimed at reducing demand for energy, and a mix of energy supply technologies to satisfy the resultant overall demand over the planning horizon.

Candidate plans will be screened and ranked according to the degree to which they achieve the following objectives *on an economy-wide basis*:

- Minimize the *net present cost* of energy use
- Minimize the cost of GHG emissions and other forms of environmental damage, or maintain them below a certain pre-determined upper limit
- Maximize the Renewability Index (*the percentage of renewable energy in the total primary energy supply mix*), or maintain it above a certain pre-determined lower limit
- Minimize dependence on foreign energy sources, or maintain it below a certain pre-determined upper limit
- Maximize the diversity of the energy supply mix, or maintain it above a certain pre-determined lower limit
- Maximize the use of electricity in the secondary energy supply mix, or maintain it above a certain pre-determined lower limit

In order to ensure that the final selected plan comprises as much as possible the least cost mix of energy end-use technologies and measures and supply-side technologies and fuels required to achieve plan objectives, the framework will utilize a full financial cash flow model that takes into account the full costs of all elements used in the mix.

The selected long-term plan will be updated once per year to take account of changes in short-term growth rates of consumption drivers and other parameters. *Policies may be changed to reflect changes in the plan*.

The entire planning process will be repeated a minimum of once every three years to take account of new developments and technology improvements in the local, regional and global energy industries. However, a new run of the process may also be triggered at any time if a major significant event such as a steep rise in oil prices or a major energy supply technology breakthrough causes a concomitant significant change in any of the parameter forecasts, thus changing the conditions under which the least cost plan was derived in the first place.

Whether done as part of the three-year planning cycle or triggered by the occurrence of a major significant event, the previously selected plan may be changed out if it is no longer the least cost plan. The economy-wide costs of switching to a new plan and hence course of action, given that consumers and suppliers may have made investments and commitments that would no longer be needed under the new plan, should be taken into consideration when making a final determination.

Adopt a Formal Procedure to formulate Approved Policies from Planning Targets

The NEP Team recommends the adoption of the following formal procedure, to be executed and supervised by the NEEPI, for the formulation (and subsequent approval) of policies from planning targets:

- The NEEPI will craft the requisite policies, along with recommended incentives and penalties, targeted for various stakeholders to ensure that the planning targets are achieved as closely as possible.
- These policy proposals will be sent to the relevant Government Ministries for their inputs and for approval to proceed to the stakeholder consultation phase.
- Once approved, a policy proposal, which may have been amended as a result of the inputs from the relevant Ministry, will then be circulated to stakeholders for their feedback.
- Once the consultation phase is finished, the proposed policy may be further amended as a consequence of the feedback from stakeholders.
- Whether amended or not, the resulting policy, along with a summary of the results of the stakeholder consultation phase, is once again sent to the relevant Government Ministry for final approval. It is the Ministry's prerogative to decide what legislative instrument is to be used to formalize the policy.
- Finally, once formally approved, the policy is communicated to all stakeholders.

Screening of Energy Supply Technologies using Lifecycle Unit Cost Analysis

An energy plan is a sequenced roll-out of a mix of energy supply technologies, energy end-use technologies, and end-use efficiency-improvement and conservation measures used to satisfy pre-determined objectives and constraints. In order to facilitate the formulation of candidate plans, competing technologies and measures must firstly be screened on the basis of their full relevant costs.

The commonly-adopted metric used within the Energy Industry for comparing and screening energy supply technologies is the Levelized Cost of Energy (LCOE), which is the net present value of the cost of the initial investment in a typical plant (that uses the technology) plus the yearly O&M and fuel costs incurred over the economic life of the plant, divided by the net present value of the projected yearly output of the plant. The initial investment cost is the cost of procuring, setting up and commissioning the plant; and includes land use costs and the costs of interconnection to the grid (if plant is used to generate electricity). O&M costs are the day-to-day costs incurred in running the plant, and includes environmental damage prevention and cleanup costs and de-commissioning costs (significant for nuclear plants). The cost of capital is taken into account in the discount factor used in the net present value calculations. Since the objective is to arrive at the true cost of these technologies, none of these costs should reflect any taxes, duties, special incentives, subsidies or any other artificial cost applicable to the particular technology.

The LCOE of a particular supply-side technology takes into account costs of energy supply up to the "bus bar" only. The costs of distributing the energy supplied by a particular technology beyond the "bus bar" to final end-users are not usually included in the LCOE. However, for a true apples-to-apples comparison between technologies, these distribution costs should also be taken into account. It would be misleading, for example, to compare the cost of transport using gasoline versus using electricity on the bases of the retail cost of gasoline and the cost of generation *only* of electricity. In order to be comparable with the retail cost of gasoline, the cost of delivering electricity from the point of generation to the point of delivery to final end-users – a charging station – would have to be added to the generation cost of electricity. This delivery cost comprises the capital and O&M costs of the transmission and distribution infrastructure and final customer connection costs.

For imported fuels similarly, the cost of delivery from the port (where the fuel is received) to the filling station, inclusive of all storage, transportation and related overhead costs, must be accounted for in the final (retail) cost to end-users. For locally-produced fuels, this is the cost of delivery from the factory to the filling station.

This cost of delivered energy should be calculated and expressed in a similar way to the LCOE. For our purposes, we will call this new metric, LCODE (Levelized Cost of Delivered Energy). It is calculated as the net present value of the cost of the initial investment in a typical plant (that uses the technology) plus the yearly O&M and fuel costs incurred over the economic life of the plant PLUS the applicable portion[169] of the net present value of the cost of the initial investment in the delivery infrastructure for the particular fuel type plus the yearly O&M costs incurred over the economic life of the delivery infrastructure, divided by the net present value of the projected yearly volume of fuel (or energy) delivered to the end point.

It is important to point out that if a particular technology such as an offshore wind farm requires a separate and relatively more costly transmission line – in this case, a submarine transmission cable – to conduct its output to the existing transmission network, then it would be best that the entire cost of the transmission line be incorporated as a part of the energy supply cost of the technology: that is, the "bus bar" in such a case would be the point where the submarine cable meets the existing transmission network. The applicable portion of the cost of the existing delivery infrastructure would then be applied on top of this energy supply cost.

Adopt a Lifecycle Unit Cost Metric to be used for Comparing and Screening of Energy Supply Options

The NEP Team recommends that a consistent per-unit metric such as the LCODE, which takes into account all relevant life-cycle costs from project development to de-commissioning, be adopted and used to compare and screen supply side options on the basis of costs and outputs.

This Unit Cost Metric should also take into account the following cost factors:

- The full cost of delivery of the energy to final end-users.
- The opportunity cost of utilization (or destruction) of scarce resources such as water, air and land: As a minimum, the degree of utilization of each of these scarce resources for the particular energy supply option should be measured and documented (and updated as underlying technologies change) so that environmental impacts can be measured.
- The impact of the deployment and the operation of the particular energy supply option on employment and the economic viability of local communities in which they are deployed: If this impact is – as would be expected – positive, then it should be treated as a negative cost, thus reducing overall unit cost. This should be updated as underlying technologies change.
- All taxes, duties, special incentives, subsidies and any other artificial cost applicable to the particular technology should be excluded from the Unit Cost Metric calculus.

Electricity Planning

[169] That is the portion of costs that is allocated to the energy (and power) being distributed for the particular project.

Traditionally, electricity supply planning has always been conducted by the sole electric utility as a separate exercise from overall energy planning, with little or no provision made for the possible impacts of substitution with respect to other energy forms in response to changes in consumer behavior and public policy. Electric utility planners project demand for electricity by the various categories of end-users (residential, commercial and industrial), in terms of both energy and peak power requirements; and formulate least cost plans for the provision of sufficient capacity and associated energy to meet the demand for electricity in accordance with pre-determined reliability targets.

Ideally, however, electricity supply planning should follow from overall long-term energy planning. The overall long-term energy plan determines *amongst other things* what forms of energy are required, using what technologies, and in what quantities. Within the context of this overall energy plan, electricity is treated as just another form of energy that can be produced by a range of supply-side technologies: the cost per unit of energy (LCOE or LCODE) for each of the electricity supply-side technologies is used to come up with total cost of energy (from each of the electricity supply sources), which forms a part of the optimization objective function for the overall energy plan. Once the overall energy plan has been developed, the optimal amounts of electricity required (and the technologies used to supply these requirements) can be derived from the plan. However, rather than issuing directives requiring utilities to supply the optimal quantities as prescribed by the plan, policies are used to guide utilities towards this optimum path, leaving room for the utilities to bring their own perspective and particular circumstances to bear on the final outcome.

Transmission planning within utilities has also historically been done separately from electricity supply/generation planning. Depending on system design philosophy, transmission costs as a whole, including losses incurred in transferring energy from Point A to Point B in an electricity system, may constitute a significant component of overall costs in systems such as Belize's, which are characterized by large spatial separations between load centers and energy supply points relative to demand and load factor on the system. For example, a particular load may be served by building a new gas turbine plant in its vicinity or by building a lower costing biomass plant in a relatively distant location along with a new transmission line to conduct the energy to the load center. In the first case, the energy supply cost is relatively higher, and the incremental transmission costs are negligible. In the second case, the energy supply cost is relatively lower, but the transmission costs may be substantial depending on the distance between the load and the biomass plant. Moreover, the optimal solution may be to run a transmission line from the source to its nearest point to the existing transmission network plus run a separate transmission line from the load to its nearest point to the existing transmission network. Though quite over-simplified, this exemplifies the complexity of choices that system planners continually face, and underscores the critical importance of carefully coordinating energy supply and transmission plans so as to achieve least cost objectives without violating minimum reliability standards.

Perform Electricity Supply Planning as an integral part of Energy Planning

Electricity supply planning should be based on the policies resulting from the applicable energy plan. The optimal amounts of electricity required (and the technologies used to supply these requirements) as determined from the energy plan may be used as the starting point for the derivation of the explicit targets to be stipulated in the electricity supply plan.

Screening of Electricity Supply Technologies using Lifecycle Unit Cost Analysis

For electricity in particular, the output of a plant is measured in terms of both power and energy. Production of 50 GWh per year from a non-intermittent source such as a diesel-fuelled plant is not comparable to production of 50 GWh per year from an intermittent (variable output) source such as a wind plant, since the non-intermittent source provides a higher level of firm capacity (power). In order to be truly comparable, the wind plant must be "firmed up" to the firm capacity level of the diesel-fuelled plant. One way of doing this is to assume that the wind plant is provided with adequate backup capacity (such as a gas turbine), and to determine the full per-KWh cost of the combination of the wind plant and the backup plant. However, if the wind plant is being installed as part of a system that already has adequate firm capacity level, it may be more appropriate to determine the additional firm capacity needed to maintain the reliability of the system as a whole above a certain minimum level requirement. This additional firm capacity is then the backup needed for the wind plant.

Additions to Lifecycle Unit Cost Metric to be used for Comparing and Screening of Electricity Supply Options

The Unit Cost Metric used for comparing and screening electricity supply alternatives should also take into account the following cost factors the additional cost of backup capacity needed for intermittent sources in order to make their outputs comparable with firm sources, in terms of both energy and power.

Energy Sector Restructuring

Re-structure the Electricity Industry to cater for Clearer Lines of Responsibility and to prepare for the Evolution of an Export Market

The NEP Team recommends that the electricity industry be re-structured as follows:

- The center of the new structure will be the National Electricity Transmission System (NETS)[170]; consisting of transmission and sub-transmission lines and cables, transmission substations, and a National Electricity Control Center (NECC). The National Transmission System Operator (NETSO) will be responsible for managing the NETS.
- Each load center will be regarded as a Distribution Area (DA) e.g. Belmopan or Punta Gorda or Spanish Lookout. DAs will be connected to and purchase power and energy from the NETS via one or more connection points (substations) for on-selling to final consumers, or they may supply energy from their own generation facilities if not connected to the NETS. A DA that is connected to the NETS must obtain all of its power and associated energy requirements via the NETS, except in the cases where it buys back power and energy from one or more of its customers.

  DAs will be managed by a Distribution Area Operator (DAO); hence, final consumers are customers of the DAO managing the DA to which they are connected. The DAO is therefore responsible for providing all related services, including billing, to the customer. A single DAO may manage more than one DA.

  A DA may consist of two general classes of customers: low-voltage customers, who are connected to the low voltage distribution network; and high-voltage customers, who are connected directly to the DA’s high voltage distribution network.
- One or more Single Large Consumers (SLCs), who require a separate and exclusive high-voltage connection to the NETS, may also be directly connected to and purchase power and energy from the NETS via one or more connection points (substations). An SLC may be located outside of Belize’s national borders
- Generating stations or energy supply providers (ESPs) will be connected to and sell power and energy to the NETS via one or more connection points. These ESPs will bid for and enter into contracts with the NETSO to provide power and energy as required. An ESP may be located outside of Belize’s national borders.

  The NETSO may also provide its own generating facilities for backup power purposes or in cases where requests for proposals to provide energy supply are not met with acceptable or responsive bids.
- The NETSO will be responsible for liaising and transacting with DAOs, SLCs and energy suppliers in order to meet demand for power and energy.

  The NETSO may buyback power and associated energy from an SLC or DAO, via an explicit agreement between the NETSO and the SLC or DAO. In each case, appropriate metering facilities must be in place to ensure that the two way flow of power and associated energy can be reliably tracked and measured.

[170] In the future, though very unlikely, this may evolve into two or more regional transmission operators.

An ESP may *not* enter into a contract with another ESP for the supply of power and associated energy between them. Likewise, a DAO or an SLC may *not* enter into a contract with an ESP for the supply of power and associated energy to the ESP.

Establish Roles and Responsibilities for Electricity Supply and Transmission Planning

The NETSO should be charged with responsibility for electricity supply planning and transmission expansion planning in strict conformance with the policies set out by the NEEPI. Plans will be prepared on an annual and three-year cycle bases in conformity with the NEEPI’s planning cycles. Each plan must be approved by the NEEPI and the PUC before any action is taken to implement any of its provisions. The PUC’s approval is necessary to confirm that the plans adequately provide for the projected electricity needs of each DA and SLC – and, hence, of all consumers.

The NETSO will be required to take into account the forecasts of energy and peak demand at each of its existing supply nodes (connecting DAs or SLCs) as well as projected new additions (of DAs and SLCs) when preparing its electricity supply plans. The NETSO must ensure that its plans meet the minimum reliability and quality requirements for electricity supply at each of these supply nodes as set out by the PUC or as provided in an approved explicit contract between the NETSO and the DAO (of a particular DA) or SLC.

Establish Responsibility for Electricity Distribution Planning

Each DAO should be charged with responsibility for distribution planning of the DAs which are under their control. These plans are to conform to strict guidelines approved and issued by the NEEPI. Each plan must be approved by the NEEPI and the PUC before any action is taken to implement any of its provisions. The PUC’s approval is necessary to confirm that the plans adequately provide for the projected electricity needs of all consumers within a particular DA.

Put in place framework for Leasing of Transmission Capacity and Wheeling

The NETSO will also have the authority to lease “space” in its transmission lines to any ESP for the purposes of transferring (“wheeling”) power and associated energy from an ESP to an SLC.

Since ESPs and SLCs may be located outside of Belize’s national borders, the NETSO may therefore use its transmission network to facilitate the sale of power and associated energy between entities where one or both of them operate outside of Belize. However, the PUC must be satisfied that the rates of the charges levied for the use of its facilities are not lower than the rates charged to any of the local DAOs or SLCs, and that such facilitation will not cause an infringement of the minimum reliability and power quality requirements of the NETS as a whole or at any of its supply nodes.

Demarcate Distribution Areas

The NEP Team recommends that the PUC be charged with the responsibility for demarcating and declaring the boundaries of DAs, with the following provisions:

- Electricity supply to any consumer residing wholly or partly within the boundaries of the DA must be provided on request within a reasonable time frame if all the pre-conditions for connection of the premises *as stipulated by the PUC* are met and if the connection of the premises will not cause any violation of minimum quality or reliability standards on the part of the DAO.
- Under normal operating conditions, a DA should be capable of being energized directly from the NETS without the need to be linked to any part of another DA, if it is connected to the NETS.
- One or more properly-calibrated and properly-maintained energy and hourly power meters must be placed at each connection point between a DA and the NETS to measure the flow of power and energy from the NETS to the DA.
- Where a connection point between two DAs exist – whether in normally open or normally closed state - then one or more properly-calibrated and properly-maintained energy and hourly power meters must be placed at the connection point between the DAs in order to measure the flow of power and energy between them. Such a connection point will be owned, operated, maintained and administered by the NETSO.

Put in place framework for Energy Buyback between Distribution Area Operator and Customer

A DAO may buyback power and associated energy from one or more of its customers within a specific DA, via an explicit agreement between the DAO and the customer. Appropriate metering facilities must be in place to ensure that the two way flow of power and associated energy can be reliably tracked and measured. As importantly, adequate safety measures must be implemented and adhered to in order to ensure that the supply emanating from a customer's premises can be monitored in accordance with policies issued by the PUC and that any such customer premises can be readily and completely isolated from the rest of the DA as required by the DAO, without affecting the reliability and power quality requirements of the DA as a whole or at any of its service points.

Establish Responsibilities for Electricity Billing

Each DAO will be responsible for billing its customers for electricity supplied and other services rendered on a periodic basis in accordance with an approved schedule of charges approved and issued by the PUC, or in accordance with an explicit contract for the supply of services between the DAO and the customer that is also approved by the

PUC. The schedule of charges may be specific to a particular DA. Bills will also reflect setoffs or reverse charges for energy buyback arrangements.

The NETSO will be responsible for billing DAOs and SLCs for electricity supplied and other services rendered on a periodic basis in accordance with an approved schedule of charges approved and issued by the PUC, or in accordance with an explicit contract for the supply of services between the NETSO and the DAO or SLC that is also approved by the PUC. The schedule of charges may be specific to a particular DA or SLC. Bills will also reflect setoffs or reverse charges for energy buyback arrangements.

Establish Responsibility and Supporting Framework for Contracting with Energy Supply Providers for the Supply of Power and Associated Energy

The NEP Team recommends that the NETSO be charged with responsibility for contracting with independent ESPs for the supply of power and associated energy to meet demand, with oversight from the PUC.

The following formal procedure should be instituted in order to ensure that the PUC is fully involved in the contracting process and that the policies issued by the NEEPI are adhered to:

- Any request for additional power and energy must be made on the basis of the annual plan or three-year plan or due to some unforeseen event (for instance, another supplier may have ceased operations suddenly or a new unexpected load increase may have occurred).
- The NETSO must first apply to the PUC for approval to initiate a competitive bidding process for the additional power and energy required or to enter directly into negotiations with a preferred ESP. The final content and format of all documents comprising a Request for Proposal (RFP) and the particular bidding procedure used in each instance must be approved by the PUC before an RFP is sent out to potential bidders.
- Upon completion of the bid evaluation process, the NETSO should be required to send a copy of all bids received along with a summary of the evaluation of the bids and the its recommendations to the PUC. The PUC will be responsible for approving (or rejecting) the NETSO’s recommendation arising from the evaluation process.
- Once the recommendation is finally approved, the NETSO may proceed to negotiate the details of the contract with the selected ESP. The PUC must approve the contents and format of the contract before it is awarded.

Establish Maximum Term of Contract with Energy Supply Providers for the Supply of Power and Associated Energy

The NEP Team recommends that the maximum term of any contract between the NETSO and an Energy Supply Provider be limited to 25 years, in order to ensure that the NETSO is not locked into contracts for energy supply for extended periods without having the option to source energy from newer projects that feature the latest advances in technology and hence lower prices and/or more reliable supply.

Establish RFP Evaluation Criteria for Electricity Supply to yield selection of Least Cost Supply Option

The bidding process should ultimately result in selection of the least cost energy supply option that meets service quality and reliability criteria. In order to achieve this, the main criterion that should be used in the bid evaluation process is the full lifecycle cost of supplying the required power and energy from the supply source, plus the net present value of the estimated additional cost of transmission facilities (including the initial capital cost and the O&M costs) needed to connect and incorporate the supply into the NETS, plus the cost of additional losses incurred due to the energy flows within the NETS network determined using load flow analyses, all calculated over the projected lifetime of the supply[171].

RFPs should as much as possible specify what the required outputs of the supply source - quantities of power and energy, voltage and frequency range limits, emissions rate - should be, without stipulating a specific underlying technology requirement e.g. a wind energy plant or a biomass plant or a diesel plant. However, RFPs may indicate preference for certain technologies or preference for a particular supply source location (for example, Cayo District or Southern Belize) so as to meet resource and geographic diversity requirements respectively. In such cases, the bidding document must provide objective quantitative criteria that explain clearly how such preferences will be taken into account in the final evaluation.

Indigenous Energy Supply

Optimal Utilization Land and Natural Resource for Energy Supply

Enact Legislation to Vest Ownership of Natural Resources in People of Belize

GOB should immediately seek to enact legislation to vest ownership of the natural resources of Belize in the People of Belize, to enshrine such ownership so that it is non-transferable, and to ensure that the profits derived from the use of the natural resources of Belize redound to the People of Belize.

In particular for the energy industry, any business venture or undertaking which utilizes any of the natural resources of Belize for profit or gain should be allowed to recover *only* the cumulative capital applied to such business venture or undertaking plus a fair return

[171] Where the supply alternatives have different lifetimes, then this must be taken into account into the comparisons.

on the cumulative capital applied, and in any case should not be allowed to earn profits beyond a period exceeding 30 years, unless it can be shown that the cumulative net return on their investment at the end of the 30 year period is less than or equal to zero.

Accordingly, prior to final approval of its license to do business, such a business venture or undertaking should be required to submit a thorough business plan which clearly details the projections of its revenues, expenses, capital outlays and returns, and its assumptions regarding the environment in which it will operate. This business plan must be approved by a competent authority. The enterprise will afterwards be required to submit annual reports of its financial position with regard to all the items detailed in the business plan, so that the extent to which its allowable returns have been met can be gauged.

Action Recommendation – Review and Revision of All Energy Supply Contracts that use the Natural Resources of Belize to reflect the Provisions of the Policy Recommendation Above

GOB should *immediately* conduct a review of all energy supply contracts and undertake to remove and/or modify all clauses that cause such contracts to be in contravention of the policy recommendation above. Particular attention is hereby drawn to one such clause that currently exists in the contracts for the supply of hydropower from BECOL. This clause states that Fortis/BECOL has the right of first refusal for all contemplated hydro developments along the Macal River and for that matter all other rivers of Belize, and is clearly a contravention of the spirit of the proposed requirement that ownership of Belize's natural resources should at all times remain vested in the People of Belize.

Promote Local Content in Indigenous Energy Projects

Maximize Local Benefit from and Local Control of Undertakings that process Belize's Indigenous Resources

The NEP Team recommends the adoption of the following measures in order to maximize the local benefit from and local control of undertakings that process Belize's natural resources for purposes of energy production or that may be used for energy production:

- Local suppliers must be given a fair opportunity to provide goods and services required for such projects and undertakings, and must not be subject to meeting stringent standards and specifications which are not normally required for the type of undertaking, or which foreign companies are not also required to meet. Under no circumstances should good or services be purchased directly from a foreign company without local companies having been given an opportunity to provide what is required, unless the operator of the undertaking can show in each instance that the goods or services cannot be procured locally.

- Where local producers of goods and services, regarded as critical inputs to the processes of one or more of the undertakings (referred to above), are unable to compete on price with foreign suppliers, the GOB should consider providing technical assistance or financial assistance in the form of tax breaks or other subsidies to such local producers (subject to the restrictions of international and regional covenants), which may help to make them more competitive with the foreign suppliers.
- GOB should require that priority be given to Belizean citizens when filling any of the employment positions in any such undertaking.
- Where no person of Belizean citizenship can be found to fill a management position or a position requiring specialist expertise or skills such as an engineering position, then provision must be made to train at least one person of Belizean citizenship to be able to assume the role and responsibilities of the position within a suitable timeframe and as a maximum within a period of 5 years.

Where no person of Belizean citizenship can be found to fill a position requiring skills that are deemed extremely critical to the continued efficient operation of the undertaking or without which the output or efficiency – and hence viability - of the operation may be severely impaired, then provision must be made to train at least two persons of Belizean citizenship to be able to assume the role and responsibilities of the position within a suitable timeframe and as a maximum within a period of 10 years.

Renewable Energy Development

Commission Natural Resource Use Planning Study

A natural resource inventory study should be commissioned under the direction of the Ministry of Natural Resources in order to catalog the types, quantities and locations of Belize’s natural resources both terrestrial and marine areas. The results of this study should be documented in a database such as a GIS and used to produce resource contour maps.

These resource contour maps should be used as the starting point for the formulation of a Natural Resource Use Policy, where all natural resources (including those already designated for particular purposes inc. nature reserves) are assessed for their possible uses and final designations are made for their use on the basis of the configuration that confers the greatest net benefit to the country over the long run subject to the projected needs.

The natural resources that have the best potential for a particular purpose – whether renewable energy production, agriculture, nature conservation or habitation - should therefore be demarcated and reserved for that purpose; unless it can be shown that an alternative use will provide greater net benefits to the country as a whole over the long run. Thus, in the very same way that land and marine areas are reserved for conservation of plant and animal species, natural resources should also be reserved for wind energy development or some other purpose.

Strengthen Existing Land Use Policy

Government should strengthen the existing Land Use Policy, based on the recommendations of the Natural Resource Use Planning Study, detailing the boundaries of portions of land and marine areas that are to be reserved for a particular purpose and the purpose of its future use. Any proposal or request to de-reserve a portion of land or that would use a portion of land set aside for a particular purpose under the Land Use Policy should require the authorization of the Ministry of Natural Resources acting on the advice of NEEPI.

Conduct Inventory of Energy Production Potential of Natural Resources

The NEEPI should immediately commission country-wide inventory of all our natural resources with a view to determining their energy production potential: These natural resources include land (for planting energy crops), agricultural and forestry residues, sea (ocean currents and tides), wind, sun, rivers, land marshes and peat lands, petroleum deposits and natural gas fields, underground geothermal reservoirs, and waste products from our activities. The main outputs of the study should be resource contour maps (covering the entire country of Belize, including offshore areas) showing the energy production potential of each of the natural resources in different locations.

The following projects should be given special priority as part of the inventory study:

Country-wide Wind Speed Mapping Project

The NEEPI should, in conjunction with the NMS, commission a wind speed mapping project encompassing all onshore and offshore areas in Belize. This project will entail setting up and monitoring wind speed gauges at selected locations over all areas of Belize to measure wind speed continuously. As this will be on-going, it should provide for organizational support for continuous monitoring and data collection (preferably via automatic electronic data transmission), maintenance of the gauges, as well as installing new gauges in new locations as required. The wind speed map of Belize so developed will be used to prepare the wind energy resource maps (for the 'Inventory of Energy Production Potential of Natural Resources' above) and will be useful for ranking and selecting the best sites for future wind energy projects.

Country-wide Hydrological Data Collection and Monitoring Project

The 2006 BECOL-commissioned Hydropower Potential Study identified a number of serious deficiencies and anomalies in the deployment and condition of stream gauges and pluviometers which had still not been rectified 18 years after they were first highlighted in the 1988 CIPower Study. In order to properly assess hydropower potential, optimize natural resource utilization and save on costs of over-designing or under-designing hydro power stations and associated structures, a reliable hydrological databank of river flow and pluviometric data must be put in place.

The NEEPI should, in conjunction with the NMS, commission a stream gauging and pluviometric data measurement project covering all rivers and catchment areas in Belize, particularly the catchment areas which have been identified, in preliminary studies, as possessing good hydropower development potential.

This project will entail strategically restoring abandoned stream gauging and pluviometric stations and setting up new ones at selected locations in order to capture data necessary to derive reliable flow duration curves, flood hydrographs and generally prepare a comprehensive hydrological database. As this will be an on-going project, it should provide for organizational support for continuous monitoring and data collection (preferably via automatic electronic data transmission), maintenance of the gauges, as well as installing new gauges in new locations as required. The hydrological database so developed will be used to prepare hydropower resource maps (for the 'Inventory of Energy Production Potential of Natural Resources' above) and will be useful for ranking and selecting the best sites for future hydropower projects.

Geological and Hydro-geological Inspection of the Most Promising Sites for Future Utility-Scale Hydropower Development

A geological and hydro-geological inspection of the most promising sites for future utility-scale hydropower development, specifically the Chalillo Site (upgrade), the Lower Macal River, the Mopan River, the Bladen and Swasey Rivers, and the Chiquibul Site should be done to determine if the geological properties of these sites are conducive to hydropower development.

Conduct Pre-Feasibility Assessment of Implementing GSHP-based Cooling for Buildings in Selected Urban Areas

GOB should undertake a pre-feasibility assessment of implementing GSHP-based cooling for buildings in selected urban areas.

The two most essential pre-requirements for embarking on any GSHP-based cooling/heating project is preparing a cooling/heating load profile based on projected weather conditions and doing a proper hydro-geological investigation of the terrain in which the GSHP system will be laid. While each GSHP-cooling project has to be evaluated on the basis of its particular attributes, a ballpark estimate of the amount of cooling (and heating) that will be needed for typical residential and commercial buildings can be derived using historical local temperature and humidity records. An estimate of the type(s), size(s) and cost of GSHP systems needed to meet these typical cooling loads can be determined by conducting a study of the thermal and hydro-geological properties of local terrain. These estimates can then serve as the basis for making a general assessment of the feasibility of implementing GSHP-based cooling in these areas.

GOB can then disseminate information aimed at prospective developers and design incentive programs based on the results of the pre-feasibility study.

Ensure Optimization of Indigenous Energy Conversion Processes

IPPs and others engaged in primary-to-secondary energy conversion need to be monitored to ensure that the process being used is the most efficient one for the given conditions. If, for example, there is a point along a river course that can potentially supply 30 MW of power at 85% capacity factor and an IPP sets up a plant that can produce only 20 MW at 70% capacity factor, then the entire country is cheated of an opportunity to extract more from our renewable natural resources. The parameters for what should be set up in a certain area must be pre-determined: a developer will then make proposals that meet the criteria.

The NEP Team recommends the adoption of the following measures in order to ensure the optimal utilization of the natural resources of Belize for purposes of energy production or that may be used for energy production:

- The NEEPI should require that the pre-feasibility or feasibility study of any project that exploits our natural resources includes an investigation into the expected output of the resource site using best available technologies and optimum project parameters compared with the expected output using the proposed technology and project parameters, and also a benefit-cost analysis of the optimum versus the proposed project. The results of the investigation and analysis should be reviewed by the NEEPI in order to determine if the project as proposed should be approved, assuming that it is feasible, or if an effort should be made to undertake a project with parameters that are closer to those of the optimum project.
- The NEEPI should regularly monitor the efficiency of the processes of any facility used to extract our natural resources or convert any natural resource into useful energy and require that the facility owner take the necessary steps to improve the efficiency of the processes if found to be below the currently-applicable required standard or benchmark. If a significant new technology improvement has become commercially available after the initial deployment of the project facility, the NEEPI will investigate the economic and technical feasibility of upgrading the facility with the new technology, and if found to be feasible, the facility owner will be required to upgrade the facility with the new technology.

Facilitate Renewable Energy Development Process

Demarcate and Designate Renewable Energy Zones

The NEEPI should be charged with the responsibility for demarcating and designating renewable energy zones throughout Belize. The starting point for circumscribing the boundaries of these zones will be the resource maps produced from a country-wide inventory of the energy production potential of Belize's natural resources. Updated maps of existing land and marine area reservations including highways, roads and boundaries of municipalities will be superimposed on these resource maps in order to come up with a final map designating the *best available sites* for renewable energy development with minimal environmental impact. **These renewable energy zones should be afforded the same protections, under law, which are currently given to nature reserves**.

Licenses should only be approved for renewable energy projects which are to be developed within the renewable energy zones. Such a map will be useful as a guide for potential investors who would normally have to spend an inordinate amount of time doing investigative research.

Promulgate Best Practices for Renewable Energy Projects

The NEP Team recommends that the NEEPI develop a set of best practices for different categories of renewable energy projects based on the renewable energy resource type, project size and other applicable parameters to serve as benchmarks and guides for potential renewable energy projects. These best practices can be formulated from surveys of the practices of other successful - and not-so-successful - projects within Belize, best practices recommended from industry bodies or touted by regional and world leaders in renewable energy deployments, and other relevant scientific reports.

These best practices should be updated on a regular basis (every five years or if a significant project success or failure has occurred) and made available to all potential renewable energy developers as guidelines to inform their own plans.

Facilitate Renewable Energy Project Development Process

The NEP Team recommends that the NEEPI setup a facility within its organization to provide full assistance to potential renewable energy developers from project idea and feasibility study, through acquiring the necessary financing, to final licensing by the relevant authority. This facility will provide information on relevant policies and the permitting process in general, give advice on best available sites for renewable energy development, and expedite the acquiring of necessary permits and licenses.

Introduce Transmission Network for Renewable Energy Development Credit Incentive

In order to further encourage the development of renewable energy projects, GOB should setup a Transmission Network Development Credit Incentive: giving a fixed amount of tax credit (to the NETSO) for every mile of transmission network that passes through any of the designated renewable energy zones.

Introduce Annual Renewable Energy Portfolio Standards for Each Renewable Energy Type

A renewable portfolio standard (RPS) requires that a certain amount or percentage of a utility’s power plant capacity or electricity sales come from renewable sources by a given date. RPSs encourage investment in new renewable electricity generation by guaranteeing a market for project outputs.

The NEP Team recommends that annual RPS targets for each renewable energy type (wind, solar, biomass, hydro) in the electricity sub-sector be formulated based on the requirements of the optimal long-term energy plan. These targets will be publicized by bulk purchasers of electricity and used as the basis for entering into long-term contracts for the supply of renewable electricity.

Introduce Annual Minimum Feed-In Tariffs for Each Renewable Energy Type

A feed-in tariff sets a long-term guaranteed payment for renewable electricity produced by providers of renewable energy. The NEP Team recommends that annual feed-in tariffs for each renewable energy type in each of the electricity consumption sector should be set based on the provisions of the optimal long-term energy plan. These targets will be publicized by bulk purchasers of electricity and used as the basis for entering into long-term contracts for the supply of renewable electricity.

Build Public Awareness and Acceptance of Renewable Energy Projects

Introduce Renewable Energy Technologies in School Curricula

“Education of the next generations in a way that … the need for cleaner energy becomes an integral part of their mindset can help to influence their future behavior (and maybe even that of their parents) and move us towards the desired cultural shift. One of the most effective ways to engage the interest of children in the energy agenda must be through interaction with new technologies. The installation of renewable technologies in schools can bring the curriculum to life in ways that textbooks cannot. With schools often being the focal point of communities, the installation of renewable could help to shape attitudes in the wider community”. (DTI, 2006)

The Government through the Ministry of Education should launch an annual Renewable Energy for Schools Program aimed at the primary school and high school levels. The program should entail the construction of small-scaled renewable energy projects by students to serve their school’s needs. Projects may be entered into a nation-wide competition where competing projects are given national coverage on radio and TV.

Setup Renewable Energy Projects for Demonstration and Educational Purposes

A number of small-scaled renewable energy projects should be developed for demonstration and educational purposes in order to build public awareness of the efficacy and environmental-friendliness of the technology in preparation for future commercial and utility-scale deployments.

The NEP Team recommends that an RD&D Section of the NEEPI be charged with planning, designing, developing, deploying, operating and maintaining such projects serving Government buildings, schools and villages. Arrangements should be made through the PUC to transfer such projects over the private entities at an appropriate time after RD&D objectives have been met.

Manage impacts of Indigenous Energy Projects on Local Communities

Promote Stakeholder Involvement and Information Sharing in Renewable Energy Projects built around Environmental Impact Assessment[172]

A full Environmental Impact Assessment for each new renewable energy project should be conducted, in conjunction with relevant Government departments, responsible environmental NGOs and other local organizations involved with the protection of wild life, and local and international environmental experts. In fact, these organizations should be involved from the early planning stages. Investigations carried out as part of these environmental impact studies must comply fully with the highest international standards, such as those issued by the World Bank.

A full disclosure policy should be adopted in discussing the possible impacts – both positive and negative – of all aspects of the project on the environment, tourism and the livelihood of local communities , particularly with the parties that could be most affected.

Institute Measures to Mitigate Visual and Environmental Impacts of Renewable Energy Projects on Local Communities

In order to reduce noise pollution and visual impacts from wind turbines and solar farms and towers, wind and solar energy projects should be sited at a suitable distance from the closest boundary point of any existing or planned community, unless such restriction is waived by a resolution of the local authority in charge of the community. Access paths for transmission line structures will also be considered as a part of the area designated for project development.

In the case of hydropower projects, visual impacts can be mitigated by encapsulating structures (such as switchyards), conducting water for diversion schemes through

[172] Adapted from recommendations made in 2006 BECOL-commissioned Hydropower Potential (Electrowatt Ekono - Energy Business Group, March 2006)

underground tunnels, and using cavern power houses. (Electrowatt Ekono - Energy Business Group, March 2006)

Establish Notice Periods and Compensation Scheme for Displacement and Lost Property Value due to Local Renewable Energy Projects

The NEP Team recommends that the PUC draft and, on approval, disseminate detailed policies on prior notification requirements, notice periods for evacuation from land designated for development in the public interest, and a compensation scheme for displacement and lost property value resulting from the siting of local renewable energy projects in the vicinity of communities.

Encourage Participation of Local Communities in Renewable Energy Projects

The NEP Team recommends the adoption of the following measures to encourage the participation and ownership of local communities in renewable energy projects:

- Where a renewable energy project is to be sited within or near to a particular community (or communities), then the project developer will be required to source as much of its unskilled labor requirement as possible from the particular community (or communities).
- At least 10% of the ordinary shares of the business vehicle carrying the renewable energy project should be made available to members of the local community in which the project is sited.
- At least 25% of the ordinary shares of the business vehicle carrying the renewable energy project should be made available to citizens of Belize as a whole.

Indigenous Petroleum

Apportion Petroleum Royalties to Areas That Could Be Most Negatively Affected by Petroleum Production-Related Activities

Government could build support for petroleum exploration and subsequent production activities by pledging allocation of a portion of petroleum royalties for use in areas that could be most negatively affected by petroleum-related activities as follows[173]:

- When production occurs onshore or in lakes or rivers:
  a) 50% to be committed to the Government for financing projects and paying obligations as it sees fit;
  b) 10% to the Ministry of Natural Resources and the Environment for financing programs supporting scientific research, technology development and capacity building applied to the petroleum industry;

[173] Adapted from (Regulation of the Petroleum Industry in Brazil, August 6, 1997)

c) 10% to be allocated to a special Environmental Risk Management and Oil Spill Mitigation Fund (ERMOSM) used for financing programs supporting scientific research, technology development and capacity building applied to environmental risk management and oil spill prevention and mitigation activities;

d) 15% to the Ministry of Tourism and the BTB for financing terrestrial infrastructure and capacity building projects;

e) 10% to be used for financing projects aimed in the district where the production occurs;

f) 5% to be used for financing projects in the municipalities where the production occurs.

- When production occurs offshore:

a) 40% to be committed to the Government for financing projects and paying obligations as it sees fit;

b) 10% to the Ministry of Natural Resources for financing programs supporting scientific research, technology development and capacity building applied to the petroleum industry;

c) 15% to be allocated to a special Environmental Risk Management and Oil Spill Mitigation Fund (ERMOSM) used for financing programs supporting scientific research, technology development and capacity building applied to environmental risk management and oil spill prevention and mitigation activities;

d) 15% to the Ministry of Tourism and the BTB for financing marine infrastructure and capacity building projects;

e) 20% to be used for financing projects in the district or caye fronting the area where the production occurs;

Earmark Local Crude Oil and its Products for International Markets

Locally-produced crude oil and any locally-refined oil products should be earmarked for international markets, with the exception of crude oil, HFO and diesel that can be used in the industrial sector. Promoting the sale of oil and oil products locally could potentially cause policy conflicts with the NEP Team's recommendations for reducing dependence on fossil fuels in general.

Maximize Processing of Associated Gas of Crude Oil Extraction

The "associated gas" of crude oil extraction is a significant natural resource that can be processed into useful hydrocarbons that can be used for electricity generation, food processing, cooling, transport and other industrial purposes, and so provide further benefits to the People of Belize. Presently, only a portion of this associated gas is further processed to produce natural gas for on-site electricity generation and LPG for sale; the rest is flared.

Government should commission the GPD to conduct a study of the potential for further processing of the associated gas from Belize’s current petroleum extraction operations into useful hydrocarbons (particularly for electricity generation, transport, cooking and for use as a refrigerant fluid for cooling) using best practice technologies and best available technologies, and to prepare a cost-benefit analysis of the various options available.

If one or more of the options are deemed feasible and profitable, then the concessionaire should be given the opportunity to pursue and develop the most profitable option for processing the “associated gas” to the extent possible, otherwise the Government should pursue the opportunity on its own or in the way it sees fit to do. This provision should be reflected in all existing and future concession contracts.

Investigate Potential of Electricity Production from Associated Waste Hot Water of Crude Oil Extraction and from Abandoned Oil Wells

The waste hot water produced as a by-product of petroleum extraction may be used to produce electricity via a process called *Binary Cycle Power Generation*, or directly in industries sited nearby. The NEEPI in conjunction with the GPD should investigate the potential for electricity production using this technology at our current petroleum extraction site at Spanish Lookout. If deemed feasible and profitable, then the concessionaire should be given the opportunity to pursue and develop the most profitable option for processing waste hot water for electricity production or other industrial use to the extent possible; otherwise the Government should pursue the opportunity on its own or in the way it sees fit to do. This provision should be reflected in all existing and future concession contracts.

Enact Legislation to ensure that Government Royalties should be tied to Full Production Potential of the Petroleum Production Site

The calculation of the total royalties attributable to the GOB should be based on the full production potential of the extracted petroleum resources using best practice technologies applicable to the particular petroleum production site. On-site usage and resource losses - such as flaring of associated gas - that exceed industry benchmarks applicable to the site, given its characteristics and the nature of its operations, should be counted in this production potential. Current legislation should be updated to reflect this principle.

Investigate how and how much Unrefined Oil is used locally

Crude oil is sold on the local market and used – without further processing – mainly as a substitute for bunker fuel in boilers by sugar processors, citrus processors, rum distilleries, aquaculture farms, and poultry and meat processors, as well as for electricity generation by Farmers Light and Power Company (FLPC) in Spanish Lookout in the Cayo District. There are reports that crude oil is also being used directly in heavy-duty vehicles as a substitute for diesel.

The NEEPI in conjunction with the DOE should conduct an investigation into how crude oil is used on the local market and the extent to which it is being used as a substitute for refined petroleum products in vehicles, motors and generators, and perform further research and analysis to determine what effects this may have on engines and motors in which it is used. Follow-up action should be taken on the basis of the results of this investigation and analysis.

Limit extent of GOB's Support for Building of Local Refineries

Government may support any business initiative to setup a refinery in Belize for the purposes of refining crude oil provided that the developers demonstrate a sound financially-viable business plan and that the target market does not include local transport vehicles and electricity generation. The latter condition is necessary to prevent possible policy conflicts with the NEP Team's recommendations for reducing dependence on fossil fuels in transport and other electricity generation and for transforming the vehicle fleet to use bio-fuels and electricity.

Demarcate an Offshore No-Drill Zone with Barrier Reef as Center-line

An offshore no-drill zone should be demarcated to maintain the barrier reef and cayes at a sufficiently "safe" distance from any offshore oil drilling rigs in order to mitigate the visual impacts of oil rigs on the natural seascape in the area of the barrier reef and cayes and to reduce the probability of the spread of effluent from potential oil spills into these areas.

Formulate a National Petroleum Safety and Oil Spill Mitigation Standard

A National Petroleum Safety and Oil Spill Mitigation Standard should be formulated to guide action to prevent and mitigate the impacts of oil spills, accidents and other environmental disasters, and should reflect the latest post-Gulf of Mexico Oil Spill mandates put into effect by the USA. The standard should provide for the following[174]:

- Operators will be required to prepare an Internal Procedures Manual for the management of oil spill and pollution risks;

[174] Informed to a large extent by (Bezerra de Souza Jr, Lèbre La Rovere, Blajberg Schaffel, & Barboza Mariano)

- Operators will be required to prepare individual emergency plans for combating oil spills and pollution and the release of other harmful and dangerous substances; and for getting approval for the plans from the National Petroleum Safety and Oil Spill Mitigation Authority;
- Clear guidelines for an Operator to notify the National Petroleum Safety and Oil Spill Mitigation Authority and the National Coast Guard of any incident which might cause water pollution or negatively impact the environment or affect the safety of sea-faring vessels or persons in the area;
- Clear guidelines for the National Petroleum Safety and Oil Spill Mitigation Authority to put its Spill Mitigation and Containment Emergency Response Plan into action;
- Proposed exploration plans must demonstrate that the operator has the contingency plans in place – and the capacity to implement those plans - to respond to a potential blowout and the potential worst-case discharge scenario.
- Operators will be required to develop a comprehensive management program for identifying, addressing and managing operational safety and environmental hazards and impacts, with the goal of reducing the risk of human error and improving workplace safety and environmental protection.
- Operators must adhere to the latest US standards for blowout preventers, well design, casing, cementing, and safety equipment. Blowout preventers must also meet new US standards for testing and must be independently certified.
- The Board of Directors and CEOs of drilling companies will be required to certify that their rigs comply with all safety and environmental laws and regulations, and should bear personal consequences for providing knowingly false or erroneous or unsubstantiated information.

Form a National Petroleum Safety and Oil Spill Mitigation Authority

A National Petroleum Safety and Oil Spill Mitigation Authority should be setup with responsibility for enforcing adherence by all operators to the National Petroleum Safety and Oil Spill Mitigation Standard and for formulating, directing and coordinating the Spill Mitigation and Containment Emergency Response Plan. This body should be adequately staffed with competent and experienced personnel with specific expertise in petroleum safety, oil spill mitigation in general and offshore oil spill mitigation in particular, disaster management, and emergency response planning.

Biofuels

"A policy initiative for bio-energy is most effective when it is part of a long-term vision that builds on specific national or regional characteristics and strengths, e.g. in terms of existing or potential biomass feedstocks available, specific features

of the industrial and energy sector, and the infrastructure and trade context.” (WEC, 2010)

Pursue Biofuels Development within Broader National Development Context

Following in the footsteps of other developing countries, Belize should develop its biofuels industry to contribute to larger environmental and social objectives such as rural development, land rehabilitation and waste treatment apart from GHG emissions reduction. Biofuels development initiatives that target the use of semi-arid soils and other marginal lands should be promoted to enhance biodiversity, revitalize natural ecosystems, support the development of rural populations in poorer regions, and hence maximize the efficiency of the utilization of our natural resources.

Promulgate National Biofuel Product Standards

Biofuels standards are needed to ensure that biofuels can be blended with petro-fuels to meet current fuel blend specifications and also to assure compatibility with future designs of engines in which they can be used. Moreover, the lack of comprehensive and generally adopted international standards is one of the most important factors currently limiting the development of regional and global biofuels markets. International standards are important because they will help in assuring local producers that their biofuel exports will be accepted in international markets while simultaneously allowing room for imports from countries that can provide low-priced quality biofuels. These international standards cover not only technical specifications of the product but the environmental and labor standards of the production processes (Domingos Padula & Boeira, November 26-28, 2009).

As a first step toward creating a viable market for biofuels in Belize, the NEEPI should prepare a set of biofuel standards for the major classes of biofuels, bio-ethanol and bio-diesel, as well as standards for feedstock inputs into biofuel production. The development of these standards should be guided by international and regional standards such as those currently being prepared by the ISO. The enforcement of these standards will have to be underpinned by proper certification procedures with a supporting cast of technology and technical expertise to conduct compliance testing.

The GOB should use its vote and influence in international and regional associations to lobby for the adoption of a common set of biofuels standards world-wide.

Develop the Biofuels Industry along the lines of the Most Efficient Bio-Energy Chains

Bio-energy routes that substitute fossil fuels by generating heat and electricity from residues and wastes are - by a large and significant margin - more efficient than those that substitute gasoline and diesel for transport (e.g. cellulosic ethanol). The former rely on proven commercial technologies, thus leading to a better utilization of raw materials, and "result in clear GHG savings and possibly other emission reductions compared to fossil fuels" (WEC, 2010). However, while there are many other renewable energy options available for electricity and heat generation, biofuels are the only currently-available alternatives to fossil fuels used in the Transport Sector.

In keeping with long-term energy supply development plans, the Government should focus on using biomass residues, including bagasse and other agricultural and forestry wastes (except wood fuel), for electricity generation, sugar cane for ethanol production, and jatropha, other local oil-producing plants and , in the future, alga-culture for biodiesel production.

Ethanol production should be focused on supplying the local blended fuel market, for use in the transesterification process of local biodiesel production, and for export to the USA and Europe. Given our comparative advantages in biomass-based electricity generation and biodiesel production, these bio-energy chains should be optimized for sufficing local requirements and for export.

Promulgate Biofuel Production Technologies that cater to Multiple Feedstocks and Small Scale Deployment

The NEEPI should promote the deployment of advanced technologies such as multiproduct bio-refineries that allow for feedstock flexibility using non-food crops with minimal environmental and social risks, and lower GHG emissions; and technologies with improved economics at a smaller scale to allow for more distributed use of biomass.

Conduct a Cost-Benefit Analysis of Upgrading BSI's Refinery Infrastructure for Dual Sugar/Ethanol Production

The NEEPI should undertake a cost-benefit analysis of upgrading BSI's sugar refinery infrastructure to accommodate dual sugar/ethanol production, similar to the strategic production philosophy utilized in Brazil, where revenues are maximized by tweaking the production processes to produce more or less sugar versus ethanol in any year in accordance with the fluctuations in their relative prices[175].

This analysis must necessarily weigh the benefits of product diversification given uncertain future market conditions, especially as production volumes grow, versus the incremental costs of providing dual sugar/ethanol production capability, including

[175] Apparently such a plan had been proposed to Government in the past by Sir Barry Bowen, the late owner of Belize Brewing Company and a number of local business ventures. However, it was deemed prohibitive because of the financial commitments that would have been required of the Government at the time. (Source: Informal Interview in September 2011 with Mr. Hugh O'Brien, former CEO of Ministry of National Development 2004-2008).

capital costs of retrofitting and expanding the current refinery infrastructure and the additional operations and maintenance expenses that would be incurred.

Conduct Market Research of Viability of Regional Biofuels Export Market

The NEEPI in conjunction with BELTRAIDE should commission a market research into the viability exporting locally-produced biofuels into regional markets (especially border town markets). The study should identify the biofuels product performance standards approved for or in effect in these markets, and investigate the trade and tax policies and legislations of these territories that enable or hinder the development of the market as well as the pricing policies of competing energy products.

Private sector stakeholders that are actively involved in the local market should be invited to participate and help fund this market research.

Promote Sustainable Biofuels Production Practices

Different types of biofuels as well as different production technologies for the same biofuel have different sustainability challenges and can result in different overall energy efficiencies. In order to maximize sustainable biofuel production potential, the NEEPI should commission a study to do the following:

a) Identify the right place for biofuel production in the agricultural economy - for example, whether to produce bio-ethanol directly from sugar cane or from the bagasse produced as a by-product of sugar cane processing, or whether to produce bio-diesel from new vegetable oil or waste vegetable oil.

b) Determine the choices of the actual types - whether to produce bio-ethanol from sugar cane or corn (maize) - and the maximum producible amounts of each type to avoid sustainability conflicts.

c) Determine the applicable bio-fuel-to-energy paths and technology mix that should be deployed, taking into consideration the development stage of each of the technologies.

Furthermore, feasibility studies of all biofuel projects should be required to include an evaluation of the sustainability of all activities involved in the biofuel production process, particularly the production of the raw materials (feedstocks) used, in order to ensure that biofuels development does not occur in areas where it competes with agricultural ecosystems for basic resources such as soil, water and air or where it negatively affects biodiversity.

Promote Local Biofuels Research

The Government should actively promote and support research into ways to improve the productivity and sustainability of biofuel feedstocks: by seeking improved yields from conventional feedstocks through better agricultural and forestry practices, by exploring the potential for cultivation of native perennial ligno-cellulosic crops (e.g.

jatropha) throughout the districts, and by developing breeding programs for higher-yielding species and novel energy crops, such as algae.

Belize, through the Ministry of Agriculture, UB and the TSDF, is already party to a 2009 Memorandum of Understanding signed with Mexico, the rest of Central America, Colombia, and the Dominican Republic for further collaboration and research in the biofuels field[176]. The GOB is strongly encouraged to use this platform as a launch pad to start up an International Biofuels Research Center within the University of Belize, in conjunction with the National Coordination Committee for Agricultural Research and Development (NCCARD), to attract the inflow of international funding, best available technologies and technical expertise into Belize.

Seek Technical Assistance for Biofuels Industry Development from Industry Leaders

The Government should initiate a National Biofuels Industry and Market Development Program with technical assistance and guidance from the world industry leaders, Brazil and the USA. Brazil is the world's most efficient bio-ethanol producer and has been actively engaging in "bio-ethanol diplomacy" with neighboring countries - Colombia, Peru, Panama, Argentina, and Venezuela - through technology cooperation and information exchange agreements. The USA is a world technology leader especially in the more advanced biomass-to-liquids production technologies.

Encourage Private Sector Participation in Biofuels Industry Development

The GOB should encourage private sector investment into commercial scale production of biofuels for proven technologies (e.g. bio-ethanol from sugar cane and bio-diesel production from Jatropha and other oil-producing plants), including setting up transparent incentive systems for scaling-up from pilot to demonstration to commercial scale. In this regard, the GOB must be mindful of the deleterious effect that early failures may have on the nascent industry, and become involved as early as possible to ensure a high probability of meeting project objectives. In fact, GOB is advised to withhold permission for any proposed biofuel development business venture until it is fully convinced of the viability of the business plan, the resourcefulness of the management team, and the credibility of the project financiers.

Encourage Public-Private Investment Partnerships to support Smallholder Participation in Biofuel Value Chains

The GOB should encourage public-private sector investment partnerships in the commercial scale production of biofuels in order to facilitate smallholder participation

[176] First Meeting of the Biofuels Research and Development Network of the Mesoamerican Project (Primera Reunión de la Red Mesoamericana de Investigación y Desarrollo en Biocombustibles) held from 23-27 August, 2009, in Tuxtla-Gutierrez, Chiapas, México.

as much as possible in biofuel value chains. This may be mandated by requiring that say 20% of the shareholdings in such partnerships are open to take up by such smallholders.

Distribute Biofuels through Existing Fuel Supply Infrastructure

A study should be conducted to work out the logistical arrangements that must be setup to facilitate the transfer of biofuels from factory to ports (for export) or to local depots (for eventual transfer to ports or distribution to retailers), and determine the extent and cost of modifications that will have to be made to the existing fuel supply infrastructure – storage tanks, pipelines, carriers – to accommodate the handling, storage, and transportation of biofuels in keeping with applicable safety and environmental compliance standards.

Introduce Annual Renewable Fuel Standards for Each Biofuel Type

A renewable fuel standard (RFS) requires that a certain amount or percentage of the transport fuel mix be supplied from biofuel sources by a given date. RFSs encourage investment in biofuel production by guaranteeing a market for project outputs.

The NEP Team recommends that annual RFS targets for each biofuel type (bio-ethanol and bio-diesel) in the transport and electricity sub-sectors be formulated based on the requirements of the optimal long-term energy plan. These targets will be publicized by bulk purchasers of fuel and electricity and used as the basis for entering into long-term contracts for the supply of bio-fuels.

Introduce Annual Minimum Feed-In Tariffs for Each Biofuel Type

A biofuel feed-in tariff sets a long-term guaranteed payment for a particular biofuel type. The NEP Team recommends that annual feed-in tariffs for each biofuel type in each of the renewable energy consumption sectors (electricity and transport) should be set based on the provisions of the optimal long-term energy plan. These targets will be publicized by bulk purchasers of fuel and electricity and used as the basis for entering into long-term contracts for the supply of bio-fuels.

Micro-Generation

Commission Study on Impacts of Micro-Generation on Grid Electricity Supply Operation, Reliability and Cost

The NEP Team recommends that the NEEPI commission a study on the predicted impacts that connected micro-generation would have on the operation and reliability (including power quality) of the grid electricity supply system and on system costs.

One of the important required outputs of this study should be a proposed Balancing and Settlement System between the electricity provider(s) and micro-generators which determines pricing arrangements and also defines the recommended transactional arrangements between the electricity provider(s) and micro-generators, including requirements for submission of production and demand forecasts (of micro-generators) in advance, that would help to reduce any negative impacts of connecting multiple small variable and distributed generation sources.

Another important required output should be how to incorporate micro-generation sources and capacities into short-term, medium-term and long-term plans in order to optimize system cost and system reliability.

Evaluate Different Energy Buyback Metering Modes

The NEP Team recommends that the PUC conduct consultations amongst energy stakeholders, including a wide cross-section of consumers, DAOs, the NETSO and Government, to determine the underlying metering arrangements that are to be used for energy buyback with different categories of consumers. This may be done as part of the study recommended above.

Establish Formal Energy Buyback Pricing and Payment Scheme for Micro-Generation

The NEP Team recommends the adoption of two pricing schemes for energy buyback from micro-generation sources:

- Micro-generation from residential premises that have a maximum power output up to 200 KW should be priced on the basis of a basic net metering-based energy buyback scheme.
- Pricing for micro-generation from sources with a maximum power output above 200 KW should be based on a gross metering (two-meter) arrangement, where the total quantity of energy exported can be tracked separately. The applicable price should be calculated *on a monthly basis* as the NETSO’s average actual marginal cost of energy supply in the month in which the buyback took place. The price then will only be determinable after the end of the month in which the energy buyback occurred. The payment is calculated as the price so determined multiplied by the total quantity exported or whatever applicable formula underlies the agreement between the electricity provider and the micro-generator.

  The NETSO will therefore be required to publish (as public information) its average monthly marginal cost of energy supply at the end of each month and preferably before energy buyback payments are calculated.

  In order to make the energy buyback compensation scheme as efficient as possible, payments are to be made against the customer’s electricity account. A customer may request payment of the net amount outstanding on his electricity account that is to be made *once per year* immediately after the end of each year.

Action Recommendation – Preparation for Micro-Generation: Setting up of a Micro-Generation for Interconnection Pilot Program (M-GIPP)

The NEP Team recommends the setting up of a *Micro-Generation for Interconnection Pilot Program* (M-GIPP) under the direction and supervision of the PUC. This program should be planned, directed and supervised by the NEEPI, in conjunction with the PUC. The TOR for the program is to test how micro-generation *would* work in a real setting and come up with a proposal for how it *should* work. The program will be conducted in two sequential testing phases and a parallel consultation phase, with the lessons from the first testing phase applied to the second testing phase. In the first testing phase, micro-generators will produce for own consumption only: no electricity will be exported to the grid. In the second phase, the connections of some of the already-connected micro-generators will be upgraded to facilitate export to the grid *plus* a new set of micro-generators will be connected to the grid directly and will be able to immediately export micro-generated electricity and use it for their own consumption.

Data and information on all aspects of related activities undertaken by the micro-generator and all transactions between the micro-generator and the electricity service provider will be collected, as well as meter readings (power and demand) of the electricity generated, consumed and exported. This data will be compiled and collated with information from the focus groups, surveys and interviews gathered during the consultation phase, and used to inform the formulation of a comprehensive set of standards for the interconnection of micro-generation sources to the electric grid as well as accompanying energy buyback rules.

Formulate Interconnection Standards for Micro-Generation Sources

The NEP Team recommends that the PUC draft and, *after taking into account the findings of the M-GIPP (discussed above) and other consultations amongst relevant stakeholders*, approve detailed standards that set out the pre-requisites for grid interconnection and the administrative and technical procedures for installing, testing, operating (including handling emergency situations), maintaining, inspecting and de-commissioning the grid connection to a micro-generation source within the premises of a consumer – such as a house or building with solar panels - to the electric grid.

These pre-requisites should clearly distinguish between a micro-generation source and an ESP (in terms of maximum power output); stipulate the acceptable technologies and fuel sources for micro-generation; delineate the grid boundary; detail the specifications of micro-generation equipment, including associated protection; specify the electrical design and layout of the required connection linking the micro-generation source and the consumer’s premises to the grid, including the design of protective and metering circuits; provide the specifications for all materials, equipments and devices that may be used for linking the micro-generation source and the consumer’s premises with the grid, including materials, equipments and devices that may be used for the protective and metering circuits, as well as the specifications for the housing of the connection equipment.

The technical procedures of the standard should include procedures for installation of the micro-generation source(s); procedures for connecting the micro-generation source and the consumer's premises to the grid, including installation of protective equipment and meters; procedures for testing the micro-generation source and the connection, separately and as a combined unit; procedures for operating and maintaining the connection in a safe and efficient manner, including handling emergency situations; procedures for inspecting the connection and the connected micro-generation source to ensure on-going compliance with the articulated technical standards; and procedures for de-commissioning the connection between the grid and the micro-generation source and the consumer's premises. These procedures should stipulate the minimum competency level and required technical certification of persons authorized to engage in installing, operating and maintaining micro-generation equipment and grid connections.

The administrative procedures must clearly state the exact chronology of actions to be taken and approvals necessary to connect a micro-generation source and the consumer's premises to the grid, to operate and maintain as well as de-commission the connection, to handle emergency situations, and for the PUC or authorized third-party to inspect the connection for on-going compliance with the published technical standards. These procedures must also clearly delineate the boundaries of responsibility and liability between the parties involved.

Institute Safety and Environmental Standards for Micro-Generation Sources

There are a number of negative environmental impacts and safety concerns associated with the deployment of micro-generation sources in urban settings in general and residential neighborhoods specifically: negative visual impacts; high noise levels (of wind turbines); increased risk of lightning strikes; and other dangers associated with having tall, protruding, unplanned-for structures atop rooftops and near other residences especially in areas prone to severe weather due to tropical cyclones.

BEECs and other building permitting standards should be formulated to regulate the installation of such structures atop or on buildings, whether for new buildings or as retrofits. These standards should stipulate maximum heights of structures, minimum clearances from other nearby structures, and minimum requirements for proper grounding of structures to protect against lightning strikes, adequate shielding from and reinforcement to bolster against wind gusts associated with severe weather events, and provisions for hiding structures from view.

These standards may be incorporated into the interconnection standards proposed just above, or maintained separately depending on the overall permitting process path chosen.

Delineate Ownership and Responsibility for Installing, Maintaining and Testing of Meters

The meter(s) used for grid interconnection for micro-generation will be the property of the electricity provider. The electricity provider will be responsible for installing and maintaining the meter and for testing and calibrating it at regular intervals; and shall bear all costs of doing so. The micro-generator will have the right to be present during testing and calibration, and may also request that tests be carried out to verify the accuracy of the meter. Such tests will be carried out in the presence of the provider, and the micro-generator shall bear all related costs of such verification tests. The electricity provider will be afforded the necessary facilities at the customer's premises to provide for remote querying of the meter.

Establish Energy Buyback Rules

The NEP Team recommends that the PUC draft and, after consultations with the relevant energy stakeholders, implement *Energy Buyback Rules* to underpin agreements for energy buyback between electricity providers and micro-generators and that are based on the following principles:

- Whether electricity export to the grid (energy buyback) is allowed or not allowed for a particular micro-generator can be set by the electricity provider and automatically enforced at the connection point.
- The maximum possible *power* output to the grid by a particular micro-generator can be set by the electricity provider and automatically enforced at the connection point.
- The maximum *energy* output to the grid over a particular period of time (a month or year) by a particular micro-generator can be set by the electricity provider and automatically enforced at the connection point, or the micro-generator may agree that the electricity provider will not be required to pay for energy exported in excess of the *maximum energy output* limit.
- *For Energy Buyback using Net Metering*: How net excess energy accumulated at the end of a period (month or year) is handled can be set by the electricity provider according to its agreement with the micro-generator. The parties can agree whether excess net energy can be carried over from month to month (or year to year), or whether the micro-generator receives a credit on his electricity bill for the excess energy exported, or if the excess energy is lost (meaning the customer is forced to manage export to the grid so that it is never greater than a net of zero at the end of each month or year). In the latter case, export to the grid is allowed within each period, but it must be balanced off to zero – with an equal amount of imports - within the same period.

  Meters used for Net Metering should be configurable so as to accommodate energy buyback rules. The electricity provider will have the sole responsibility and authority to configure meters. This should be done in accordance with the terms of the agreement between the electricity provider and the micro-generator. The micro-generator will have the right to be present during configuration.

Energy Imports and Exports

Electricity Imports

Action Recommendation – Investigation of the Technical and Economic Feasibility of Upgrading the Interconnection with Mexico

BEL is currently unable to take more than 50 MW of power from Mexico without experiencing voltage regulation problems at certain load center bus bars. CFE has indicated that it is prepared to supply up to 60 MW to Belize as long as certain power flow conditions are met.

The NEP Team recommends that BEL urgently look into the technical and economic feasibility of making the necessary transmission system upgrades to overcome these problems so that full advantage can be taken of the supply from CFE.

Limit Dependence on Foreign Electricity Imports

Limit Maximum Amount of Total Foreign Electricity Imports

The Government should limit the maximum amount of foreign electricity imports in terms of energy that can be purchased in each year. This limit should be set on the advice from the NEEPI. The NETSO must submit a special request to the Government to purchase imported electricity beyond this limit.

Limit Maximum Term of Contracts for the Import of Electricity

The Government should limit the maximum term of contracts for electricity imports so as to ensure that local supply sources are not shut out for extended periods of time. This limit should be set on the advice from the NEEPI. The NETSO must submit a special request to the Government to enter into contracts to purchase imported electricity beyond this maximum term.

Electricity Exports

URGENT Action Recommendation – Seek Membership or Direct Involvement in SIEPAC

BEL and the GOB should vigorously pursue membership or direct involvement in SIEPAC as a long term measure in order to enhance the security of electricity supply but *more importantly* to be in a position to sell energy to the SIEPAC market in the future.

In the short-term, access to the SIEPAC market can be arranged by supplying excess energy to Mexico and/or Guatemala. The GOB and BEL should immediately pursue this opportunity by writing a formal letter to CFE asking if this arrangement (with Mexico) can be setup. **This action is critical to the development of an electricity-for-export industry**.

Limit Participation in Contracts to export Electricity to ESPs only

Only authorized ESPs should be allowed to enter into contracts with foreign entities to export electricity. The authorization to enter into such contracts should be conferred as a special provision of the terms and conditions of the license of the particular ESP at the request of the ESP and must be approved by the GOB acting on the advice of both the NEEPI and the PUC.

All other non-authorized ESPs and all DAOs and SLCs should be expressly excluded from participating in such contracts with foreign entities to export electricity. The NETSO can be a party to such a contract only to extent that it is required to provide facilities for transmission of the power and associated energy from the ESP to the connection point with the foreign entity.

Require GOB's Approval to enter into Contracts to export Electricity

The Government should require that all contracts for the export of electricity – whether written or unwritten – must be approved by the Government before being enacted.

Establish formal basis for Pricing of Electricity Exports

The Government should mandate that the price of electricity sold as exports under contracts, other than spot price contract arrangements, must be set to enable the recovery *as a minimum* of the full long run marginal costs of the energy supplied over the term of the contract inclusive of all relevant transmission and system usage costs. Termination clauses of such contracts should provide for recovery of the unrecovered amount up to the time of the contract termination if the full term of the contract has not expired.

The price of electricity exported under spot price contracts should be set no lower than the short-term marginal cost of the energy supply including any relevant transmission and system usage costs.

Action Recommendation – Definition of Temporary State of Emergency due to Persistent Unforeseen In-country Shortages of Electricity

The Government should require the PUC to determine the parameters of the condition that would constitute a temporary state of emergency due to persistent in-country shortages of electricity so that this can be used as the technical benchmark for the decision to declare a Temporary State of Emergency due to Persistent Unforeseen In-country Shortages of Electricity in Belize.

Include a Declaration by the Government of Belize of a Temporary State of Emergency due to Persistent Unforeseen In-country Shortages of Electricity as a Condition of Force Majeure in Contracts for the Export of Electricity

The GOB should require that all contracts for the export of electricity on a firm power or firm energy basis include a provision that a Declaration by the Government of Belize of a Temporary State of Emergency due to Persistent Unforeseen In-country Shortages of Electricity in Belize should be treated as a condition of force majeure in such contracts.

Energy Distribution Infrastructure & Pricing

Electricity Distribution Infrastructure

Transmission & Distribution Lines

Revise Transmission Line Construction and O&M Standards

In anticipation of and in preparation for further connection of the NETS with regional electricity transmission networks to accommodate electricity importation and exportation transactions with regional partners, the NEP Team recommends that the construction and O&M standards of the NETS be set as a minimum to meet the regional standards of Mexico and the rest of Central America.

Formulate plans for the Transition to a Smart Grid Electricity System

In order to facilitate and foster grid connection of utility-scaled renewable energy sources such as wind and solar energy plants and micro-generation sources in general, the NEEPI should conduct a feasibility study of overlaying a smart grid system on top of the national electricity system. This study should chart alternative transition paths for upgrading from the existing electricity network to a fully-covered smart grid system and to assess the requirements and costs of these upgrades.

The smart grid system should ultimately be capable of controlling the level of output from connected sources (from utility-scale sources to micro-generation sources) as well as the load levels from connected sinks (from SLCs to individual households to a separate individual circuit or electrical appliance within a household) in order to manage supply and demand as cost-efficiently as possible.

Prepare an Updated Transmission Grid Code to accommodate Variable Power and Micro-Generation Sources

Transmission Grid Codes stipulate what is required of power plants when connected to the transmission system, such as voltage control, frequency control and low-voltage and fault ride-through capabilities. Given the variable nature of wind and to a lesser extent solar plants, the existing transmission grid code will have to be revised and updated to cater for the new system dynamics that can potentially be introduced by the addition of these types of power sources.

Rural Electrification

“The design of subsidy-oriented social policy must be guaranteed in the long term and not distort market performance… Any benefits should not be seen as a right but as a privilege, subject to a specific circumstance.” (WEC, 2010)

Rural electrification is usually undertaken as part of a Government initiative to improve the standard of living and productivity in certain rural areas of the country that are deemed as under-developed, and primarily so because of a lack of access to modern technologies and modern forms of energy. Government’s intervention is usually required because energy service providers cannot usually justify the investments needed for rural electrification on the basis of electricity revenues at prevailing electricity rates. More importantly, Government can use the opportunity to influence the path towards modern energy supply development and energy end use behaviors at an early stage in the birth of rural communities.

Demarcate and Declare Rural or Low-Energy Density Distribution Areas

The NEP Team recommends that the PUC be charged with the responsibility for demarcating and declaring the boundaries of a particular Rural or Low Energy-Density Distribution Area (ROLEDA), at the request of the GOB and subject to it meeting certain pre-conditions set out by the PUC. Once an area is so declared, it is subject to rural standards for energy supply and distribution; and is eligible for certain special funding, subsidies and tariffs applicable to ROLEDAs.

The PUC is responsible for upgrading a ROLEDA to normal DA status. The decision to do so should be based on the parameters used for classification of an area as a ROLEDA, and made only after approval from the Government

Formulate Separate Rural Electricity Distribution Standards

The NEP Team recommends that the PUC prepare a separate set of technical standards for the construction of electricity distribution lines in ROLEDAs, which minimize the cost of construction while maintaining adequate service reliability concomitant with the purposes of electricity use in such areas.

Setup a Special Rural Electricity Pricing Mechanism

A special tariff schedule for electricity service to ROLEDAs should be formulated. DAOs will be required to incorporate these tariffs into their overall pricing schemes. The GOB should be required to pay the difference between the revenues from such tariffs and the actual cost of service directly to the affected DAOs.

A customer should *not* be automatically eligible for having the rural electricity tariff applied to his account simply by virtue of residing or operating within a ROLEDA. Parameters (to be assessed over a year) should be set for the applicability of Rural Electricity Tariffs to a particular consumer. Each customer account with Rural Electricity Tariff should be reviewable once per year in order to determine if it meets the parameters set and if such tariffs are therefore still applicable.

Influence pattern of development of Rural Energy Services to maximize use of renewable energy-based community-managed distributed generation sources

Initial energy supply for ROLEDAs should, where possible and as much as possible, be provided from renewable energy-based community-managed distributed generation sources such as mini-wind turbines and mini-hydro plants. This energy can be used to generate electricity and/or used directly to pump water and drive equipment motors. Lighting and heating should, where technically and economically feasible, be provided via solar technologies. Grid supply should be used for back-up purposes only, and sold to the ROLEDA by the closest DA at the special high-voltage customer rate.

At the time when a ROLEDA is upgraded to a DA, the supply from the distributed generation sources should be upgraded into energy buyback contracts with the relevant DAO.

Energy Pricing

Electricity Pricing

Action Recommendation – Derivation of Formulae for Calculating the Long Run Marginal Cost and Short Run Marginal Cost of Electricity Supply

The long run marginal cost (LRMC) and the short run marginal cost (SRMC) of electricity supply are important reference points for price setting of electricity tariffs.

A study should be undertaken to derive formulae, and to develop a software tool that uses the formulae, for calculating the LRMC and the SRMC of electricity supply. In each case, the marginal cost is to be broken down into its components: generation (energy supply), transmission and distribution; and separate marginal cost formulae are to be derived for each of the different categories of consumers: DAs, SLCs, foreign entities, and end-use consumers within each DA (Residential, Commercial, and Industrial).

The formulae (and accompanying software tool) should provide for estimation of marginal cost under different scenarios of fuel prices, hydrological conditions, mix of supply technologies etc.; by year (of the energy plan), month of year, day of week and time of day. A separate set of formulae should also be derived for the marginal cost of supply due to micro-generation, with provision for calculating the marginal cost using different micro-generation technologies and different supply arrangements.

Action Recommendation – Proposed Study of Consumer Electricity Tariff-Setting Methodology

A study should be undertaken to investigate and assess the current electricity tariff-setting methodology employed by the PUC and to come up with a new methodology that removes price distortions and that reflects the following principles:

- The tariffs should fully reflect *all economic costs* of providing the service.
- Tariffs must be *forward-looking* and so based on the *least cost* that *it would take* to provide the service during the time it is being provided assuming the service provider were starting from scratch. In this regard, the NEP team recommends the study consider the adoption of the LRMC as the basis for determining such costs.
- Efficient use of electricity should be promoted. In particular, the goal is to encourage reduced consumption during the peak period of power demand, which will help reduce generation, transmission and distribution investments in the long run.
- Service providers must be allowed to recover expenses incurred and investment outlays and make a fair return on investment in order to ensure their viability and enable future expansion of their operations.
- Fairness and equal treatment should be promoted by eliminating as much as possible cross subsidization from one consumer category to another. The tariffs should reflect the true cost of service to each consumer category. *Where the GOB mandates a certain schedule of tariffs for a certain class of consumers, such as Social Tariffs, which would result in that class of consumers paying at rates below their true cost of service, GOB should be required to pay the difference directly to the affected DAOs*.
- Prices should be fairly stable and should not fluctuate substantially from year to year.
- The tariffs should be flexible and adaptable to structural changes in underlying costs such as fuel prices and other exogenous costs.
- The tariff structure should be transparent and simple so that consumers may be able to easily understand the implications of their consumption behaviors.

Introduce Special Electricity Tariffs for SLCs

In keeping with the principles of cost reflexivity and fairness, electricity tariffs charged to SLCs, who are connected directly to the NETS, should only bear their share of costs related to energy supply, transmission and connection to the NETS, and should not bear any distribution-related costs. Likewise, high-voltage consumers who are connected directly to the high-voltage distribution network of the DA in which they are located should only bear their share of costs related to energy supply, transmission, high-voltage distribution, and connection to the high-voltage network, and should not bear any low voltage distribution-related costs.

Conduct Service Provider Cost Assessment Study as first step in introducing standard-costing-based control of service provider costs

In keeping with the principle of forward-looking costs in tariff-setting, the NEP Team recommends that, prior to each tariff cycle, the PUC, with the assistance of the NEEPI, should undertake a study to assess the projected standard cost of various activities, equipment and items – as single items or as an aggregation of single items – that will be used in the production and/or distribution of electricity in the upcoming tariff cycle, and use these standard costs as the basis for determining the true cost of service in each tariff period.

The PUC may also use these standard costs as the basis for the approval of certain capital purchases that are required to be approved by the PUC.

Introduce a Two-Part Electricity Tariff for All Consumers

In keeping with the principles of transparency and revenue adequacy in tariff-setting, a two-part electricity tariff, consisting of a periodic fixed charge and a volumetric energy charge, should be applied to all customers. The periodic fixed charge should reflect the provider's fixed costs, while the volumetric energy charge is the cost of energy. Such a tariff scheme would also fulfill the revenue adequacy requirement as the fixed charge recovers the provider's fixed costs, while the energy charge recovers the energy costs. Consequently, if, for some reason, there is a marked reduction in energy consumption in a particular year, the provider will still recover all of its fixed costs – which are independent of consumption level - and all of its energy costs - which are related to the volume of consumption.

Introduce a Time-of-Use Electricity Tariff for Major Electricity Consumers

A time-of-use (TOU) electricity tariff should be introduced and applied to customers who consume electricity above a certain threshold level – particularly SLCs, high-voltage, commercial and industrial customers – in order to encourage reduced consumption during the peak periods of power demand, which will help reduce generation, transmission and distribution investments – and hence costs - in the long run. With experience, this tariff should be rolled out to other lower-consumption blocks of consumers.

Introduce a Seasonal Electricity Tariff for Major Consumers

BEL's cost of energy supply is higher during the "dry season" because of reduced output from the hydro plants and BELCOGEN, which are currently its lowest cost energy supply sources, resulting in greater dependence on supply from electricity imports and diesel generation.

Due consideration should be given to implementing a seasonal electricity tariff schedule - comprising a relatively lower energy charge for electricity during the "wet season" and a relatively higher energy charge during the "dry season" – initially for customers who consume electricity above a certain threshold level and later for all consumers. This would have the effect of communicating the correct price signal to such consumers; who could change their consumption habits in step with the energy charges. It could also provide a steadier stream of cash flows into BEL.

Rate Stabilization Accounts

Rate Stabilization Accounts (RSAs) are used to reduce the impact of changes in the cost of electricity from year to year on the price charged to consumers in keeping with the principle of stability in tariffs. If, for example, total costs in a particular year are higher than the revenues collected from consumers, this additional cost (over revenues) is debited to the provider's RSA to reflect the amount owed by consumers to the provider. Similarly, if the total costs in a particular year are lower than the revenues collected from consumers, the additional revenues cost are credited to the provider's RSA to reflect the amount owed by provider to consumers. The net balance of the account (including interest charges at the rate of the provider's cost of capital) at the end of the tariff cycle is then annuitized and recovered from or paid back to consumers during the next tariff cycle.

The major disadvantage of RSAs is that using them may send incorrect pricing signals to consumers, particularly during times of structural changes in the underlying cost structure of electricity. Another shortcoming of having such accounts in place is that if a customer suddenly closes his electricity account with the provider when the RSA has a net debit balance, the remaining customers will be left to pay that customer's portion of the debit balance during the next tariff cycle. Conversely, if he closes his account when the RSA has a net credit balance, he loses and the remaining customers will be left to benefit from his portion of the credit balance during the next tariff cycle. Either way, this can be a significant loss or gain if the customer leaving is a major consumer.

Remove Rate Stabilization for High-Consumption Customer Accounts

Rate stabilization *should not be* applicable to customers who consume electricity above a certain threshold level – particularly SLCs, high-voltage, commercial and industrial customers – and who can therefore have a significant impact on overall cost borne by other consumers if they suddenly close their electricity accounts. Moreover, this is the class of consumers that is best able to respond – and whose response yields the most significant economic impacts - to the correct price signals that tend to be distorted by rate stabilization mechanisms. Furthermore, such customers are usually in a better position than smaller consumers to negotiate terms and make adjustments on their own to counteract price fluctuations.

Action Recommendation – Study on Efficacy of Rate Stabilization as Currently Implemented and Consideration of Alternative Methodologies

A study of the impact of rate stabilization on electricity prices and consequent consumer behavior should be commissioned with a view to determining if rate stabilization, as currently implemented, is efficacious; and to consider alternative methodologies for effecting rate stabilization. This study should include a survey of public attitudes towards rate stabilization, especially in view of the fact that the prices of all other forms of energy are not currently “stabilized”. The study should consider - as an alternative methodology that yields a better compromise between the competing principles of stability and flexibility - reducing the span of stabilization from a tariff cycle to a year: that is, to stabilize prices from month to month within a year; but to eliminate carry-overs from year to year.

Fuel Industry Regulation & Pricing

Re-evaluate Belize’s Future with Petro-Caribe

Regardless of any ulterior motives on the part of Venezuela, Belize can benefit significantly from the low cost financing terms offered under the Petro-Caribe Agreement: gaining as much as $27,000,000 USD per year if all our gasoline and diesel requirements are supplied from Venezuela (*under the Baseline Plan*).

Petro-Caribe represents an opportunity for Belize to gain substantial revenues from favorable financing terms, diversify its imported petroleum fuel supply sources, and establish a significant relationship with an important petroleum-rich regional partner. Government should revitalize this now defunct arrangement on the conditions that GOB is completely satisfied that the supply from Venezuela will be reliable and that importers can make their own shipping arrangements in order that the costs of freight and insurance can be sufficiently reduced so that the benefits obtained from the low cost financing are not negated.

Once the arrangement has been revived, a portion of the gains from the favorable financing terms made available to the Government should be used to offset the per-unit CIF cost differential, if any, between the supply from Petro-Caribe and the traditional supply from Esso on a month-by-month basis, in order to equalize the CIF cost borne by the various importers in each month.

Action Recommendation – Formulation and Implementation of Regulatory Framework for Fuel Supply and Distribution

In order to allay concerns that might arise from the transition from a monopolistic to an oligopolistic supply arrangement and to better manage this new arrangement, Government should set up a formal regulatory framework to regulate and preserve (the viability of the) downstream fuels sector, including issuing licenses, setting and enforcing quality standards and setting prices. This responsibility for putting this regulatory framework into effect should be assigned to the PUC, and a Director of Fuel Supply should be hired to work on setting up the new regulatory framework.

Establish a Temporary Methodology for the Stabilization and Rationalization of Fuel Prices

In keeping with the principle of stability, transparency and simplicity, fuel prices should *in the meantime and pending the outcome of a Fuel Price-Setting Methodology Study* be fixed on a month by month basis (from the 1st day through to the last day of the month). The price for the next month should be based on the average CIF cost of all fuel received over the last 10 days of the previous month and the first 20 or 21 days of the current month, and should be advertised at least five days before the start of the next month. Importers should be required to standardize order amounts as much as possible.

Given the relatively small cost of transportation as a percentage of total fuel price (less than 3% in all cases), a country-wide standard transportation charge should be introduced to cover the cost of transportation. While transportation companies will still be remunerated according to the current schedule of charges, final consumers will see one fixed charge regardless of where fuel is purchased.

Action Recommendation – Proposed Study of Refined Petroleum Products, Biofuels and Fuel Blends Price-Setting Methodology

A study should be undertaken to investigate and assess the current refined petroleum products price-setting methodology employed by the GOB and to come up with a new methodology that also provides for pricing of biofuels and fuel blends, removes price distortions and that reflects the following principles:

- The fuel prices should fully reflect *all economic costs* of providing the service (cost reflexivity). These should *importantly* include the carbon pollution costs, environmental and safety costs and blending costs (applicable to fuel blends).
- Fuel prices must be *forward-looking* and so based on the *least cost* that *it would take* to provide the service during the time it is being provided assuming the service provider were starting from scratch.
- Service providers must be allowed to recover investment outlays and make a fair return on investment in order to ensure their viability and enable future expansion of their operations.
- Cross subsidization between different fuels should be minimized. The price of a particular fuel should reflect the true cost of supplying and distributing *that* fuel type. For example, the incremental cost of compliance with the higher safety standards required for a particular fuel should be applied to that fuel type only. Similarly, blending costs should be applied to fuel blends only.

- Fuel prices should be fairly stable and should not fluctuate substantially from month to month.
- Fuel prices should be flexible and adaptable to structural changes in underlying costs such as imported fuel prices and other exogenous costs.
- The fuel pricing structure should be transparent and simple so that consumers may be able to easily understand the implications of their consumption behaviors.

Rationalize Current Fuel Pricing Methodology for Specific Fuel Types

In keeping with the principle of full cost reflexivity, fuel prices should *in the meantime and pending the outcome of a Fuel Price-Setting Methodology Study* be rationalized to reflect all economic costs, including: the CIF importation costs or local production costs ex-factory (for locally-produced fuels), local transportation and storage costs, and retailing costs; as well as GHG emissions and other environmental compliance costs, and safety compliance costs. Moreover, in order to meet GOB’s tax revenue requirements it is recommended that fuel tax structure (revenue replacement duty and import duties) be configured to guarantee collection of the budgeted tax revenue collections in each month.

The recommended basic pricing structure for each fuel type is as follows:

- Total unit cost = Unit acquisition cost + Unit GHG emissions cost + Unit cost of storage and transportation + Unit cost of (retailing) distribution + Unit fuel tax + Unit prior month adjustment.
- The unit acquisition cost comprises the unit CIF importation costs and port fees, applicable to the fuel type, *adjusted for losses up to the distribution point*. Depending on the stipulations of international treaties, import duties may also be included as part of the unit acquisition cost. For locally-produced biofuels or petro-fuels the unit acquisition cost is the unit production cost ex-factory.
- The unit GHG emissions cost is based on the GHG emissions rate of the fuel type and the current carbon price, *adjusted for losses up to the distribution point*.
- Unit cost of storage and transportation (to retail stations) consists of a portion that reflects the fixed cost (of equipment, facilities, labor, and overheads, including environmental and safety compliance measures) *applicable to the fuel type* and a portion that reflects the variable cost of transportation *applicable to the fuel type*.
- Unit distribution cost includes the cost of equipment, facilities, labor, and overheads (including, environmental and safety compliance measures) *applicable to the fuel type* used for distributing fuel to final consumers.
- Unit fuel tax is the combination of the Revenue Replacement Duty and Import Duty.
- Unit prior month adjustment is the unit cost increase or decrease that is added to the total unit cost in a month to make up for over-collection or under-collection of fuel

purchase revenues in the previous month due to acquisition cost and sales volume forecasting errors.

The methodology being proposed as a short-term measure for calculating the unit cost components and hence the total unit cost applicable to *a particular fuel type* for the *next month* is as follows:

- The total projected consumption of the particular fuel type for the next month is determined in the current month. This projection should be based on the daily fuel consumption rate of the last 10 days of the previous month and the first 20 or 21 days of the current month. This is the *total basis volume* for the particular fuel type that will be used to calculate the per-unit costs in the upcoming month.

  The total basis volume can be broken down by retail distribution area (e.g. Belize City, Ladyville, Corozal, Benque Viejo), using the historical proportion of total projected consumption applicable to the retail distribution area. The *per-retail distribution area basis volume* is therefore the basis volume for a particular fuel type that is applicable to a particular retail distribution area.

  The total basis volume can be broken down by retail distribution area (e.g. Belize City, Ladyville, Corozal, Benque Viejo), using the proportion of total projected consumption applicable to the retail distribution area and dividing by the number of retail distributors in the area. The *per-retail distributor basis volume* is therefore the basis volume for a particular fuel type that is applicable to a retail distributor in a particular retail distribution area.

- The gross unit acquisition cost for the fuel type is the total CIF value (and production cost ex-factory) of all shipments of the fuel received over the last 10 days of the previous month and the first 20 or 21 days of the current month plus applicable port fees divided by the corresponding total volume. This gross unit acquisition cost is then adjusted upward by dividing it by the efficiency of storage, transportation and distribution, which is 100% *minus* the average percent loss in fuel quantity due to storage, transportation and distribution between the point of importation (or factory) and the point of delivery to the final consumer. The resultant is the final unit acquisition cost.

- The gross unit GHG emissions cost is calculated as the tonnes of CO2e GHG emissions per gallon of the fuel type multiplied by the current carbon price. This gross unit GHG emissions cost is then adjusted upward by dividing it by the efficiency of storage, transportation and distribution, which is 100% *minus* the average percent loss in fuel quantity due to storage, transportation and distribution between the point of importation and the point of delivery to the final consumer. The resultant is the final unit GHG emissions cost.

- The present value of costs of equipment, facilities, labor, and overheads (including, environmental and safety compliance measures) used for storage and transportation to retail distributors is annuitized and divided by 12 to derive the forecasted monthly fixed cost of storage and transportation for the upcoming year. This is done at the end of each year. This monthly fixed cost is then allocated amongst the refined fuels commensurate with their historical proportions in the total fuel products supply mix. The corresponding unit fixed cost of storage and transportation is then derived by dividing the fixed cost allocation by the *total basis volume* for that fuel type.

  The gross unit variable cost of transportation is equal to the sum of the unit cost of transportation for delivery to each retail distribution area multiplied by the basis volume for that retail distribution area, all divided by the country-wide basis volume. This gross unit variable cost of transportation is then adjusted upward by dividing it by the efficiency of transportation and distribution, which is 100% *minus* the percent loss in fuel quantity due to transportation and distribution between the central storage location and the point of delivery to the final consumer. The resultant is the unit variable cost of transportation *specific to the particular fuel type and the particular retail distribution area*.

- The present value of costs of equipment, facilities, labor, and overheads (including, environmental and safety compliance measures) used for retail distribution by a typical retail distributor is annuitized and divided by 12 to derive the forecasted monthly fixed cost of retail distribution for the upcoming year. This is done at the end of each year. This monthly fixed cost is then allocated amongst the refined fuels commensurate with their historical proportions in the total fuels products supply mix. The corresponding unit cost is then derived by dividing the fixed cost allocation by the *per-retail distributor basis volume* for that fuel type applicable to the particular retail distributor.

- The total required revenues from fuel taxes for each fuel type should be determined in advance (before the start of the year) and allocated to each month of the year in proportion to the days in each month or historical fuel consumption in each month or a combination of both. The unit fuel tax for a particular fuel type is then derived by dividing the required revenues from fuel taxes for that month by the *total basis volume* for that fuel type.

- The total adjustment for a particular fuel type for next month is the total quantum of over-collected or under-collected revenues that occurred in the previous (to the current) month: so the adjustment lags the occurrence of the over-collection or under-collection by two months. The total quantum of over-collected or under-collected revenues that occurred in a particular month is the *total basis volume* for the fuel type multiplied by the unit acquisition cost forecasting error for that month, plus the unit acquisition cost for that month multiplied by the total basis volume forecasting error for that month, plus unit acquisition cost forecasting error for that month multiplied by the total basis volume forecasting error for that month. The unit prior month adjustment is the total adjustment for the fuel type divided by the total basis volume for the fuel type.

Internalization of the Costs of GHG Emissions and Other Pollutants

There are a number of options available for implementing a GHG emissions price - or carbon price - in the global economy or in our local economy: using direct approaches such as a carbon tax, a cap-and-trade system, or a baseline-and-credit system; or using indirect measures such as emissions performance standards, alternative energy standards and efficiency standards. These measures will cause a change in the relative cost rankings of the products that are produced by processes that emit GHGs into the atmosphere, or of products that emit GHGs into the atmosphere when consumed: thus increasing their price in the local economy relative to other products, and ultimately leading to reduced demand for and consequently lower production levels of these (GHG-intensive) products.

Cap-and-Trade System

Under a cap-and-trade system, also called an emissions trading system, the total emissions for a particular entity – whether a country or a particular industry within a country or even a particular company operating in a particular industry within a particular country - is *capped*: meaning that some authority, such as the UNFCC or the Government, mandates the maximum GHG emissions that can be produced yearly by the entity. The supervising authority then allocates emissions permits to the entity in the amount of the maximum annual emissions allowed[177].

For example, if the entity is allowed to emit up to 20,000 tonnes of GHGs in a year, it is issued 20,000 such permits. The actual emissions of the entity are *measured, reported and verified* (MRV) by the authority, and, at the end of each year of operation, the entity is required to surrender the number of permits corresponding to its actual emissions produced during the year. If the actual emissions are less than the cap, then the entity will be left with extra permits that it can then sell to (*trade with*) other entities that exceeded their cap. If the actual emissions are more than the cap, the entity will have to purchase permits to make up its deficit, or face fines and punitive action from the

[177] The number of permits initially allocated to each company is usually determined on the basis of historical emissions. Permits may be auctioned to companies or freely allocated ("grandfathering"). The former raises money – much like a carbon tax – that may be used for other purposes. Critics have argued against "grandfathering" since historical high polluters are given an automatic undeserved advantage.

scheme administrators. Over time, the price that a particular entity will be willing to pay for an emissions permit will depend on the cost it would incur if it undertook carbon reduction measures to reduce its total emissions on its own: if it can reduce its emissions on its own by *x* dollars per tonne, it will be willing to pay at most *x* dollars per tonne for a permit. Consequently, the market price of emissions permits at any time will eventually equate with the cost of the lowest costing carbon abatement measures available to entities operating in the market during that time. In this way, cap-and-trade establishes a market price that is automatically set by market forces, while ensuring that the required carbon reduction is being achieved as efficiently as possible.

The major challenge to cap-and-trade is the administrative burden and cost involved in implementing it and MRVing emissions, particularly if there are numerous small entities involved. Further complexities would also arise if cap-and-trade systems across countries are being harmonized to achieve a global carbon policy.

Project-based Cap-and-Trade

Cap-and-trade can also be implemented on a project basis: an example of this is the CDM, discussed in Chapter 2 of this report. The total emissions (per year) for a project are capped at a certain level; usually based on a best available technology benchmark. Emissions certificates earned by the project can be sold into a larger encompassing cap-and-trade system.

Carbon Tax

A carbon tax is fixed tax – usually denoted on a per-tCO2e basis - that is introduced at some point in the value chain of the processing of a good or service: for example, it may be levied upstream on fossil fuels at the point of importation, or downstream at the retail end when a consumer purchases gasoline or diesel to refuel his vehicle. It is considered by many as the most efficient policy option for reducing GHG emissions (CBO, 2008) and is the approach most favored by economists because it is simple to understand and to implement.

The major challenges with it are that the difficulty of determining what the level of the tax should be, and the fact that it does not expressly limit total emissions: that is, a company can theoretically emit as much GHG pollutants as it wants to as long as it is willing to pay the required tax. The counter argument to the latter point is that any profit-making venture would seek to lower its costs as much as possible and that a company will prefer to avoid carbon pollution or undertake carbon abatement action in lieu of paying taxes if it is more profitable to do so. Getting the price point right – and continually reviewing this price point in light of new carbon abatement innovations - is therefore crucial to the efficacy of a direct carbon tax regime.

How is a carbon tax more efficient than an emissions cap?

Let us assume that the carbon tax in a particular year is set at $30 USD per tonne of CO2e emissions. If, during the year, the actual cost of carbon abatement is $15 per tonne, then companies will reduce emissions as much as possible in order to avoid paying the tax. If the actual cost is double the tax rate, then companies will prefer to pay the tax. A carbon tax regime allows companies the flexibility to undertake carbon abatement when it is most cost-effective for them to do so[178].

The outcome would be different under a cap-and-trade (emissions cap) regime. Once a company cuts back its emissions in line with its cap for a particular year, it has no further incentive to do more, no matter how low the actual carbon abatement cost. On the other hand, the company will be forced to pay the price of carbon abatement in a particular year to cut back its emissions in line with its cap no matter how high the actual carbon abatement cost is in that particular year. An emissions cap regime therefore does not allow a company the flexibility to undertake carbon abatement when it is most cost-effective to do so.

Baseline-and-Credit System

The baseline-and-credit system works in a similar way to cap-and-trade; however, emissions intensity (e.g. tonnes of CO2e per tonne of production units) - as opposed to absolute emissions - is used as the benchmark. A company earns credits for beating the baseline set and surrenders credits if its emissions intensity exceeds the baseline.

This approach is applicable for controlling emissions on a per-sector or per-industry basis. In order to facilitate trading of credits across sectors, conversion rates have to be established to determine equivalency of the different emissions intensities between different sectors. Unlike cap-and-trade, however, this system does not expressly limit total emissions, which are dependent on the total production.

Emissions Performance Standards

Emissions performance standards are simply Government-mandated emissions intensity limits imposed on a per-sector or per-industry basis. These may be implemented on their own or as part of a larger baseline-and-credit system as discussed above. The latter provides the flexibility required for pursuing carbon abatement at the lowest possible cost to each sector or industry and further efficiencies can be gained if credits are tradable across industries and sectors.

Other Measures

[178] Of course, poor forecasting can detract from the efficiency of the regime: if a company undertakes most of its carbon abatement in a year when carbon abatement costs are higher than succeeding years, then it would have missed out on the opportunity to do the same thing at a lower cost.

Alternative energy standards (e.g. RPS for renewable energy technologies and RFS for biofuels) have already been discussed in earlier sections of this chapter as a means of meeting renewable energy utilization targets; similarly, efficiency standards (e.g. VAFE for vehicles and appliance efficiency standards) were earlier recommended as policy instruments for minimizing sectoral energy use. These "command-and-control" approaches will therefore help to achieve overall GHG reduction as a "collateral consequence" of the pursuit of the other goals.

Implement GHG Pricing in Local Economy

Although the international community has reached a broad level of consensus on the need to act with urgency to combat climate change, there has not been a uniform and consistent response on the way forward on the part of individual countries or even regions. As climate change is a global problem, in the sense that a tonne of GHG emissions produced anywhere ultimately has the same consequences for all countries everywhere, alignment and consistency across countries and regions on policies tackling climate change are needed to prevent "carbon leakage" [179] and other inefficiencies arising from policy conflicts and thus to establish a level playing field across international markets. **Government should therefore, through its membership on regional and international bodies and participation in regional and international forums, vigorously lobby for agreement on adopting a fair and consistent global carbon pricing regime, that is implemented incrementally so as to give less-developed countries sufficient time to make the required adjustments**, and where the more advanced countries – who are responsible for over 70% of the accumulated atmospheric GHGs – are required to pay a proportionate part of the cost of making these adjustments.

In the meantime, Belize must begin the process of preparing our local economy for the inevitability of the adoption – or imposition – of this global carbon pricing regime. How can this be done without causing undesirable distortions and without putting our

[179] "Carbon leakage" occurs when a company moves from one country where a carbon price has been implemented (in the form of a tax, emissions cap or some other restrictive standard) to another where no carbon price is implemented or the price level is lower or where enforcement is more lax. By doing so, the company has the opportunity to emit more carbon into the atmosphere because the costs of doing so are lower or non-existent in the other country: that is, carbon is "leaked" through cracks in the consistency of the carbon price implementation regimes across the countries. Even if companies that operate in more restrictive carbon pricing regimes do not move to countries with less restrictive carbon pricing regimes, their costs of doing business will increase relative to those of their competitors operating in such regimes, resulting in a relative increase in demand for their competitors' products and hence relatively higher emissions of carbon into the atmosphere, because these competitors are not faced with the tighter carbon pollution restrictions: thus, carbon leakage, in this case, occurs in the form of increased emissions from competing companies operating in countries with less restrictive standards.

export-oriented industries at a disadvantage to other countries - especially direct competitors - that are slower to introduce a carbon-pricing regime?

We recommend three complementary courses of action:

a) *Setting up of a pilot baseline-and-credit regime with the following parameters*:

i. This pilot should be regarded as a test run for a possible future regime and should therefore cause no financial or economic consequences on the companies involved. The main objective is to develop the institutional structures required, to instill the required institutional discipline in the administrators and participants for measuring, reporting and verifying relevant emissions data, to get the actors accustomed to operating – particularly trading credits - within the new regime, and to document the actual trends in carbon intensity. The latter will be especially crucial when negotiating future carbon financing through the CDM or other bi-lateral arrangements, as most carbon offset schemes and emission reduction credits use a country's or industry's historical emissions trajectory as the reference (baseline) from which reductions are assessed.

ii. A baseline should be set for each industry/sector – on an annual basis - according to regional benchmarks and historical trends. A participating company can earn credits for beating the baseline set for its parent industry and must surrender credits if its emissions intensity exceeds the baseline. However, these should simply be booked: companies will not actually pay for credits or earn money from the sale of credits. Companies whose emissions intensities exceed the baseline will be required to submit a detailed report, supported by a full cost benefit analyses, on measures that can be pursued to reduce emissions in line with baseline limits[180].

iii. It should be setup with no formal ties to any other global, regional or otherwise extra-national carbon emissions reduction regimes. It should initially cover only the major GHG-emitting sectors including electricity, petroleum, transportation, and major industries.

b) *Implementing a carbon tax on petroleum and other fossil fuels used in transport and for electricity generation*. The level of such a carbon tax should be dictated by the global GHG emissions market price. Specifically, it is recommended that the carbon tax be set as the global market price of CERs, in markets that are accessible by Belize, less the transaction costs of participating in programs that allow for generation and redeeming of CERs that are tradable in these markets. The main focus of the tax at this juncture is to curb domestic consumption from – and hence production of - products with a relatively higher carbon footprint to products with a relatively lower carbon footprint.

[180] It may be more practical to require that this report be prepared by an external consultant.

The tax must be accompanied by an appropriate rebate for all export-oriented industries in order to ensure that the competitiveness of our exports is not adversely affected by the additional cost (tax burden)[181]. It is not to be used as a revenue generator for government, but as an economic price signal: the proceeds, less the rebates, are therefore to be re-distributed back to tax-payers – particularly the lower income classes - in the form of a lower income tax or subsidy. A carbon tax is regressive in nature; that is, it results in the lower-income households, who spend a larger proportion of their income on energy and hence carbon products, being taxed at a relatively higher rate (of their income) compared with higher-income earners. Redistributing the carbon tax proceeds as a flat dividend (e.g. *x* dollars per person or household) will diminish the negative income distribution effect of the tax on lower-income classes.

Some regimes use the tax proceeds to subsidize clean energy projects. This is not recommended if the quantum of the tax already reflects the full cost of carbon; otherwise it would over-penalize products with a high carbon foot print relative to products with a low carbon footprint: once in the form of the tax imposed on the high carbon-footprint products and additionally in the form of the subsidy given to the low carbon-footprint products.

c) Finally, Belize must continue to take advantage of the CDM and any other beneficial opportunities for obtaining carbon finance for undertaking economically feasible renewable and energy efficiency projects. The CDM is essentially a mechanism formulated to facilitate developed countries to meet their Kyoto Protocol-imposed emissions reduction targets at the lowest cost *to them*[182]. For our part therefore, aside from the institutional structures being put in place to prepare us for an impending global carbon regime, the CDM should, at this time, be used solely as a source of low-cost finance and subsidies for eligible RE and EE projects[183]; and not as a framework directly dictating any national or sectoral strategy.

In a nutshell, the CDM must serve our purposes for local RE and EE projects that are deemed feasible: projects are not to be promoted simply to get on the CDM band-wagon, or to access CDM money if the underlying economics are not

[181] The quantum of the rebates applicable to each industry and the way in which these rebates are re-distributed would have to be carefully calculated and determined to ensure that the cost-neutrality objective is achieved on a per-industry basis.

[182] They also get the additional benefit of selling – and gaining from - the clean energy technologies that are sold to developing countries as part of the entire deal: shifting the monies we currently pay for oil, which for the most part comes from other countries, towards the technology products that they produce.

[183] In this regard, setting up a local carbon tax regime may affect the potential for earnings from CDM under the "additionality" principle. This should be investigated as part of the necessary pre-implementation feasibility study of a local carbon tax regime.

sound, or if viable CER markets (where earned CERs are traded) are not yet in place.

Evaluate Cost of Impacts of Non-GHG Pollutants on Belize's Economy

The NEEPI should undertake a comprehensive study of the cost of the impacts of non-GHG pollutants on Belize's economy as a first step towards deriving formulae for pricing these externalities and hence controlling their impacts through market-based and other mechanisms. Such pollutants include those emitted during wood fuel combustion (particulate matter, carbon monoxide etc), sulphur emissions from diesel combustion and others such as mercury, hydrogen chloride and nitrogen oxide. It is advisable to undertake such a study in collaboration with regional partners in the LAC region as they face the similar problem of not knowing what the quantified impacts and costs of these externalities are.

Energy Supply Resilience

Establish Strategic Petroleum Stock Levels

In an effort to better manage the uncertainty of supply and the price volatility of petroleum imports and to protect against extended disruptions of fuel supply due to disasters, the NEEPI should establish minimum stock reorder points and safety stock levels for all refined fuel types at the national level and at each major population center level.

Establish Requirement for Geographic Diversity of Electricity Supply Sources

In order to enhance energy resilience, RFPs for electricity supply should stipulate evaluation criteria that promote geographic diversity of supply sources as a whole. Thus, one such criterion for a specific instance of an RFP may be that the supply source must be located within the Toledo District, simply to ensure that supply is sufficiently bolstered in that district. An alternative less limiting criterion may add (or subtract) evaluation points for each 1% improvement in the calculated geographic diversity index of the national electricity supply grid as a whole due to the addition of the supply source.

Build Resilience into the National Electricity Supply Network

Developing a smart grid is a key element in the effort to attain the broader goal of energy resilience. The NEEPI should prepare and monitor the implementation of a long term plan to transition to a smart grid overlay of the national electricity system in order to mitigate disruptions of electricity supply: by automatically serving deprived or stranded loads from other parts of the network and redirecting energy flows around damaged equipment when a supply path fails or, isolating and maintaining individual sub-networks intact and energized even when the national grid as a whole fails.

Setup standards to ensure that Power Lines, Wind Turbines and Solar Panels are built and installed to withstand Extreme Weather Conditions

As Belize is within the Hurricane (Tropical Cyclone) Belt and has suffered major infrastructural damage as a consequence of the passage of tropical cyclones over various parts of our country, the NEP Team strongly recommends that the standards for construction/installation (inc. equipment quality), operation and maintenance of transmission and distribution lines and power plant components, that by design have to be exposed to the elements, provide for mitigation of the probable effects of extreme weather events associated with tropical cyclones.

Wind turbine installations, for instance, should be designed to withstand hurricane force winds by using reinforced tower bases (e.g. tripod as opposed to single pole) and/or tilt-down designs to lower turbines so that they are not exposed to the greater wind speeds occurring at higher elevations, and/or free yaw systems that allow the turbine blade system to be disengaged to freely move about its axis to a position of least resistance to the wind.

These standards should also cover grounding requirements for micro-generation equipment such as wind turbines and solar panels which are placed on top of buildings or on tall structures near buildings, especially in residential neighborhoods, so as to prevent damage to life, property and the equipment themselves from the increased risk of lightning strikes.

Setup a Self-Insurance Scheme against Potential Loss from Natural and Other Disasters

A self-insurance scheme should be setup to enable funding of restoration of the electricity transmission and distribution systems in cases of natural and other disasters. This would essentially be constituted as a sinking fund, with monthly contributions afforded from a per-KWh or a percentage-of-total-electricity-bill surcharge added to electricity tariffs. The surcharge would have to be worked out to ensure that the fund builds up to the level of the expected total cost of restoration within the *mean time between disasters*. Once the level of the fund has reached this amount, the surcharge can be removed. If the fund builds up over the level of the expected total cost of restoration as a result of interest earnings, then the additional amount above the expected level can be rebated to consumers over the ensuing year.

Financing for Indigenous Energy Development

"Incentive packages for the energy industry should be underpinned by clear, transparent analyses focused on the likely costs of the package relative to the benefits to be obtained; the potential returns that participating energy companies

might achieve; and the relative attractiveness of the offerings of other countries seeking the involvement of the same energy companies." (WEC, 2010)

Over the years, developed countries have employed a host of financing models to boost renewable energy deployment in their local economies: grants, low-interest loans, feed-in tariffs (FITs), production tax credits (PTCs), and renewable portfolio standards (RPSs). The objective in each case has been to correct a perceived market failure as viewed from the national perspective: whether a failure of the market to take into account externalities such as carbon pollution costs, or the effect of a particular technology on rural employment and productivity, or the potential of a technology for long-term cost reduction, or the importance of the technology in enhancing the diversity of the energy supply mix and hence overall supply security.

Our analyses of the various energy supply options – wind power, solar PV, hydro, biomass, biofuels, solar thermal energy for water heating, GSHP for cooling and heating – have shown that, based on the project economics alone and without taking potential carbon savings into account, almost all of these renewable energy forms are ready for deployment in Belize. In fact, Belize's lowest costing energy sources are currently the hydro plants from Hydro Maya and BECOL and the co-generation bagasse-fuelled plant from BELCOGEN. There is no need therefore for any preferential above-market price incentives to be given to any renewable energy development projects, except perhaps for PV and offshore wind (which are discussed separately further below). What is needed are supporting frameworks and financing mechanisms that cater to the unique characteristics of such renewable energy investments, namely: more costly feasibility and siting studies, high upfront capital costs, output variability, and carbon savings.

Feasibility and Siting Studies

As recommended earlier, instead of assisting with financing feasibility studies on an individual project basis, it is best for Government to sponsor country-scoped studies to gauge the energy production potential of our natural resources (wind, hydro, geothermal, biomass, biofuel etc) and prepare resource potential maps so as to defray costs that individual project developers would have had to bear on their own if they had to search for optimum areas for renewable energy development from scratch. This is also important for securing the necessary financing.

Lending institutions typically require evidence that RE resource supplies will last beyond the period of financing: for biomass projects, a long term resource supply contract; for wind projects, at least one year of on-site measurements that can be shown to have a good correlation with historical data gathered from a nearby site for which measurements are available over a longer period of time; and for hydro projects, a year of hydrological data that has a good correlation with local historical pluviometric data and historical river flow data from downstream and/or upstream gauges for which measurements are available over a longer period of time (Fieldstone Private Capital

Group Ltd, Revised 2000). These studies should also include undertaking pilot/demonstration projects for technologies that have not so far been deployed on a commercial scale in Belize to gain a better understanding of the particular challenges that could be faced when deploying and operating plants based on such technologies under local conditions.

The operational results of these studies could then be disseminated to the commercial insurance market for use in actuarial analyses and in the development of RE-specific commercial insurance products, since commercial insurers are known to insure particular risks on the basis of "practical experience and commercial considerations". The availability of such insurance products could significantly spur private sector investment in the industry. (Marsh Ltd; Andlug Consulting; Roedl & Partner; Climate Change Capital; Det Norske Veritas; Global Sustainable Development Project, 2004)

High Upfront Capital Costs and Output Variability

Utility-scale renewable energy projects – particularly hydro, wind, and solar – are usually characterized by high upfront capital investment requirements and variable energy and power outputs. The standard financing arrangements for these investment outlays usually stipulate fixed monthly repayments of capital and interest: requirements that are often at variance with a RE project's energy payment receipts (if based on per-unit of production charges), which vary from month to month according to the output of RE plant. RE developers will require non-traditional innovative financing mechanisms that incorporate flexibility in repayment schedules or government guarantees to bridge the gap between the fixed repayment commitments and varying energy revenues.

Carbon Savings

Most RE projects are eligible for participation in the CDM and other GHG reduction programs. The revenues derived from redeeming CERs earned through participation in these programs can help to offset operational expenditures and debt servicing costs. Alternatively, a project's total projected carbon earnings can be used to finance the project's initial cost by assigning the earnings to the financier in exchange for a concomitant reduction in the initial debt. Although, in such a case, all the risk – including the CER market and hence CER price risk, the project production and hence CER volume risk, and to a lesser extent the interest rate risk – is borne by the financier, the financier is also is in a better position than an individual project developer to manage this risk (by holding CERs from a diverse portfolio of RE projects) and to reduce transaction costs through volume economies of scale.

Financing Vehicles

Most of the requisite financing assistance for RE projects can be rendered through two facilities working in collaboration with each other: a facility administered by the NEEPI to provide full assistance to potential renewable energy developers from project idea and feasibility study, through acquiring the necessary financing, to final licensing by the relevant authority (introduced in an earlier section above); and a "Green Investment" Bank, similar to the one being planned for the UK[184].

Green Investment Bank

The main objective of setting up a Green Investment Bank is to vest the decision-making process for financing renewable energy projects and the expertise for making such decisions in a single entity at this critical juncture in the development of the local renewable energy industry. Through this arrangement, Government will also be able to implement innovative financing models such as packaging smaller projects into one proposition for greater management efficiency and taking advantage of special financing streams such as programmatic CDM; streamline and provide better oversight and control of the renewable energy project financing process; and attract and aggregate equity and debt capital from various sources into one pool. Importantly, one such source (of capital) could be the local populace: thus providing yet another avenue for them to participate in the new renewable energy economy.

Beyond its necessary involvement in setting up the bank, Government's primary role in assisting with this facility would be to underwrite loans for projects with marginal returns and to facilitate access to capital from unilateral and multilateral financing sources.

Special Incentives for Promising and Near-commercial Technologies

A key feature of any transition to a renewable energy-based economy is the provision of supporting mechanisms for the nurturing of near-commercial and promising technologies such as offshore wind, PV, and algae fuel. Government could bolster the Green Bank's mission by providing interest rate and other subsidies for initial feasibility and siting studies and mandating special financial incentives (FITs, PTCs etc) for early demonstration of near-commercial technologies. These subsidies and financial incentives could be partially funded directly through a small fee added to consumer electric utility bills and vehicle fuel charges.

Regardless of how they are financed, the quantum of these subsidies and incentives should be determined on the basis of full economic cost-benefit analyses that are done as part of the energy planning process and that take into account externalities. Providing subsidies for a technology simply on the basis of the hype surrounding it is surely not acceptable. Moreover, such subsidies and incentives should be subject to continual review to ensure that they are phased out in line with the achievement of cost parity and the removal of the market barriers.

[184] Chapter on the 'Investment Environment' (WEC, 2010)

Energy Efficiency and Conservation

"Energy efficiency has always had an image problem. Voters associate efficiency programs with energy shortages and rationing, so politicians prefer to avoid the subject. In public debates, efficiency is often dismissed as a timid answer to a problem that requires bold solutions. Faced with a choice between building a new power plant and promoting reduced energy consumption, leaders will almost always choose the former—regardless of which is most effective." (Constance, 2008)

"The best energy efficiency programmes are multi-faceted (focusing on both supply and demand) and have over time become part of the cultural fabric of industry and household management. Countries that do not have established efficiency programmes should learn from the experience of others with regards to identifying appropriate programmes." (WEC, 2010)

This section proffers various policy instruments that can be used by Government to directly promote energy conservation and efficient energy use. Together they form part of a multi-faceted energy efficiency program covering the major energy consumption sectors, primarily transport, buildings (and appliances) and certain industries. These measures are mainly focused on technological changes in energy-consuming devices or curbing outwardly energy-intensive behaviors. However, true and lasting energy efficiency can only be achieved by weaving it into the fabric of our lifestyles, or – said another way – orienting our lifestyles along its path. To do this, we must start by **planning for energy efficiency** – that is by avoiding the building of unnecessary energy loads into long-lived assets and hence our way of life: because once so ingrained, we are forced to deal with the consequences for extended periods of time – usually the entire life of the asset - and the degree of effort (and energy) that will be required to overcome this built-in inertia are at times insurmountable. Examples are myriad:

- Choosing to site a rural population center near an ample water resource to avoid having to use energy to pump the water from a distance and to pay for the additional capital and maintenance costs of a larger pump.
- Investing in an online school instead of a regular school to avoid the energy costs of students and teachers commuting to class, the costs of lighting and cooling class-rooms and all the other costs related to maintaining traditional class-rooms.
- Building well-ventilated homes to cut down on the cost of having to use fans and A/Cs.
- Strategically siting a power plant next to a food and beverage factory so that the waste steam or heat from the power plant can be used directly by the factory for food processing.

- Enabling online issuance of and payment for registration documents to avoid the energy cost of throngs of people having to travel to registry offices and the costs of having to provide office space (and cooling) to accommodate them.
- Choosing to build a bridge across a ravine instead of around it to avoid an extra mile of road that over the long term would have resulted in huge fuel costs and tons of carbon pollution.
- Teaching children from a young age to turn off the lights when leaving an empty room instead of having to put occupancy-sensors in every room of a home.

These examples underscore the importance of incorporating planning for energy efficiency beyond the energy sector and at the very highest levels of national strategy formulation. The *macro-level energy efficiency* impact – that is, the effect of a project on the energy efficiency of the nation as a whole - should therefore be a fundamental criterion and determinant in all major economic investment decisions. They also point to the need for a fundamental rethink in the way we do things, particularly in light of the occurrence of structural changes and significant innovations. The second and fifth examples above clearly show that innovations in telecommunications have created a host of new opportunities for doing things far more efficiently. In such cases, greater macro-efficiency gains are gotten by focusing on building a reliable telecommunication infrastructure rather than simply focusing on reducing the cost of the traditional energy supply infrastructure: low telecommunications costs will instigate a shift towards far less energy-intensive service models in business and industry.

Planning

Establish Requirement of Cost Neutrality of Imposed Efficiency Standards

The NEP Team recommends that the GOB mandate that the required upgrading to any efficiency standard imposed for end-use equipment and appliances be at neutral cost to consumers (for each category of consumer): that is, the projected energy savings resulting from the upgrade should *as a minimum* cover the estimated incremental cost of the upgrade plus any associated incremental costs of O&M *on a net present value basis* measured over the lifetime of the upgrade. Before such standards are imposed therefore, extensive cost-benefit analysis should be done involving potential impacts on consumers and this analysis should be subject to scrutiny and input from equipment importers, efficiency advocates, and other stakeholders.

Limit Total Financial Incentives & Penalties Applicable to Energy Efficiency Projects

Energy efficiency improvements are obtained via a bundle of energy efficiency measures. This means that a specific project may be inadvertently impacted – in terms of either benefits or penalties - from more than one financial/economic incentive measures aimed at achieving the same EE target, resulting at times in unintended or over-extended benefits (or penalties). The policy planning process must therefore ensure that the total financial/economic incentives that can be applied to a specific project for achieving a particular EE target do not exceed the total net energy savings that can be gained from achieving the target.

Transportation

Studies & Data Collection

Action Recommendation – Mileage Data to be gathered at time of Vehicle Licensing

The Transport Authority should put in place a data collection system to capture the vehicle mileage data (that is, the total miles travelled to date) at the time of licensing. This data can be used by the NEEPI for analyzing transport energy demand.

Action Recommendation – Setting up of an Transport Information Sharing Protocol

The NEEPI and the Transport Authority put in place a transport information sharing protocol to enable NEEPI to get the related transport data that it needs on a timely basis.

Action Recommendation – Data Collection on Energy Usage Patterns of Mass Transport Land Vehicles

The NEEPI in conjunction with the Transport Authority should commission a survey to determine the quantity of mass transport vehicles used in Belize by vehicle type and size (cross-sectional area and weight) and engine size, the average yearly mileage by vehicle type and size and engine size, the average fuel consumption by vehicle type and size and engine size, and the total quantity of diesel and gasoline used per year by mass transport vehicles as a whole. The survey results should be updated on a yearly basis. This data will be used by the NEEPI for enhancing analyses and fine-tuning related policies.

Action Recommendation – Data Collection on Energy Usage Patterns of Marine Vessels

The NEEPI in conjunction with the Transport Authority should commission a survey to determine the quantity of marine vessels used in Belize by vessel type and engine size, the average engine hours by vessel type and engine size, and the total quantity of diesel and gasoline used per year by marine vessels as a whole. The survey results should be updated on a yearly basis. This data will be used by the NEEPI for enhancing analyses and fine-tuning related policies.

Action Recommendation – Data Collection on Energy Usage Patterns of Local Airplanes and Helicopters

The NEEPI in conjunction with the Transport Authority should commission a survey to determine the quantity of airplanes and helicopters used in Belize by vessel type and engine size, the average engine hours by vessel type and engine size, and the total quantity of kerosene and aviation gasoline used per year by airplanes and helicopters as a whole. The survey results should be updated on a yearly basis. This data will be used by the NEEPI for enhancing analyses and fine-tuning related policies.

Action Recommendation – Verification of Fuel Blend Capabilities of Spark-Ignition and Compression-Ignition Vehicles

The Transport Authority should conduct a data-mining analysis of its vehicle registration and licensing records to estimate the fuel blend capabilities of spark-ignition and compression-ignition vehicles based on their make (brand) and year of manufacture. The data gathered via the analysis should be verified the next time the vehicle is brought in for re-licensing. The data that is mined and verified should be used to initialize a data collection system setup to register and track the fuel blending capabilities of the vehicle stock in preparation for the introduction of fuel blends into the vehicle fuels market.

Action Recommendation – Verification of Fuel Blend Capabilities of Local Fuel Distribution and Dispensing Systems

The Transport Authority in conjunction with fuel retailers should conduct an investigation into the capabilities of the existing fuel distribution systems for dispensing up to E10 and higher blends, and the costs of any upgrades needed if necessary.

Instigate change-over to More Energy-Efficient and Environmentally-Friendly Vehicles and Modes of Transport

Adopt Vehicle Average Fuel Economy (VAFE) Standards

The NEEPI should *each year* prepare the Recommended and Minimum VAFE Standards (miles per gallon or miles per KWh for EVs) for brand-new vehicles classified by class – for example, light-duty pickup trucks or large buses - and fuel type. *The VAFE for mass transport vehicles should be expressed in person-miles per gallon*.

The Recommended VAFE Standard in a particular vehicle category (that is, vehicle class and fuel type) should be the fuel economy of the vehicle, which is currently available in the USA and other world markets and costs the least on a net present value life-cycle cost basis (relative to Belize). This life-cycle cost assessment should take into account capital cost, fuel costs, O&M costs, and environmental emissions costs.

The Minimum VAFE Standard in a particular vehicle category is the lowest fuel economy acceptable for any and all vehicles in that category.

The Recommended and Minimum VAFE Standards should be well-advertised to vehicle importers and the public in general *at least a year in advance of its effective date* through sustained educational and informational campaigns.

These standards should **not** be applicable to military and diplomatic vehicles.

Action Recommendation – Study to Derive Formulae for Estimating Fuel Economy of Vehicles

The Transport Authority in conjunction with the Customs Department should commission a study to derive formulae for estimating the highway and city average fuel economy of vehicles, which are based on the manufacturer's estimated fuel economy (or - if not available - the vehicle weight, cross-sectional area and engine configuration), the mileage to date, and the perceived condition of the vehicle. Assessing the fuel efficiency of used vehicles and how fuel efficiency decreases with vehicle mileage and/or years in operation in general will be a critical aspect of this study.

The fuel efficiencies so derived will be shown on the vehicle fuel consumption labels and will also be used to calculate the VAFE for the vehicle, which in turn is used as the basis for calculating import duties and licensing fees.

Require that Permission for Vehicle Importation and Vehicle Licensing be tied to the Minimum VAFE Standard

In order to encourage use of fuel-efficient vehicles, permission should not be granted to import any vehicle with assessed fuel economy below the applicable Minimum VAFE Standard. Moreover, a vehicle should not be licensed for operation if the assessed fuel economy of the vehicle at the time of licensing is below the applicable Minimum VAFE Standard for two consecutive years.

Introduce Cash-for-Scrap Program

A cash-for-scrap program could be implemented as a backup to the minimum VAFE standard. Once permission to license a vehicle is denied on the basis of its assessed fuel economy, then the owner of the vehicle would be eligible to receive a cash rebate in return for scrapping the vehicle. The estimated savings (from a national perspective) of replacing the vehicle with an acceptable one would serve as a guide for determining the quantum of the rebate.

Require that Vehicle Import Duties and Vehicle Licensing Fees be tied to the Recommended VAFE Standard

In order to encourage purchase and use of fuel-efficient vehicles, a portion of import duties and licensing fees should be tied to the actual purchase cost of the vehicle and the other portion should be tied to the Recommended VAFE Standard applicable to the vehicle category (categorized by vehicle class and fuel type). Keeping a portion of import duty and licensing fee tied to purchase cost reflects the principle of ability to pay as well as serving as a penalty for the loss of foreign exchange incurred in paying for the vehicle.

Total Import Duty (or licensing fee) = Purchase Cost-Related Duty + VAFE-Related Duty

The basis of the formula for calculating the VAFE-related portion of the import duty should be the present value of the projected fuel and emissions costs over the lifetime of the vehicle, *using the same lifetime for both new and used vehicles*. This formula should be such that the VAFE-related portion of the import duty is zero, once the assessed fuel economy of the vehicle is exactly equal to the Recommended VAFE Standard, and becomes more negative – a rebate - as the assessed fuel economy deviates further above the Recommended VAFE Standard. The Recommended VAFE Standard therefore serves as the pivot point: about which fee-bates and rebates are applied. The residual effect for a vehicle with assessed fuel economy higher than the Recommended VAFE Standard is that the total import duty or license fee payable will be the purchase cost-related portion of the import duty (or licensing fee) less the rebate[185].

Promote VAFE Standards to Lending Institutions for Inclusion in criteria for Approval of Vehicle Loans

The Government should actively promote Minimum and Recommended VAFE Standards to lending institutions to consider as part of the criteria for approval of vehicle loans. Presentations should be made to lending institutions to demonstrate that the incremental increase in monthly repayments due to the higher purchase costs of more energy-efficient vehicles are more than offset by fuel cost savings. Lending institutions should also be encouraged to factor VAFE ratings into interest rates and allow spreading of loan repayments over longer periods of time for vehicles that meet the Recommended VAFE Standard (in its category) so that vehicles with higher capital costs but better efficiencies can be purchased.

Institute a Vehicle Fuel Consumption and GHG Emissions Guide Label

The Transport Authority in conjunction with the Customs Department should institute a vehicle fuel consumption and GHG emissions guide labeling policy for all vehicles imported into Belize. The label should show the following information: year of manufacture, type of fuel used, estimated highway fuel consumption rating (in miles per gallon), estimated city/town fuel consumption rating (in miles per gallon), estimated idling fuel consumption rating (gallons per hour), estimated GHG emissions (in tonnes of CO2e per mile travelled), vehicle weight, and maximum cross-sectional area. This information can be used by buyers to compare the vehicle's fuel efficiency with that of other vehicles.

This labeling scheme must be supported by legislation imposing severe penalties and fines on any company or person who provides false information on energy labels.

[185] A 2010 Report "Should Hybrid Vehicles Be Subsidized?" noted that subsidies that are applied directly on the price of a vehicle, rather than in the form of a tax rebate, tend to be most effective (based on evidence from an analysis of current subsidy policies). (McConnell & Turrentine, 2010)

Action Recommendation – Commissioning of Research on Use of Biofuels and Fuel Blends as Alternative Vehicle Fuels

The NEEPI should conduct research on how to introduce biofuels and biofuel-based blends as fuels for use into the local transport market. This research should focus on the technical specifications of the biofuels and blends; the minimum standards and certification for the retrofitting of the vehicles for biofuels and blends; changes in minimum safety standards for refueling facilities as a consequence of handling of biofuels and blends; the extent and costs of modifications to refueling facilities (retail stations and their fuel dispensing systems) that will have to be made to accommodate biofuels and fuel blends; and a system for easily testing and differentiating between the different blends and non-blends.

Action Recommendation – Commissioning of Research on Use of LPG and Natural Gas as Alternative Vehicle Fuels

A small proportion of the gasoline vehicle fleet in Belize has been retrofitted for dual fuel (gasoline/LPG) use. However, there are no safety standards governing how these retrofits are to be done, and no properly-outfitted LPG stations equipped with the appropriate dispenser pumps for filling the LPG tanks attached unto the vehicles.

The NEEPI should conduct research on how to introduce natural gas and auto gas (LPG) as fuels for use by commercial and industrial vehicle fleets, but not for the general retail market. This research should focus of the technical specifications of the natural gas and auto gas; the minimum standards and certification for the retrofitting of the vehicles for natural gas and/or LPG use; the minimum safety standards for refueling facilities; a system for easily differentiating between auto gas and cooking gas; and a system for testing and certification of meters.

Action Recommendation – Launching of a Country-wide Campaign to promote the Benefits of Walking, Cycling, Carpooling and Mass Transport

A country-wide campaign should be launched to promote the energy-savings benefits of walking, cycling, car-pooling and mass transport as alternatives to using private transport. The campaign should also tout the health benefits of walking and cycling, and the safety benefits of mass transport.

Such a campaign must necessarily be timed to coincide with improvements in urban security conditions and the service standards of mass transport in general.

Action Recommendation – Commissioning of Study on Public Attitudes towards Urban and Inter-urban Mass Transport

A country-wide study on public attitudes towards mass transport should be commissioned with a view to determining what factors are hampering take-up and what factors would encourage take-up amongst the various socio-economic classes. Riders (and non-riders) should specifically be polled on whether they would view take-over of the mass transport system by GOB or a single company as more or less beneficial and whether it would deter or encourage take-up on their part.

The study should consider urban and inter-urban mass transport separately, and present recommendations for changes and improvements to the urban and interurban mass transport systems in Belize, based on riders’ concerns and preferences.

Action Recommendation – Study on Urban and Interurban Mass Transport System in Belize to determine Required Service Standards, Required Service Infrastructure, Costs and Pricing Policies

A study on urban and inter-urban mass transport in Belize should be commissioned with a view to determining the service standards required by different classes of riders (shoppers, professionals, business persons, students, tourists, workers etc), the service infrastructure required to deliver services to the standard required, the cost of setting up the required service infrastructure and the pricing structure that would enable full payment for the cost of the service.

Service standards refer to routes, schedules, availability of non-stop and limited-stop service, condition of buses, seating arrangements, comfortableness of seats, spaciousness, smoking versus non-smoking restrictions, availability of toilets on board, availability of shuttle services to and from neighborhoods, availability of air-conditioning, internal décor, availability of different payment options including passes, condition of bus terminals, availability of amenities at bus terminals, location of bus terminals, availability and location of bus stops, and condition of bus stops.

Service infrastructure includes the buses themselves, bus terminals, bus stops, operators and service personnel, as well as bus right-of-ways.

The recommended pricing structure should reflect the price-setting principles of full cost reflexivity, fairness, transparency, simplicity, flexibility, stability, and revenue adequacy for service providers.

The results of this study should be used to determine what classes of riders should be targeted for mass transport based on the assessment, from a national perspective, of the costs of providing the service required versus the gains from reduced fuel consumption and other related benefits of using mass transport.

Build Driver Awareness of Factors influencing Vehicle Efficiency

Revise Driver Licensing Examination Content and Other Requirements

The content of the driver licensing examination should be upgraded to include testing of knowledge of: the main factors affecting vehicle efficiency; driver behaviors conducive to efficient energy use; vehicle operations and maintenance practices conducive to efficient energy use; savings possible from using different vehicle sizes, technology types and fuel types; and savings possible from using alternatives to private vehicle transport. The practical part of the examination should also test a driver’s ability to visually check lube oil levels and lube oil condition in her/his vehicle, as well the condition and inflation of tires.

Drivers of heavy-duty and mass transport vehicles will be required to do (over) and pass the currently-applicable examination every five years, in order to keep them up to date with the latest best practices for achieving optimal vehicle efficiency.

Action Recommendation – Preparation and Dissemination of Vehicle Fuel Efficiency Handbook

The Transport Authority should prepare a vehicle fuel efficiency information booklet for dissemination to drivers. This booklet should provide drivers with information on how to drive and maintain their personal vehicles to maximize fuel efficiency and present them with tips for purchasing fuel efficient vehicles. The information in the booklet should be used as the basis for testing drivers on the subject of fuel efficiency.

Implement a Smart Driver Training Workshop for Heavy-Duty and Mass Transport Vehicle Drivers

The Transport Authority should prepare and administer a smart driver training workshop for heavy-duty and mass transport vehicle drivers. The workshop program content should cover the following topics: factors affecting vehicle fuel efficiency, good and bad driving habits, preventative maintenance, the impact of idling, and tips on how to avoid causing traffic congestion or interfering with the smooth flow of traffic. The workshop should feature practical training in preventative maintenance and other checks that can be carried out by vehicle operators.

Completion of this training program will be a pre-requisite for obtaining a license to drive heavy-duty and mass transport vehicles.

Implement a Smart Fleet Manager Training Workshop

The Transport Authority should prepare and administer a yearly smart fleet manager training workshop to educate fleet managers about best practices and technologies that can be integrated into their fleet management programs to reduce overall energy use and carbon emissions, including technical advice on how to prepare and implement fuel management plans.

Influence Behavior towards More Efficient Vehicle Operations and Maintenance Practices

Launch an EE in Transport Rating Program underpinned by Mandatory Audits of Mass Transport and Freight Carriers Companies

The Transport Authority should launch an EE (Energy Efficiency) in Transport Rating Program to rate mass transport and freight carrier companies and companies with vehicle fleets of significant size on the extent to which best practices and technologies are incorporated into their fleet management programs to reduce vehicle energy use and emissions. This EE in Transport Rating Program should be underpinned by yearly mandatory audits of the operations and maintenance practices of these companies, and should be aligned with similar exemplary programs in other developing countries.

The companies will be ranked on how well they perform on a number of criteria, based on the results of the audits, and given an overall EE Star rating (from A-G). Companies with high ratings may be eligible for reductions in import duties and licensing fees beyond reductions already earned from surpassing applicable VAFE standards.

Revise Pre-requirements for Vehicle Licensing

The pre-requirements for vehicle licensing should be upgraded to include a pre-requirement that the condition of the vehicle *assessed at the time of the licensing* – such as condition of lube oil and tires (rolling resistance) – as it affects the overall fuel economy of the vehicle should meet minimum acceptability levels.

Enforce Vehicle Speed Limits on Highways

The Transport Authority should enforce vehicle speed limits on highways for all vehicles *including mass transport buses* by instituting highway traffic patrols on the major highways. Instead of having round-the-clock patrols, the patrols could be setup to run from 6:00 am in the morning until 10:00 pm at night, and involve two highway patrol vehicles moving in opposite directions on each highway throughout the 16-hour surveillance period.

Build Mobile Efficiency into Urban Plans

"Cars promise mobility, and they provide it in a largely rural setting. But in an urbanizing world there is an inherent conflict between the automobile and the city. After a point, as their numbers multiply, automobiles provide not mobility but immobility." From the Chapter on 'Designing Cities for People' (Brown, Plan B 3.0: Mobilizing to Save Civilization, 2008)

Restrict Heavy Vehicle Traffic through Urban Areas

The Transport Authority should implement laws to restrict slow-moving and heavy-duty vehicles above certain sizes - measured in terms of cross-sectional area, width, height and length - from trafficking through urban areas during high traffic hours in order to avoid congestion and hence reduce energy losses from idling. The Transport Authority should consider restricting extremely heavy vehicles, such as cranes, to passing through urban areas only during very low traffic hours.

Give Precedence to the Most Efficient Forms of Urban Mobility

"If you plan only for cars then drivers will feel like the King of the Road. This reinforces the attitude that the bicycle is backward and used only by the poor. But if you plan for bicycles, it changes the public attitude." *Roelof Wittink, Head of Interface for Cycling Expertise, a Netherlands NGO* (Brown, Plan B 3.0: Mobilizing to Save Civilization, 2008).

In addition to modifying street routes to accommodate motor-cycles and bicycles, legislation should be put in place to give cyclists the advantage over motorists in right-of-way and at traffic lights. Traffic signals should permit cyclists to move out before cars.

Reduce Traffic Congestion within Belize City and along the Main Routes leading into Belize City during Rush Hours

The Transport Authority should investigate various options for reducing traffic congestion within Belize City itself and along the main routes leading into Belize City during rush hours. Some of these options are:

- Converting the main highways and arteries into Belize City into four-lane routes (two-lanes in each direction) with each of the incoming lanes joining a different main street within Belize City.
- Setting up a tolling system for *incoming* traffic along the Northern Highway Entrance. The toll fee should vary by time of day – higher during rush hours - and should not be applicable to mass transport vehicles. Eventually, this tolling system can be upgraded to enable electronic operation, where electronic sensors installed at the tolling booth identify a vehicle and automatically charge the owner's credit or debit card.
- Carving out or reclaiming (from the seashore) a right-of-way going completely around Belize City's shoreline to be used for a free way that segues from the main highways and arteries, before their entrance into Belize City proper, and joins into its main streets along the circular route. The right-of-way should also provide for large-scale parking space along the shoreline outside of the central Belize City areas.
- Building an Urban Electric Tram Transport System through Belize City and concomitantly banning vehicle traffic along the tram routes.
- Building motor-cycle and bicycle paths along with pedestrian walkways along tram routes to encourage less energy-intensive and healthier forms of mobility.

Buildings, Lighting & Cooling

Stimulate (consumer) investment in energy efficient homes and buildings

Update Building Codes to reflect Mandatory Energy Efficiency Provisions

Municipal building codes should be updated to reflect mandatory BEECs (Building Energy Efficiency Codes) including minimum energy efficiency requirements for building components including windows (size and glazing), wall and rooftop materials, building orientation, electrical wiring standards, and equipment sizes. Designs that do not meet the minimum requirements for each component will not be approved for further construction.

Enforce Compliance with BEECs

After-construction inspection should be done to verify that BEEC design specifications were complied with. BEEC compliance should be administered and enforced by a competent government department or government-controlled body, with the legal authority to impose fines and other penalties for non-compliance, such as withholding utility connections until the necessary upgrades have been made to satisfy the full compliance requirements.

The technical staff of the compliance authority should possess a certain minimum level of technical education and be properly trained in compliance evaluation and enforcement.

Establish a Mandatory Green Building Certification Program for Domestic and Commercial Buildings

A Mandatory Green Building Certification (GBC) Program should be setup for domestic and commercial buildings similar to the LEED and Energy Star Certification Programs in the US in order to encourage a shift towards low-carbon, zero-energy or even energy-plus buildings. The intent is to look at the building as a whole in order to evaluate its *net* energy requirements - that is, the total estimated energy requirements of the building less energy provided by renewable and recoverable energy sources - versus the estimated cost of providing these net energy requirements, and then assign it a GBC rating - for example on a scale of U (Un-certified), E, D, C, B and A. An A rating might for instance be assigned to an Energy-Plus building, and a B rating to a Zero-Energy building.

The certification rating awarded could be based on a building's score in a number of categories, including: provision for day-lighting and natural light sensors in lighting systems, incorporation of occupancy sensors in lighting systems, use of solar lighting technologies, provisions for passive cooling using natural ventilation, provision of energy-efficient window glazing and frames, insulation of roofs and walls, air-tightness of the building envelope, provisions for use of geothermal cooling and solar cooling technologies, provisions for use of solar water heating technologies, use of indigenous materials, adequacy of internal electrical wiring, provisions for water conservation, and proximity to urban centers. Alternatively or additionally, certification could be based on the estimated percentage of the building's projected energy use that would/could be provided by renewable or recoverable energy sources based on the provisions made in the building's design and layout for the incorporation of renewable and recoverable energy equipment.

Green Building Certification should be mandatory: and any building that does not undergo certification should automatically be given a U (Un-certified) rating. Legislation to enforce this requirement should be enacted and backed up with stiff penalties. The GBC rating of a previously-certified commercial building or residential building which uses energy above a certain threshold will automatically reset to U if it has not undergone re-certification after five years. Re-certification is required in order to take into account any modifications that may have been made since the last certification. Moreover, when a new building is being certified, it may not be possible to assess its projected energy use based on the actual deployment of end use appliances and equipment in the building, since these may not have been purchased or installed as yet. The NEP Team recommends, however, that an energy audit of the actual end use appliances and equipment in the building be done at each re-certification *of commercial buildings only* to come up with a more precise estimate of the building's projected energy use. This will serve to further encourage purchase of energy-efficient appliances and equipment from the start.

Institute Capacity Building for Green Building Certification Process

Green Building certification should be administered by a competent authority, whose technical staff should be properly trained in Building Codes, Energy Audits, Building Control Systems, Integrated Building Design and Building Energy Management. Building assessments should be conducted by certified third party inspectors, who must possess a certain minimum level of technical education and undergo a thorough yearly training program on how to conduct building energy audits. Certification of the inspectors will be based on examination. The GBC and audit (inspection) processes must be carried out by separate parties.

Require New Government Buildings to be Zero-Energy or Energy-Plus Buildings

In fulfillment of its public leadership role in driving the energy efficiency movement forward, Government should mandate that all new government buildings over a certain size be designed and constructed as Zero-Energy or Energy-Plus buildings. It is important that the design is professionally thought out and planned, that the construction is done in accordance with the plans, and that the building is managed and maintained in accordance with the prescribed guidelines. A failure to deliver the promise of Zero-Energy or Energy-Plus at this level can have debilitating effects on the entire energy efficiency improvement program.

Promote Green Building Certification to Lending Institutions as a part of Lending Criteria for Home and Commercial Building Mortgages

The Government should actively promote Green Building Certification to lending institutions (banks, credit unions, the DFC and even government housing projects) as part of the lending criteria for home and commercial building mortgages.

Presentations should be made to lending institutions to encourage them to finance upfront energy-efficiency investments for new homes and commercial buildings by demonstrating that the incremental increase in monthly repayments due to such investments are more than offset by energy cost savings. Lending institutions should also be encouraged to factor energy cost savings into interest rates (to reduce them) and building worth valuations (to increase them), and to formulate and promote mortgage packages with clear links to GBC levels.

Government could also consider providing a credit guarantee for the energy efficiency portion of the loans on the condition that this guarantee is also factored into the overall mortgage interest rate for the particular loan application.

Launch an Energy Efficiency for Buildings Upgrade Program

Given the historical slow turn-over of the building stock, Government should launch a voluntary Energy Efficiency for Buildings Upgrade Program (EE-BUP) to improve the energy-efficiency of the current building stock. Any such improvement should be cost neutral to the building owners.

Participants will be required to undergo GBC certification and get a certification rating. If the rating is below an acceptable minimum level – say, a D rating – the building owner will be eligible to receive a grant and/or low-interest loan to be used towards the cost of retrofitting the building and a free technical assessment of the required retrofits needed to upgrade the building to meet the minimum GBC rating. Program officers will help to formulate and negotiate repayment plans for any loans so that the sum of the monthly loan repayment (if any) plus the new energy bills after the upgrade will be equal to or less than the sum of the energy bills before the upgrade. Grant amounts will be calibrated to offset loan amounts so that the cost neutrality criterion is maintained.

Require that Property and Property Sale Taxes be tied to Green Building Certification Rating

In order to encourage the shift towards a more energy-efficient building stock, a portion of property taxes should be tied to the actual building and land value and the other portion should be tied to the building's latest GBC rating.

Total Property Tax = Land + Building Value-Related Tax + GBC-Related Tax

This formula should be such that the GBC-related portion of the property tax is zero, once the building's GBC rating is an C rating, and becomes more negative – a rebate - as the GBC rating increases to 'A'. The residual effect for a building with a GBC rating above C is that the total property tax payable will be the land plus building value-related portion of the property tax less the rebate earned due to surpassing building energy efficiency requirements.

Resolve “Split Incentives” problem surrounding Energy Efficiency Improvement Projects

The adoption of EE improvement projects amongst households and commercial enterprises is often stymied by the “split-incentives” problem arising between landlords and tenants. In order to resolve the legal uncertainty issues surrounding EE project ownership and post-rental obligations arising in tenancy situations, legislation should be passed to clarify and protect the rights of both landlords and tenants engaged in EPC projects. A possible solution could be requiring that all EE projects undertaken in tenancy situations should be undertaken by the landlord only, or, if undertaken by the tenant, that there be no further obligation on the part of the landlord beyond the terms of the original contract. In the former case, the shared savings model, with an ESCO bearing all the EE project risks but sharing in the cost savings according to a pre-determined formula, could be employed; the agreement with the landlord could then stipulate that the ESCO should be paid off (by the landlord) for all unrecovered outlays should the tenancy contract be terminated before the end of the EPC between the landlord and the ESCO.

Introduce an Energy Efficiency Improvement Program for Commercial & Services Sector

The GOB in partnership with the Belize Tourism Industry Association (BTIA) should setup a *Voluntary Energy Efficiency Improvement Program* for the Commercial and Services Sector whereby an individual enterprise can voluntarily enter into an agreement with the GOB (or BTIA) to achieve certain energy efficiency targets within a certain time frame, in return for receiving technical and financial support.

This program will entail conducting energy audits of the facilities and buildings each of the participating companies to be conducted every two years. These audits should cover mainly lighting, cooling and heating systems with a view to detecting inefficient components and systems and system leakages, evaluating maintenance practices, and seeking opportunities for renewable and recoverable energy use.

Some of the major efficiency improvement projects, envisioned as part of this program, are:

A. Re-distributing and changing out lamps to reduce the occurrence of over-lighting, which is a common and often-overlooked problem especially in the hotel industry.

B. Integrating occupancy sensors and natural light sensors into lighting systems.

C. Upgrading to T5 fluorescent lamp luminaires using a mirror louvre fixture from equivalent T8 mirror louvre fixtures.

D. Installing water to refrigerant heat exchangers on cooling systems and upgrading to high energy efficiency ratio (EER) A/C systems with heat recovery for supplying hot water.

E. Retrofitting air conditioners with hydrocarbon LPG and NG refrigerant to lower maintenance cost and extend equipment life.

F. Installing solar water heaters using solar thermal technology.

G. Installing geothermal pumps for both space cooling and water heating.

Encourage Provision for Vents in Rural Households where Wood Fuel Cooking is done

Studies have shown that providing vents for rural households where firewood-based cooking is done can help to mitigate the health effects of dangerous products released due to incomplete wood fuel combustion. While it may be impractical to enforce rural household building standards generally, GOB can require that rural houses built under any government-financed project should be fitted with proper vents as a condition of government's participation in the project. This requirement should also be extended to DFC-backed mortgages. Beyond this, GOB should embark on a country-wide sensitization campaign targeting local builders of rural households, providing them with technical know-how for incorporating vents into their building plans and for constructing vents.

Stimulate (consumer) investment in energy efficient appliances

Action Recommendation – Country-wide Project to Change-over from Electric Incandescent to Solar and Electric Fluorescent and LED Lamps

A country-wide project should be undertaken to replace all electric incandescent lamps with solar-powered and electric fluorescent and LED lamps. Such a project could be carried out in four phases:

A. An informational and educational campaign phase, where the energy-savings benefits of fluorescent and LED lamps and solar lighting in general are promoted and the procedures for change-out are explained;

B. An enrolment phase, where interested households sign-up for the program;

C. An evaluation phase, where the stock of lamps in each enrolled household are evaluated and a determination made as to how many lamps need to be replaced, and with what types (e.g. solar-fluorescent, solar-LED, electric-fluorescent or electric LED) and sizes of lamps;

D. An implementation phase, involving the actual change-outs. This implementation phase would have to be carefully planned and monitored to prevent abuse. One of the conditions of enrolment would have to be requiring that the replaced incandescent bulbs be handed over to the supervising authority at the time of replacement.

It is likely that financial incentives would have to be given in order to encourage mass uptake. The quantum of such incentives would be dependent on the cost-benefit underpinnings worked out by the NEEPI. A possible route to consider is having the GOB pay for the replacement lamps (or a portion of the costs) while the owner of the premises pays for the labor.

Action Recommendation – Procedures for Proper Cleanup of Breakages of Fluorescent Lamps

Educational campaigns via public service radio, TV and text message announcements and directly in all schools should be conducted to inform the public of the dangers of being exposed to mercury emissions from fluorescent lamp breakages and of the proper procedures for mitigation and cleanup.

Action Recommendation – Disposal of Spent Fluorescent Lamps

Spent fluorescent lamps should be classified as hazardous waste and legislation should be enacted to effect penalties for non-compliance with the required procedures for proper disposal.

Government should setup a local facility, with collection centers in each city and town, through which fluorescent lamps can be recycled. The facility could work in cooperation with a recycling factory in Mexico or the US to which spent lamps can be sent in bulk. The lamps can be stored in a safe location at the local facility until a certain critical volume (mass) is reached for sending to the recycling facility abroad.

Action Recommendation – Country-wide Project to Change-over to Hybrid Solar-Electric Street Lights

A country-wide project should be undertaken to replace all electric streetlights with hybrid solar-electric streetlights. These hybrid solar-electric streetlights would use electricity discharged from batteries, which are charged up by sunlight during the day, and automatically switch over to grid electricity if the batteries run out of charge (as could be the case after a day of reduced sunlight hours due to heavy cloud cover or overcast or rainy skies).

Lower Import Duties on Solar and Electric Fluorescent and LED Lamps relative to Incandescent Lamps

Import duties on lamps should be calculated on the basis of their net present value of lifecycle cost per lumen of output. This should ensure that incandescent lamps incur substantially higher import duties than fluorescent and LED lamps, and that solar-powered lamps feature lower duties than electric lamps for the same illumination technology, resulting in a mass discontinuation of the use of incandescent bulbs in new buildings and a shift towards solar-powered lights where feasible.

In support of Belize's tourism industry, commercial enterprises, such as restaurants, hotels and certain stores, which may require incandescent lamps for ambience lighting purposes, should be given permission to import limited quantities of incandescent lamps directly at a discounted import duty rate.

Introduce Energy Labeling of Appliances

An *Appliance Energy Efficiency Labeling Scheme* should be implemented for certain classes of appliances: for example, refrigerators, washing machines, dryers, and air-conditioners. The appliance label should show the following information: year of manufacture, type of energy form or fuel used, estimated energy consumption per hour of use at high load and at normal load, and estimated GHG emissions (in tonnes of CO2e per hour of use). The intention is to increase consumer's awareness of the real energy use of household appliances at the point of purchase through a liable and clear labeling.

This labeling scheme must be supported by legislation imposing severe penalties and fines on any company or person who provides false information on energy labels.

Introduce Recommended and Minimum Appliance Energy Efficiency Standards

The NEEPI should *each year* prepare the Recommended and Minimum Appliance Energy Efficiency Standards for certain classes of appliances.

The Recommended Appliance Energy Efficiency Standard in a particular appliance class should be the energy consumption rate of the appliance which is currently available in the USA and other world markets and costs the least on a net present value life-cycle cost basis (relative to Belize). This life-cycle cost assessment should take into account acquisition cost, fuel (energy) costs, O&M costs, and environmental emissions costs.

The Minimum Appliance Energy Efficiency Standard in a particular appliance class is the lowest appliance energy efficiency acceptable.

The Recommended and Minimum Appliance Energy Efficiency Standards should be well-advertised to appliance importers and the public in general *at least a year in advance of its effective date* through sustained educational and informational campaigns.

Implement Stringent Energy Efficiency Standards for Refrigerators and Air-Conditioners

Particular attention should be paid to the minimum energy efficiency standards required for refrigerators and air conditioning systems, as these are probably the single largest energy-consuming appliances in households and commercial buildings respectively. Energy efficiency standards for these appliances must be stringent. Wiring and building inspections done on households and commercial buildings should ensure that electrical circuits linking these appliances to the electricity mains are adequately-sized, that the A/C systems themselves are properly-sized and that rooms with A/Cs are properly sealed off to minimize heat exchange with their surroundings.

Establish Limits for Stand-by Electricity Use of Certain Appliances and Devices

Electricity used by appliances while in stand-by mode adds up to as much as 10% of residential electricity use world-wide. Government should mandate maximum power consumption limits while in standby-mode for certain appliances and devices such as TVs, computers, microwaves, and DVD players, following along the lines of the 1-W limit on most appliances being adopted by South Korea and Australia.

Require that Appliance Import Duties be tied to the Recommended Appliance Efficiency Standard

In order to encourage purchase and use of energy-efficient appliances, a portion of import duties should be tied to the actual purchase cost of the appliance and the other portion should be tied to the Recommended Appliance Efficiency Standard applicable to the appliance class. Keeping a portion of import duty tied to purchase cost reflects the principle of ability to pay as well as serving as a penalty for the loss of foreign exchange incurred in paying for the appliance.

Total Import Duty = Purchase Cost-Related Duty + Energy Efficiency-Related Duty

The basis of the formula for calculating the Energy Efficiency-related portion of the import duty should be the present value of the projected energy and emissions costs over the lifetime of the appliance. This formula should be such that the Energy Efficiency -related portion of the import duty is zero, once the assessed efficiency of the appliance is exactly equal to the Recommended Appliance Energy Efficiency Standard, and becomes more negative – a rebate - as the assessed energy efficiency deviates further above the Recommended Appliance Energy Efficiency Standard. The residual effect for an appliance with assessed efficiency higher than the Recommended Appliance Energy Efficiency Standard is that the total import duty payable will be the purchase cost-related portion of the import duty less the rebate.

Require that Permission for Appliance Importation be tied to the Minimum Appliance Energy Efficiency Standard

In order to encourage use of energy-efficient appliances, permission should not be granted to import any appliance with assessed energy efficiency below the applicable Minimum Appliance Energy Efficiency Standard.

Rationalize Import Duties on Solar and Geothermal Cooling and Heating Equipment relative to Electric Air-conditioners and Water Heaters

Import duties on cooling and heating equipment for households and commercial buildings should be calculated on the basis of their net present value of lifecycle cost per unit volume of space or water cooled or heated. This should ensure that energy savings are taken into account in import duty calculations.

Require Mandatory Use of Solar Water Heaters

Government should mandate that all water heating used in residential and commercial buildings should be provided by solar technology. The importation of electric-only water heaters should be halted immediately.

Setup Program to Replace Traditional Wood Stoves with New Improved Wood Stoves for Cooking and Water Heating

Replacing wood fuel for cooking and water heating with LPG is not recommended for communities that currently use wood for these purposes. Wood fuel is a relatively plentiful renewable natural resource and the net GHG emissions from its combustion are negligible. LPG, on the other hand, is a petroleum-based non-renewable fuel with relatively high GHG emissions, which costs four times more than wood fuel for cooking. Our cursory analyses have shown that it would cost over $7 million USD per year in additional fuel costs alone to replace wood fuel cooking with LPG range cooking.

The NEP Team recommends that the Government launch a program to replace all traditional wood stoves instead with improved wood stoves in order to improve wood burning efficiency, thus resulting in reduced and hence more sustainable wood fuel consumption and substantially lower levels of particulate emissions (by about 67%). This program may need to be backed up by a policy requiring that all traditional wood stoves be phased out within a certain timeline and a supporting rebate program, where a financial incentive is given towards the purchase of the new stove.

Action Recommendation – Setting up of a National Laboratory for Testing of Appliance and Equipment Energy Performance

Government should setup a *National Appliance and Equipment Testing and Certification Center* attached to the NEEPI to make sure that appliance standards are effectively enforced, to check the compliance of imported and marketed products with national standards, and to continually adapt the national standards to reflect the best practice and best available technologies.

Influence Consumer End-Use Energy Consumption Patterns

Action Recommendation – Country-wide Campaign to Install Occupancy Sensors in Government Office Buildings, Commercial Buildings and Hotels

A sector-wide campaign should be launched to encourage the installation of occupancy (presence) sensors in the lighting systems of offices and rooms in all commercial and government buildings. The main targets of this initiative should be government offices, hotel rooms, hospitals and school class-rooms.

Government can in fact lead this initiative by making it mandatory for occupancy sensors to be installed in all its main offices within a certain time frame.

Action Recommendation – Country-wide Campaign to Install Natural Light Sensors in Government Office Buildings, Commercial Buildings and Hotels

A sector-wide campaign should be launched to encourage the installation of natural light sensors in the lighting systems of lobbies, offices and rooms in commercial and government buildings. The main targets of this initiative should be government offices, hospitals, hotels and school class-rooms.

Government can lead this initiative by making it mandatory for natural light sensors to be installed in all its main lobbies and offices within a certain time frame.

Encourage Use of Energy Monitors in High Energy Consumption Residential and Commercial Buildings

Energy Monitors are devices that provide instantaneous feedback on energy consumption in households and businesses. Government should *encourage* the use of energy monitors in residential buildings that consume energy above a certain threshold and *require* that energy monitors be installed in all commercial buildings that consume energy above a certain threshold so as to help consumers make more informed choices in changing their energy use patterns and ultimately reducing their consumption costs.

To further encourage uptake and reduce financial burden, no import duties should be charged on Energy Monitors.

Action Recommendation – Preparation and Dissemination of Residential and Commercial Energy Efficiency Handbook and Website

An energy efficiency information booklet should be prepared for dissemination to energy consumers in general. This booklet should provide information to consumers on a number of topics related to energy efficiency in homes and in office buildings such as: the recommended energy efficiency and typical daily or yearly consumption of the main types of appliance, showing how consumption varies with efficiency; how to read energy efficiency labels; how to operate and maintain refrigerators, A/C's, dryers and washers for maximum efficiency; the benefits and costs of occupancy sensors and natural light sensors; the costs of standby electricity use and how to reduce it; and the importance of having properly-sized appliances and properly-designed electrical wiring circuits.

An accompanying website should be developed to disseminate information contained in the booklet with links to further details. The website should provide an energy calculator where estimates of energy consumption and costs can be calculated for typical household appliances as well as for an entire household. Users should be able to make changes to the types of appliances used or the energy efficiency of individual appliances to see how the total energy bill varies with changes made.

Industry

Encourage Participation in Voluntary Certification Programs for Energy Efficiency Improvement

The GOB should promulgate relevant ISO energy efficiency-related standards to industries and encourage participation of local industrial companies in voluntary ISO certification programs for energy efficiency improvement. This can be initiated by holding an annual seminar where ISO experts can explain the standards, the protocols for participation, and sign up companies. Companies who sign up and demonstrate adherence to the program – as judged from energy audits – should be acknowledged in relevant publications by Government and other local industry organizations.

Introduce Voluntary Target-Setting Agreements for Energy Efficiency Improvements

The GOB should setup a *Voluntary Energy Efficiency Improvement Program* whereby an individual industrial company can voluntarily enter into an agreement with the GOB to achieve certain energy efficiency targets within a certain time frame, in return for receiving technical and financial support and other economic incentives such as tax breaks and import duty reductions.

Regular energy efficiency audits will necessarily be conducted as a part of this program. Such audits will involve a thorough energy audit of all of the company’s systems and processes in order to detect leakages and inefficiencies and exploit opportunities for quantum leaps in energy efficiency improvement.

These voluntary energy efficiency agreements should be aimed mainly at companies whose annual energy consumption rate is above a certain level and companies engaged in the major energy-consuming industries; specifically the sugar-cane processing, citrus processing, petroleum extraction, transport, water supply and electricity production industries. A separate program should be designed for the Hotel Industry, based on the CHENACT model. This program could be administered by the BTB.

Action Recommendation – Mandatory Enrolment of BSI/BELCOGEN in Efficiency Improvement Program

BSI/BELCOGEN is currently Belize’s single largest consumer of energy, and the single largest producer of energy. This company must therefore be singled out for special immediate attention for energy efficiency improvements, and should be required to enroll in the Efficiency Improvement Program.

An Energy Manager should be appointed to the technical staff to head the effort to systematically optimize the operations of the combined facility for maximum energy efficiency.

Implement Mandatory Energy Audits that are tied to Licenses, Concessions and Other Economic Incentives

The GOB should mandate that all companies operating within certain high-priority industries, and that are not engaged in its *Voluntary Energy Efficiency Improvement Program*, be required to undergo regular energy audits as a condition of their license to operate or for the continued receipt of other economic incentives and concessionary benefits.

The results of these audits will be compared with benchmarks established by the NEEPI and fed back to the companies with recommendations for improvement.

The GOB will need to assure such companies that the specific details of the outcome of such audits will be fed back to them, that no information or data will be shared with any other party and that the results will be compiled and used only in an aggregate way that does not tie them (the results) back to the company itself.

Action Recommendation – Development of Benchmarks for Industrial Facilities, Systems and Processes

The NEEPI should be commissioned to prepare energy-efficiency benchmarks for all major industries such as sugar-cane processing, citrus processing, water processing, electricity production, petroleum extraction and beverage processing. Benchmarks may be established for industrial facilities as a whole, or individual systems within facilities, or individual processes within these systems; and should reflect both Best Practice Technologies (BPT) and Best Available Technologies (BAT) in emerging economies and countries in the region. These benchmarks should be used to support the voluntary and mandatory target-setting agreements referred to above.

Place a High Priority on Maintenance of Large Energy-Intensive Equipment

Industrial companies (and large commercial companies such as hotels) should be required to perform maintenance of large energy-intensive equipment such as boilers and cooling systems in accordance with manufacturer's recommendations or schedules issued by NEEPI. These companies should be required to submit proof of maintenance work done in the form of certified maintenance reports.

Energy audits should verify conformance with the maintenance schedules of these large energy-intensive equipment.

Place a High Priority on Exploitation of Opportunities for Waste Heat Recovery and Waste Reuse as Feedstock

Energy efficiency measures undertaken within industries and even for commercial establishments should place a high priority on exploiting opportunities for waste heat recovery (for electricity generation and water and space heating) and waste reuse as feedstock for other processes within the facility or in a different facility. Energy audits should purposely seek out and target such opportunities.

Require that Energy Manager/Coordinator Position be setup within Certain Industrial Companies

Certain high energy consumption industrial companies that participate in the *Voluntary Energy Efficiency Improvement Program* should be required to establish a senior management-level post for an Energy Manager. This person must be a certified engineer – preferably an industrial engineer, with over 10 years of engineering experience, and specially trained in systems optimization principles and techniques.

Action Recommendation – Fostering a Corporate Culture focused on Energy Efficiency

In order to create and foster a corporate culture focused on energy efficiency improvement throughout commercial and industrial enterprises in Belize, the GOB should initiate a sustained country-wide educational and informational campaign to create awareness and engender action amongst key management, engineering and technical staff. Such a campaign could entail having regular high-level seminars featuring talks by well-respected local and international energy experts.

Action Recommendation – Establish a Leadership in Energy Efficiency Recognition Program

Studies have shown that getting esteem from others is a strong motivator of "good" behavior (Babcock, 2009). In order to support the various energy efficiency initiatives and engender support at the highest levels within enterprises, an annual recognition program should be launched to honor the top-performing companies and executives who had a transformational impact on energy efficiency improvement in their enterprise or in Belize as a whole.

Agriculture & Forestry

Launch a Renewable Energy for Agriculture Program

Modern farm practices are heavily dependent on petroleum by-products for fuel, fertilizer and pest management. Renewable energy technologies - such as solar, wind, and biofuels - can play a key role in creating a sustainable future in agriculture. The GOB should launch a *Renewable Energy for Agriculture Program* to encourage the use of renewable energy technologies in farms and agro-processing: including solar crop dryers; solar water heating for dairy operations and pen and equipment cleaning; solar PV solutions for small motors, lighting and water pumping, especially in remote off-grid farms; and wind-pumping solutions for irrigating agricultural fields with surface water and pasturelands from underground aquifers.

Support Local Research of and Education of Farmers in Low-Energy Agricultural Practices

In order to wean the modern agricultural production systems off their heavy dependence on fossil fuels for energy, fertilizers and pest management, the GOB should support local research into and education of stakeholders in incorporating the latest scientific advances with low-energy cost-effective agricultural practices.

Action Recommendation – Measurement of Biomass Production Potential of Forestry, Agro-Processing and Industrial Activities

The 2009 Cellulosic Biomass Study (Contreras & De Cuba, Feasibility Study on the Cellulosic Ethanol Market Potential in Belize, 2009) derived rough estimates of Belize's biomass production potential based on a combination of reported figures and rule-of-thumb calculations. A much more in-depth measurement of Belize's biomass production potential should be done in order to be able to properly assess the energy from biomass production potential. This study should also classify these biomass-producing sites by output potential, determine the locations of these sites and come up with more precise costs for collecting biomass from dispersed locations to central locations.

Action Recommendation – Commission a Cost-Benefit Analysis of Commercialization of Dried Fuelwood Processing and Distribution

The use of dried firewood in modern wood-burning stoves results in significantly lower (67%) emissions of particulate matter - the most dangerous of the pollutants produced by wood combustion - since wood with lower moisture levels burns more completely and modern stoves are designed to capture and contain pollutants. Ensuring that the moisture content of firewood has been reduced to sufficiently low levels before burning is difficult because of the way wood is currently collected – directly by individual families.

The GOB should commission a study into the commercial arrangements that can be implemented to collect and deliver wood to a central facility for proper drying and controlled distribution in the communities that are dependent on its use for cooking and water heating. This study should also address concerns regarding the sustainable rate of local wood fuel consumption.

Education and Information Dissemination

Ensure that Government plays a Visible Leadership Role in Promulgating Policies issued by NEEPI

Government can help to promulgate policies issued by NEEPI by taking a visible first-adopter leadership role in complying with policies so issued; particularly those related to transport, buildings (lighting and cooling) and appliances.

The GOB should for instance require that Transport Fleet Managers at all levels of government and in government-controlled statutory bodies adopt and implement transport policies issued by the NEEPI as soon as practicable. Entire vehicle fleets can be changed over to biofuels for instance or to hybrid-electric or all-electric in accordance with NEEPI's targets. Prominent stickers on Government vehicles such as 'Powered by Locally-Produced Sugar Cane Ethanol' can make a difference in influencing public opinion. Moreover, because of the sheer size of the Government's fleet, suppliers will be forced to put in place the necessary fuel (energy) dispensing facilities required by the new NEEPI-issued standards.

Disseminate Success Stories to Gain Support for and Encourage Participation in Programs

Successful outcomes of programs as whole, especially voluntary programs, and of individual instances should be publicized so as to gain support for and encourage participation in programs.

Capacity Building

Build Strong Technical and Scientific Education Foundation to support Local Energy Development

There is a severe paucity of local engineering expertise currently employed in the major industries involved in the energy supply value chain, such as the agro-processing and petroleum industries. With the discovery of crude oil in 2005, there has been a greater demand for highly-skilled as well as semi-skilled personnel, ranging from engineers, technical consultants and geologists to welders, rig operators, and lab technicians. However, presently, all of the top technical positions in crude exploration and processing are filled by foreigners from the US, UK and Guatemala. Similarly, the top technical positions leading the refinery operation at Blue Sky were also filled by foreigners, during the period of its short existence.

Building a robust and viable energy industry that harnesses our renewable and recoverable energy sources and seeks to capitalize on energy efficiency opportunities requires a range of expertise and skilled labor in various key technical areas, including: solar panel installation and maintenance; wind turbine installation and maintenance; geothermal pump installation and maintenance; micro-generation grid connection; biofuel feedstock research and cultivation; biofuel plant processing construction, operations and maintenance; retrofitting for building energy efficiency; auditing of industry operations and buildings; and residential EE inspections. Having readily available competent expertise is critical to building stakeholder confidence in the efficacy of these technologies and hence their rate of uptake. This is especially so during the early stages of the launch of a new and unproven technology into the local market, when poor workmanship is often mistaken for a failure of the technology itself.

To adequately prepare for new opportunities in this sector and to nurture the development of the nascent renewable energy and energy efficiency industries, the Government should, through the Ministry of Education acting in conjunction with the new Science and Technology Council, spearhead a study to assess the quality and quantity of engineering, scientific and technical expertise that will be needed to support the energy sector development plan over the planning horizon. This includes all the sectors involved: electricity, renewable energy, biofuels, agriculture and agro-processing (for feedstock), petroleum, energy efficiency, and technical planning. The study should identify which technical and engineering programs can be supplied locally, which can be done via distance learning programs and which will require study abroad; as well as what changes will be required to local tertiary curricula and what further professional teacher training will be required to undertake the programs that are to be supplied locally. The results of the study should be used as the basis for further action from the Government and to determine how the programs and scholarships will be financed.

Financing for Energy Efficiency and Recoverable Energy Projects

Most EE projects entail significant upfront capital outlays, and this has been cited by almost all the reports and papers as one of the single most significant hurdles to overcome in getting EE off the ground. This finding is no less applicable to Belize, particularly amongst residential and commercial users. Paying thousands of dollars upfront to reduce one's energy bills by 20% say is not readily regarded as an "affordable" investment prospect. In fact, given our history of high lending interest rates, Belizeans may probably be investment-averse, concerned about not being able to keep up with the stringent repayment schedules. For this reason, many of the experts have recommended putting in place subsidies and tax credits to lower this barrier.

Government Programs

The NEP Team recommends that the Government should provide full subsidies for initial energy audits particularly for larger commercial and industrial EE projects on the condition that, once these companies are made aware of the potential for savings and hence for increasing profits, they should find ways to access the capital needed for the upfront investment.

The same cannot be expected from residential consumers or even smaller commercial consumers. Government may, for instance, through special programs, provide these categories of consumers with free technical assessments of the retrofits needed to upgrade the buildings they own in order to meet the minimum GBC rating. Some will also likely require grants and/or low-interest loans to be used towards the cost of retrofitting these buildings. In many cases, they will need to formulate and negotiate repayment plans for any loans so that the sum of the monthly loan repayment (if any) plus the new energy bills after the upgrade will be equal to or less than the sum of the energy bills before the upgrade. Additional grants may have to be given to offset loan amounts so that the cost neutrality criterion is maintained.

Financial Institutions

Lending institutions should be encouraged to factor energy cost savings into interest rates (to reduce them) and building worth valuations (to increase them), and to formulate and promote mortgage packages with clear links to GBC levels.

Government could also consider providing a credit guarantee for the energy efficiency portion of the loans on the condition that this guarantee is also factored into the overall mortgage interest rate for the particular loan application.

ESCOs

Studies have shown that motivational tools alone including informational campaigns and financial incentives are not sufficient to compel households to invest in energy saving measures (Babcock, 2009). For such groups, EE projects will likely have to be structured so that owners spend as little time and energy as possible planning and managing the project, and so that they “see” only the net benefits from the investment over the project life as opposed to an initial high cost followed by later savings. Government can promote the development of Energy Service Companies (ESCOs) to help in this regard: these are companies that plan, implement and manage EE and recoverable energy projects on behalf of households, providing assurance of a certain level of annual energy savings for their clients.

Put in Place Institutional and Legal Framework to Foster the Development of ESCOs in Belize

In order to reduce the extent of the disconnect between the potential and the actual rate of uptake of energy efficiency improvement and micro-generation projects, Government needs to create a local climate conducive to the development of ESCOs.

The Government should put in place the institutional and legal framework to foster the development of Energy Service Companies (ESCOs) in Belize. ESCOs require access to low-cost financing, technical and financial experts and legal protections. Government can negotiate the seed capital (sourced from countries and international agencies wishing to participate in bi-lateral technology transfer arrangements) needed to initiate a revolving fund for on-lending to ESCOs. This can be further backed up by providing ESCOs with credit guarantees for project loans and investment recovery guarantees for projects abandoned by homeowners. The extent of such guarantees may vary for different project types or may be limited on a per project basis.

Appropriate third-party ownership legislation should also be enacted to protect investments made by ESCOs for energy efficiency projects that are deployed in households and buildings. ESCOs must be assured that they can recover stranded investments if a homeowner or building owner abandons the EE project or that they are fully compensated for on-site equipment damages that are deemed within the control of the homeowner or building owner.

Action Recommendation – Encourage the Use of Programmatic CDM Financing for ESCOs

Programmatic CDM allows for a single entity to manage and coordinate a number of smaller CDM-eligible projects under a single program manager. ESCOs should be encouraged to consider signing up as CDM program managers in order to take advantage of carbon credits earnable by EE projects included as part of a registered CDM program that otherwise could not be cost-effectively earned by the project owner on his own. The CERs earned may be used to help finance the initial investments needed for the EE projects, resulting in further benefits for both ESCO and participant.

IMPLEMENTATION PLAN

A National Database of Energy Data and Information

In order to be able to make rational energy policy decisions, policy-makers and planners must first model the often complex inter-relationships between energy and the economy and the environment. Once such an energy-economic model has been formulated, the quantitative effects of proposed energy policy instruments on indicators such as overall energy cost and emissions intensity can be properly tested and evaluated.

This energy-economic model must necessarily be developed on the basis of projections of energy consumption, production, exports, imports, primary-to-secondary energy conversion efficiencies, secondary energy distribution efficiencies, secondary-to-final end use energy conversion efficiencies, and energy prices over a suitable forecast horizon. These projections are themselves underpinned by assumptions about local macroeconomic – and, in many cases, microeconomic - factors, world and regional energy markets, local resource availability and costs, cost and performance characteristics of energy technologies, technology innovation paths and rates, and behavioral and technological choice trends.

The number one priority of the NEEPI must therefore be to develop a vast compendium of continuously-updated data and technical knowledge that form the basis of the energy-economic model and that can be fed into a computer-based tool – whether a basic home-grown spreadsheet tool or a more advanced analytical framework such as NEMS (EIA) or SIEN (OLADE) or LEAP[186] that is then used to analyze the impact of energy policy proposals on key economic performance areas. These tools can be used to develop desired scenarios consisting of key policies affecting different areas of the energy sector: for example, introduction of biofuels in transport as of a particular year, followed by the introduction of electric cars say 10 years later; plus new energy efficiency targets for appliances. The economic and financial impacts of these policy packages (scenarios) can then be evaluated and compared in order to determine the best way forward.

The resultant energy information system should also be used to produce energy intelligence and reports for dissemination to the various industries and other energy stakeholders. In the absence of a local central energy information authority, stakeholders are currently forced to individually invest an inordinate amount of time and resources to gather data from the various disparate sources. Others, who cannot afford a dedicated information gathering and data mining function, resort to regional and international energy information authorities such as the EIA and DOE. However, these information sources are only as reliable as the local data sources that they use.

For instance, in researching the data needed for these analyses, we relied heavily upon the EIA and the WEC. In their electricity consumption statistics, the EIA gives a figure of 0.199 billion KWhs for Belize's total electricity consumption in 2007. However, total sales of electricity (as recorded at customers' meters) in 2007 were actually about 0.400 billion KWhs: twice as much as the EIA figure. The same kind of error was observed with the electricity generation data published by the EIA. Where is the EIA sourcing its data from? In one sense this tells us that we cannot rely upon the EIA for accurate data, but more importantly it underscores the urgency of setting up this national database of energy data and technical information.

Proper and detailed protocols stipulating exactly what data are required, and how – meaning the format, precision and frequency - these data are to be shared between the NEEPI and the data sources, are therefore vital to the work of the NEEPI. Energy service providers should be required to categorize customers by sector (Residential, Commercial, Services, Industrial) and micro-sector e.g. Commercial – Restaurant; Industrial – Food Processing, using an appropriate classification system recommended by the NEEPI. For instance, the categorization of electricity customers by BEL as residential, commercial and industrial is currently done according to a customer's rate class; and not according to the actual purpose that electricity is being used for. For instance, there are many consumers who are small restaurants or shops that are assigned a 'Residential' rate class and so appear as 'Residential' customers, although they are actually commercial customers. Similarly, there are many small industries like Glass Shops and Furniture Shops that are assigned 'Commercial' rate class and so

[186] Developed by the Stockholm Environment Institute, it is a widely-used tool in energy policy analysis and assessment of climate change.

categorized as 'Commercial' customers. It is understood that BEL's billing software application already provides user defined fields that can be used to categorize customers by a number of additional attributes.

Likewise, it would be useful for the Custom Department to become the key data source for basic volumetric data on petroleum products exports and consumption in addition to collecting duties and taxes: presently, the data being collected are incomplete and inaccurate and cannot be relied upon as inputs to the required analyses underpinning policy-formulation.

An Organizational Structure to Move Us Forward

"To develop strong energy systems, policymakers need a complex range of capacities: effective processes for engaging with the energy industry and other stakeholders; openness to policy innovation; and the ability to assess the costs and benefits of different options rigorously and transparently. These will enable them to make long-range commitments, while retaining the capability to respond to market changes in the short-term, and without sacrificing coherence and clarity of approach". (WEC, 2010)

This policy framework eschews a haphazard all-solutions-accepted approach that is narrowly confined to solving our energy-related problems for one based on a long-term energy plan that leverages our particular strengths and covers our relative vulnerabilities and that is underpinned by clear strategic objectives to solve our energy-related problems as well as to take advantage of energy-related opportunities. Such a plan must be built on the basis of comprehensive analyses of reliable, accurate and relevant data. The collection, compilation, collation and updating of this data; the subsequent analyses of the data; the derivation of plans and policy proposals from the results of these analyses; and the assessment of the impact of proposed plans and policies on other sectors of Belize's economy require a concerted, focused and consistent effort. In our view, such an effort can best be channeled and managed through a *National Energy and Electricity Planning Institute (NEEPI)*.

TOR of NEEPI

As proposed in an earlier section of this chapter, the NEEPI should be charged with the responsibility for formulating energy plans and policies in coordination with relevant stakeholders, for disseminating these plans and policies to relevant stakeholders (after the requisite approvals have been gotten), for monitoring adherence to these plans and policies through the bodies charged with administering them, and for providing information feedback to stakeholders.

NEEPI Outputs

The major outputs of the NEEPI should be the following:

- Policy proposals
- *Energy plans* on which the policy proposals are based
- Annual energy reports, similar to the Annual Energy Outlook produced by the US DOE
- *Quarterly energy reports*, following the same format as the annual energy report
- Aggregate energy statistics by sector

Relationship with Government and Other Organizations

The NEEPI should be setup as an autonomous statutory body under the auspices of the Ministry of Public Utilities or the Ministry of Natural Resources or a new Ministry of Energy. The NEEPI should have its own Board of Directors consisting of representatives from Government, Commerce & Industry and other energy stakeholders. From a high-level perspective, therefore, the NEEPI should not directly report to any particular Ministry or other Government department. Government exerts its control over the direction of the NEEPI through the representatives it appoints on the NEEPI's board and, more importantly, through Government's stated national priorities and objectives, which the NEEPI should be bound to follow.

The NEEPI should NOT be treated as an advisory body. It is to be charged with delivering specific results – that is, charting and managing the course of the development of the energy sector *in accordance with Government's national priorities and objectives*. It should usurp the functions of the disparate policy-making and advisory boards that currently serve the energy sector such as the Petroleum Advisory Board; thus bringing some much needed cohesion to the sector.

Proposed Technical Organizational Structure

The technical responsibilities of the NEEPI should be assigned to units on the basis of area of energy supply or consumption sector: upstream petroleum, agriculture and upstream biofuels, transport (which would include downstream petroleum fuels and biofuels), renewable electricity, buildings, and industry (including agro-processing). Technical responsibilities assigned to each unit may be further re-assigned to sub-units within the unit. For example, the responsibilities of the unit in charge of upstream petroleum may be divided between two sub-units: one in charge of upstream-crude oil and the other responsible for upstream-other petroleum products; or into one responsible for onshore petroleum and the other, offshore petroleum. Similarly, the responsibilities of the unit in charge of buildings may be divided between two sub-units: one in charge of residential buildings and the other, commercial buildings; or one in charge of cooling and heating, and the other, lighting and other end-uses.

These units should work closely with stakeholders and other government organizations, such as the Department of Transport, the Customs Department, the PUC, the Bureau of Standards, the Petroleum Industry Association, the Petroleum Service Dealers

Association, BTB, BTIA, CBA, BCCI and other private sector organizations, in gathering the data and information requisite for energy policy formulation.

A separate technical planning and policy-formulation unit should be setup to receive the results of analyses and recommendations from each of the other units, and to collate these results and recommendations into the energy plan and final policy proposals. The technical planning unit should be headed by a technical planning committee, made up of the heads of each of the other units and technical planning experts. The recommendations of this technical planning committee are then submitted to the Board of the NEEPI for their approval, before submission to the Cabinet or appropriate Ministry for final ratification and follow-up action.

APPENDICES

APPENDIX A: WIND TURBINE ENERGY OUTPUT METHODOLOGY

Method of calculation[187]

The calculation method used is mainly suited for horizontal axis wind turbines and delivers only a rough estimate of the annual energy output for this type of wind turbines. In practice big differences can occur, depending on the brand and type of the actual wind turbine.

The energy of the wind can be expressed with the formula:
$P = 1/2 \times Rho \times v^3 \times A$

Where:
P = the power of the wind in Watt
Rho = the density of air, in kg/m^3
v = speed (velocity), in m/s
A = the area that is swept by the rotorblades, in m^2

For a wind turbine with diameter D and operating at sea level and 15 degrees Celsius (an air density of 1,225 kg/m^3) the power of the wind is:
$P(wind) = 0{,}48 \times V^3 \times D^2$

Betz' law says that a wind turbine can extract a maximum of 16/27 (in other words 60%) of the energy from the wind :
$P\ (Betz) = 16/27 * P(wind)$

To get an estimation of the annual energy output of a wind turbine in kWh the follwing formula is used: $E\ (kWh) = 0.48 * 8760/1000 \times Cp \times v^3 \times D^2$

Where:
E (kWh) = annual energy output in kWh
Cp = efficiency factor of the wind turbine
v = wind speed in m/s
D = rotor diameter of the wind turbine in meters (*average of 65 m used for calculations in this NEP Report*)

For this calculation an efficiency factor Cp of 0.6 is used. To get a result in kWh the number of hours in a year (8760) is divided by 1000.

The wind speed at a certain height above ground level is:
$v_h = v_{10} * \log(h/z) / \log(10/z)$

Where:
v_h = wind speed at height h in m/s
v_{10} = wind speed at a height of 10 meter in m/s
z = roughness length of the site in meter

[187] Gleaned directly from (Sustainable Energy World, 2009)

The roughness length is defined in the following table:

Roughness length (meter), description

0.001: Ice, water surface

0.03: Grass, airports

0.2: Trees, hedgerows, scattered buildings

0.25: Rough terrain

0.5: Villages, very rough terrain

1: Cities, forests

2: City centre, skyscrapers

APPENDIX B: PETRO-CARIBE AGREEMENT

PETROCARIBE AGREEMENT OF ENERGETIC COOPERATION BETWEEN THE GOVERNMENT OF THE BOLIVARIAN REPUBLIC OF VENEZUELA AND THE GOVERNMENT OF BELIZE

The Government of the Bolivarian Republic of Venezuela and the Government of Belize.

Considering the creation of PETROCARIBE, on 29th June 2005, as an organism facilitator of policies and energetic plans, aimed to integrate Caribbean peoples through the sovereign use of natural and energy resources, in direct benefit of its citizens;

Reaffirming the close friendship and cooperation ties existing between the Government of the Bolivarian Republic of Venezuela and the Government of Belize;

Acknowledging the indispensability of actions of cooperation and solidarity between the Government of the Bolivarian Republic of Venezuela and the Government of Belize, and their essential nature in order to achieve our mutual objectives of socio-economic progress in a setting of peace and social justice;

Recognizing the need to adapt to the changing conditions of the hydrocarbon markets;

Agree to execute the "PETROCARIBE Agreement of Energetic Cooperation", specified as follows:

Article I

The Government of the Bolivarian Republic of Venezuela will directly provide the Government of Belize with crude, refined products and LPG (Liquified Petroleum Gas) or its energetic equivalents, to a monthly average of four thousand barrels per day (4.000 b/day). The supply will be subject to evaluation and adjustment according to the evolution of the acquisitions made by the Government of Belize, the availability of the Government of the Bolivarian Republic of Venezuela, the decisions adopted by the OPEC (Organization of Petroleum Exporting Countries), and any other circumstance that may force the Government of the Bolivarian Republic of Venezuela to adjust the quota allocated through this Agreement. The quantities specified in the present Agreement will override those stipulated by existing agreements on energetic matters between the Government of the Bolivarian Republic of Venezuela and the Government of Belize.

Article II

The supply provided by the Government of the Bolivarian Republic of Venezuela to those public entities designated by the parties, in accordance with this Agreement, will be subject to the commercial policy and practice of PDVSA (Petroleum of Venezuela, S.A.), who will regulate the supply, according to the quota established by the Government of the Bolivarian Republic of Venezuela. At the request of the National Executive, PDVSA will administer any application on the basis of the quota established in this Agreement.

Article III

The Government of the Bolivarian Republic of Venezuela, in conformity with the supply quota established by the present Agreement, will make available financing schemes under the following conditions: a grace period of two (2) years for the repayment of capital, and an annual interest rate of two per cent (2%). The amount of applicable financial resources and the financing period will be determined according to the following scale:

Current purchase prices (FOB-VZLA) per barrel (USD)	Determining factor of financial resources (%)	Financing period (years)
>15	5	15
>20	10	15
>22	15	15
>24	20	15
>30	25	15
>40	30	23
>50	40	23
>100	50	23

The Government of Belize will be invoiced on the basis of the international market's current referential prices.

The share requiring full payment must be paid within ninety (90) of issuing the Bill of Landing. No interest will be applied to the first 30 days of this period. An annual interest rate of 2% will apply to the remaining 60 days of this period. The Government of the Bolivarian Republic of Venezuela reserves the right to present shipments to the port of entry, in which case the financing will only cover the product's value (FOB-VZLA), while the cost of chartering must be paid in full immediately following unloading.

When oil prices exceed $40 per barrel, the repayment period will increase to 23 years, plus a grace period of two years, totaling to a total repayment period of 25 years, and reducing the interest rate to 1%. With regards to the share to be settled by deferred payment, the Government of the Bolivarian Republic of Venezuela may accept payment in specific assets, to be mutually determined, for which the Government of Belize will offer preferential prices.

The products acquired by the Government of the Bolivarian Republic of Venezuela at preferential prices may include the specific assets that the parties approve, and may be affected by the commercial policies of wealthy countries.

Article IV

Interest repayment and asset amortization related to debts contracted by the Government of Belize may take place through the use of mechanisms of commercial compensation, if and when required by the Government of the Bolivarian Republic of Venezuela.

Article V

To the effects of this Agreement, the turnover financed by the Government of the Bolivarian Republic of Venezuela will be dedicated to Belize’s internal consumption. Turnover will be ratified on every occasion by the Government of the Bolivarian Republic of Venezuela.

Article VI

It is expressly agreed by the signatory parties of this Agreement that to the effects of financing, and in applicable circumstances, the aggregate turnover specified by the Agreement of San Jose and the present Agreement of Energetic Cooperation, shall not exceed Belize’s internal consumption.

Article VII

The turnover resulting from the application of the present Agreement will not have any effect on the financing mechanisms established by the Agreement of San Jose, since they are different instruments of cooperation. In this respect, the Government of Belize will notify PDVSA of the volume of sales required within the context of the present Agreement.

Article VIII

The Government of the Bolivarian Republic of Venezuela, by means of the Ministry of Energy and Oil and PDVSA, will be the executant of this Agreement, responsible for the establishment of any mechanisms and procedures required for its implementation.

Article IX

The present Agreement will come into force following the ratification of this instrument, and will remain in force for a period of one (1) year, being automatically renewed for equal and successive periods.

The present Agreement may be amended or abrogated when it is so required by the Government of the Bolivarian Republic of Venezuela. In this event, the Government of Belize will be notified in writing and by diplomatic means, with thirty (30) days notice. Any query or controversy arising from the interpretation or implementation of the present Agreement will be resolved by the direct negotiations of both parties, through their diplomatic bodies.

Article X

It is expressly agreed by the signatory parties that the present Agreement is an extension of the Caracas' Agreement of Energetic Cooperation, subscribed by the Government of the Bolivarian Republic of Venezuela and the Government of Belize on 19th October 2001. In this respect, the dispositions established in articles FIRST and FOURTH of the present Agreement substitute articles FIRST and FOURTH of the Caracas' Agreement of Energetic Cooperation, subscribed on 19th October 2001.

(Translation for Portal ALBA by Damaris Garzón)

Original document: http://www.alternativabolivariana.org/pdf/Acuerdo_Belice.PDF

APPENDIX C: COST OF TRAFFIC PATROLS TO CURB AGGRESSIVE DRIVING

What would it cost to put in place the necessary traffic patrols to curb aggressive driving on highways to achieve our target?

Let us say we need to setup traffic patrols on the two major highways – the Western and Northern highways. The patrols will start from 6:00 am in the morning until 10:00 pm at night, and will involve two highway patrol vehicles moving in opposite directions on each highway throughout the 16-hour surveillance period. So the total number of vehicles required = 4 + 1 (additional one to be used if one of the others is not available). The daily miles travelled per vehicle at 45 mph = 16 hours x 45 mph = 720 miles. If the patrols are done randomly but on average 50% of the time, total miles travelled for a year = 50% x 4 vehicles x 365 days x 720 miles = 525,600 vehicle-miles. The total fuel consumed at 25 mpg = 525,600/25 = 21,024 gallons.

Annual costs: capital cost of vehicles at $40,000 USD per vehicle =$8,000 USD per vehicle per year = $40,000 USD per year.

Fuel costs = $3.00 x 21,024 = $63,072 USD per year.

O&M Costs = $2,500 USD per vehicle per year = $12,500 USD per year.

Insurance costs = $1,000 USD per vehicle per year = $5,000 USD per year.

Patrol officer costs = $20,000 USD per officer per year = [Total man-hours of patrol, assuming two patrol officers per vehicle = 50% x 2 officers x 4 vehicles x 16 hours per day x 365 days = 23,360 man-hours per year]. Now since each officer works 2,000 hours per year, the total patrol officer cost = $20,000 x (23,360/2,000) = $233,600 USD per year.

Total costs = 40,000 + 63,072 + 12,500 + 5,000 + 233,600 = $354,172USD per year.

If one patrol officer per patrol car is used instead, total costs = $237,372 USD per year.

APPENDIX D.1: BASELINE PLAN – DETAILS

PARAMETERS	2010		2015	2020	2025	2030	2035	2040
End-Use Energy								
Energy content (Gasoline)	131	MJ/gallon						
Energy content (Diesel)	144	MJ/gallon						
Energy content (Ethanol)	87	MJ/gallon						
Energy content (Biodiesel)	132	MJ/gallon						
Energy content (Crude Oil)	144	MJ/gallon						
Electricity	3.60	MJ/KWh						
ECONOMIC PARAMETERS								
Annual Increase (Economy)	4.00%							
Real GDP Growth Rate (5-year rate)			15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
GDP (2010 USD)	$1,431,000,000.00		$1,645,650,000.00	$1,892,497,500.00	$2,176,372,125.00	$2,502,827,943.75	$2,878,252,135.31	$3,309,989,955.61
Population Growth Rate (5-year rate)			15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Population	312,000		358,800	412,620	474,513	545,690	627,543	721,675
TRANSPORT								
Annual Increase (Fuel Efficiency)	1.00%							
Highway Travel as % of Total Mileage (Light Duty, Non-Mass)	50.00%		50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Highway Travel Efficiency Increase over Average (Light Duty, Non-Mass)	20.00%		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Highway Travel Efficiency Factor (Light Duty, Non-Mass)	120.00%		120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Urban Travel Efficiency Factor (Light Duty, Non-Mass)	85.71%		85.71%	85.71%	85.71%	85.71%	85.71%	85.71%
Average number of persons in private transport	2		2	2	2	2	2	2
% of highway travel substituted in mass transport switch	80.00%		80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
% of urban travel substituted in mass transport switch	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GASOLINE VEHICLES								
Total Number of Gasoline Vehicles	16,500		20,075	24,424	29,716	36,154	43,986	53,516
Miles per Vehicle (per annum)	12,800		12,800	12,800	12,800	12,800	12,800	12,800
Miles per vehicle (urban)	6,400		6,400	6,400	6,400	6,400	6,400	6,400
Miles per vehicle (highway)	6,400		6,400	6,400	6,400	6,400	6,400	6,400
% Switch to Mass Transport (from Gasoline Vehicles)	**0.00%**		**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Gasoline Vehicles								
Typical Vehicle (Gasoline)	100.00%		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Small Vehicle (Gasoline)	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Ethanol Blend)	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hybrid Vehicle	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Plugin Hybrid Vehicle	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
All-Electric Vehicle	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Vehicle (Gasoline)								

Number of vehicles	16,500	20,075	24,424	29,716	36,154	43,986	53,516
Total vehicle-miles (urban)	105,600,000	128,478,546	156,313,796	190,179,634	231,382,604	281,512,317	342,502,777
Total vehicle-miles (highway)	105,600,000	128,478,546	156,313,796	190,179,634	231,382,604	281,512,317	342,502,777
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	1,844	2,135	2,471	2,860	3,311	3,833	4,437
Small Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Flex Fuel Vehicle (Ethanol Blend)							
% Ethanol in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Total energy use (TJ) [Ethanol]	0	0	0	0	0	0	0
Hybrid Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Plugin Hybrid Vehicle (Gasoline)							
% Mileage on Electric	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (Gasoline)	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Average fuel economy (Electric)	3.00	3.15	3.31	3.48	3.66	3.85	4.04
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Total energy use (TJ) [Electricity]	0	0	0	0	0	0	0
All-Electric Vehicle (Gasoline)							
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (mpk)	3.33	3.50	3.68	3.87	4.07	4.27	4.49

Total energy use (TJ) [Electricity]	0	0	0	0	0	0	0
Other Transport (Gasoline)							
Energy consumption (overall)	567	690	839	1,021	1,242	1,512	1,839
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Gasoline]	567	656	760	880	1,018	1,179	1,364
LIGHT-DUTY DIESEL VEHICLES							
Total Number of Light-Duty Diesel Vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Miles per Vehicle (per annum)	12,395	12,395	12,395	12,395	12,395	12,395	12,395
Miles per vehicle (urban)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
Miles per vehicle (highway)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
% Switch to Mass Transport (from Diesel Vehicles)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Light-Duty Diesel Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Small Vehicle (Diesel)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Vehicle (Diesel)							
Number of vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Total vehicle-miles (urban)	12,395,000	15,080,413	18,347,628	22,322,695	27,158,971	33,043,041	40,201,912
Total vehicle-miles (highway)	12,395,000	15,080,413	18,347,628	22,322,695	27,158,971	33,043,041	40,201,912
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	179	207	240	278	322	372	431
Small Vehicle (Diesel)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	24.00	25.22	26.51	27.86	29.28	30.78	32.35
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Flex Fuel Vehicle (Diesel)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
MASS TRANSPORT DIESEL VEHICLES							
Highway Travel as % of Total Mileage (Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%

Average number of persons per highway travel mass transport	50	50	50	50	50	50	50
Highway Fuel Economy (Mass) [*Miles per Gallon*]	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Highway Fuel Economy (Mass) [*Person-miles per Gallon*]	300	315	331	348	366	385	404
Average number of persons per urban travel mass transport	20	20	20	20	20	20	20
Urban Fuel Economy (Mass) [*Miles per Gallon*]	5.00	5.26	5.52	5.80	6.10	6.41	6.74
Urban Travel Fuel Economy (Mass) [*Person-miles per Gallon*]	100	105	110	116	122	128	135

Total Number of Urban Travel Person-Miles (Non-Switch)	**18,000,000**	**21,899,752**	**26,644,397**	**32,416,983**	**39,440,217**	**47,985,054**	**58,381,155**
Total Number of Urban Travel Vehicle-Miles (Switch)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Typical Gasoline Vehicles	0	0	0	0	0	0	0
Small Gasoline Vehicles	0	0	0	0	0	0	0
Flex Fuel (Ethanol Blend) Vehicles	0	0	0	0	0	0	0
Hybrid Vehicles	0	0	0	0	0	0	0
Plugin Hybrid Vehicles	0	0	0	0	0	0	0
Electric Vehicles	0	0	0	0	0	0	0
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0
Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0

<u>Distribution between Urban Mass Transport Vehicles</u>

Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

<u>Typical Mass Transport (Diesel)</u>

Total person-miles (urban)	18,000,000	21,899,752	26,644,397	32,416,983	39,440,217	47,985,054	58,381,155
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	26	30	35	40	47	54	63

<u>Flex Fuel Mass Transport (Biodiesel Blend)</u>

% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (urban)	0	0	0	0	0	0	0
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0

Total Number of Highway Travel Vehicle-Miles (Non-Switch)	**1,250,750,000**	**1,521,728,618**	**1,851,415,539**	**2,252,530,090**	**2,740,547,271**	**3,334,294,792**	**4,056,679,436**
Total Number of Highway Travel Vehicle-Miles (Switch)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Typical Gasoline Vehicles	0	0	0	0	0	0	0
Small Gasoline Vehicles	0	0	0	0	0	0	0
Flex Fuel (Ethanol Blend) Vehicles	0	0	0	0	0	0	0
Hybrid Vehicles	0	0	0	0	0	0	0
Plugin Hybrid Vehicles	0	0	0	0	0	0	0
Electric Vehicles	0	0	0	0	0	0	0
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0

Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0
Distribution between Highway Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Mass Transport (Diesel)							
Total person-miles (highway)	1,250,750,000	1,521,728,618	1,851,415,539	2,252,530,090	2,740,547,271	3,334,294,792	4,056,679,436
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	602	697	807	934	1,081	1,252	1,449
Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
HEAVY-DUTY DIESEL VEHICLES							
Total Number of Heavy Duty Diesel Vehicles	2,400	2,920	3,553	4,322	5,259	6,398	7,784
Miles per Vehicle (per annum)	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Distribution between Heavy Duty Diesel Vehicles							
Typical Vehicle (Diesel)	60.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Typical Vehicle (Crude Blend)	40.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Heavy Duty Vehicle (Diesel)							
Number of vehicles	1,440	2,920	3,553	4,322	5,259	6,398	7,784
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	630	1,215	1,407	1,629	1,885	2,182	2,526
Typical Heavy Duty Vehicle (Crude Blend)							
% Crude in Blend	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	960	0	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	210	0	0	0	0	0	0
Total energy use (TJ) [Crude Oil]	210	0	0	0	0	0	0
Flex Fuel Heavy Duty Vehicle (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09

Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
Other Transport (Diesel)							
Energy consumption (overall)	242	294	358	436	530	645	785
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	242	280	324	375	434	503	582
Aviation Transport (Kerosene)							
Energy consumption (overall)	582.64	708.87	862.45	1,049.31	1,276.64	1,553.23	1,889.74
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	583	674	781	904	1,046	1,211	1,402
Transport (LPG)							
Energy consumption (overall)	31.60	38.45	46.78	56.91	69.24	84.24	102.49
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	32	37	42	49	57	66	76
RESIDENTIAL							
Number of households	80,000	97,332	118,420	144,075	175,290	213,267	259,472
Annual Increase (Efficiency)	1.00%						
Lighting							
Distribution							
Electric	82.00%	85.00%	90.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	5.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Kerosene	18.00%	10.00%	5.00%	0.00%	0.00%	0.00%	0.00%
Electric Lighting							
Number of households	65,600	82,732	106,578	129,668	140,232	149,287	155,683
Energy consumption per household	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	295	354	434	503	517	524	520
Solar Lighting							
Number of households	0	4,867	5,921	14,408	35,058	63,980	103,789
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	14	16	37	86	150	231
Kerosene Lighting							
Number of households	14,400	9,733	5,921	0	0	0	0
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	43	28	16	0	0	0	0

Refrigeration							
% of households	66.50%	70.00%	75.00%	75.00%	80.00%	80.00%	85.00%
Number of households	53,200	68,133	88,815	108,057	140,232	170,614	220,551
Energy consumption per household	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	105	128	159	184	228	263	324
Other Electricity Use							
% of households	80.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Number of households	64,000	82,732	100,657	122,464	148,996	181,277	220,551
Energy consumption per household	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	319	393	455	527	610	706	817
Cooking							
Distribution							
LPG	84.00%	85.00%	90.00%	90.00%	95.00%	95.00%	95.00%
Wood	16.00%	15.00%	10.00%	10.00%	5.00%	5.00%	5.00%
LPG Range Cooking							
Number of households	67,200	82,732	106,578	129,668	166,525	202,604	246,498
Energy consumption per household	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	520	609	746	864	1,056	1,222	1,415
Wood Stove Cooking							
Number of households	12,800	14,600	11,842	14,408	8,764	10,663	12,974
Energy consumption per household	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Wood]	830	901	695	805	466	539	624
COMMERCIAL & SERVICES							
Annual Increase (Efficiency)	1.00%						
Energy Audit Feedback Recommendations							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution of Electricity Use	**146,718,000**	KWh					
Lighting	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Refrigeration	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Space Cooling	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Water Heating	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Other	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%

Total Electricity Use (TJ)	**528**	**643**	**782**	**951**	**1,157**	**1,408**	**1,713**
Total Energy Use for Lighting (TJ)	**211**	**257**	**313**	**380**	**463**	**563**	**685**
Commercial Lighting Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	85.00%	80.00%	75.00%
Solar	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Electric Lighting							
Energy consumption (overall)	211	257	297	342	393	451	514
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	211	245	269	295	322	351	381
Solar Lighting							
Energy consumption (overall)	0	0	16	38	69	113	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	14	33	57	88	127
Refrigeration							
Energy consumption (overall)	79	96	117	143	174	211	257
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	79	92	106	123	142	165	191
Total Energy Use for Space Cooling (TJ)	**106**	**129**	**156**	**190**	**231**	**282**	**343**
Space Cooling Distribution							
Electric	100.00%	100.00%	95.00%	85.00%	75.00%	60.00%	50.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Solar	0.00%	0.00%	0.00%	5.00%	10.00%	20.00%	25.00%
Electric Cooling							
Energy consumption (overall)	106	129	149	162	174	169	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	134	139	142	132	127
Geothermal Cooling							
Energy consumption (overall)	0	0	8	19	35	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	7	16	28	44	64
Solar Cooling							
Energy consumption (overall)	0	0	0	10	23	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	8	19	44	64
Total Energy Use for Water Heating (TJ)	**26**	**32**	**39**	**48**	**58**	**70**	**86**
Water Heating Distribution							
Electric	100.00%	90.00%	65.00%	30.00%	0.00%	0.00%	0.00%

LPG	0.00%	5.00%	15.00%	30.00%	30.00%	20.00%	10.00%
Solar	0.00%	5.00%	15.00%	30.00%	50.00%	60.00%	70.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	20.00%	20.00%	20.00%
Electric Water Heating							
Energy consumption (overall)	26	29	25	14	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	26	28	23	12	0	0	0
LPG Water Heating							
Energy consumption (overall)	0	2	6	14	17	14	9
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	2	5	12	14	11	6
Solar Water Heating							
Energy consumption (overall)	0	2	6	14	29	42	60
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	2	5	12	24	33	44
Geothermal Water Heating							
Energy consumption (overall)	0	0	2	5	12	14	17
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	2	4	9	11	13
Other Electricity Use							
Energy consumption (overall)	106	129	156	190	231	282	343
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	142	164	190	220	254
Total Energy Use for Streetlighting (TJ)	**88**	**107**	**131**	**159**	**194**	**235**	**286**
Streetlighting Energy Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	0.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Electric Streetlight Energy Use							
Energy consumption (overall)	88	107	124	143	155	165	172
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	88	102	112	123	127	129	128
Solar Streetlight Energy Use							
Energy consumption (overall)	0	0	7	16	39	71	115
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	6	14	32	55	85
LPG Energy Use for Cooking & Other Heating Purposes							
Energy consumption (overall)	90	109	133	162	197	240	292

Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	90	104	121	140	162	187	217
INDUSTRIAL							
Annual Increase (Efficiency)	1.00%						
Energy Audit Recommendations Implementation							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Energy Use (for industrial applications that use LPG in 2010)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Distribution of Energy							
LPG	100.00%	100.00%	90.00%	85.00%	80.00%	75.00%	75.00%
Solar	0.00%	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Industrial Solar Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Industrial LPG Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	0	0	0	0	0	0
Total Petroleum Use	**1,839.50**	**2,238.03**	**2,722.91**	**3,312.84**	**4,030.57**	**4,903.81**	**5,966.23**
Distribution of Petroleum Use							
Diesel	47.90%	50.00%	50.00%	40.00%	30.00%	20.00%	10.00%
HFO	37.00%	40.00%	30.00%	20.00%	20.00%	10.00%	10.00%
NG	0.00%	0.00%	20.00%	40.00%	50.00%	70.00%	80.00%
Crude Oil	15.10%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial Diesel Use							
Energy consumption (overall)	881	1,119	1,361	1,325	1,209	981	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	881	1,065	1,233	1,141	991	765	443
Industrial HFO Use							
Energy consumption (overall)	681	895	817	663	806	490	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [HFO]	681	852	740	571	661	382	443
Industrial NG Use							
Energy consumption (overall)	0	0	545	1,325	2,015	3,433	4,773
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [NG]	0	0	493	1,141	1,652	2,677	3,541

Industrial Crude Oil Use							
Energy consumption (overall)	278	224	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Crude Oil]	278	213	0	0	0	0	0
Industrial LP Steam Use (BSI)							
Energy consumption (overall)	639	639	639	639	639	639	639
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	639	608	578	550	524	498	474
Industrial Own Electricity Use (BSI/BELCOGEN)	**55,076,903**	63,757,215	73,805,575	85,437,591	98,902,854	114,490,288	132,534,358
Energy consumption (overall)	198	198	198	198	198	198	198
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	198	189	179	171	162	155	147
Industrial Electricity Use	**90,398,000**	KWh					
Energy consumption (overall)	325	396	482	586	713	868	1,056
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	325	377	436	505	584	676	783
CONVERSION EFFICIENCY							
LPG	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Diesel	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
BEL Diesel	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
HFO	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Gasoline	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Kerosene	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Crude Oil	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Natural Gas	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Biomass	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
MSW	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Fuelwood	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Geothermal	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Wind	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Hydro	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Imported Electricity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Electricity Transmission & Distribution Losses	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%
Fuel Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WORLD MARKET PRICES - Oil & Natural Gas							
WTI Crude Oil Price (USD per bbl)	79.00	94.58	108.10	117.54	123.09	124.94	134.60
Reference Oil Price Case	79.00	94.58	108.10	117.54	123.09	124.94	134.60
High Oil Price Case	79.00	146.10	169.08	185.87	196.07	199.95	226.23
LSD No. 2 Diesel (Distillate Fuel) Price (USD/gal)	2.38	2.84	3.24	3.52	3.69	3.75	4.04

Residual Fuel Oil No.6 Price (USD/gal)	1.33	1.90	2.53	3.14	3.69	3.75	4.04
Henry Hub Natural Gas Price (USD per MMBTU)	4.12	4.66	5.05	5.97	6.40	7.07	7.62
Reference Natural Gas Price Case	4.12	4.66	5.05	5.97	6.40	7.07	7.62
High Natural Gas Price Case	4.12	4.74	5.22	6.19	6.63	7.20	8.15
Reference Natural Gas Price Case (Delivered to Electric Power)	4.84	4.79	5.13	5.91	6.36	6.97	7.89
High Natural Gas Price Case (Delivered to Electric Power)	4.84	4.85	5.28	6.10	6.49	7.07	8.00
CFE Capacity Charges (per KWh)	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219
CFE Energy Charges (per KWh)	0.0946	0.1159	0.1190	0.1221	0.1245	0.1253	0.1273
MSD Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 80%]	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 10%]	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 60%]	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00

FUEL PRICES (USD per TJ) ***excl. Carbon Price***

LPG	21,691.97	24,535.10	26,588.46	31,432.30	33,696.27	37,223.85	40,100.66
Diesel	16,491.37	19,634.75	22,441.49	24,401.23	25,553.40	25,937.46	27,942.01
Diesel-fired Electricity (Peaking)	47,177.38	51,368.55	55,110.88	57,723.86	59,260.10	59,772.17	62,444.91
Diesel-fired Electricity (Baseload)	18,858.04	22,001.41	24,808.16	26,767.90	27,920.07	28,304.13	30,308.68
HFO	8,431.15	12,060.12	16,031.39	19,874.90	23,372.28	23,723.55	25,557.00
HFO-fired Electricity	11,093.65	14,722.62	18,693.89	22,537.40	26,034.78	26,386.05	28,219.50
Gasoline	18,009.30	21,561.01	24,643.11	26,795.10	28,060.32	28,482.05	30,683.26
Kerosene	16,901.35	20,234.55	23,127.03	25,146.64	26,334.01	26,729.80	28,795.59
Crude Oil	12,909.93	15,455.97	17,665.36	19,208.02	20,114.98	20,417.30	21,995.24
Natural Gas	6,445.16	7,013.85	7,424.57	8,393.45	8,846.30	9,551.90	10,127.33
NG-fired Electricity (Peaking)	25,336.83	25,905.52	26,316.24	27,285.12	27,737.97	28,443.56	29,018.99
NG-fired Electricity (Baseload)	9,220.16	9,788.85	10,199.57	11,168.45	11,621.30	12,326.90	12,902.33
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	207,500.00	177,175.93	146,851.85	116,527.78	86,203.70	55,879.63	25,555.56
Solar (PV) Electricity	95,250.00	69,055.56	42,861.11	35,722.22	28,583.33	26,194.44	23,805.56
Wind Electricity	24,861.11	23,777.78	22,694.44	21,597.22	20,500.00	20,347.22	20,194.44
Hydro Electricity	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89
Imported Electricity	32,355.78	38,282.31	39,138.84	40,017.42	40,660.22	40,895.92	41,446.35

FUEL PRICES (USD per TJ) ***incl. Carbon Price***

LPG	23,155.41	26,587.64	29,467.26	35,469.96	39,359.30	45,166.54	51,240.69
Diesel	18,241.89	22,089.95	25,885.04	29,230.98	32,327.38	35,438.32	41,267.45
Diesel-fired Electricity (Peaking)	48,927.91	53,823.75	58,554.42	62,553.61	66,034.07	69,273.03	75,770.34
Diesel-fired Electricity (Baseload)	20,608.56	24,456.61	28,251.70	31,597.65	34,694.05	37,804.98	43,634.12
HFO	10,277.81	14,650.17	19,664.06	24,969.91	30,518.29	33,746.21	39,614.30
HFO-fired Electricity	12,940.31	17,312.67	22,326.56	27,632.41	33,180.79	36,408.71	42,276.80
Gasoline	19,687.24	23,914.41	27,943.87	31,424.59	34,553.41	37,588.96	43,456.16
Kerosene	18,615.45	22,638.66	26,498.92	29,875.89	32,967.03	36,032.95	41,843.73
Crude Oil	14,660.46	17,911.17	21,108.91	24,037.77	26,888.96	29,918.16	35,320.67

Natural Gas	7,731.48	8,817.98	9,954.96	11,942.45	13,823.95	16,533.31	19,919.12
NG-fired Electricity (Peaking)	26,623.15	27,709.65	28,846.63	30,834.12	32,715.62	35,424.98	38,810.78
NG-fired Electricity (Baseload)	10,506.48	11,592.98	12,729.96	14,717.45	16,598.95	19,308.31	22,694.12
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	208,347.22	178,364.20	148,518.47	118,865.29	89,482.19	60,477.87	32,004.83
Solar (PV) Electricity	95,986.11	70,087.99	44,309.15	37,753.18	31,431.85	30,189.64	29,409.02
Wind Electricity	25,006.94	23,982.32	22,981.32	21,999.58	21,064.33	21,138.72	21,304.56
Hydro Electricity	26,743.06	26,784.99	26,843.80	26,926.29	27,041.98	27,204.25	27,431.83
Imported Electricity	38,598.83	47,038.52	51,419.87	57,242.21	64,818.88	74,779.68	88,970.09
EMISSION FACTORS (tCO2e per TJ) [PEe]							
LPG	58.54	58.54	58.54	58.54	58.54	58.54	58.54
Diesel	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Diesel-fired Electricity	70.02	70.02	70.02	70.02	70.02	70.02	70.02
HFO	73.87	73.87	73.87	73.87	73.87	73.87	73.87
HFO-fired Electricity	73.87	73.87	73.87	73.87	73.87	73.87	73.87
Gasoline	67.12	67.12	67.12	67.12	67.12	67.12	67.12
Kerosene	68.56	68.56	68.56	68.56	68.56	68.56	68.56
Crude Oil	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Natural Gas	51.45	51.45	51.45	51.45	51.45	51.45	51.45
NG-fired Electricity	51.45	51.45	51.45	51.45	51.45	51.45	51.45
Bioethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass (Fuel & Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MSW (Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuelwood	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Electricity	33.89	33.89	33.89	33.89	33.89	33.89	33.89
Solar (PV) Electricity	29.44	29.44	29.44	29.44	29.44	29.44	29.44
Wind Electricity	5.83	5.83	5.83	5.83	5.83	5.83	5.83
Hydro Electricity	4.17	4.17	4.17	4.17	4.17	4.17	4.17
Imported Electricity	249.72	249.72	249.72	249.72	249.72	249.72	249.72
EMISSIONS PRICE (USD/tCO2e)	25.00	35.06	49.18	68.98	96.74	135.69	190.31
Annual Rate of price increase	7.00%						
					116,508		
GRID ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BECOL	249,564	249,564	249,564	249,564	249,564	249,564	249,564
Maximum Energy from Hydro Maya	13,586	13,680	13,680	13,680	13,680	13,680	13,680
Maximum Energy from BELCOGEN	48,632	102,600	102,600	102,600	102,600	102,600	102,600
BELCOGEN (% Total Energy from Biomass)	*78%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
BELCOGEN (% Remaining Energy from HFO)	*46.25%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum Energy from BAL	4,799	66,576	111,150	111,150	111,150	111,150	111,150
BAL (% Total Energy from HFO)	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*

Maximum Energy from CFE	160,000	346,896	346,896	346,896	346,896	346,896	346,896
Maximum Energy from SIEPAC	0	0	693,792	693,792	693,792	693,792	693,792
Minimum Energy from BEL (current)	7,608	0	0	0	0	0	0
Maximum Energy from Other HFO Plant(s)	0	0	71,569	151,569	157,680	315,360	473,040
Maximum Energy from New Natural Gas Plant(s)	0	0	0	0	0	0	0
Maximum Energy from Solar	0	0	0	0	0	0	0
Maximum Energy from Wind	0	0	0	0	0	0	0
Maximum Energy from Other Hydro	0	0	0	0	0	0	0
Maximum Energy from Other Biomass	0	0	0	0	0	0	0
Maximum Energy from MSW	0	0	0	0	0	0	0

Maximum Capacity from BECOL	54.00	54.00	54.00	54.00	54.00	54.00	54.00
Maximum Capacity from Hydro Maya	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Maximum Capacity from BELCOGEN	6.53	13.78	13.78	13.78	13.78	13.78	13.78
Maximum Capacity from BAL	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Maximum Capacity from CFE	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Maximum Capacity from SIEPAC	0.00	0.00	99.00	99.00	99.00	99.00	99.00
Maximum Capacity from BEL	25.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other HFO Plant(s)	0.00	0.00	13.62	28.84	30.00	60.00	90.00
Maximum Capacity from New Natural Gas Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from MSW	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Maximum Power Output (MW)	153	135	248	263	264	294	324
Peak Demand Growth Rate (5-year rate)		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Peak Demand (MW)	80	100	125	156	195	244	305
Supply Reserve (%)	91.29%	35.28%	98.32%	68.39%	35.31%	20.54%	6.26%
Supply Reserve % (Largest Supply Out)	23.79%	-18.72%	19.12%	5.03%	-15.38%	-20.01%	-26.18%

SELF-GENERATED ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BELCOGEN/BSI	55,077	63,757	73,806	85,438	98,903	114,490	132,534
Maximum Energy from BAL	26,705	26,705	26,705	26,705	26,705	26,705	26,705
Maximum Energy from BNE	7,008	7,008	7,008	7,008	7,008	7,008	7,008
Maximum Energy from CPBL	1,711	1,711	1,711	1,711	1,711	1,711	1,711
CPBL (% Total Energy from Crude Oil)	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
Maximum Energy from Others	0	0	0	0	0	0	0

Net Present Cost (over Evaluation Period)		$468,891,515.79	
Cost *without* Carbon Pricing	**$3,206,418,586.12**		17,561,533
Cost *with* Carbon Pricing	**$3,675,310,101.90**		

RESULTS	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**

ENERGY							
TPES (in TJ)	12,888	15,821	17,563	19,401	20,972	23,403	26,447
TPES (in TOE)	307,823	377,867	419,480	463,393	500,919	558,982	631,675
Energy Intensity (BTU/$GDP[2010 USD])	8,536	9,112	8,796	8,449	7,942	7,707	7,573
Energy Supply Per Capita (TOE per capita)	0.9866	1.0531	1.0166	0.9766	0.9180	0.8907	0.8753
Secondary Energy Consumption Breakdown by Sector							
% Transport	46.81%	47.54%	49.09%	49.58%	51.14%	51.54%	51.84%
% Residential	19.31%	19.45%	18.03%	18.21%	16.46%	16.47%	16.53%
% Commercial & Services	6.45%	6.54%	6.73%	6.76%	6.97%	7.05%	7.12%
% Industrial	27.43%	26.47%	26.16%	25.45%	25.42%	24.93%	24.51%
EMISSIONS							
Total GHG Emissions (tCO2e)	702,461	778,597	880,594	988,424	1,146,168	1,239,325	1,381,691
Overall GHG Emissions Intensity (tCO2e/TJ)	55.99	50.36	51.14	51.75	54.98	53.15	52.31
Electricity Sector GHG Emissions Intensity (tCO2e/TJ)	52.74	35.05	35.71	38.01	43.56	39.67	37.67
Emissions Breakdown by Sector							
Transport	49.09%	51.32%	51.11%	51.18%	50.34%	52.00%	52.91%
Residential	15.17%	14.50%	15.62%	16.32%	17.28%	16.91%	16.70%
Commercial & Services	9.72%	8.65%	8.91%	9.11%	9.44%	9.04%	8.76%
Industrial	26.03%	25.53%	24.37%	23.39%	22.94%	22.06%	21.63%
COSTS							
Total Cost of Energy w/o CP	$205,897,584.54	$278,475,925.44	$374,192,293.36	$442,707,251.64	$523,882,752.52	$605,020,563.00	$732,349,037.57
Total Cost of Energy as a % of GDP [2010 USD]	14.39%	16.92%	19.77%	20.34%	20.93%	21.02%	22.13%
Unit Cost of Energy w/o CP (USD/TJ)	$15,976.01	$17,602.19	$21,305.98	$22,818.39	$24,979.56	$25,851.77	$27,691.22
Total Cost of Energy w/ CP	$223,459,117.25	$305,776,497.29	$417,498,842.75	$510,884,556.24	$634,765,507.69	$773,179,351.81	$995,293,608.22
Unit Cost of Energy w/ CP (USD/TJ)	$17,338.65	$19,327.83	$23,771.79	$26,332.44	$30,266.62	$33,036.98	$37,633.54
Carbon Cost as % of Total Energy Cost w/ CP	7.86%	8.93%	10.37%	13.34%	17.47%	21.75%	26.42%
Unit Cost of Electricity w/o CP (USD/TJ) [*Assessed at Primary Energy Supply Point*]	$20,516.0477	$18,131.77	$21,475.85	$20,398.95	$21,474.77	$21,155.18	$21,798.81
Unit Cost of Electricity w/o CP (USD/MWh) [*Assessed at Generation Supply Point*]	$131.2516	$146.79	$182.55	$174.29	$178.77	$186.20	$199.36
PEe Cost Breakdown by Sector							
Transport	42.65%	43.96%	43.27%	46.07%	47.20%	48.05%	49.51%
Residential	20.78%	20.80%	21.75%	21.56%	21.72%	22.54%	22.63%
Commercial & Services	13.07%	12.52%	13.35%	12.49%	12.12%	12.08%	11.58%
Industrial	23.50%	22.72%	21.62%	19.89%	18.97%	17.33%	16.29%
DIVERSITY & SECURITY							
Resource Type Diversity Index	34.07%	36.16%	41.94%	43.31%	44.62%	47.82%	50.76%
Foreign Oil Imports (BOE)	1,551,033	1,815,936	2,142,016	2,412,816	2,760,699	3,065,298	3,478,733
% Dependence on Foreign Sources (TPES)	63.33%	61.88%	67.19%	68.80%	71.72%	73.26%	74.88%
% Electricity (of Total PEe Energy Supply)	28.77%	34.24%	35.80%	35.30%	34.20%	34.22%	34.02%
% Electricity (of Total Secondary Energy Supply)	16.99%	17.24%	17.52%	17.13%	16.81%	16.06%	15.44%
% Wind Energy of Total Utility Electricity Generation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
% Dependence on Foreign Sources (Electricity)	30.72%	24.10%	33.77%	38.32%	39.41%	44.66%	48.70%
% Renewables (of TPES)	30.05%	34.45%	30.73%	29.31%	26.53%	25.18%	23.74%
% Renewables (of Electricity Supply)	65.48%	73.30%	64.07%	59.76%	58.80%	53.79%	49.96%
% Renewables (of Transport Fuels)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Renewables as % of Total PEe Sector Energy							
Transport	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Residential	**62.56%**	**67.35%**	**58.55%**	**56.14%**	**51.07%**	**48.11%**	**45.95%**
Commercial & Services	**60.97%**	**69.27%**	**61.14%**	**57.82%**	**57.86%**	**54.62%**	**52.42%**
Industrial	**37.46%**	**39.60%**	**34.64%**	**31.16%**	**28.76%**	**26.04%**	**23.73%**

APPENDIX D.2: PLAN A – DETAILS

PARAMETERS	2010		2015	2020	2025	2030	2035	2040
End-Use Energy								
Energy content (Gasoline)	131	MJ/gallon						
Energy content (Diesel)	144	MJ/gallon						
Energy content (Ethanol)	87	MJ/gallon						
Energy content (Biodiesel)	132	MJ/gallon						
Energy content (Crude Oil)	144	MJ/gallon						
Electricity	3.60	MJ/KWh						
ECONOMIC PARAMETERS								
Annual Increase (Economy)	4.00%							
Real GDP Growth Rate (5-year rate)			15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
GDP (2010 USD)	$1,431,000,000.00		$1,645,650,000.00	$1,892,497,500.00	$2,176,372,125.00	$2,502,827,943.75	$2,878,252,135.31	$3,309,989,955.61
Population Growth Rate (5-year rate)			15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Population	312,000		358,800	412,620	474,513	545,690	627,543	721,675
TRANSPORT								
Annual Increase (Fuel Efficiency)	1.00%							
Highway Travel as % of Total Mileage (Light Duty, Non-Mass)	50.00%		50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Highway Travel Efficiency Increase over Average (Light Duty, Non-Mass)	20.00%		20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Highway Travel Efficiency Factor (Light Duty, Non-Mass)	120.00%		120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Urban Travel Efficiency Factor (Light Duty, Non-Mass)	85.71%		85.71%	85.71%	85.71%	85.71%	85.71%	85.71%
Average number of persons in private transport	2		2	2	2	2	2	2
% of highway travel substituted in mass transport switch	80.00%		80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
% of urban travel substituted in mass transport switch	0.00%		0.00%	10.00%	20.00%	30.00%	40.00%	50.00%
GASOLINE VEHICLES								
Total Number of Gasoline Vehicles	16,500		20,075	24,424	29,716	36,154	43,986	53,516
Miles per Vehicle (per annum)	12,800		12,800	12,800	12,800	12,800	12,800	12,800
Miles per vehicle (urban)	6,400		6,400	6,400	6,400	6,400	6,400	6,400
Miles per vehicle (highway)	6,400		6,400	6,400	6,400	6,400	6,400	6,400
% Switch to Mass Transport (from Gasoline Vehicles)	**0.00%**		**5.00%**	**10.00%**	**15.00%**	**20.00%**	**25.00%**	**30.00%**
Distribution between Gasoline Vehicles								
Typical Vehicle (Gasoline)	100.00%		95.00%	65.00%	35.00%	25.00%	15.00%	0.00%
Small Vehicle (Gasoline)	0.00%		5.00%	10.00%	20.00%	20.00%	20.00%	20.00%
Flex Fuel Vehicle (Ethanol Blend)	0.00%		0.00%	20.00%	25.00%	20.00%	15.00%	10.00%
Hybrid Vehicle	0.00%		0.00%	5.00%	10.00%	15.00%	15.00%	15.00%
Plugin Hybrid Vehicle	0.00%		0.00%	0.00%	5.00%	10.00%	15.00%	25.00%
All-Electric Vehicle	0.00%		0.00%	0.00%	5.00%	10.00%	20.00%	30.00%

Typical Vehicle (Gasoline)

Number of vehicles	16,500	19,071	15,876	10,400	9,038	6,598	0
Total vehicle-miles (urban)	105,600,000	122,054,619	100,587,928	64,565,986	54,374,912	38,004,163	0
Total vehicle-miles (highway)	105,600,000	117,172,434	93,475,650	58,575,327	48,590,347	33,781,478	0
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	1,844	1,994	1,543	934	744	494	0
Small Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	1,004	2,442	5,943	7,231	8,797	10,703
Total vehicle-miles (urban)	0	6,423,927	15,475,066	36,894,849	43,499,930	50,672,217	58,225,472
Total vehicle-miles (highway)	0	6,166,970	14,380,869	33,471,616	38,872,277	45,041,971	52,060,422
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	87	198	445	496	548	601
Flex Fuel Vehicle (Ethanol Blend)							
% Ethanol in Blend	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%	25.00%
Number of vehicles	0	0	4,885	7,429	7,231	6,598	5,352
Total vehicle-miles (urban)	0	0	30,950,132	46,118,561	43,499,930	38,004,163	29,112,736
Total vehicle-miles (highway)	0	0	28,761,739	41,839,520	38,872,277	33,781,478	26,030,211
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	0	0	425	572	487	404	295
Total energy use (TJ) [Ethanol]	0	0	50	95	108	90	66
Hybrid Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	1,221	2,972	5,423	6,598	8,027
Total vehicle-miles (urban)	0	0	7,737,533	18,447,425	32,624,947	38,004,163	43,669,104
Total vehicle-miles (highway)	0	0	7,190,435	16,735,808	29,154,208	33,781,478	39,045,317
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	99	222	372	411	451
Plugin Hybrid Vehicle (Gasoline)							
% Mileage on Electric	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	0	0	0	1,486	3,615	6,598	13,379
Total vehicle-miles (urban)	0	0	0	9,223,712	21,749,965	38,004,163	72,781,840
Total vehicle-miles (highway)	0	0	0	8,367,904	19,436,139	33,781,478	65,075,528
Average fuel economy (Gasoline)	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Average fuel economy (Electric)	3.00	3.15	3.31	3.48	3.66	3.85	4.04
Total energy use (TJ) [Gasoline]	0	0	0	67	149	247	451
Total energy use (TJ) [Electricity]	0	0	0	9	20	34	62
All-Electric Vehicle (Gasoline)							
Number of vehicles	0	0	0	1,486	3,615	8,797	16,055
Total vehicle-miles (urban)	0	0	0	9,223,712	21,749,965	50,672,217	87,338,208
Total vehicle-miles (highway)	0	0	0	8,367,904	19,436,139	45,041,971	78,090,633
Average fuel economy (mpk)	3.33	3.50	3.68	3.87	4.07	4.27	4.49

Total energy use (TJ) [Electricity]	0	0	0	16	37	81	134
Other Transport (Gasoline)							
Energy consumption (overall)	567	690	839	1,021	1,242	1,512	1,839
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Gasoline]	567	656	760	880	1,018	1,179	1,364
LIGHT-DUTY DIESEL VEHICLES							
Total Number of Light-Duty Diesel Vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Miles per Vehicle (per annum)	12,395	12,395	12,395	12,395	12,395	12,395	12,395
Miles per vehicle (urban)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
Miles per vehicle (highway)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
% Switch to Mass Transport (from Diesel Vehicles)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Light-Duty Diesel Vehicles							
Typical Vehicle (Diesel)	100.00%	90.00%	90.00%	85.00%	70.00%	60.00%	50.00%
Small Vehicle (Diesel)	0.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Vehicle (Diesel)							
Number of vehicles	2,000	2,190	2,664	3,062	3,068	3,199	3,243
Total vehicle-miles (urban)	12,395,000	13,572,371	16,512,865	18,974,291	19,011,280	19,825,825	20,100,956
Total vehicle-miles (highway)	12,395,000	13,572,371	16,512,865	18,974,291	19,011,280	19,825,825	20,100,956
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	179	187	216	236	225	223	215
Small Vehicle (Diesel)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	243	296	360	438	533	649
Total vehicle-miles (urban)	0	1,508,041	1,834,763	2,232,269	2,715,897	3,304,304	4,020,191
Total vehicle-miles (highway)	0	1,508,041	1,834,763	2,232,269	2,715,897	3,304,304	4,020,191
Average fuel economy	24.00	25.22	26.51	27.86	29.28	30.78	32.35
Total energy use (TJ) [Diesel]	0	17	20	23	27	31	36
Flex Fuel Vehicle (Diesel)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	180	876	1,600	2,595
Total vehicle-miles (urban)	0	0	0	1,116,135	5,431,794	9,912,912	16,080,765
Total vehicle-miles (highway)	0	0	0	1,116,135	5,431,794	9,912,912	16,080,765
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	0	0	0	9	34	47	55
Total energy use (TJ) [Biodiesel]	0	0	0	5	31	65	117
MASS TRANSPORT DIESEL VEHICLES							
Highway Travel as % of Total Mileage (Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%

Average number of persons per highway travel mass transport	50	50	50	50	50	50	50
Highway Fuel Economy (Mass) [*Miles per Gallon*]	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Highway Fuel Economy (Mass) [*Person-miles per Gallon*]	300	315	331	348	366	385	404
Average number of persons per urban travel mass transport	20	20	20	20	20	20	20
Urban Fuel Economy (Mass) [*Miles per Gallon*]	5.00	5.26	5.52	5.80	6.10	6.41	6.74
Urban Travel Fuel Economy (Mass) [*Person-miles per Gallon*]	100	105	110	116	122	128	135

Total Number of Urban Travel Person-Miles (Non-Switch)	**18,000,000**	**21,899,752**	**26,644,397**	**32,416,983**	**39,440,217**	**47,985,054**	**58,381,155**
Total Number of Urban Travel Vehicle-Miles (Switch)	**0**	**0**	**3,126,276**	**11,410,778**	**27,765,912**	**56,302,463**	**102,750,833**
Typical Gasoline Vehicles	0	0	2,032,079	3,993,772	6,941,478	8,445,369	0
Small Gasoline Vehicles	0	0	312,628	2,282,156	5,553,182	11,260,493	20,550,167
Flex Fuel (Ethanol Blend) Vehicles	0	0	625,255	2,852,695	5,553,182	8,445,369	10,275,083
Hybrid Vehicles	0	0	156,314	1,141,078	4,164,887	8,445,369	15,412,625
Plugin Hybrid Vehicles	0	0	0	570,539	2,776,591	8,445,369	25,687,708
Electric Vehicles	0	0	0	570,539	2,776,591	11,260,493	30,825,250
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0
Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0

Distribution between Urban Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%

Typical Mass Transport (Diesel)							
Total person-miles (urban)	18,000,000	21,899,752	29,770,673	41,636,373	53,764,903	73,001,262	96,679,193
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	26	30	39	52	64	82	104

Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (urban)	0	0	0	2,191,388	13,441,226	31,286,255	64,452,795
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	0	0	0	2	8	15	22
Total energy use (TJ) [Biodiesel]	0	0	0	1	8	20	47

Total Number of Highway Travel Vehicle-Miles (Non-Switch)	**1,250,750,000**	**1,521,728,618**	**1,851,415,539**	**2,252,530,090**	**2,740,547,271**	**3,334,294,792**	**4,056,679,436**
Total Number of Highway Travel Vehicle-Miles (Switch)	**0**	**10,278,284**	**25,010,207**	**45,643,112**	**74,042,433**	**112,604,927**	**164,401,333**
Typical Gasoline Vehicles	0	9,764,370	16,256,635	15,975,089	18,510,608	16,890,739	0
Small Gasoline Vehicles	0	513,914	2,501,021	9,128,622	14,808,487	22,520,985	32,880,267
Flex Fuel (Ethanol Blend) Vehicles	0	0	5,002,041	11,410,778	14,808,487	16,890,739	16,440,133
Hybrid Vehicles	0	0	1,250,510	4,564,311	11,106,365	16,890,739	24,660,200
Plugin Hybrid Vehicles	0	0	0	2,282,156	7,404,243	16,890,739	41,100,333
Electric Vehicles	0	0	0	2,282,156	7,404,243	22,520,985	49,320,400
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0

Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0
Distribution between Highway Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Mass Transport (Diesel)							
Total person-miles (highway)	1,250,750,000	1,532,006,901	1,876,425,747	2,183,264,542	2,251,671,764	2,412,829,803	2,532,648,461
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	602	702	818	905	889	906	905
Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (highway)	0	0	0	114,908,660	562,917,941	1,034,069,915	1,688,432,307
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	0	0	0	30	116	163	192
Total energy use (TJ) [Biodiesel]	0	0	0	18	106	225	411
HEAVY-DUTY DIESEL VEHICLES							
Total Number of Heavy Duty Diesel Vehicles	2,400	2,920	3,553	4,322	5,259	6,398	7,784
Miles per Vehicle (per annum)	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Distribution between Heavy Duty Diesel Vehicles							
Typical Vehicle (Diesel)	60.00%	70.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Typical Vehicle (Crude Blend)	40.00%	30.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Heavy Duty Vehicle (Diesel)							
Number of vehicles	1,440	2,044	3,553	4,106	4,207	4,479	4,670
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	630	851	1,407	1,547	1,508	1,528	1,516
Typical Heavy Duty Vehicle (Crude Blend)							
% Crude in Blend	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	960	876	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	210	182	0	0	0	0	0
Total energy use (TJ) [Crude Oil]	210	182	0	0	0	0	0
Flex Fuel Heavy Duty Vehicle (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	216	1,052	1,919	3,114
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09

Total energy use (TJ) [Diesel]	0	0	0	51	197	276	322
Total energy use (TJ) [Biodiesel]	0	0	0	31	180	379	689
Other Transport (Diesel)							
Energy consumption (overall)	242	294	358	436	530	645	785
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	242	280	324	375	434	503	582
Aviation Transport (Kerosene)							
Energy consumption (overall)	582.64	708.87	862.45	1,049.31	1,276.64	1,553.23	1,889.74
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	583	674	781	904	1,046	1,211	1,402
Transport (LPG)							
Energy consumption (overall)	31.60	38.45	46.78	56.91	69.24	84.24	102.49
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	32	37	42	49	57	66	76
RESIDENTIAL							
Number of households	80,000	97,332	118,420	144,075	175,290	213,267	259,472
Annual Increase (Efficiency)	1.00%						
Lighting							
Distribution							
Electric	82.00%	85.00%	90.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	5.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Kerosene	18.00%	10.00%	5.00%	0.00%	0.00%	0.00%	0.00%
Electric Lighting							
Number of households	65,600	82,732	106,578	129,668	140,232	149,287	155,683
Energy consumption per household	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	295	354	434	503	517	524	520
Solar Lighting							
Number of households	0	4,867	5,921	14,408	35,058	63,980	103,789
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	14	16	37	86	150	231
Kerosene Lighting							
Number of households	14,400	9,733	5,921	0	0	0	0
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	43	28	16	0	0	0	0

Refrigeration

% of households	66.50%	70.00%	75.00%	75.00%	80.00%	80.00%	85.00%
Number of households	53,200	68,133	88,815	108,057	140,232	170,614	220,551
Energy consumption per household	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	105	128	159	184	228	263	324

Other Electricity Use

% of households	80.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Number of households	64,000	82,732	100,657	122,464	148,996	181,277	220,551
Energy consumption per household	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	319	393	455	527	610	706	817

Cooking

Distribution

LPG	84.00%	85.00%	90.00%	90.00%	95.00%	95.00%	95.00%
Wood	16.00%	15.00%	10.00%	10.00%	5.00%	5.00%	5.00%

LPG Range Cooking

Number of households	67,200	82,732	106,578	129,668	166,525	202,604	246,498
Energy consumption per household	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	520	609	746	864	1,056	1,222	1,415

Wood Stove Cooking

Number of households	12,800	14,600	11,842	14,408	8,764	10,663	12,974
Energy consumption per household	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Wood]	830	901	695	805	466	539	624

COMMERCIAL & SERVICES

Annual Increase (Efficiency)	1.00%						
Energy Audit Feedback Recommendations							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%

Distribution of Electricity Use	**146,718,000**	KWh					
Lighting	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Refrigeration	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Space Cooling	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Water Heating	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Other	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%

Total Electricity Use (TJ)	**528**	**643**	**782**	**951**	**1,157**	**1,408**	**1,713**
Total Energy Use for Lighting (TJ)	**211**	**257**	**313**	**380**	**463**	**563**	**685**
Commercial Lighting Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	85.00%	80.00%	75.00%
Solar	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Electric Lighting							
Energy consumption (overall)	211	257	297	342	393	451	514
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	211	245	264	286	310	334	362
Solar Lighting							
Energy consumption (overall)	0	0	16	38	69	113	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	14	32	55	83	121
Refrigeration							
Energy consumption (overall)	79	96	117	143	174	211	257
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	79	92	104	119	137	156	181
Total Energy Use for Space Cooling (TJ)	**106**	**129**	**156**	**190**	**231**	**282**	**343**
Space Cooling Distribution							
Electric	100.00%	100.00%	95.00%	85.00%	75.00%	60.00%	50.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Solar	0.00%	0.00%	0.00%	5.00%	10.00%	20.00%	25.00%
Electric Cooling							
Energy consumption (overall)	106	129	149	162	174	169	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	132	135	137	125	121
Geothermal Cooling							
Energy consumption (overall)	0	0	8	19	35	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	7	16	27	42	60
Solar Cooling							
Energy consumption (overall)	0	0	0	10	23	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	8	18	42	60
Total Energy Use for Water Heating (TJ)	**26**	**32**	**39**	**48**	**58**	**70**	**86**
Water Heating Distribution							
Electric	100.00%	90.00%	65.00%	30.00%	0.00%	0.00%	0.00%

LPG	0.00%	5.00%	15.00%	30.00%	30.00%	20.00%	10.00%
Solar	0.00%	5.00%	15.00%	30.00%	50.00%	60.00%	70.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	20.00%	20.00%	20.00%
Electric Water Heating							
Energy consumption (overall)	26	29	25	14	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	26	28	23	12	0	0	0
LPG Water Heating							
Energy consumption (overall)	0	2	6	14	17	14	9
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	2	5	12	14	10	6
Solar Water Heating							
Energy consumption (overall)	0	2	6	14	29	42	60
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	2	5	12	23	31	42
Geothermal Water Heating							
Energy consumption (overall)	0	0	2	5	12	14	17
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	2	4	9	10	12
Other Electricity Use							
Energy consumption (overall)	106	129	156	190	231	282	343
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	139	159	182	209	241
Total Energy Use for Streetlighting (TJ)	**88**	**107**	**131**	**159**	**194**	**235**	**286**
Streetlighting Energy Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	0.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Electric Streetlight Energy Use							
Energy consumption (overall)	88	107	124	143	155	165	172
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	88	102	110	120	122	122	121
Solar Streetlight Energy Use							
Energy consumption (overall)	0	0	7	16	39	71	115
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	6	13	30	52	81
LPG Energy Use for Cooking & Other Heating Purposes							
Energy consumption (overall)	90	109	133	162	197	240	292

Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	90	104	118	135	155	178	206
INDUSTRIAL							
Annual Increase (Efficiency)	1.00%						
Energy Audit Recommendations Implementation							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Total Energy Use (for industrial applications that use LPG in 2010)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Distribution of Energy							
LPG	100.00%	100.00%	90.00%	85.00%	80.00%	75.00%	75.00%
Solar	0.00%	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Industrial Solar Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Industrial LPG Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	0	0	0	0	0	0
Total Petroleum Use	**1,839.50**	**2,238.03**	**2,722.91**	**3,312.84**	**4,030.57**	**4,903.81**	**5,966.23**
Distribution of Petroleum Use							
Diesel	47.90%	50.00%	50.00%	40.00%	30.00%	20.00%	10.00%
HFO	37.00%	40.00%	30.00%	20.00%	20.00%	10.00%	10.00%
NG	0.00%	0.00%	20.00%	40.00%	50.00%	70.00%	80.00%
Crude Oil	15.10%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial Diesel Use							
Energy consumption (overall)	881	1,119	1,361	1,325	1,209	981	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	881	1,054	1,208	1,107	951	727	421
Industrial HFO Use							
Energy consumption (overall)	681	895	817	663	806	490	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [HFO]	681	843	725	554	634	363	421
Industrial NG Use							
Energy consumption (overall)	0	0	545	1,325	2,015	3,433	4,773
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [NG]	0	0	483	1,107	1,586	2,543	3,364

Industrial Crude Oil Use							
Energy consumption (overall)	278	224	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Crude Oil]	278	211	0	0	0	0	0
Industrial LP Steam Use (BSI)							
Energy consumption (overall)	639	639	639	639	639	639	639
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	639	608	578	550	524	498	474
Industrial Own Electricity Use (BSI/BELCOGEN)	**55,076,903**	63,757,215	73,805,575	85,437,591	98,902,854	114,490,288	132,534,358
Energy consumption (overall)	198	198	198	198	198	198	198
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	198	189	179	171	162	155	147
Industrial Electricity Use	**90,398,000**	KWh					
Energy consumption (overall)	325	396	482	586	713	868	1,056
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	325	373	427	490	561	643	744
CONVERSION EFFICIENCY							
LPG	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Diesel	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
BEL Diesel	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
HFO	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Gasoline	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Kerosene	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Crude Oil	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Natural Gas	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Biomass	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
MSW	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Fuelwood	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Geothermal	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Wind	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Hydro	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Imported Electricity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Electricity Transmission & Distribution Losses	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%
Fuel Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WORLD MARKET PRICES - Oil & Natural Gas							
WTI Crude Oil Price (USD per bbl)	79.00	94.58	108.10	117.54	123.09	124.94	134.60
Reference Oil Price Case	79.00	94.58	108.10	117.54	123.09	124.94	134.60
High Oil Price Case	79.00	146.10	169.08	185.87	196.07	199.95	226.23
LSD No. 2 Diesel (Distillate Fuel) Price (USD/gal)	2.38	2.84	3.24	3.52	3.69	3.75	4.04

Residual Fuel Oil No.6 Price (USD/gal)	1.33	1.90	2.53	3.14	3.69	3.75	4.04
Henry Hub Natural Gas Price (USD per MMBTU)	4.12	4.66	5.05	5.97	6.40	7.07	7.62
Reference Natural Gas Price Case	4.12	4.66	5.05	5.97	6.40	7.07	7.62
High Natural Gas Price Case	4.12	4.74	5.22	6.19	6.63	7.20	8.15
Reference Natural Gas Price Case (Delivered to Electric Power)	4.84	4.79	5.13	5.91	6.36	6.97	7.89
High Natural Gas Price Case (Delivered to Electric Power)	4.84	4.85	5.28	6.10	6.49	7.07	8.00
CFE Capacity Charges (per KWh)	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219
CFE Energy Charges (per KWh)	0.0946	0.1159	0.1190	0.1221	0.1245	0.1253	0.1273
MSD Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 80%]	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 10%]	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 60%]	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
FUEL PRICES (USD per TJ) *excl. Carbon Price*							
LPG	21,691.97	24,535.10	26,588.46	31,432.30	33,696.27	37,223.85	40,100.66
Diesel	16,491.37	19,634.75	22,441.49	24,401.23	25,553.40	25,937.46	27,942.01
Diesel-fired Electricity (Peaking)	47,177.38	51,368.55	55,110.88	57,723.86	59,260.10	59,772.17	62,444.91
Diesel-fired Electricity (Baseload)	18,858.04	22,001.41	24,808.16	26,767.90	27,920.07	28,304.13	30,308.68
HFO	8,431.15	12,060.12	16,031.39	19,874.90	23,372.28	23,723.55	25,557.00
HFO-fired Electricity	11,093.65	14,722.62	18,693.89	22,537.40	26,034.78	26,386.05	28,219.50
Gasoline	18,009.30	21,561.01	24,643.11	26,795.10	28,060.32	28,482.05	30,683.26
Kerosene	16,901.35	20,234.55	23,127.03	25,146.64	26,334.01	26,729.80	28,795.59
Crude Oil	12,909.93	15,455.97	17,665.36	19,208.02	20,114.98	20,417.30	21,995.24
Natural Gas	6,445.16	7,013.85	7,424.57	8,393.45	8,846.30	9,551.90	10,127.33
NG-fired Electricity (Peaking)	25,336.83	25,905.52	26,316.24	27,285.12	27,737.97	28,443.56	29,018.99
NG-fired Electricity (Baseload)	9,220.16	9,788.85	10,199.57	11,168.45	11,621.30	12,326.90	12,902.33
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	207,500.00	177,175.93	146,851.85	116,527.78	86,203.70	55,879.63	25,555.56
Solar (PV) Electricity	95,250.00	69,055.56	42,861.11	35,722.22	28,583.33	26,194.44	23,805.56
Wind Electricity	24,861.11	23,777.78	22,694.44	21,597.22	20,500.00	20,347.22	20,194.44
Hydro Electricity	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89
Imported Electricity	32,355.78	38,282.31	39,138.84	40,017.42	40,660.22	40,895.92	41,446.35
FUEL PRICES (USD per TJ) *incl. Carbon Price*							
LPG	23,155.41	26,587.64	29,467.26	35,469.96	39,359.30	45,166.54	51,240.69
Diesel	18,241.89	22,089.95	25,885.04	29,230.98	32,327.38	35,438.32	41,267.45
Diesel-fired Electricity (Peaking)	48,927.91	53,823.75	58,554.42	62,553.61	66,034.07	69,273.03	75,770.34
Diesel-fired Electricity (Baseload)	20,608.56	24,456.61	28,251.70	31,597.65	34,694.05	37,804.98	43,634.12
HFO	10,277.81	14,650.17	19,664.06	24,969.91	30,518.29	33,746.21	39,614.30
HFO-fired Electricity	12,940.31	17,312.67	22,326.56	27,632.41	33,180.79	36,408.71	42,276.80
Gasoline	19,687.24	23,914.41	27,943.87	31,424.59	34,553.41	37,588.96	43,456.16
Kerosene	18,615.45	22,638.66	26,498.92	29,875.89	32,967.03	36,032.95	41,843.73
Crude Oil	14,660.46	17,911.17	21,108.91	24,037.77	26,888.96	29,918.16	35,320.67

Natural Gas	7,731.48	8,817.98	9,954.96	11,942.45	13,823.95	16,533.31	19,919.12
NG-fired Electricity (Peaking)	26,623.15	27,709.65	28,846.63	30,834.12	32,715.62	35,424.98	38,810.78
NG-fired Electricity (Baseload)	10,506.48	11,592.98	12,729.96	14,717.45	16,598.95	19,308.31	22,694.12
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	208,347.22	178,364.20	148,518.47	118,865.29	89,482.19	60,477.87	32,004.83
Solar (PV) Electricity	95,986.11	70,087.99	44,309.15	37,753.18	31,431.85	30,189.64	29,409.02
Wind Electricity	25,006.94	23,982.32	22,981.32	21,999.58	21,064.33	21,138.72	21,304.56
Hydro Electricity	26,743.06	26,784.99	26,843.80	26,926.29	27,041.98	27,204.25	27,431.83
Imported Electricity	38,598.83	47,038.52	51,419.87	57,242.21	64,818.88	74,779.68	88,970.09

EMISSION FACTORS (tCO2e per TJ) [PEe]							
LPG	58.54	58.54	58.54	58.54	58.54	58.54	58.54
Diesel	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Diesel-fired Electricity	70.02	70.02	70.02	70.02	70.02	70.02	70.02
HFO	73.87	73.87	73.87	73.87	73.87	73.87	73.87
HFO-fired Electricity	73.87	73.87	73.87	73.87	73.87	73.87	73.87
Gasoline	67.12	67.12	67.12	67.12	67.12	67.12	67.12
Kerosene	68.56	68.56	68.56	68.56	68.56	68.56	68.56
Crude Oil	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Natural Gas	51.45	51.45	51.45	51.45	51.45	51.45	51.45
NG-fired Electricity	51.45	51.45	51.45	51.45	51.45	51.45	51.45
Bioethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass (Fuel & Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MSW (Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuelwood	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Electricity	33.89	33.89	33.89	33.89	33.89	33.89	33.89
Solar (PV) Electricity	29.44	29.44	29.44	29.44	29.44	29.44	29.44
Wind Electricity	5.83	5.83	5.83	5.83	5.83	5.83	5.83
Hydro Electricity	4.17	4.17	4.17	4.17	4.17	4.17	4.17
Imported Electricity	249.72	249.72	249.72	249.72	249.72	249.72	249.72

EMISSIONS PRICE (USD/tCO2e)	25.00	35.06	49.18	68.98	96.74	135.69	190.31
Annual Rate of price increase	7.00%						

GRID ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BECOL	249,564	249,564	249,564	249,564	249,564	249,564	249,564
Maximum Energy from Hydro Maya	13,586	13,680	13,680	13,680	13,680	13,680	13,680
Maximum Energy from BELCOGEN	48,632	102,600	102,600	102,600	102,600	102,600	102,600
BELCOGEN (% Total Energy from Biomass)	*78%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
BELCOGEN (% Remaining Energy from HFO)	*46.25%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum Energy from BAL	4,799	66,576	111,150	111,150	111,150	111,150	111,150
BAL (% Total Energy from HFO)	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*

Maximum Energy from CFE	160,000	346,896	346,896	346,896	346,896	346,896	346,896
Maximum Energy from SIEPAC	0	0	693,792	693,792	693,792	693,792	693,792
Minimum Energy from BEL (current)	7,608	0	0	0	0	0	0
Maximum Energy from Other HFO Plant(s)	0	0	62,680	147,680	157,680	315,360	473,040
Maximum Energy from New Natural Gas Plant(s)	0	0	0	0	0	0	0
Maximum Energy from Solar	0	0	0	0	0	0	0
Maximum Energy from Wind	0	0	0	0	0	0	0
Maximum Energy from Other Hydro	0	0	0	0	0	0	0
Maximum Energy from Other Biomass	0	0	0	0	0	0	0
Maximum Energy from MSW	0	0	0	0	0	0	0

Maximum Capacity from BECOL	54.00	54.00	54.00	54.00	54.00	54.00	54.00
Maximum Capacity from Hydro Maya	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Maximum Capacity from BELCOGEN	6.53	13.78	13.78	13.78	13.78	13.78	13.78
Maximum Capacity from BAL	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Maximum Capacity from CFE	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Maximum Capacity from SIEPAC	0.00	0.00	99.00	99.00	99.00	99.00	99.00
Maximum Capacity from BEL	25.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other HFO Plant(s)	0.00	0.00	11.93	28.10	30.00	60.00	90.00
Maximum Capacity from New Natural Gas Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Hydro	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Biomass	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from MSW	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Maximum Power Output (MW)	153	135	246	262	264	294	324
Peak Demand Growth Rate (5-year rate)		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Peak Demand (MW)	80	100	125	156	195	244	305
Supply Reserve (%)	91.29%	35.28%	96.96%	67.92%	35.31%	20.54%	6.26%
Supply Reserve % (Largest Supply Out)	23.79%	-18.72%	17.76%	4.56%	-15.38%	-20.01%	-26.18%

SELF-GENERATED ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BELCOGEN/BSI	55,077	63,757	73,806	85,438	98,903	114,490	132,534
Maximum Energy from BAL	26,705	26,705	26,705	26,705	26,705	26,705	26,705
Maximum Energy from BNE	7,008	7,008	7,008	7,008	7,008	7,008	7,008
Maximum Energy from CPBL	1,711	1,711	1,711	1,711	1,711	1,711	1,711
CPBL (% Total Energy from Crude Oil)	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
Maximum Energy from Others	0	0	0	0	0	0	0

Net Present Cost (over Evaluation Period)		
Cost *without* Carbon Pricing	**$3,073,966,847.66**	433,438,097
Cost *with* Carbon Pricing	**$3,507,404,944.50**	

RESULTS	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**

ENERGY							
TPES (in TJ)	12,888	15,743	17,176	18,591	19,625	21,421	23,645
TPES (in TOE)	307,823	376,019	410,231	444,043	468,736	511,637	564,744
Energy Intensity (BTU/$GDP[2010 USD])	8,536	9,067	8,602	8,097	7,432	7,054	6,771
Energy Supply Per Capita (TOE per capita)	0.9866	1.0480	0.9942	0.9358	0.8590	0.8153	0.7825
Secondary Energy Consumption Breakdown by Sector							
% Transport	46.81%	47.42%	48.45%	47.71%	48.20%	47.57%	46.52%
% Residential	19.31%	19.57%	18.45%	19.20%	17.87%	18.37%	18.92%
% Commercial & Services	6.45%	6.58%	6.75%	6.91%	7.27%	7.47%	7.75%
% Industrial	27.43%	26.43%	26.34%	26.17%	26.66%	26.59%	26.81%
EMISSIONS							
Total GHG Emissions (tCO2e)	702,461	772,533	852,392	922,893	1,025,008	1,058,716	1,122,273
Overall GHG Emissions Intensity (tCO2e/TJ)	55.99	50.22	50.67	50.55	52.79	50.06	48.22
Electricity Sector GHG Emissions Intensity (tCO2e/TJ)	52.74	34.88	35.40	37.76	43.47	40.50	40.02
Emissions Breakdown by Sector							
Transport	49.09%	51.27%	50.54%	49.02%	46.26%	45.85%	43.82%
Residential	15.17%	14.57%	15.96%	17.36%	19.17%	19.73%	20.69%
Commercial & Services	9.72%	8.69%	8.89%	9.39%	10.06%	10.05%	10.38%
Industrial	26.03%	25.47%	24.60%	24.24%	24.51%	24.38%	25.10%
COSTS							
Total Cost of Energy w/o CP	$205,897,584.54	$276,086,386.12	$353,805,314.32	$420,408,694.16	$486,077,114.84	$549,988,034.12	$648,584,947.33
Total Cost of Energy as a % of GDP [2010 USD]	14.39%	16.78%	18.70%	19.32%	19.42%	19.11%	19.59%
Unit Cost of Energy w/o CP (USD/TJ)	$15,976.01	$17,536.92	$20,599.34	$22,613.32	$24,768.23	$25,674.90	$27,430.44
Total Cost of Energy w/ CP	$223,459,117.25	$303,174,320.18	$395,724,928.19	$484,065,974.04	$585,238,571.29	$693,640,723.96	$862,160,641.30
Unit Cost of Energy w/ CP (USD/TJ)	$17,338.65	$19,257.53	$23,039.99	$26,037.37	$29,821.04	$32,380.99	$36,463.14
Carbon Cost as % of Total Energy Cost w/ CP	7.86%	8.93%	10.59%	13.15%	16.94%	20.71%	24.77%
Unit Cost of Electricity w/o CP (USD/TJ) [*Assessed at Primary Energy Supply Point*]	$20,516.0477	$18,115.76	$19,750.86	$20,381.00	$21,466.15	$21,233.46	$22,016.64
Unit Cost of Electricity w/o CP (USD/MWh) [*Assessed at Generation Supply Point*]	$131.2516	$146.80	$166.94	$174.29	$178.81	$185.82	$197.97
PEe Cost Breakdown by Sector							
Transport	42.65%	43.66%	43.98%	44.14%	44.33%	44.43%	44.69%
Residential	20.78%	20.98%	21.58%	22.70%	23.41%	24.76%	25.45%
Commercial & Services	13.07%	12.63%	12.79%	12.76%	12.54%	12.60%	12.36%
Industrial	23.50%	22.73%	21.66%	20.40%	19.72%	18.20%	17.51%
DIVERSITY & SECURITY							
Resource Type Diversity Index	34.07%	34.82%	40.76%	40.79%	39.60%	40.09%	39.51%
Foreign Oil Imports (BOE)	1,551,033	1,769,932	2,066,388	2,243,942	2,448,225	2,589,639	2,780,216
% Dependence on Foreign Sources (TPES)	63.33%	60.55%	66.45%	67.44%	69.78%	70.78%	71.90%
% Electricity (of Total PEe Energy Supply)	28.77%	34.39%	36.04%	36.65%	36.46%	37.38%	38.15%
% Electricity (of Total Secondary Energy Supply)	16.99%	17.32%	17.75%	17.96%	18.23%	18.08%	18.17%
% Wind Energy of Total Utility Electricity Generation	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
% Dependence on Foreign Sources (Electricity)	30.72%	24.04%	32.71%	38.02%	39.38%	44.88%	49.27%
% Renewables (of TPES)	30.05%	34.62%	31.71%	31.40%	30.56%	31.14%	32.18%
% Renewables (of Electricity Supply)	65.48%	73.36%	65.09%	60.04%	58.82%	53.58%	49.40%
% Renewables (of Transport Fuels)	0.00%	0.00%	0.75%	2.62%	6.43%	10.49%	15.97%
Renewables as % of Total PEe Sector Energy							
Transport	0.00%	0.00%	0.75%	2.62%	6.43%	10.49%	15.97%

Residential	**62.56%**	**67.39%**	**59.20%**	**56.33%**	**51.09%**	**47.95%**	**45.53%**
Commercial & Services	**60.97%**	**69.33%**	**62.08%**	**58.08%**	**57.89%**	**54.44%**	**51.99%**
Industrial	**37.46%**	**39.76%**	**35.16%**	**31.56%**	**29.13%**	**26.30%**	**23.72%**

APPENDIX D.3: PLAN B – DETAILS

PARAMETERS	2010	2015	2020	2025	2030	2035	2040
End-Use Energy							
Energy content (Gasoline)	131	MJ/gallon					
Energy content (Diesel)	144	MJ/gallon					
Energy content (Ethanol)	87	MJ/gallon					
Energy content (Biodiesel)	132	MJ/gallon					
Energy content (Crude Oil)	144	MJ/gallon					
Electricity	3.60	MJ/KWh					
ECONOMIC PARAMETERS							
Annual Increase (Economy)	4.00%						
Real GDP Growth Rate (5-year rate)		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
GDP (2010 USD)	$1,431,000,000.00	$1,645,650,000.00	$1,892,497,500.00	$2,176,372,125.00	$2,502,827,943.75	$2,878,252,135.31	$3,309,989,955.61
Population Growth Rate (5-year rate)		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Population	312,000	358,800	412,620	474,513	545,690	627,543	721,675
TRANSPORT							
Annual Increase (Fuel Efficiency)	1.00%						
Highway Travel as % of Total Mileage (Light Duty, Non-Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Highway Travel Efficiency Increase over Average (Light Duty, Non-Mass)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Highway Travel Efficiency Factor (Light Duty, Non-Mass)	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Urban Travel Efficiency Factor (Light Duty, Non-Mass)	85.71%	85.71%	85.71%	85.71%	85.71%	85.71%	85.71%
Average number of persons in private transport	2	2	2	2	2	2	2
% of highway travel substituted in mass transport switch	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
% of urban travel substituted in mass transport switch	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GASOLINE VEHICLES							
Total Number of Gasoline Vehicles	16,500	20,075	24,424	29,716	36,154	43,986	53,516
Miles per Vehicle (per annum)	12,800	12,800	12,800	12,800	12,800	12,800	12,800
Miles per vehicle (urban)	6,400	6,400	6,400	6,400	6,400	6,400	6,400
Miles per vehicle (highway)	6,400	6,400	6,400	6,400	6,400	6,400	6,400
% Switch to Mass Transport (from Gasoline Vehicles)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Gasoline Vehicles							
Typical Vehicle (Gasoline)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Small Vehicle (Gasoline)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Ethanol Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Hybrid Vehicle	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Plugin Hybrid Vehicle	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
All-Electric Vehicle	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Typical Vehicle (Gasoline)

Number of vehicles	16,500	20,075	24,424	29,716	36,154	43,986	53,516
Total vehicle-miles (urban)	105,600,000	128,478,546	156,313,796	190,179,634	231,382,604	281,512,317	342,502,777
Total vehicle-miles (highway)	105,600,000	128,478,546	156,313,796	190,179,634	231,382,604	281,512,317	342,502,777
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	1,844	2,135	2,471	2,860	3,311	3,833	4,437
Small Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Flex Fuel Vehicle (Ethanol Blend)							
% Ethanol in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Total energy use (TJ) [Ethanol]	0	0	0	0	0	0	0
Hybrid Vehicle (Gasoline)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Plugin Hybrid Vehicle (Gasoline)							
% Mileage on Electric	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (Gasoline)	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Average fuel economy (Electric)	3.00	3.15	3.31	3.48	3.66	3.85	4.04
Total energy use (TJ) [Gasoline]	0	0	0	0	0	0	0
Total energy use (TJ) [Electricity]	0	0	0	0	0	0	0
All-Electric Vehicle (Gasoline)							
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (mpk)	3.33	3.50	3.68	3.87	4.07	4.27	4.49

Total energy use (TJ) [Electricity]	0	0	0	0	0	0	0
Other Transport (Gasoline)							
Energy consumption (overall)	567	690	839	1,021	1,242	1,512	1,839
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Gasoline]	567	656	760	880	1,018	1,179	1,364
LIGHT-DUTY DIESEL VEHICLES							
Total Number of Light-Duty Diesel Vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Miles per Vehicle (per annum)	12,395	12,395	12,395	12,395	12,395	12,395	12,395
Miles per vehicle (urban)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
Miles per vehicle (highway)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
% Switch to Mass Transport (from Diesel Vehicles)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Light-Duty Diesel Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Small Vehicle (Diesel)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Vehicle (Diesel)							
Number of vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Total vehicle-miles (urban)	12,395,000	15,080,413	18,347,628	22,322,695	27,158,971	33,043,041	40,201,912
Total vehicle-miles (highway)	12,395,000	15,080,413	18,347,628	22,322,695	27,158,971	33,043,041	40,201,912
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	179	207	240	278	322	372	431
Small Vehicle (Diesel)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	24.00	25.22	26.51	27.86	29.28	30.78	32.35
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Flex Fuel Vehicle (Diesel)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Total vehicle-miles (urban)	0	0	0	0	0	0	0
Total vehicle-miles (highway)	0	0	0	0	0	0	0
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
MASS TRANSPORT DIESEL VEHICLES							
Highway Travel as % of Total Mileage (Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%

Average number of persons per highway travel mass transport	50	50	50	50	50	50	50
Highway Fuel Economy (Mass) [*Miles per Gallon*]	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Highway Fuel Economy (Mass) [*Person-miles per Gallon*]	300	315	331	348	366	385	404
Average number of persons per urban travel mass transport	20	20	20	20	20	20	20
Urban Fuel Economy (Mass) [*Miles per Gallon*]	5.00	5.26	5.52	5.80	6.10	6.41	6.74
Urban Travel Fuel Economy (Mass) [*Person-miles per Gallon*]	100	105	110	116	122	128	135

Total Number of Urban Travel Person-Miles (Non-Switch)	**18,000,000**	**21,899,752**	**26,644,397**	**32,416,983**	**39,440,217**	**47,985,054**	**58,381,155**
Total Number of Urban Travel Vehicle-Miles (Switch)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Typical Gasoline Vehicles	0	0	0	0	0	0	0
Small Gasoline Vehicles	0	0	0	0	0	0	0
Flex Fuel (Ethanol Blend) Vehicles	0	0	0	0	0	0	0
Hybrid Vehicles	0	0	0	0	0	0	0
Plugin Hybrid Vehicles	0	0	0	0	0	0	0
Electric Vehicles	0	0	0	0	0	0	0
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0
Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0

<u>Distribution between Urban Mass Transport Vehicles</u>

Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

<u>Typical Mass Transport (Diesel)</u>

Total person-miles (urban)	18,000,000	21,899,752	26,644,397	32,416,983	39,440,217	47,985,054	58,381,155
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	26	30	35	40	47	54	63

<u>Flex Fuel Mass Transport (Biodiesel Blend)</u>

% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (urban)	0	0	0	0	0	0	0
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0

Total Number of Highway Travel Vehicle-Miles (Non-Switch)	**1,250,750,000**	**1,521,728,618**	**1,851,415,539**	**2,252,530,090**	**2,740,547,271**	**3,334,294,792**	**4,056,679,436**
Total Number of Highway Travel Vehicle-Miles (Switch)	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Typical Gasoline Vehicles	0	0	0	0	0	0	0
Small Gasoline Vehicles	0	0	0	0	0	0	0
Flex Fuel (Ethanol Blend) Vehicles	0	0	0	0	0	0	0
Hybrid Vehicles	0	0	0	0	0	0	0
Plugin Hybrid Vehicles	0	0	0	0	0	0	0
Electric Vehicles	0	0	0	0	0	0	0
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0

Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0
Distribution between Highway Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Mass Transport (Diesel)							
Total person-miles (highway)	1,250,750,000	1,521,728,618	1,851,415,539	2,252,530,090	2,740,547,271	3,334,294,792	4,056,679,436
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	602	697	807	934	1,081	1,252	1,449
Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (highway)	0	0	0	0	0	0	0
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
HEAVY-DUTY DIESEL VEHICLES							
Total Number of Heavy Duty Diesel Vehicles	2,400	2,920	3,553	4,322	5,259	6,398	7,784
Miles per Vehicle (per annum)	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Distribution between Heavy Duty Diesel Vehicles							
Typical Vehicle (Diesel)	60.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Typical Vehicle (Crude Blend)	40.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Typical Heavy Duty Vehicle (Diesel)							
Number of vehicles	1,440	2,920	3,553	4,322	5,259	6,398	7,784
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	630	1,215	1,407	1,629	1,885	2,182	2,526
Typical Heavy Duty Vehicle (Crude Blend)							
% Crude in Blend	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	960	0	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	210	0	0	0	0	0	0
Total energy use (TJ) [Crude Oil]	210	0	0	0	0	0	0
Flex Fuel Heavy Duty Vehicle (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09

Total energy use (TJ) [Diesel]	0	0	0	0	0	0	0
Total energy use (TJ) [Biodiesel]	0	0	0	0	0	0	0
Other Transport (Diesel)							
Energy consumption (overall)	242	294	358	436	530	645	785
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	242	280	324	375	434	503	582
Aviation Transport (Kerosene)							
Energy consumption (overall)	582.64	708.87	862.45	1,049.31	1,276.64	1,553.23	1,889.74
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	583	674	781	904	1,046	1,211	1,402
Transport (LPG)							
Energy consumption (overall)	31.60	38.45	46.78	56.91	69.24	84.24	102.49
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	32	37	42	49	57	66	76
RESIDENTIAL							
Number of households	80,000	97,332	118,420	144,075	175,290	213,267	259,472
Annual Increase (Efficiency)	1.00%						
Lighting							
Distribution							
Electric	82.00%	85.00%	90.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Kerosene	18.00%	15.00%	10.00%	10.00%	20.00%	30.00%	40.00%
Electric Lighting							
Number of households	65,600	82,732	106,578	129,668	140,232	149,287	155,683
Energy consumption per household	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	295	354	434	503	517	524	520
Solar Lighting							
Number of households	0	0	0	0	0	0	0
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Kerosene Lighting							
Number of households	14,400	14,600	11,842	14,408	35,058	63,980	103,789
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	43	42	32	37	86	150	231

Refrigeration							
% of households	66.50%	70.00%	75.00%	75.00%	80.00%	80.00%	85.00%
Number of households	53,200	68,133	88,815	108,057	140,232	170,614	220,551
Energy consumption per household	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	105	128	159	184	228	263	324
Other Electricity Use							
% of households	80.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Number of households	64,000	82,732	100,657	122,464	148,996	181,277	220,551
Energy consumption per household	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	319	393	455	527	610	706	817
Cooking							
Distribution							
LPG	84.00%	85.00%	90.00%	90.00%	95.00%	95.00%	95.00%
Wood	16.00%	15.00%	10.00%	10.00%	5.00%	5.00%	5.00%
LPG Range Cooking							
Number of households	67,200	82,732	106,578	129,668	166,525	202,604	246,498
Energy consumption per household	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	520	609	746	864	1,056	1,222	1,415
Wood Stove Cooking							
Number of households	12,800	14,600	11,842	14,408	8,764	10,663	12,974
Energy consumption per household	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Wood]	830	901	695	805	466	539	624
COMMERCIAL & SERVICES							
Annual Increase (Efficiency)	1.00%						
Energy Audit Feedback Recommendations							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Distribution of Electricity Use	**146,718,000**	KWh					
Lighting	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Refrigeration	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Space Cooling	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Water Heating	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Other	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%

Total Electricity Use (TJ)	**528**	**643**	**782**	**951**	**1,157**	**1,408**	**1,713**
Total Energy Use for Lighting (TJ)	**211**	**257**	**313**	**380**	**463**	**563**	**685**
Commercial Lighting Distribution							
Electric	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Lighting							
Energy consumption (overall)	211	257	313	380	463	563	685
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	211	245	283	328	379	439	508
Solar Lighting							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Refrigeration							
Energy consumption (overall)	79	96	117	143	174	211	257
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	79	92	106	123	142	165	191
Total Energy Use for Space Cooling (TJ)	**106**	**129**	**156**	**190**	**231**	**282**	**343**
Space Cooling Distribution							
Electric	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Geothermal	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Cooling							
Energy consumption (overall)	106	129	156	190	231	282	343
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	142	164	190	220	254
Geothermal Cooling							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	0	0	0	0	0
Solar Cooling							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Total Energy Use for Water Heating (TJ)	**26**	**32**	**39**	**48**	**58**	**70**	**86**
Water Heating Distribution							
Electric	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

LPG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Geothermal	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Water Heating							
Energy consumption (overall)	26	32	39	48	58	70	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	26	31	35	41	47	55	64
LPG Water Heating							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	0	0	0	0	0	0
Solar Water Heating							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Geothermal Water Heating							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	0	0	0	0	0
Other Electricity Use							
Energy consumption (overall)	106	129	156	190	231	282	343
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	142	164	190	220	254
Total Energy Use for Streetlighting (TJ)	**88**	**107**	**131**	**159**	**194**	**235**	**286**
Streetlighting Energy Distribution							
Electric	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Electric Streetlight Energy Use							
Energy consumption (overall)	88	107	131	159	194	235	286
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	88	102	118	137	159	184	213
Solar Streetlight Energy Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
LPG Energy Use for Cooking & Other Heating Purposes							
Energy consumption (overall)	90	109	133	162	197	240	292

Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	90	104	121	140	162	187	217
INDUSTRIAL							
Annual Increase (Efficiency)	1.00%						
Energy Audit Recommendations Implementation							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Energy Use (for industrial applications that use LPG in 2010)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Distribution of Energy							
LPG	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial Solar Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Industrial LPG Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	0	0	0	0	0	0
Total Petroleum Use	**1,839.50**	**2,238.03**	**2,722.91**	**3,312.84**	**4,030.57**	**4,903.81**	**5,966.23**
Distribution of Petroleum Use							
Diesel	47.90%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
HFO	37.00%	39.00%	39.00%	39.00%	39.00%	39.00%	39.00%
NG	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Crude Oil	15.10%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%
Industrial Diesel Use							
Energy consumption (overall)	881	1,007	1,225	1,491	1,814	2,207	2,685
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	881	958	1,109	1,284	1,486	1,721	1,992
Industrial HFO Use							
Energy consumption (overall)	681	873	1,062	1,292	1,572	1,912	2,327
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [HFO]	681	830	961	1,113	1,288	1,491	1,726
Industrial NG Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [NG]	0	0	0	0	0	0	0

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Industrial Crude Oil Use							
Energy consumption (overall)	278	358	436	530	645	785	955
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Crude Oil]	278	341	394	457	529	612	708

Industrial LP Steam Use (BSI)							
Energy consumption (overall)	639	639	639	639	639	639	639
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	639	608	578	550	524	498	474

Industrial Own Electricity Use (BSI/BELCOGEN)	**55,076,903**	63,757,215	73,805,575	85,437,591	98,902,854	114,490,288	132,534,358
Energy consumption (overall)	198	198	198	198	198	198	198
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	198	189	179	171	162	155	147

Industrial Electricity Use	**90,398,000**	KWh					
Energy consumption (overall)	325	396	482	586	713	868	1,056
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	325	377	436	505	584	676	783

CONVERSION EFFICIENCY							
LPG	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Diesel	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
BEL Diesel	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
HFO	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Gasoline	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Kerosene	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Crude Oil	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Natural Gas	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Biomass	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
MSW	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Fuelwood	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Geothermal	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Wind	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Hydro	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Imported Electricity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Electricity Transmission & Distribution Losses	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%
Fuel Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

WORLD MARKET PRICES - Oil & Natural Gas							
WTI Crude Oil Price (USD per bbl)	79.00	94.58	108.10	117.54	123.09	124.94	134.60
Reference Oil Price Case	79.00	94.58	108.10	117.54	123.09	124.94	134.60
High Oil Price Case	79.00	146.10	169.08	185.87	196.07	199.95	226.23
LSD No. 2 Diesel (Distillate Fuel) Price (USD/gal)	2.38	2.84	3.24	3.52	3.69	3.75	4.04

Residual Fuel Oil No.6 Price (USD/gal)	1.33	1.90	2.53	3.14	3.69	3.75	4.04
Henry Hub Natural Gas Price (USD per MMBTU)	4.12	4.66	5.05	5.97	6.40	7.07	7.62
Reference Natural Gas Price Case	4.12	4.66	5.05	5.97	6.40	7.07	7.62
High Natural Gas Price Case	4.12	4.74	5.22	6.19	6.63	7.20	8.15
Reference Natural Gas Price Case (Delivered to Electric Power)	4.84	4.79	5.13	5.91	6.36	6.97	7.89
High Natural Gas Price Case (Delivered to Electric Power)	4.84	4.85	5.28	6.10	6.49	7.07	8.00
CFE Capacity Charges (per KWh)	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219
CFE Energy Charges (per KWh)	0.0946	0.1159	0.1190	0.1221	0.1245	0.1253	0.1273
MSD Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 80%]	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 10%]	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 60%]	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00

FUEL PRICES (USD per TJ) *excl. Carbon Price*

LPG	21,691.97	24,535.10	26,588.46	31,432.30	33,696.27	37,223.85	40,100.66
Diesel	16,491.37	19,634.75	22,441.49	24,401.23	25,553.40	25,937.46	27,942.01
Diesel-fired Electricity (Peaking)	47,177.38	51,368.55	55,110.88	57,723.86	59,260.10	59,772.17	62,444.91
Diesel-fired Electricity (Baseload)	18,858.04	22,001.41	24,808.16	26,767.90	27,920.07	28,304.13	30,308.68
HFO	8,431.15	12,060.12	16,031.39	19,874.90	23,372.28	23,723.55	25,557.00
HFO-fired Electricity	11,093.65	14,722.62	18,693.89	22,537.40	26,034.78	26,386.05	28,219.50
Gasoline	18,009.30	21,561.01	24,643.11	26,795.10	28,060.32	28,482.05	30,683.26
Kerosene	16,901.35	20,234.55	23,127.03	25,146.64	26,334.01	26,729.80	28,795.59
Crude Oil	12,909.93	15,455.97	17,665.36	19,208.02	20,114.98	20,417.30	21,995.24
Natural Gas	6,445.16	7,013.85	7,424.57	8,393.45	8,846.30	9,551.90	10,127.33
NG-fired Electricity (Peaking)	25,336.83	25,905.52	26,316.24	27,285.12	27,737.97	28,443.56	29,018.99
NG-fired Electricity (Baseload)	9,220.16	9,788.85	10,199.57	11,168.45	11,621.30	12,326.90	12,902.33
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	207,500.00	177,175.93	146,851.85	116,527.78	86,203.70	55,879.63	25,555.56
Solar (PV) Electricity	95,250.00	69,055.56	42,861.11	35,722.22	28,583.33	26,194.44	23,805.56
Wind Electricity	24,861.11	23,777.78	22,694.44	21,597.22	20,500.00	20,347.22	20,194.44
Hydro Electricity	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89
Imported Electricity	32,355.78	38,282.31	39,138.84	40,017.42	40,660.22	40,895.92	41,446.35

FUEL PRICES (USD per TJ) *incl. Carbon Price*

LPG	23,155.41	26,587.64	29,467.26	35,469.96	39,359.30	45,166.54	51,240.69
Diesel	18,241.89	22,089.95	25,885.04	29,230.98	32,327.38	35,438.32	41,267.45
Diesel-fired Electricity (Peaking)	48,927.91	53,823.75	58,554.42	62,553.61	66,034.07	69,273.03	75,770.34
Diesel-fired Electricity (Baseload)	20,608.56	24,456.61	28,251.70	31,597.65	34,694.05	37,804.98	43,634.12
HFO	10,277.81	14,650.17	19,664.06	24,969.91	30,518.29	33,746.21	39,614.30
HFO-fired Electricity	12,940.31	17,312.67	22,326.56	27,632.41	33,180.79	36,408.71	42,276.80
Gasoline	19,687.24	23,914.41	27,943.87	31,424.59	34,553.41	37,588.96	43,456.16
Kerosene	18,615.45	22,638.66	26,498.92	29,875.89	32,967.03	36,032.95	41,843.73
Crude Oil	14,660.46	17,911.17	21,108.91	24,037.77	26,888.96	29,918.16	35,320.67

Natural Gas	7,731.48	8,817.98	9,954.96	11,942.45	13,823.95	16,533.31	19,919.12
NG-fired Electricity (Peaking)	26,623.15	27,709.65	28,846.63	30,834.12	32,715.62	35,424.98	38,810.78
NG-fired Electricity (Baseload)	10,506.48	11,592.98	12,729.96	14,717.45	16,598.95	19,308.31	22,694.12
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	208,347.22	178,364.20	148,518.47	118,865.29	89,482.19	60,477.87	32,004.83
Solar (PV) Electricity	95,986.11	70,087.99	44,309.15	37,753.18	31,431.85	30,189.64	29,409.02
Wind Electricity	25,006.94	23,982.32	22,981.32	21,999.58	21,064.33	21,138.72	21,304.56
Hydro Electricity	26,743.06	26,784.99	26,843.80	26,926.29	27,041.98	27,204.25	27,431.83
Imported Electricity	38,598.83	47,038.52	51,419.87	57,242.21	64,818.88	74,779.68	88,970.09

EMISSION FACTORS (tCO2e per TJ) [PEe]							
LPG	58.54	58.54	58.54	58.54	58.54	58.54	58.54
Diesel	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Diesel-fired Electricity	70.02	70.02	70.02	70.02	70.02	70.02	70.02
HFO	73.87	73.87	73.87	73.87	73.87	73.87	73.87
HFO-fired Electricity	73.87	73.87	73.87	73.87	73.87	73.87	73.87
Gasoline	67.12	67.12	67.12	67.12	67.12	67.12	67.12
Kerosene	68.56	68.56	68.56	68.56	68.56	68.56	68.56
Crude Oil	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Natural Gas	51.45	51.45	51.45	51.45	51.45	51.45	51.45
NG-fired Electricity	51.45	51.45	51.45	51.45	51.45	51.45	51.45
Bioethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass (Fuel & Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MSW (Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuelwood	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Electricity	33.89	33.89	33.89	33.89	33.89	33.89	33.89
Solar (PV) Electricity	29.44	29.44	29.44	29.44	29.44	29.44	29.44
Wind Electricity	5.83	5.83	5.83	5.83	5.83	5.83	5.83
Hydro Electricity	4.17	4.17	4.17	4.17	4.17	4.17	4.17
Imported Electricity	249.72	249.72	249.72	249.72	249.72	249.72	249.72

EMISSIONS PRICE (USD/tCO2e)	25.00	35.06	49.18	68.98	96.74	135.69	190.31
Annual Rate of price increase	7.00%						

GRID ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BECOL	249,564	249,564	249,564	249,564	249,564	249,564	249,564
Maximum Energy from Hydro Maya	13,586	13,680	13,680	13,680	13,680	13,680	13,680
Maximum Energy from BELCOGEN	48,632	102,600	153,900	153,900	153,900	153,900	153,900
BELCOGEN (% Total Energy from Biomass)	*78%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
BELCOGEN (% Remaining Energy from HFO)	*46.25%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum Energy from BAL	4,799	66,576	0	0	0	0	0
BAL (% Total Energy from HFO)	*25%*	*25%*	*75%*	*75%*	*75%*	*75%*	*75%*

Maximum Energy from CFE	160,000	346,896	346,896	346,896	346,896	346,896	346,896
Maximum Energy from SIEPAC	0	0	693,792	693,792	693,792	693,792	693,792
Minimum Energy from BEL (current)	7,608	0	0	0	0	0	0
Maximum Energy from Other HFO Plant(s)	0	0	0	0	0	0	0
Maximum Energy from New Natural Gas Plant(s)	0	0	0	0	0	0	0
Maximum Energy from Solar	0	0	0	0	0	0	0
Maximum Energy from Wind	0	0	52,560	65,700	109,500	142,350	142,350
Maximum Energy from Other Hydro	0	0	81,802	162,832	221,962	221,962	221,962
Maximum Energy from Other Biomass	0	0	140,160	140,160	140,160	210,240	343,392
Maximum Energy from MSW	0	0	0	0	0	0	0

Maximum Capacity from BECOL	54.00	54.00	54.00	54.00	54.00	54.00	54.00
Maximum Capacity from Hydro Maya	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Maximum Capacity from BELCOGEN	6.53	13.78	20.67	20.67	20.67	20.67	20.67
Maximum Capacity from BAL	15.00	15.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from CFE	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Maximum Capacity from SIEPAC	0.00	0.00	99.00	99.00	99.00	99.00	99.00
Maximum Capacity from BEL	25.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other HFO Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from New Natural Gas Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Hydro	0.00	0.00	18.68	37.18	50.68	50.68	50.68
Maximum Capacity from Other Biomass	0.00	0.00	26.67	26.67	26.67	40.00	65.33
Maximum Capacity from MSW	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Maximum Power Output (MW)	153	135	272	290	304	317	342
Peak Demand Growth Rate (5-year rate)		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Peak Demand (MW)	80	100	125	156	195	244	305
Supply Reserve (%)	91.29%	35.28%	117.21%	85.61%	55.40%	29.78%	12.13%
Supply Reserve % (Largest Supply Out)	23.79%	-18.72%	38.01%	22.25%	4.71%	-10.77%	-20.32%

SELF-GENERATED ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BELCOGEN/BSI	55,077	63,757	73,806	85,438	98,903	114,490	132,534
Maximum Energy from BAL	26,705	26,705	0	0	0	0	0
Maximum Energy from BNE	7,008	7,008	7,008	7,008	7,008	7,008	7,008
Maximum Energy from CPBL	1,711	1,711	0	0	0	0	0
CPBL (% Total Energy from Crude Oil)	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
Maximum Energy from Others	0	0	0	0	0	0	0

Net Present Cost (over Evaluation Period)				
Cost *without* Carbon Pricing	**$2,961,116,790.59**			414,976,848
Cost *with* Carbon Pricing	**$3,376,093,638.27**			

RESULTS	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**

ENERGY							
TPES (in TJ)	12,888	15,838	19,624	21,836	23,877	27,709	33,055
TPES (in TOE)	307,823	378,281	468,722	521,543	570,284	661,821	789,502
Energy Intensity (BTU/$GDP[2010 USD])	8,536	9,122	9,828	9,510	9,042	9,125	9,465
Energy Supply Per Capita (TOE per capita)	0.9866	1.0543	1.1360	1.0991	1.0451	1.0546	1.0940
Secondary Energy Consumption Breakdown by Sector							
% Transport	46.81%	47.53%	49.07%	49.55%	51.10%	51.51%	51.83%
% Residential	19.31%	19.45%	18.02%	18.20%	16.45%	16.46%	16.52%
% Commercial & Services	6.45%	6.55%	6.77%	6.83%	7.05%	7.10%	7.15%
% Industrial	27.43%	26.46%	26.15%	25.43%	25.40%	24.92%	24.51%
EMISSIONS							
Total GHG Emissions (tCO2e)	702,461	780,333	699,512	815,024	946,127	1,102,234	1,273,414
Overall GHG Emissions Intensity (tCO2e/TJ)	55.99	50.43	36.20	37.75	39.78	39.77	38.53
Electricity Sector GHG Emissions Intensity (tCO2e/TJ)	52.74	35.19	1.63	2.17	1.84	1.99	1.21
Emissions Breakdown by Sector							
Transport	49.09%	51.24%	65.95%	65.67%	65.57%	65.24%	65.49%
Residential	15.17%	14.58%	7.23%	7.39%	7.81%	8.14%	8.19%
Commercial & Services	9.72%	8.69%	1.61%	1.76%	1.60%	1.68%	1.45%
Industrial	26.03%	25.50%	25.21%	25.19%	25.02%	24.94%	24.87%
COSTS							
Total Cost of Energy w/o CP	$205,897,584.54	$277,452,274.81	$312,601,834.80	$388,776,377.13	$468,014,372.45	$549,581,515.85	$673,226,406.84
Total Cost of Energy as a % of GDP [2010 USD]	14.39%	16.86%	16.52%	17.86%	18.70%	19.09%	20.34%
Unit Cost of Energy w/o CP (USD/TJ)	$15,976.01	$17,518.26	$15,929.20	$17,804.41	$19,601.35	$19,833.96	$20,366.93
Total Cost of Energy w/ CP	$223,459,117.25	$304,813,722.44	$347,003,000.92	$444,993,276.61	$559,544,675.64	$699,139,023.36	$915,565,276.50
Unit Cost of Energy w/ CP (USD/TJ)	$17,338.65	$19,245.86	$17,682.18	$20,378.92	$23,434.81	$25,231.37	$27,698.34
Carbon Cost as % of Total Energy Cost w/ CP	7.86%	8.98%	9.91%	12.63%	16.36%	21.39%	26.47%
Unit Cost of Electricity w/o CP (USD/TJ) [*Assessed at Primary Energy Supply Point*]	$20,516.0477	$18,144.75	$9,199.13	$9,800.86	$10,178.89	$9,640.98	$8,713.18
Unit Cost of Electricity w/o CP (USD/MWh) [*Assessed at Generation Supply Point*]	$131.2516	$146.77	$97.26	$96.95	$95.44	$94.90	$94.52
PEe Cost Breakdown by Sector							
Transport	42.65%	44.13%	51.80%	52.46%	52.83%	52.90%	53.86%
Residential	20.78%	20.63%	17.16%	17.03%	16.86%	17.20%	16.83%
Commercial & Services	13.07%	12.58%	9.01%	8.54%	8.17%	8.14%	7.75%
Industrial	23.50%	22.67%	22.04%	21.98%	22.13%	21.76%	21.56%
DIVERSITY & SECURITY							
Resource Type Diversity Index	34.07%	35.33%	34.92%	34.71%	36.29%	36.90%	37.41%
Foreign Oil Imports (BOE)	1,551,033	1,797,348	1,706,783	1,984,615	2,310,576	2,692,075	3,119,390
% Dependence on Foreign Sources (TPES)	63.33%	61.12%	49.66%	51.80%	55.25%	55.40%	53.90%
% Electricity (of Total PEe Energy Supply)	28.77%	34.26%	41.55%	39.84%	38.70%	39.22%	41.03%
% Electricity (of Total Secondary Energy Supply)	16.99%	17.27%	17.79%	17.74%	17.82%	17.44%	17.12%
% Wind Energy of Total Utility Electricity Generation	0.00%	0.00%	7.59%	8.30%	12.30%	14.27%	12.65%
% Dependence on Foreign Sources (Electricity)	30.72%	24.15%	0.04%	0.23%	0.06%	0.20%	0.00%
% Renewables (of TPES)	30.05%	34.42%	46.56%	44.51%	41.08%	41.14%	42.90%
% Renewables (of Electricity Supply)	65.48%	73.26%	98.48%	98.39%	98.64%	98.70%	99.11%
% Renewables (of Transport Fuels)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Renewables as % of Total PEe Sector Energy							
Transport	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Residential	**62.56%**	**66.95%**	**83.10%**	**82.31%**	**78.46%**	**77.89%**	**78.43%**
Commercial & Services	**60.97%**	**69.21%**	**94.29%**	**93.93%**	**93.93%**	**94.20%**	**95.00%**
Industrial	**37.46%**	**39.58%**	**50.73%**	**47.31%**	**44.47%**	**43.79%**	**44.55%**

APPENDIX D.4: PLAN C – DETAILS

PARAMETERS	2010	2015	2020	2025	2030	2035	2040
End-Use Energy							
Energy content (Gasoline)	131	MJ/gallon					
Energy content (Diesel)	144	MJ/gallon					
Energy content (Ethanol)	87	MJ/gallon					
Energy content (Biodiesel)	132	MJ/gallon					
Energy content (Crude Oil)	144	MJ/gallon					
Electricity	3.60	MJ/KWh					
ECONOMIC PARAMETERS							
Annual Increase (Economy)	4.00%						
Real GDP Growth Rate (5-year rate)		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
GDP (2010 USD)	$1,431,000,000.00	$1,645,650,000.00	$1,892,497,500.00	$2,176,372,125.00	$2,502,827,943.75	$2,878,252,135.31	$3,309,989,955.61
Population Growth Rate (5-year rate)		15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Population	312,000	358,800	412,620	474,513	545,690	627,543	721,675
TRANSPORT							
Annual Increase (Fuel Efficiency)	1.00%						
Highway Travel as % of Total Mileage (Light Duty, Non-Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Highway Travel Efficiency Increase over Average (Light Duty, Non-Mass)	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Highway Travel Efficiency Factor (Light Duty, Non-Mass)	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%	120.00%
Urban Travel Efficiency Factor (Light Duty, Non-Mass)	85.71%	85.71%	85.71%	85.71%	85.71%	85.71%	85.71%
Average number of persons in private transport	2	2	2	2	2	2	2
% of highway travel substituted in mass transport switch	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%	80.00%
% of urban travel substituted in mass transport switch	0.00%	0.00%	0.00%	20.00%	30.00%	40.00%	50.00%
GASOLINE VEHICLES							
Total Number of Gasoline Vehicles	16,500	20,075	24,424	29,716	36,154	43,986	53,516
Miles per Vehicle (per annum)	12,800	12,800	12,800	12,800	12,800	12,800	12,800
Miles per vehicle (urban)	6,400	6,400	6,400	6,400	6,400	6,400	6,400
Miles per vehicle (highway)	6,400	6,400	6,400	6,400	6,400	6,400	6,400
% Switch to Mass Transport (from Gasoline Vehicles)	**0.00%**	**5.00%**	**10.00%**	**15.00%**	**20.00%**	**25.00%**	**30.00%**
Distribution between Gasoline Vehicles							
Typical Vehicle (Gasoline)	100.00%	95.00%	65.00%	35.00%	25.00%	15.00%	0.00%
Small Vehicle (Gasoline)	0.00%	5.00%	10.00%	20.00%	20.00%	20.00%	20.00%
Flex Fuel Vehicle (Ethanol Blend)	0.00%	0.00%	20.00%	25.00%	20.00%	15.00%	10.00%
Hybrid Vehicle	0.00%	0.00%	5.00%	10.00%	15.00%	15.00%	15.00%
Plugin Hybrid Vehicle	0.00%	0.00%	0.00%	5.00%	10.00%	15.00%	25.00%
All-Electric Vehicle	0.00%	0.00%	0.00%	5.00%	10.00%	20.00%	30.00%

Typical Vehicle (Gasoline)

Number of vehicles	16,500	19,071	15,876	10,400	9,038	6,598	0
Total vehicle-miles (urban)	105,600,000	122,054,619	101,603,968	64,565,986	54,374,912	38,004,163	0
Total vehicle-miles (highway)	105,600,000	117,172,434	93,475,650	58,575,327	48,590,347	33,781,478	0
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	1,844	1,994	1,553	934	744	494	0

Small Vehicle (Gasoline)

Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	1,004	2,442	5,943	7,231	8,797	10,703
Total vehicle-miles (urban)	0	6,423,927	15,631,380	36,894,849	43,499,930	50,672,217	58,225,472
Total vehicle-miles (highway)	0	6,166,970	14,380,869	33,471,616	38,872,277	45,041,971	52,060,422
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	87	199	445	496	548	601

Flex Fuel Vehicle (Ethanol Blend)

% Ethanol in Blend	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%	25.00%
Number of vehicles	0	0	4,885	7,429	7,231	6,598	5,352
Total vehicle-miles (urban)	0	0	31,262,759	46,118,561	43,499,930	38,004,163	29,112,736
Total vehicle-miles (highway)	0	0	28,761,739	41,839,520	38,872,277	33,781,478	26,030,211
Average fuel economy	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Total energy use (TJ) [Gasoline]	0	0	427	572	487	404	295
Total energy use (TJ) [Ethanol]	0	0	50	95	108	90	66

Hybrid Vehicle (Gasoline)

Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	0	1,221	2,972	5,423	6,598	8,027
Total vehicle-miles (urban)	0	0	7,815,690	18,447,425	32,624,947	38,004,163	43,669,104
Total vehicle-miles (highway)	0	0	7,190,435	16,735,808	29,154,208	33,781,478	39,045,317
Average fuel economy	18.00	18.92	19.88	20.90	21.96	23.08	24.26
Total energy use (TJ) [Gasoline]	0	0	100	222	372	411	451

Plugin Hybrid Vehicle (Gasoline)

% Mileage on Electric	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	0	0	0	1,486	3,615	6,598	13,379
Total vehicle-miles (urban)	0	0	0	9,223,712	21,749,965	38,004,163	72,781,840
Total vehicle-miles (highway)	0	0	0	8,367,904	19,436,139	33,781,478	65,075,528
Average fuel economy (Gasoline)	15.00	15.77	16.57	17.41	18.30	19.24	20.22
Average fuel economy (Electric)	3.00	3.15	3.31	3.48	3.66	3.85	4.04
Total energy use (TJ) [Gasoline]	0	0	0	67	149	247	451
Total energy use (TJ) [Electricity]	0	0	0	9	20	34	62

All-Electric Vehicle (Gasoline)

Number of vehicles	0	0	0	1,486	3,615	8,797	16,055
Total vehicle-miles (urban)	0	0	0	9,223,712	21,749,965	50,672,217	87,338,208
Total vehicle-miles (highway)	0	0	0	8,367,904	19,436,139	45,041,971	78,090,633
Average fuel economy (mpk)	3.33	3.50	3.68	3.87	4.07	4.27	4.49

Total energy use (TJ) [Electricity]	0	0	0	16	37	81	134
Other Transport (Gasoline)							
Energy consumption (overall)	567	690	839	1,021	1,242	1,512	1,839
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Gasoline]	567	656	760	880	1,018	1,179	1,364
LIGHT-DUTY DIESEL VEHICLES							
Total Number of Light-Duty Diesel Vehicles	2,000	2,433	2,960	3,602	4,382	5,332	6,487
Miles per Vehicle (per annum)	12,395	12,395	12,395	12,395	12,395	12,395	12,395
Miles per vehicle (urban)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
Miles per vehicle (highway)	6,198	6,198	6,198	6,198	6,198	6,198	6,198
% Switch to Mass Transport (from Diesel Vehicles)	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**
Distribution between Light-Duty Diesel Vehicles							
Typical Vehicle (Diesel)	100.00%	90.00%	90.00%	85.00%	70.00%	60.00%	50.00%
Small Vehicle (Diesel)	0.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Vehicle (Diesel)							
Number of vehicles	2,000	2,190	2,664	3,062	3,068	3,199	3,243
Total vehicle-miles (urban)	12,395,000	13,572,371	16,512,865	18,974,291	19,011,280	19,825,825	20,100,956
Total vehicle-miles (highway)	12,395,000	13,572,371	16,512,865	18,974,291	19,011,280	19,825,825	20,100,956
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	179	187	216	236	225	223	215
Small Vehicle (Diesel)							
Increase in efficiency (compared with 'Typical Vehicle')	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Number of vehicles	0	243	296	360	438	533	649
Total vehicle-miles (urban)	0	1,508,041	1,834,763	2,232,269	2,715,897	3,304,304	4,020,191
Total vehicle-miles (highway)	0	1,508,041	1,834,763	2,232,269	2,715,897	3,304,304	4,020,191
Average fuel economy	24.00	25.22	26.51	27.86	29.28	30.78	32.35
Total energy use (TJ) [Diesel]	0	17	20	23	27	31	36
Flex Fuel Vehicle (Diesel)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	180	876	1,600	2,595
Total vehicle-miles (urban)	0	0	0	1,116,135	5,431,794	9,912,912	16,080,765
Total vehicle-miles (highway)	0	0	0	1,116,135	5,431,794	9,912,912	16,080,765
Average fuel economy	20.00	21.02	22.09	23.22	24.40	25.65	26.96
Total energy use (TJ) [Diesel]	0	0	0	9	34	47	55
Total energy use (TJ) [Biodiesel]	0	0	0	5	31	65	117
MASS TRANSPORT DIESEL VEHICLES							
Highway Travel as % of Total Mileage (Mass)	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%

Average number of persons per highway travel mass transport	50	50	50	50	50	50	50
Highway Fuel Economy (Mass) [*Miles per Gallon*]	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Highway Fuel Economy (Mass) [*Person-miles per Gallon*]	300	315	331	348	366	385	404
Average number of persons per urban travel mass transport	20	20	20	20	20	20	20
Urban Fuel Economy (Mass) [*Miles per Gallon*]	5.00	5.26	5.52	5.80	6.10	6.41	6.74
Urban Travel Fuel Economy (Mass) [*Person-miles per Gallon*]	100	105	110	116	122	128	135

Total Number of Urban Travel Person-Miles (Non-Switch)	**18,000,000**	**21,899,752**	**26,644,397**	**32,416,983**	**39,440,217**	**47,985,054**	**58,381,155**
Total Number of Urban Travel Vehicle-Miles (Switch)	**0**	**0**	**0**	**11,410,778**	**27,765,912**	**56,302,463**	**102,750,833**
Typical Gasoline Vehicles	0	0	0	3,993,772	6,941,478	8,445,369	0
Small Gasoline Vehicles	0	0	0	2,282,156	5,553,182	11,260,493	20,550,167
Flex Fuel (Ethanol Blend) Vehicles	0	0	0	2,852,695	5,553,182	8,445,369	10,275,083
Hybrid Vehicles	0	0	0	1,141,078	4,164,887	8,445,369	15,412,625
Plugin Hybrid Vehicles	0	0	0	570,539	2,776,591	8,445,369	25,687,708
Electric Vehicles	0	0	0	570,539	2,776,591	11,260,493	30,825,250
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0
Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0

Distribution between Urban Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%

Typical Mass Transport (Diesel)							
Total person-miles (urban)	18,000,000	21,899,752	26,644,397	41,636,373	53,764,903	73,001,262	96,679,193
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	26	30	35	52	64	82	104

Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (urban)	0	0	0	2,191,388	13,441,226	31,286,255	64,452,795
Average fuel economy (person-miles per gallon)	100.00	105.10	110.46	116.10	122.02	128.24	134.78
Total energy use (TJ) [Diesel]	0	0	0	2	8	15	22
Total energy use (TJ) [Biodiesel]	0	0	0	1	8	20	47

Total Number of Highway Travel Vehicle-Miles (Non-Switch)	**1,250,750,000**	**1,521,728,618**	**1,851,415,539**	**2,252,530,090**	**2,740,547,271**	**3,334,294,792**	**4,056,679,436**
Total Number of Highway Travel Vehicle-Miles (Switch)	**0**	**10,278,284**	**25,010,207**	**45,643,112**	**74,042,433**	**112,604,927**	**164,401,333**
Typical Gasoline Vehicles	0	9,764,370	16,256,635	15,975,089	18,510,608	16,890,739	0
Small Gasoline Vehicles	0	513,914	2,501,021	9,128,622	14,808,487	22,520,985	32,880,267
Flex Fuel (Ethanol Blend) Vehicles	0	0	5,002,041	11,410,778	14,808,487	16,890,739	16,440,133
Hybrid Vehicles	0	0	1,250,510	4,564,311	11,106,365	16,890,739	24,660,200
Plugin Hybrid Vehicles	0	0	0	2,282,156	7,404,243	16,890,739	41,100,333
Electric Vehicles	0	0	0	2,282,156	7,404,243	22,520,985	49,320,400
Typical Diesel Vehicles	0	0	0	0	0	0	0
Small Diesel Vehicles	0	0	0	0	0	0	0

Flex Fuel (Biodiesel Blend) Vehicles	0	0	0	0	0	0	0
Distribution between Highway Mass Transport Vehicles							
Typical Vehicle (Diesel)	100.00%	100.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Mass Transport (Diesel)							
Total person-miles (highway)	1,250,750,000	1,532,006,901	1,876,425,747	2,183,264,542	2,251,671,764	2,412,829,803	2,532,648,461
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	602	702	818	905	889	906	905
Flex Fuel Mass Transport (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Total person-miles (highway)	0	0	0	114,908,660	562,917,941	1,034,069,915	1,688,432,307
Average fuel economy (person-miles per gallon)	300.00	315.30	331.39	348.29	366.06	384.73	404.35
Total energy use (TJ) [Diesel]	0	0	0	30	116	163	192
Total energy use (TJ) [Biodiesel]	0	0	0	18	106	225	411
HEAVY-DUTY DIESEL VEHICLES							
Total Number of Heavy Duty Diesel Vehicles	2,400	2,920	3,553	4,322	5,259	6,398	7,784
Miles per Vehicle (per annum)	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Distribution between Heavy Duty Diesel Vehicles							
Typical Vehicle (Diesel)	60.00%	70.00%	100.00%	95.00%	80.00%	70.00%	60.00%
Typical Vehicle (Crude Blend)	40.00%	30.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Flex Fuel Vehicle (Biodiesel Blend)	0.00%	0.00%	0.00%	5.00%	20.00%	30.00%	40.00%
Typical Heavy Duty Vehicle (Diesel)							
Number of vehicles	1,440	2,044	3,553	4,106	4,207	4,479	4,670
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	630	851	1,407	1,547	1,508	1,528	1,516
Typical Heavy Duty Vehicle (Crude Blend)							
% Crude in Blend	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%	50.00%
Number of vehicles	960	876	0	0	0	0	0
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09
Total energy use (TJ) [Diesel]	210	182	0	0	0	0	0
Total energy use (TJ) [Crude Oil]	210	182	0	0	0	0	0
Flex Fuel Heavy Duty Vehicle (Biodiesel Blend)							
% Biodiesel in Blend	10.00%	20.00%	30.00%	40.00%	50.00%	60.00%	70.00%
Number of vehicles	0	0	0	216	1,052	1,919	3,114
Miles per vehicle	18,170	18,170	18,170	18,170	18,170	18,170	18,170
Average fuel economy	6.00	6.31	6.63	6.97	7.32	7.69	8.09

Total energy use (TJ) [Diesel]	0	0	0	51	197	276	322
Total energy use (TJ) [Biodiesel]	0	0	0	31	180	379	689
Other Transport (Diesel)							
Energy consumption (overall)	242	294	358	436	530	645	785
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	242	280	324	375	434	503	582
Aviation Transport (Kerosene)							
Energy consumption (overall)	582.64	708.87	862.45	1,049.31	1,276.64	1,553.23	1,889.74
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	583	674	781	904	1,046	1,211	1,402
Transport (LPG)							
Energy consumption (overall)	31.60	38.45	46.78	56.91	69.24	84.24	102.49
Average fuel economy	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	32	37	42	49	57	66	76
RESIDENTIAL							
Number of households	80,000	97,332	118,420	144,075	175,290	213,267	259,472
Annual Increase (Efficiency)	1.00%						
Lighting							
Distribution							
Electric	82.00%	85.00%	90.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	5.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Kerosene	18.00%	10.00%	5.00%	0.00%	0.00%	0.00%	0.00%
Electric Lighting							
Number of households	65,600	82,732	106,578	129,668	140,232	149,287	155,683
Energy consumption per household	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500	0.004500
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	295	354	434	503	517	524	520
Solar Lighting							
Number of households	0	4,867	5,921	14,408	35,058	63,980	103,789
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	14	16	37	86	150	231
Kerosene Lighting							
Number of households	14,400	9,733	5,921	0	0	0	0
Energy consumption per household	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000	0.003000
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Kerosene]	43	28	16	0	0	0	0

Refrigeration							
% of households	66.50%	70.00%	75.00%	75.00%	80.00%	80.00%	85.00%
Number of households	53,200	68,133	88,815	108,057	140,232	170,614	220,551
Energy consumption per household	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980	0.001980
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	105	128	159	184	228	263	324
Other Electricity Use							
% of households	80.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%
Number of households	64,000	82,732	100,657	122,464	148,996	181,277	220,551
Energy consumption per household	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992	0.004992
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	319	393	455	527	610	706	817
Cooking							
Distribution							
LPG	84.00%	85.00%	90.00%	90.00%	95.00%	95.00%	95.00%
Wood	16.00%	15.00%	10.00%	10.00%	5.00%	5.00%	5.00%
LPG Range Cooking							
Number of households	67,200	82,732	106,578	129,668	166,525	202,604	246,498
Energy consumption per household	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737	0.007737
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	520	609	746	864	1,056	1,222	1,415
Wood Stove Cooking							
Number of households	12,800	14,600	11,842	14,408	8,764	10,663	12,974
Energy consumption per household	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844	0.064844
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Wood]	830	901	695	805	466	539	624
COMMERCIAL & SERVICES							
Annual Increase (Efficiency)	1.00%						
Energy Audit Feedback Recommendations							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Distribution of Electricity Use	**146,718,000**	KWh					
Lighting	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
Refrigeration	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Space Cooling	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Water Heating	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
Other	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%

Total Electricity Use (TJ)	**528**	**643**	**782**	**951**	**1,157**	**1,408**	**1,713**
Total Energy Use for Lighting (TJ)	**211**	**257**	**313**	**380**	**463**	**563**	**685**
Commercial Lighting Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	85.00%	80.00%	75.00%
Solar	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Electric Lighting							
Energy consumption (overall)	211	257	297	342	393	451	514
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	211	245	264	286	310	334	362
Solar Lighting							
Energy consumption (overall)	0	0	16	38	69	113	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	14	32	55	83	121
Refrigeration							
Energy consumption (overall)	79	96	117	143	174	211	257
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	79	92	104	119	137	156	181
Total Energy Use for Space Cooling (TJ)	**106**	**129**	**156**	**190**	**231**	**282**	**343**
Space Cooling Distribution							
Electric	100.00%	100.00%	95.00%	85.00%	75.00%	60.00%	50.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%
Solar	0.00%	0.00%	0.00%	5.00%	10.00%	20.00%	25.00%
Electric Cooling							
Energy consumption (overall)	106	129	149	162	174	169	171
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	132	135	137	125	121
Geothermal Cooling							
Energy consumption (overall)	0	0	8	19	35	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	7	16	27	42	60
Solar Cooling							
Energy consumption (overall)	0	0	0	10	23	56	86
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	8	18	42	60
Total Energy Use for Water Heating (TJ)	**26**	**32**	**39**	**48**	**58**	**70**	**86**
Water Heating Distribution							
Electric	100.00%	90.00%	65.00%	30.00%	0.00%	0.00%	0.00%

LPG	0.00%	5.00%	15.00%	30.00%	30.00%	20.00%	10.00%
Solar	0.00%	5.00%	15.00%	30.00%	50.00%	60.00%	70.00%
Geothermal	0.00%	0.00%	5.00%	10.00%	20.00%	20.00%	20.00%
Electric Water Heating							
Energy consumption (overall)	26	29	25	14	0	0	0
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	26	28	23	12	0	0	0
LPG Water Heating							
Energy consumption (overall)	0	2	6	14	17	14	9
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	2	5	12	14	10	6
Solar Water Heating							
Energy consumption (overall)	0	2	6	14	29	42	60
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	2	5	12	23	31	42
Geothermal Water Heating							
Energy consumption (overall)	0	0	2	5	12	14	17
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Geothermal]	0	0	2	4	9	10	12
Other Electricity Use							
Energy consumption (overall)	106	129	156	190	231	282	343
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	106	122	139	159	182	209	241
Total Energy Use for Streetlighting (TJ)	**88**	**107**	**131**	**159**	**194**	**235**	**286**
Streetlighting Energy Distribution							
Electric	100.00%	100.00%	95.00%	90.00%	80.00%	70.00%	60.00%
Solar	0.00%	0.00%	5.00%	10.00%	20.00%	30.00%	40.00%
Electric Streetlight Energy Use							
Energy consumption (overall)	88	107	124	143	155	165	172
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	88	102	110	120	122	122	121
Solar Streetlight Energy Use							
Energy consumption (overall)	0	0	7	16	39	71	115
Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	6	13	30	52	81
LPG Energy Use for Cooking & Other Heating Purposes							
Energy consumption (overall)	90	109	133	162	197	240	292

Average appliance efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	90	104	118	135	155	178	206
INDUSTRIAL							
Annual Increase (Efficiency)	1.00%						
Energy Audit Recommendations Implementation							
Reduction in Energy Use	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Share of Sector Affected	0.00%	5.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Total Energy Use (for industrial applications that use LPG in 2010)	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Distribution of Energy							
LPG	100.00%	100.00%	90.00%	85.00%	80.00%	75.00%	75.00%
Solar	0.00%	0.00%	10.00%	15.00%	20.00%	25.00%	25.00%
Industrial Solar Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Solar]	0	0	0	0	0	0	0
Industrial LPG Use							
Energy consumption (overall)	0	0	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [LPG]	0	0	0	0	0	0	0
Total Petroleum Use	**1,839.50**	**2,238.03**	**2,722.91**	**3,312.84**	**4,030.57**	**4,903.81**	**5,966.23**
Distribution of Petroleum Use							
Diesel	47.90%	50.00%	50.00%	40.00%	30.00%	20.00%	10.00%
HFO	37.00%	40.00%	30.00%	20.00%	20.00%	10.00%	10.00%
NG	0.00%	0.00%	20.00%	40.00%	50.00%	70.00%	80.00%
Crude Oil	15.10%	10.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Industrial Diesel Use							
Energy consumption (overall)	881	1,119	1,361	1,325	1,209	981	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Diesel]	881	1,054	1,208	1,107	951	727	421
Industrial HFO Use							
Energy consumption (overall)	681	895	817	663	806	490	597
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [HFO]	681	843	725	554	634	363	421
Industrial NG Use							
Energy consumption (overall)	0	0	545	1,325	2,015	3,433	4,773
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [NG]	0	0	483	1,107	1,586	2,543	3,364

Industrial Crude Oil Use							
Energy consumption (overall)	278	224	0	0	0	0	0
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Crude Oil]	278	211	0	0	0	0	0
Industrial LP Steam Use (BSI)							
Energy consumption (overall)	639	639	639	639	639	639	639
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	639	608	578	550	524	498	474
Industrial Own Electricity Use (BSI/BELCOGEN)	**55,076,903**	63,757,215	73,805,575	85,437,591	98,902,854	114,490,288	132,534,358
Energy consumption (overall)	198	198	198	198	198	198	198
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Biomass]	198	189	179	171	162	155	147
Industrial Electricity Use	**90,398,000**	KWh					
Energy consumption (overall)	325	396	482	586	713	868	1,056
Average process efficiency	100.00%	105.10%	110.46%	116.10%	122.02%	128.24%	134.78%
Total energy use (TJ) [Electricity]	325	373	427	490	561	643	744
CONVERSION EFFICIENCY							
LPG	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Diesel	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%	40.00%
BEL Diesel	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%	33.33%
HFO	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
Gasoline	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Kerosene	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Crude Oil	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Natural Gas	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Biomass	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
MSW	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Fuelwood	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Geothermal	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Solar	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Wind	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Hydro	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Imported Electricity	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Electricity Transmission & Distribution Losses	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%	11.80%
Fuel Distribution Losses	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
WORLD MARKET PRICES - Oil & Natural Gas							
WTI Crude Oil Price (USD per bbl)	79.00	94.58	108.10	117.54	123.09	124.94	134.60
Reference Oil Price Case	79.00	94.58	108.10	117.54	123.09	124.94	134.60
High Oil Price Case	79.00	146.10	169.08	185.87	196.07	199.95	226.23
LSD No. 2 Diesel (Distillate Fuel) Price (USD/gal)	2.38	2.84	3.24	3.52	3.69	3.75	4.04

Residual Fuel Oil No.6 Price (USD/gal)	1.33	1.90	2.53	3.14	3.69	3.75	4.04
Henry Hub Natural Gas Price (USD per MMBTU)	4.12	4.66	5.05	5.97	6.40	7.07	7.62
Reference Natural Gas Price Case	4.12	4.66	5.05	5.97	6.40	7.07	7.62
High Natural Gas Price Case	4.12	4.74	5.22	6.19	6.63	7.20	8.15
Reference Natural Gas Price Case (Delivered to Electric Power)	4.84	4.79	5.13	5.91	6.36	6.97	7.89
High Natural Gas Price Case (Delivered to Electric Power)	4.84	4.85	5.28	6.10	6.49	7.07	8.00
CFE Capacity Charges (per KWh)	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219	0.0219
CFE Energy Charges (per KWh)	0.0946	0.1159	0.1190	0.1221	0.1245	0.1253	0.1273
MSD Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 80%]	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00	1,750.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 10%]	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00	10,000.00
SCGT Capital and O&M Cost Recovery (per TJ) [Capacity Factor = 60%]	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00	2,000.00
FUEL PRICES (USD per TJ) *excl. Carbon Price*							
LPG	21,691.97	24,535.10	26,588.46	31,432.30	33,696.27	37,223.85	40,100.66
Diesel	16,491.37	19,634.75	22,441.49	24,401.23	25,553.40	25,937.46	27,942.01
Diesel-fired Electricity (Peaking)	47,177.38	51,368.55	55,110.88	57,723.86	59,260.10	59,772.17	62,444.91
Diesel-fired Electricity (Baseload)	18,858.04	22,001.41	24,808.16	26,767.90	27,920.07	28,304.13	30,308.68
HFO	8,431.15	12,060.12	16,031.39	19,874.90	23,372.28	23,723.55	25,557.00
HFO-fired Electricity	11,093.65	14,722.62	18,693.89	22,537.40	26,034.78	26,386.05	28,219.50
Gasoline	18,009.30	21,561.01	24,643.11	26,795.10	28,060.32	28,482.05	30,683.26
Kerosene	16,901.35	20,234.55	23,127.03	25,146.64	26,334.01	26,729.80	28,795.59
Crude Oil	12,909.93	15,455.97	17,665.36	19,208.02	20,114.98	20,417.30	21,995.24
Natural Gas	6,445.16	7,013.85	7,424.57	8,393.45	8,846.30	9,551.90	10,127.33
NG-fired Electricity (Peaking)	25,336.83	25,905.52	26,316.24	27,285.12	27,737.97	28,443.56	29,018.99
NG-fired Electricity (Baseload)	9,220.16	9,788.85	10,199.57	11,168.45	11,621.30	12,326.90	12,902.33
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	207,500.00	177,175.93	146,851.85	116,527.78	86,203.70	55,879.63	25,555.56
Solar (PV) Electricity	95,250.00	69,055.56	42,861.11	35,722.22	28,583.33	26,194.44	23,805.56
Wind Electricity	24,861.11	23,777.78	22,694.44	21,597.22	20,500.00	20,347.22	20,194.44
Hydro Electricity	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89	26,638.89
Imported Electricity	32,355.78	38,282.31	39,138.84	40,017.42	40,660.22	40,895.92	41,446.35
FUEL PRICES (USD per TJ) *incl. Carbon Price*							
LPG	23,155.41	26,587.64	29,467.26	35,469.96	39,359.30	45,166.54	51,240.69
Diesel	18,241.89	22,089.95	25,885.04	29,230.98	32,327.38	35,438.32	41,267.45
Diesel-fired Electricity (Peaking)	48,927.91	53,823.75	58,554.42	62,553.61	66,034.07	69,273.03	75,770.34
Diesel-fired Electricity (Baseload)	20,608.56	24,456.61	28,251.70	31,597.65	34,694.05	37,804.98	43,634.12
HFO	10,277.81	14,650.17	19,664.06	24,969.91	30,518.29	33,746.21	39,614.30
HFO-fired Electricity	12,940.31	17,312.67	22,326.56	27,632.41	33,180.79	36,408.71	42,276.80
Gasoline	19,687.24	23,914.41	27,943.87	31,424.59	34,553.41	37,588.96	43,456.16
Kerosene	18,615.45	22,638.66	26,498.92	29,875.89	32,967.03	36,032.95	41,843.73
Crude Oil	14,660.46	17,911.17	21,108.91	24,037.77	26,888.96	29,918.16	35,320.67

Natural Gas	7,731.48	8,817.98	9,954.96	11,942.45	13,823.95	16,533.31	19,919.12
NG-fired Electricity (Peaking)	26,623.15	27,709.65	28,846.63	30,834.12	32,715.62	35,424.98	38,810.78
NG-fired Electricity (Baseload)	10,506.48	11,592.98	12,729.96	14,717.45	16,598.95	19,308.31	22,694.12
Bioethanol	18,499.25	18,860.56	19,221.88	19,366.40	19,510.93	19,655.45	19,799.98
Biodiesel	29,049.60	29,627.70	30,205.80	30,639.38	31,072.96	31,217.48	31,362.01
Biomass (Fuel & Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
MSW (Electricity)	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14	5,214.14
Fuelwood	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70	1,969.70
Geothermal Electricity	208,347.22	178,364.20	148,518.47	118,865.29	89,482.19	60,477.87	32,004.83
Solar (PV) Electricity	95,986.11	70,087.99	44,309.15	37,753.18	31,431.85	30,189.64	29,409.02
Wind Electricity	25,006.94	23,982.32	22,981.32	21,999.58	21,064.33	21,138.72	21,304.56
Hydro Electricity	26,743.06	26,784.99	26,843.80	26,926.29	27,041.98	27,204.25	27,431.83
Imported Electricity	38,598.83	47,038.52	51,419.87	57,242.21	64,818.88	74,779.68	88,970.09

EMISSION FACTORS (tCO2e per TJ) [PEe]							
LPG	58.54	58.54	58.54	58.54	58.54	58.54	58.54
Diesel	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Diesel-fired Electricity	70.02	70.02	70.02	70.02	70.02	70.02	70.02
HFO	73.87	73.87	73.87	73.87	73.87	73.87	73.87
HFO-fired Electricity	73.87	73.87	73.87	73.87	73.87	73.87	73.87
Gasoline	67.12	67.12	67.12	67.12	67.12	67.12	67.12
Kerosene	68.56	68.56	68.56	68.56	68.56	68.56	68.56
Crude Oil	70.02	70.02	70.02	70.02	70.02	70.02	70.02
Natural Gas	51.45	51.45	51.45	51.45	51.45	51.45	51.45
NG-fired Electricity	51.45	51.45	51.45	51.45	51.45	51.45	51.45
Bioethanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biomass (Fuel & Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MSW (Electricity)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Fuelwood	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Geothermal Electricity	33.89	33.89	33.89	33.89	33.89	33.89	33.89
Solar (PV) Electricity	29.44	29.44	29.44	29.44	29.44	29.44	29.44
Wind Electricity	5.83	5.83	5.83	5.83	5.83	5.83	5.83
Hydro Electricity	4.17	4.17	4.17	4.17	4.17	4.17	4.17
Imported Electricity	249.72	249.72	249.72	249.72	249.72	249.72	249.72

EMISSIONS PRICE (USD/tCO2e)	25.00	35.06	49.18	68.98	96.74	135.69	190.31
Annual Rate of price increase	7.00%						

GRID ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BECOL	249,564	249,564	249,564	249,564	249,564	249,564	249,564
Maximum Energy from Hydro Maya	13,586	13,680	13,680	13,680	13,680	13,680	13,680
Maximum Energy from BELCOGEN	48,632	102,600	153,900	153,900	153,900	153,900	153,900
BELCOGEN (% Total Energy from Biomass)	*78%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
BELCOGEN (% Remaining Energy from HFO)	*46.25%*	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*
Maximum Energy from BAL	4,799	66,576	0	0	0	0	0
BAL (% Total Energy from HFO)	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*	*25%*

Maximum Energy from CFE	160,000	346,896	346,896	346,896	346,896	346,896	346,896
Maximum Energy from SIEPAC	0	0	693,792	693,792	693,792	693,792	693,792
Minimum Energy from BEL (current)	7,608	0	0	0	0	0	0
Maximum Energy from Other HFO Plant(s)	0	0	0	0	0	0	0
Maximum Energy from New Natural Gas Plant(s)	0	0	0	0	0	0	0
Maximum Energy from Solar	0	0	0	0	0	0	0
Maximum Energy from Wind	0	0	31,536	31,536	42,486	73,146	73,146
Maximum Energy from Other Hydro	0	0	81,802	162,832	221,962	221,962	221,962
Maximum Energy from Other Biomass	0	0	140,160	140,160	140,160	203,232	308,352
Maximum Energy from MSW	0	0	0	0	0	0	0

Maximum Capacity from BECOL	54.00	54.00	54.00	54.00	54.00	54.00	54.00
Maximum Capacity from Hydro Maya	2.50	2.50	2.50	2.50	2.50	2.50	2.50
Maximum Capacity from BELCOGEN	6.53	13.78	20.67	20.67	20.67	20.67	20.67
Maximum Capacity from BAL	15.00	15.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from CFE	50.00	50.00	50.00	50.00	50.00	50.00	50.00
Maximum Capacity from SIEPAC	0.00	0.00	99.00	99.00	99.00	99.00	99.00
Maximum Capacity from BEL	25.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other HFO Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from New Natural Gas Plant(s)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Solar	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Maximum Capacity from Other Hydro	0.00	0.00	18.68	37.18	50.68	50.68	50.68
Maximum Capacity from Other Biomass	0.00	0.00	26.67	26.67	26.67	38.67	58.67
Maximum Capacity from MSW	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Maximum Power Output (MW)	153	135	272	290	304	316	336
Peak Demand Growth Rate (5-year rate)		25.00%	25.00%	25.00%	25.00%	25.00%	25.00%
Peak Demand (MW)	80	100	125	156	195	244	305
Supply Reserve (%)	91.29%	35.28%	117.21%	85.61%	55.40%	29.23%	9.94%
Supply Reserve % (Largest Supply Out)	23.79%	-18.72%	38.01%	22.25%	4.71%	-11.32%	-22.50%

SELF-GENERATED ELECTRICITY SUPPLY (MWh)							
Maximum Energy from BELCOGEN/BSI	55,077	63,757	73,806	85,438	98,903	114,490	132,534
Maximum Energy from BAL	26,705	26,705	0	0	0	0	0
Maximum Energy from BNE	7,008	7,008	7,008	7,008	7,008	7,008	7,008
Maximum Energy from CPBL	1,711	1,711	0	0	0	0	0
CPBL (% Total Energy from Crude Oil)	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
Maximum Energy from Others	0	0	0	0	0	0	0

Net Present Cost (over Evaluation Period)			#VALUE!
Cost *without* Carbon Pricing	**$2,798,608,328.09**		340,433,237
Cost *with* Carbon Pricing	**$3,139,041,565.18**		

RESULTS	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**

ENERGY							
TPES (in TJ)	12,888	15,743	18,842	19,874	20,825	22,725	25,768
TPES (in TOE)	307,823	376,019	450,032	474,687	497,387	542,775	615,466
Energy Intensity (BTU/$GDP[2010 USD])	8,536	9,067	9,437	8,655	7,886	7,483	7,379
Energy Supply Per Capita (TOE per capita)	0.9866	1.0480	1.0907	1.0004	0.9115	0.8649	0.8528
Secondary Energy Consumption Breakdown by Sector							
% Transport	46.81%	47.42%	48.49%	47.71%	48.20%	47.57%	46.52%
% Residential	19.31%	19.57%	18.44%	19.20%	17.87%	18.37%	18.92%
% Commercial & Services	6.45%	6.58%	6.75%	6.91%	7.27%	7.47%	7.75%
% Industrial	27.43%	26.43%	26.33%	26.17%	26.66%	26.59%	26.81%
EMISSIONS							
Total GHG Emissions (tCO2e)	702,461	772,533	641,751	666,210	709,291	707,310	724,940
Overall GHG Emissions Intensity (tCO2e/TJ)	55.99	50.22	35.16	35.06	35.76	33.47	31.12
Electricity Sector GHG Emissions Intensity (tCO2e/TJ)	52.74	34.88	1.69	1.90	2.54	1.61	1.85
Emissions Breakdown by Sector							
Transport	49.09%	51.27%	66.23%	65.67%	63.48%	63.03%	60.27%
Residential	15.17%	14.57%	7.52%	7.98%	9.22%	9.68%	10.77%
Commercial & Services	9.72%	8.69%	1.81%	2.10%	2.57%	2.68%	3.22%
Industrial	26.03%	25.47%	24.45%	24.26%	24.73%	24.61%	25.74%
COSTS							
Total Cost of Energy w/o CP	$205,897,584.54	$276,086,386.12	$302,566,730.73	$356,085,406.83	$410,481,016.19	$457,514,923.77	$530,375,107.44
Total Cost of Energy as a % of GDP [2010 USD]	14.39%	16.78%	15.99%	16.36%	16.40%	15.90%	16.02%
Unit Cost of Energy w/o CP (USD/TJ)	$15,976.01	$17,536.92	$16,058.15	$17,916.96	$19,711.34	$20,132.76	$20,582.45
Total Cost of Energy w/ CP	$223,459,117.25	$303,174,320.18	$334,127,251.10	$402,037,797.63	$479,099,346.66	$553,486,792.58	$668,335,796.13
Unit Cost of Energy w/ CP (USD/TJ)	$17,338.65	$19,257.53	$17,733.16	$20,229.12	$23,006.40	$24,355.97	$25,936.34
Carbon Cost as % of Total Energy Cost w/ CP	7.86%	8.93%	9.45%	11.43%	14.32%	17.34%	20.64%
Unit Cost of Electricity w/o CP (USD/TJ) [*Assessed at Primary Energy Supply Point*]	$20,516.0477	$18,115.76	$9,084.67	$9,606.77	$10,005.39	$9,402.62	$8,751.09
Unit Cost of Electricity w/o CP (USD/MWh) [*Assessed at Generation Supply Point*]	$131.2516	$146.80	$97.75	$97.61	$97.43	$96.16	$96.28
PEe Cost Breakdown by Sector							
Transport	42.65%	43.66%	51.51%	51.95%	52.15%	52.72%	53.49%
Residential	20.78%	20.98%	17.88%	18.77%	19.46%	20.76%	21.31%
Commercial & Services	13.07%	12.63%	9.54%	9.57%	9.45%	9.44%	9.05%
Industrial	23.50%	22.73%	21.07%	19.71%	18.94%	17.08%	16.15%
DIVERSITY & SECURITY							
Resource Type Diversity Index	34.07%	34.82%	35.69%	33.94%	33.22%	32.27%	31.92%
Foreign Oil Imports (BOE)	1,551,033	1,769,932	1,630,703	1,693,181	1,799,310	1,809,444	1,852,790
% Dependence on Foreign Sources (TPES)	63.33%	60.55%	49.66%	49.34%	51.22%	48.86%	46.06%
% Electricity (of Total PEe Energy Supply)	28.77%	34.39%	41.87%	40.84%	40.25%	41.18%	43.09%
% Electricity (of Total Secondary Energy Supply)	16.99%	17.32%	17.74%	17.96%	18.23%	18.08%	18.17%
% Wind Energy of Total Utility Electricity Generation	0.00%	0.00%	4.69%	4.18%	5.11%	7.97%	7.10%
% Dependence on Foreign Sources (Electricity)	30.72%	24.04%	0.08%	0.15%	0.39%	0.08%	0.27%
% Renewables (of TPES)	30.05%	34.62%	48.76%	49.66%	49.18%	53.03%	57.75%
% Renewables (of Electricity Supply)	65.48%	73.36%	98.43%	98.45%	98.29%	98.78%	98.79%
% Renewables (of Transport Fuels)	0.00%	0.00%	0.76%	3.15%	7.44%	12.57%	19.63%
Renewables as % of Total PEe Sector Energy							
Transport	0.00%	0.00%	0.76%	3.15%	7.44%	12.57%	19.63%

Residential	**62.56%**	**67.39%**	**83.57%**	**83.31%**	**80.24%**	**80.74%**	**81.30%**
Commercial & Services	**60.97%**	**69.33%**	**94.18%**	**93.80%**	**93.29%**	**93.77%**	**93.92%**
Industrial	**37.46%**	**39.76%**	**51.26%**	**48.16%**	**45.44%**	**44.99%**	**45.04%**

APPENDIX E: ENERGY BALANCE 2010

DETAILED ENERGY BALANCE - 2010 (in TJ)

	Crude Oil	NG	Gasoline	Diesel	HFO	Kerosene	LPG	Bioethanol	Biodiesel	Wood	Biomass	Hydro	Wind	Solar	Geothermal	Electricity	TOTAL
Energy Supply	**506**	**348**	**2,411**	**3,179**	**828**	**626**	**547**	**0**	**0**	**830**	**2,095**	**947**	**0**	**0**	**0**	**571**	**12,888**
Indigenous Supply	9,291	375	0	0	0	0	0	0	0	830	2,095	947	0	0	0	0	13,538
Import	0	0	2,411	3,179	828	626	547	0	0	0	0	0	0	0	0	571	8,162
Export	-8,743	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-8,743
Production Loss	-42	-27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-69
Transformation Sector	**-18**	**-348**	**0**	**-409**	**-147**	**0**	**95**	**0**	**0**	**0**	**-1,456**	**-947**	**0**	**0**	**0**	**1,494**	**-1,737**
Electricity Sector	***-18***	***-121***	***0***	***-409***	***-147***	***0***	***0***	***0***	***0***	***0***	***-1,456***	***-947***	***0***	***0***	***0***	***1,494***	***-1,605***
Utilities	0	0	0	-82	0	0	0	0	0	0	0	0	0	0	0	27	-55
IPPs	0	0	0	-84	-49	0	0	0	0	0	-683	-947	0	0	0	1,140	-624
Self-Generators	-18	-121	0	-243	-98	0	0	0	0	0	-773	0	0	0	0	327	-926
Petroleum Sector	***0***	***-227***	***0***	***0***	***0***	***0***	***95***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***-132***
Oil Refineries	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
NGL Producers	0	-227	0	0	0	0	95	0	0	0	0	0	0	0	0	0	-132
Distribution Loss	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**-205**	**-205**
End-Use Consumption	**488**	**0**	**2,411**	**2,770**	**681**	**626**	**642**	**0**	**0**	**830**	**639**	**0**	**0**	**0**	**0**	**1,860**	**10,946**
Transport	210	0	2,411	1,889	0	583	32	0	0	0	0	0	0	0	0	0	5,124
Residential	0	0	0	0	0	43	520	0	0	830	0	0	0	0	0	720	2,113
Commercial & Services	0	0	0	0	0	0	90	0	0	0	0	0	0	0	0	617	707
Industrial	278	0	0	881	681	0	0	0	0	0	639	0	0	0	0	524	3,002
Electricity Output (MWh)	**1,711**	**7,008**	**0**	**43,927**	**18,428**	**0**	**0**	**0**	**0**	**0**	**80,893**	**263,150**	**0**	**0**	**0**	**0**	**415,118**
Utilities	0	0	0	7,608	0	0	0	0	0	0	0	0	0	0	0	0	7,608
IPPs	0	0	0	9,350	6,148	0	0	0	0	0	37,933	263,150	0	0	0	0	316,581
Self-Generators	1,711	7,008	0	26,969	12,280	0	0	0	0	0	42,960	0	0	0	0	0	90,929

	Crude Oil	NG	Gasoline	Diesel	HFO	Kerosene	LPG	Bioethanol	Biodiesel	Wood	Biomass	Hydro	Wind	Solar	Geothermal	Electricity	TOTAL
End-Use Consumption (*PEe*)	**488**	**0**	**2,411**	**2,770**	**681**	**626**	**642**	**0**	**0**	**830**	**639**	**0**	**0**	**0**	**0**	**3,670**	**12,756**
Transport	210	0	2,411	1,889	0	583	32	0	0	0	0	0	0	0	0	0	5,124
Residential	0	0	0	0	0	43	520	0	0	830	0	0	0	0	0	1,421	2,814
Commercial & Services	0	0	0	0	0	0	90	0	0	0	0	0	0	0	0	1,216	1,306
Industrial	278	0	0	881	681	0	0	0	0	0	639	0	0	0	0	1,033	3,512
End-Use Emissions (Based on *PEe End-Use Consumption*)	**34,152**	**0**	**161,815**	**193,972**	**50,275**	**42,910**	**37,554**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**193,570**	**714,248**
Transport	14,703	0	161,815	132,275	0	39,948	1,850	0	0	0	0	0	0	0	0	0	350,591
Residential	0	0	0	0	0	2,962	30,435	0	0	0	0	0	0	0	0	74,922	108,319
Commercial & Services	0	0	0	0	0	0	5,268	0	0	0	0	0	0	0	0	64,153	69,421
Industrial	19,449	0	0	61,697	50,275	0	0	0	0	0	0	0	0	0	0	54,496	185,917
End-Use Cost (Based on *PEe End-Use Consumption*)	**$6,296,677**	**$0**	**$43,418,954**	**$45,684,451**	**$5,738,364**	**$10,577,588**	**$13,916,066**	**$0**	**$0**	**$1,634,848**	**$3,330,678**	**$0**	**$0**	**$0**	**$0**	**$75,299,959**	**$205,897,585**

Transport	$2,710,756	$0	$43,418,954	$31,153,567	$0	$9,847,450	$685,466	$0	$0	$0	$0	$0	$0	$0	$0	$0	$87,816,193
Residential	$0	$0	$0	$0	$0	$730,138	$11,278,322	$0	$0	$1,634,848	$0	$0	$0	$0	$0	$29,144,917	$42,788,225
Commercial & Services	$0	$0	$0	$0	$0	$0	$1,952,278	$0	$0	$0	$0	$0	$0	$0	$0	$24,955,772	$26,908,050
Industrial	$3,585,921	$0	$0	$14,530,884	$5,738,364	$0	$0	$0	$0	$0	$3,330,678	$0	$0	$0	$0	$21,199,270	$48,385,117

End-Use Cost inc. Carbon Pricing (Based on *PEe End-Use Consumption*)	$223,753,788
Transport	$96,580,970
Residential	$45,496,198
Commercial & Services	$28,643,577
Industrial	$53,033,043

	Crude Oil	NG	Gasoline	Diesel	HFO	Kerosene	LPG	Bioethanol	Biodiesel	Wood	Biomass	Hydro	Wind	Solar	Geothermal	Imported Electricity	TOTAL
Electricity Output - ALL Generation (DETAILED) *MWh*	**1,711**	**7,008**	**0**	**43,927**	**18,428**	**0**	**0**	**0**	**0**	**0**	**80,893**	**263,150**	**0**	**0**	**0**	**158,589**	**573,707**
Electricity Output - Local Generation (DETAILED) *MWh*	**1,711**	**7,008**	**0**	**43,927**	**18,428**	**0**	**0**	**0**	**0**	**0**	**80,893**	**263,150**	**0**	**0**	**0**	**0**	**415,118**
Utilities	***0***	***0***	***0***	***7,608***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***7,608***
BEL	0	0	0	7,608	0	0	0	0	0	0	0	0	0	0	0	0	7,608
IPPs	***0***	***0***	***0***	***9,350***	***6,148***	***0***	***0***	***0***	***0***	***0***	***37,933***	***263,150***	***0***	***0***	***0***	***0***	***316,581***
BECOL	0	0	0	0	0	0	0	0	0	0	0	249,564	0	0	0	0	249,564
Hydro Maya	0	0	0	0	0	0	0	0	0	0	0	13,586	0	0	0	0	13,586
BAL	0	0	0	3,599	1,200	0	0	0	0	0	0	0	0	0	0	0	4,799
BELCOGEN	0	0	0	5,751	4,948	0	0	0	0	0	37,933	0	0	0	0	0	48,632
Other IPP	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Self-Generators	***1,711***	***7,008***	***0***	***26,969***	***12,280***	***0***	***0***	***0***	***0***	***0***	***42,960***	***0***	***0***	***0***	***0***	***0***	***90,929***

Electricity Total Output (*TJ*) [PEe]	**18**	**121**	**0**	**409**	**147**	**0**	**0**	**0**	**0**	**0**	**1,456**	**947**	**0**	**0**	**0**	**571**	**3,670**
Electricity from Foreign Primary Energy Source (*TJ*) [PEe]	**0**	**0**	**0**	**409**	**147**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**571**	**1,127**
Electricity Total Emissions (tCO2e)	**1,294**	**6,226**	**0**	**28,642**	**10,890**	**0**	**0**	**0**	**0**	**0**	**0**	**3,947**	**0**	**0**	**0**	**142,571**	**193,570**
Electricity Total Cost *w/o Emissions* (USD) [PEe]	**$0**	**$3,065,756**	**$0**	**$19,297,861**	**$1,635,507**	**$0**	**$0**	**$0**	**$0**	**$0**	**$7,592,201**	**$25,236,085**	**$0**	**$0**	**$0**	**$18,472,548**	**$75,299,959**
Indigenous Market Value (USD)	**$119,946,190**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,634,848**	**$10,922,879**	**$25,236,085**	**$0**	**$0**	**$0**	**$0**	**$157,740,002**

DETAILED ENERGY BALANCE - 2010 (in TOE)

	Crude Oil	NG	Gasoline	Diesel	HFO	Kerosene	LPG	Bioethanol	Biodiesel	Fuelwood	Bagasse	Hydro	Wind	Solar	Geothermal	Electricity	TOTAL
Energy Supply	**12,091**	**8,312**	**57,584**	**75,935**	**19,777**	**14,948**	**13,054**	**0**	**0**	**19,824**	**50,035**	**22,627**	**0**	**0**	**0**	**13,636**	**307,823**
Indigenous Supply	221,912	8,957	0	0	0	0	0	0	0	19,824	50,035	22,627	0	0	0	0	323,354
Import	0	0	57,584	75,935	19,777	14,948	13,054	0	0	0	0	0	0	0	0	13,636	194,934
Export	-208,823	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-208,823
Production Loss	-998	-645	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1,643
Transformation Sector	**-441**	**-8,312**	**0**	**-9,770**	**-3,521**	**0**	**2,269**	**0**	**0**	**0**	**-34,778**	**-22,627**	**0**	**0**	**0**	**35,694**	**-41,486**
Electricity Sector	***-441***	***-2,890***	***0***	***-9,770***	***-3,521***	***0***	***0***	***0***	***0***	***0***	***-34,778***	***-22,627***	***0***	***0***	***0***	***35,694***	***-38,334***
Utilities	0	0	0	-1,963	0	0	0	0	0	0	0	0	0	0	0	654	-1,309
IPPs	0	0	0	-2,010	-1,175	0	0	0	0	0	-16,308	-22,627	0	0	0	27,221	-14,899

Self-Generators	-441	-2,890	0	-5,797	-2,346	0	0	0	0	0	-18,469	0	0	0	0	7,818	-22,126
Petroleum Sector	*0*	*-5,422*	*0*	*0*	*0*	*0*	*2,269*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*-3,153*
Oil Refineries	0	*0*	0	0	0	0	0	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	
NGL Producers	0	-5,422	0	0	0	0	2,269	0	0	0	0	0	0	0	0	0	-3,153
Distribution Loss	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-4,899	-4,899
End-Use Consumption	11,649	0	57,584	66,165	16,256	14,948	15,323	0	0	19,824	15,257	0	0	0	0	44,431	261,437
Transport	5,015	0	57,584	45,120	0	13,916	755	0	0	0	0	0	0	0	0	0	122,390
Residential	0	0	0	0	0	1,032	12,418	0	0	19,824	0	0	0	0	0	17,197	50,471
Commercial & Services	0	0	0	0	0	0	2,150	0	0	0	0	0	0	0	0	14,725	16,875
Industrial	6,634	0	0	21,045	16,256	0	0	0	0	0	15,257	0	0	0	0	12,509	71,701
Electricity Output (MWh)	1,711	7,008	0	43,927	18,428	0	0	0	0	0	80,893	263,150	0	0	0	0	415,118
Utilities	0	0	0	7,608	0	0	0	0	0	0	0	0	0	0	0	0	7,608
IPPs	0	0	0	9,350	6,148	0	0	0	0	0	37,933	263,150	0	0	0	0	316,581
Self-Generators	1,711	7,008	0	26,969	12,280	0	0	0	0	0	42,960	0	0	0	0	0	90,929

APPENDIX F: RESOURCE SUMMARIES

ONSHORE WIND	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (MWhs)	0	0	1,375,484	1,375,484	1,375,484	1,375,484	1,375,484
GHG Emissions Rate (tCO2e/MWh)	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210
Capital Cost (USD per KW)	$1,700.00	$1,625.00	$1,550.00	$1,475.00	$1,400.00	$1,400.00	$1,400.00
Fixed O&M Cost (USD per KW-Yr)	$40.00	$38.30	$36.60	$34.90	$33.20	$32.00	$30.80
Variable O&M Cost (USD per MWh)	$3.00	$2.87	$2.75	$2.62	$2.49	$2.40	$2.31
LCOE [CF = 30%] (USD per KWh)	$0.0895	$0.0856	$0.0817	$0.0778	$0.0738	$0.0733	$0.0727
LCOE inc. Carbon Cost	$0.0900	$0.0863	$0.0827	$0.0792	$0.0758	$0.0761	$0.0767

ONSHORE WIND (with Capacity)	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (MWhs)	0	0	1,375,484	1,375,484	1,375,484	1,375,484	1,375,484
GHG Emissions Rate (tCO2e/MWh)	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210
Capital Cost (USD per KW)	$1,700.00	$1,625.00	$1,550.00	$1,475.00	$1,400.00	$1,400.00	$1,400.00
Fixed O&M Cost (USD per KW-Yr)	$40.00	$38.30	$36.60	$34.90	$33.20	$32.00	$30.80
Variable O&M Cost (USD per MWh)	$3.00	$2.87	$2.75	$2.62	$2.49	$2.40	$2.31
LCOE [CF = 30%] (USD per KWh)	$0.1100	$0.1061	$0.1022	$0.0983	$0.0943	$0.0938	$0.0932
LCOE inc. Carbon Cost	$0.1105	$0.1068	$0.1032	$0.0997	$0.0963	$0.0966	$0.0972
Cost of Carbon	$0.0005	$0.0007	$0.0010	$0.0014	$0.0020	$0.0028	$0.0040

SHALLOW OFFSHORE WIND	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (MWhs)	0	0	0	1,180,200	1,180,200	1,180,200	1,180,200
GHG Emissions Rate (tCO2e/MWh)	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210	0.0210
Capital Cost (USD per KW)	$4,250.00	$3,984.38	$3,718.75	$3,453.13	$3,187.50	$3,081.25	$2,975.00
Fixed O&M Cost (USD per KW-Yr)	$100.00	$93.75	$87.50	$81.25	$75.00	$72.50	$70.00
Variable O&M Cost (USD per MWh)	$12.50	$11.72	$10.94	$10.16	$9.38	$9.06	$8.75
LCOE [CF = 45%] (USD per KWh)	$0.1566	$0.1469	$0.1371	$0.1273	$0.1175	$0.1136	$0.1097
LCOE inc. Carbon Cost	$0.1571	$0.1476	$0.1381	$0.1287	$0.1195	$0.1164	$0.1137

SOLAR PV	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (MWhs)	0	0	43,544,865	43,544,865	43,544,865	43,544,865	43,544,865
GHG Emissions Rate (tCO2e/MWh)	0.1060	0.1060	0.1060	0.1060	0.1060	0.1060	0.1060
Capital Cost (USD per KW)	$4,000.00	$2,900.00	$1,800.00	$1,500.00	$1,200.00	$1,100.00	$1,000.00
Fixed O&M Cost (USD per KW-Yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Variable O&M Cost (USD per MWh)	$28.53	$20.69	$12.84	$10.70	$8.56	$7.85	$7.13
LCOE [CF = 16%] (USD per KWh)	$0.3429	$0.2486	$0.1543	$0.1286	$0.1029	$0.0943	$0.0857
LCOE inc. Carbon Cost	$0.3456	$0.2523	$0.1595	$0.1359	$0.1132	$0.1087	$0.1059

SMALL HYDRO	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (MWhs)	14,016	14,016	35,916	57,816	57,816	57,816	57,816
GHG Emissions Rate (tCO2e/MWh)	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150
Capital Cost (USD per KW)	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00
Fixed O&M Cost	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00

Variable O&M Cost	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
LCOE (CF = 45%)	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685	$0.0685
LCOE inc. Carbon Cost	$0.0689	$0.0690	$0.0692	$0.0695	$0.0700	$0.0705	$0.0714

MEDIUM HYDRO	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	250,000	250,000	309,130	368,260	427,390	427,390	427,390
GHG Emissions Rate (tCO2e/MWh)	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150	0.0150
Capital Cost (USD per KW)	$2,800.00	$2,800.00	$2,800.00	$2,800.00	$2,800.00	$2,800.00	$2,800.00
Fixed O&M Cost (USD per KW-Yr)	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
LCOE [CF = 45%] (USD per KWh)	$0.0959	$0.0959	$0.0959	$0.0959	$0.0959	$0.0959	$0.0959
LCOE inc. Carbon Cost	$0.0963	$0.0964	$0.0966	$0.0969	$0.0974	$0.0979	$0.0988

ELECTRICITY IMPORTS (CFE) - Previous FC Agreement	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	372,300	372,300	744,600	744,600	744,600	744,600	744,600
GHG Emissions Rate (tCO2e/MWh)	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990
Capacity Charges (USD per KWh)	$0.0219	$0.0219	$0.0219	$0.0219	$0.0219	$0.0219	$0.0219
Energy Charges(USD per KWh)	$0.0946	$0.1159	$0.1190	$0.1221	$0.1245	$0.1253	$0.1273
LCOE (USD per KWh)	$0.1165	$0.1378	$0.1409	$0.1441	$0.1464	$0.1472	$0.1492
LCOE inc. Carbon Cost	$0.1390	$0.1693	$0.1851	$0.2061	$0.2333	$0.2692	$0.3203

ELECTRICITY IMPORTS (CFE) - Proposed FC Agreement	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	372,300	372,300	744,600	744,600	744,600	744,600	744,600
GHG Emissions Rate (tCO2e/MWh)	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990
Capacity Charges (USD per KWh)	$0.0123	$0.0123	$0.0123	$0.0123	$0.0123	$0.0123	$0.0123
Energy Charges(USD per KWh)	$0.0922	$0.1328	$0.1646	$0.1953	$0.2233	$0.2261	$0.2408
LCOE (USD per KWh)	$0.1045	$0.1451	$0.1769	$0.2076	$0.2356	$0.2384	$0.2531
LCOE inc. Carbon Cost	$0.1270	$0.1766	$0.2211	$0.2696	$0.3226	$0.3604	$0.4242

ELECTRICITY IMPORTS (CFE) - Existing EE Agreement	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	372,300	372,300	744,600	744,600	744,600	744,600	744,600
GHG Emissions Rate (tCO2e/MWh)	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990
Capacity Charges (USD per KWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
Energy Charges(USD per KWh)	$0.1098	$0.1447	$0.1924	$0.2385	$0.2805	$0.2847	$0.3067
LCOE (USD per KWh)	$0.1098	$0.1447	$0.1924	$0.2385	$0.2805	$0.2847	$0.3067
LCOE inc. Carbon Cost	$0.1323	$0.1762	$0.2366	$0.3005	$0.3674	$0.4067	$0.4778

ELECTRICITY IMPORTS (CFE) - Proposed OC Agreement	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	372,300	372,300	744,600	744,600	744,600	744,600	744,600
GHG Emissions Rate (tCO2e/MWh)	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990	0.8990
Capacity Charges (USD per KWh)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

Energy Charges(USD per KWh)	$0.0927	$0.1158	$0.1539	$0.1908	$0.2244	$0.2277	$0.2453
LCOE (USD per KWh)	$0.0927	$0.1158	$0.1539	$0.1908	$0.2244	$0.2277	$0.2453
LCOE inc. Carbon Cost	$0.1151	$0.1473	$0.1981	$0.2528	$0.3113	$0.3497	$0.4164

BIOMASS	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)	106,000	106,000	1,006,000	1,006,000	1,006,000	1,006,000	1,006,000
GHG Emissions Rate (tCO2e/MWh)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Capital Cost (USD per KW)	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00	$2,000.00
Fixed O&M Cost (USD per KW-Yr)	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00
Variable O&M Cost (USD per MWh)	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00	$6.00
Fuel Cost (USD per MWH)	$35.45	$35.45	$35.45	$35.45	$35.45	$35.45	$35.45
LCOE [CF = 60%] (USD per KWh)	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939
LCOE inc. Carbon Cost	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939	$0.0939

GEOTHERMAL	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (MWhs)							
GHG Emissions Rate (tCO2e/MWh)	0.1220	0.1220	0.1220	0.1220	0.1220	0.1220	0.1220
Capital Cost (USD per KW)	-	-	-	-	-	-	-
Fixed O&M Cost (USD per KW-Yr)	-	-	-	-	-	-	-
Variable O&M Cost (USD per MWh)	-	-	-	-	-	-	-
LCOE [CF = 60%] (USD per KWh)	$0.7470	$0.6378	$0.5287	$0.4195	$0.3103	$0.2012	$0.0920
LCOE inc. Carbon Cost	$0.7501	$0.6421	$0.5347	$0.4279	$0.3221	$0.2177	$0.1152

DIESEL GENERATION (PEAKING)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.8390	0.8390	0.8390	0.8390	0.8390	0.8390	0.8390
Capital Cost (USD per KW)	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00
Fixed O&M Cost (USD per KW-Yr)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$197.90	$235.62	$269.30	$292.81	$306.64	$311.25	$335.30
LCOE [CF = 5%] (USD per KWh)	$0.4246	$0.4623	$0.4960	$0.5195	$0.5333	$0.5379	$0.5620
LCOE inc. Carbon Cost	$0.4456	$0.4917	$0.5373	$0.5774	$0.6145	$0.6518	$0.7217

DIESEL GENERATION (BASELOAD)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.6293	0.6293	0.6293	0.6293	0.6293	0.6293	0.6293
Capital Cost (USD per KW)	$600.00	$600.00	$600.00	$600.00	$600.00	$600.00	$600.00
Fixed O&M Cost (USD per KW-Yr)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$148.42	$176.71	$201.97	$219.61	$229.98	$233.44	$251.48
LCOE [CF = 60%] (USD per KWh)	$0.1697	$0.1980	$0.2233	$0.2409	$0.2513	$0.2547	$0.2728
LCOE inc. Carbon Cost	$0.1855	$0.2201	$0.2542	$0.2843	$0.3122	$0.3401	$0.3925
Cost of Carbon	$0.0157	$0.0221	$0.0309	$0.0434	$0.0609	$0.0854	$0.1198

HFO GENERATION (BASELOAD)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.5909	0.5909	0.5909	0.5909	0.5909	0.5909	0.5909
Capital Cost (USD per KW)	$550.00	$550.00	$550.00	$550.00	$550.00	$550.00	$550.00
Fixed O&M Cost (USD per KW-Yr)	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00	$25.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$67.45	$96.48	$128.25	$159.00	$186.98	$189.79	$204.46
Non-Fuel Costs (USD per KWh)	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213	$0.0213
LCOE [CF = 60%] (USD per KWh)	$0.0887	$0.1178	$0.1496	$0.1803	$0.2083	$0.2111	$0.2258
LCOE inc. Carbon Cost	$0.1035	$0.1385	$0.1786	$0.2211	$0.2654	$0.2913	$0.3382
Cost of Carbon	$0.0148	$0.0207	$0.0291	$0.0408	$0.0572	$0.0802	$0.1125

NG GENERATION (PEAKING)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.6174	0.6174	0.6174	0.6174	0.6174	0.6174	0.6174
Capital Cost (USD per KW)	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00
Fixed O&M Cost (USD per KW-Yr)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$77.34	$84.17	$89.09	$100.72	$106.16	$114.62	$121.53
LCOE [CF = 5%] (USD per KWh)	$0.3040	$0.3109	$0.3158	$0.3274	$0.3329	$0.3413	$0.3482
LCOE inc. Carbon Cost	$0.3195	$0.3325	$0.3462	$0.3700	$0.3926	$0.4251	$0.4657

NG GENERATION (BASELOAD)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.4116	0.4116	0.4116	0.4116	0.4116	0.4116	0.4116
Capital Cost (USD per KW)	$550.00	$550.00	$550.00	$550.00	$550.00	$550.00	$550.00
Fixed O&M Cost (USD per KW-Yr)	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00	$30.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$51.56	$56.11	$59.40	$67.15	$70.77	$76.42	$81.02
LCOE [CF = 60%] (USD per KWh)	$0.0738	$0.0783	$0.0816	$0.0893	$0.0930	$0.0986	$0.1032
LCOE inc. Carbon Cost	$0.0841	$0.0927	$0.1018	$0.1177	$0.1328	$0.1545	$0.1816
Cost of Carbon	$0.0103	$0.0144	$0.0202	$0.0284	$0.0398	$0.0559	$0.0783

LPG GENERATION (PEAKING)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/MWh)	0.7024	0.7024	0.7024	0.7024	0.7024	0.7024	0.7024
Capital Cost (USD per KW)	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00	$700.00
Fixed O&M Cost (USD per KW-Yr)	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00	$20.00
Variable O&M Cost (USD per MWh)	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
Fuel Cost (USD per MWH)	$260.30	$294.42	$319.06	$377.19	$404.36	$446.69	$481.21
LCOE [CF = 5%] (USD per KWh)	$0.4870	$0.5211	$0.5458	$0.6039	$0.6311	$0.6734	$0.7079
LCOE inc. Carbon Cost	$0.5046	$0.5458	$0.5803	$0.6523	$0.6990	$0.7687	$0.8416

CANE ETHANOL	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**

Maximum Availability (gallons)		37,400,000	37,400,000	37,400,000	37,400,000	37,400,000	37,400,000
GHG Emissions Rate (tCO2e/gal)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per Gallon of Gasoline Equivalent	$2.4227	$2.4700	$2.5173	$2.5362	$2.5552	$2.5741	$2.5930
Cost per Gallon	$1.6151	$1.6467	$1.6782	$1.6908	$1.7034	$1.7161	$1.7287
Cost per Gallon inc. Carbon Cost	$1.6151	$1.6467	$1.6782	$1.6908	$1.7034	$1.7161	$1.7287
GHG Emissions Rate (tCO2e/MJ)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per MJ	$0.0185	$0.0189	$0.0192	$0.0194	$0.0195	$0.0197	$0.0198
Cost per MJ inc. Carbon Cost	$0.0185	$0.0189	$0.0192	$0.0194	$0.0195	$0.0197	$0.0198

CELLULOSIC ETHANOL	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (gallons)		50,000,000	50,000,000	50,000,000	50,000,000	50,000,000	50,000,000
GHG Emissions Rate (tCO2e/gal)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per Gallon of Gasoline Equivalent	$4.1640	$3.9841	$3.8043	$3.6718	$3.5394	$3.4542	$3.3690
Cost per Gallon	$2.7760	$1.4000	$1.1000	$1.1000	$1.1000	$1.1000	$1.1000
Cost per Gallon inc. Carbon Cost	$2.7760	$1.4000	$1.1000	$1.1000	$1.1000	$1.1000	$1.1000
GHG Emissions Rate (tCO2e/MJ)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per MJ	$0.0318	$0.0160	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126
Cost per MJ inc. Carbon Cost	$0.0318	$0.0160	$0.0126	$0.0126	$0.0126	$0.0126	$0.0126

CONVENTIONAL BIODIESEL	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (gallons)		18,818,000	18,818,000	18,818,000	18,818,000	18,818,000	18,818,000
GHG Emissions Rate (tCO2e/gal)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per Gallon of Gasoline Equivalent	$3.8043	$3.8800	$3.9558	$4.0125	$4.0693	$4.0882	$4.1072
Cost per Gallon	$3.9629	$4.0417	$4.1206	$4.1797	$4.2389	$4.2586	$4.2783
Cost per Gallon inc. Carbon Cost	$3.9629	$4.0417	$4.1206	$4.1797	$4.2389	$4.2586	$4.2783
GHG Emissions Rate (tCO2e/MJ)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per MJ	$0.0290	$0.0296	$0.0302	$0.0306	$0.0311	$0.0312	$0.0314
Cost per MJ inc. Carbon Cost	$0.0290	$0.0296	$0.0302	$0.0306	$0.0311	$0.0312	$0.0314

WOOD FUEL (FIREWOOD)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability							
GHG Emissions Rate (tCO2e/kg)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per kg	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378
Cost per kg inc. Carbon Cost	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378	$0.0378
GHG Emissions Rate (tCO2e/MJ)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Cost per MJ	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020
Cost per MJ inc. Carbon Cost	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020	$0.0020

LPG	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Maximum Availability (gallons)		1,348,618	1,348,618	1,348,618	1,348,618	1,348,618	1,348,618
GHG Emissions Rate (tCO2e/kg)	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034	0.0034
Cost per kg	$1.0000	$1.1311	$1.2257	$1.4490	$1.5534	$1.7160	$1.8486
Cost per kg inc. Carbon Cost	$1.0844	$1.2495	$1.3918	$1.6820	$1.8801	$2.1742	$2.4913
GHG Emissions Rate (tCO2e/MJ)	0.00005854	0.00005854	0.00005854	0.00005854	0.00005854	0.00005854	0.00005854
Cost per MJ	$0.0217	$0.0245	$0.0266	$0.0314	$0.0337	$0.0372	$0.0401
Cost per MJ inc. Carbon Cost	$0.0235	$0.0271	$0.0302	$0.0365	$0.0408	$0.0472	$0.0540

NG	2010	2015	2020	2025	2030	2035	2040
Maximum Availability (cubic metres)		11,644,500	11,644,500	11,644,500	11,644,500	11,644,500	11,644,500
GHG Emissions Rate (tCO2e/MJ)	0.00005145	0.00005145	0.00005145	0.00005145	0.00005145	0.00005145	0.00005145
Cost per MMBTU (at source)	$4.1200	$4.6600	$5.0500	$5.9700	$6.4000	$7.0700	$7.6164
Regasification & Transport Cost(per MMBTU)	$2.0000	$2.0000	$2.0000	$2.0000	$2.0000	$2.0000	$2.0000
Regasification & Transport Loss	10%	10%	10%	10%	10%	10%	10%
Delivered Cost per MMBTU	$6.8000	$7.4000	$7.8333	$8.8556	$9.3333	$10.0778	$10.6849
Cost per MJ	$0.0064	$0.0070	$0.0074	$0.0084	$0.0088	$0.0096	$0.0101
Cost per MJ inc. Carbon Cost	$0.0077	$0.0088	$0.0100	$0.0119	$0.0138	$0.0165	$0.0199

GASOLINE	2010	2015	2020	2025	2030	2035	2040
GHG Emissions Rate (tCO2e/gal)	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
Cost per Gallon	$2.3585	$2.8236	$3.2273	$3.5091	$3.6748	$3.7300	$4.0183
Cost per Gallon inc. Carbon Cost	$2.5785	$3.1322	$3.6600	$4.1161	$4.5261	$4.9240	$5.6930
Cost of carbon	$0.2200	$0.3086	$0.4328	$0.6070	$0.8513	$1.1940	$1.6747
GHG Emissions Rate (tCO2e/MJ)	0.00006712	0.00006712	0.00006712	0.00006712	0.00006712	0.00006712	0.00006712
Cost per MJ	$0.0180	$0.0216	$0.0246	$0.0268	$0.0281	$0.0285	$0.0307
Cost per MJ inc. Carbon Cost	$0.0197	$0.0239	$0.0279	$0.0314	$0.0346	$0.0376	$0.0435

DIESEL	2010	2015	2020	2025	2030	2035	2040
GHG Emissions Rate (tCO2e/gal)	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101
Cost per Gallon	$2.3822	$2.8363	$3.2417	$3.5248	$3.6912	$3.7467	$4.0363
Cost per Gallon inc. Carbon Cost	$2.6347	$3.1904	$3.7384	$4.2214	$4.6683	$5.1171	$5.9584
Cost of carbon	$0.2525	$0.3541	$0.4967	$0.6967	$0.9771	$1.3704	$1.9221
GHG Emissions Rate (tCO2e/MJ)	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002
Cost per MJ	$0.0165	$0.0196	$0.0224	$0.0244	$0.0256	$0.0259	$0.0279
Cost per MJ inc. Carbon Cost	$0.0182	$0.0221	$0.0259	$0.0292	$0.0323	$0.0354	$0.0412

HFO	2010	2015	2020	2025	2030	2035	2040
GHG Emissions Rate (tCO2e/gal)	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117	0.0117
Cost per Gallon	$1.3315	$1.9047	$2.5319	$3.1389	$3.6912	$3.7467	$4.0363
Cost per Gallon inc. Carbon Cost	$1.6232	$2.3137	$3.1056	$3.9435	$4.8198	$5.3296	$6.2564
Cost of carbon	$0.2916	$0.4091	$0.5737	$0.8047	$1.1286	$1.5829	$2.2201
GHG Emissions Rate (tCO2e/MJ)	0.00007387	0.00007387	0.00007387	0.00007387	0.00007387	0.00007387	0.00007387
Cost per MJ	$0.0084	$0.0121	$0.0160	$0.0199	$0.0234	$0.0237	$0.0256
Cost per MJ inc. Carbon Cost	$0.0103	$0.0147	$0.0197	$0.0250	$0.0305	$0.0337	$0.0396

KEROSENE	2010	2015	2020	2025	2030	2035	2040
GHG Emissions Rate (tCO2e/gal)	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098	0.0098
Cost per Gallon	$2.4073	$2.8821	$3.2940	$3.5817	$3.7508	$3.8072	$4.1014
Cost per Gallon inc. Carbon Cost	$2.6531	$3.2268	$3.7775	$4.2598	$4.7019	$5.1412	$5.9724
GHG Emissions Rate (tCO2e/MJ)	0.00006856	0.00006856	0.00006856	0.00006856	0.00006856	0.00006856	0.00006856
Cost per MJ	$0.0169	$0.0202	$0.0231	$0.0251	$0.0263	$0.0267	$0.0288
Cost per MJ inc. Carbon Cost	$0.0186	$0.0227	$0.0265	$0.0299	$0.0330	$0.0361	$0.0419

CRUDE OIL	2010	2015	2020	2025	2030	2035	2040

Maximum Availability (bbls)		1,697,250	1,697,250	1,697,250	1,697,250	1,697,250	1,697,250
GHG Emissions Rate (tCO2e/gal)	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101	0.0101
Cost per Gallon	$1.8810	$2.2519	$2.5738	$2.7986	$2.9307	$2.9748	$3.2047
Cost per barrel	$79.00	$94.58	$108.10	$117.54	$123.09	$124.94	$134.60
Cost per Gallon inc. Carbon Cost	$2.1335	$2.6060	$3.0705	$3.4952	$3.9078	$4.3452	$5.1268
GHG Emissions Rate (tCO2e/MJ)	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002	0.00007002
Cost per MJ	$0.0129	$0.0155	$0.0177	$0.0192	$0.0201	$0.0204	$0.0220
Cost per MJ inc. Carbon Cost	$0.0146	$0.0179	$0.0211	$0.0240	$0.0268	$0.0298	$0.0352

Refined Fuel Price Derivations	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Gasoline/Crude Oil Price Factor	2.9854	2.9854	2.9854	2.9854	2.9854	2.9854	2.9854
Kerosene/Crude Oil Price Factor	3.0472	3.0472	3.0472	3.0472	3.0472	3.0472	3.0472
Diesel/Crude Oil Price Factor	2.9988	2.9988	2.9988	2.9988	2.9988	2.9988	2.9988
HFO/Crude Oil Price Factor	1.6855	2.0138	2.3422	2.6705	2.9988	2.9988	2.9988
LPG/Natural Gas Price Factor	0.2427	0.2427	0.2427	0.2427	0.2427	0.2427	0.2427

Bioethanol Prices (USD per LGE)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Conventional	***0.73***	***0.74***	***0.75***	***0.7575***	***0.765***	***0.77***	***0.775***
Low Price Scenario	0.71	0.7	0.69	0.68	0.67	0.66	0.65
High Price Scenario	0.75	0.78	0.81	0.835	0.86	0.88	0.9
Cane	***0.64***	***0.6525***	***0.665***	***0.67***	***0.675***	***0.68***	***0.685***
Low Price Scenario	0.63	0.63	0.63	0.63	0.63	0.63	0.63
High Price Scenario	0.65	0.675	0.7	0.71	0.72	0.73	0.74
Cellulosic	***1.1***	***1.0525***	***1.005***	***0.97***	***0.935***	***0.9125***	***0.89***
Low Price Scenario	1.1	1.015	0.93	0.9	0.87	0.845	0.82
High Price Scenario	1.1	1.09	1.08	1.04	1	0.98	0.96

Biodiesel Prices (USD per LGE)	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**
Conventional	***1.005***	***1.025***	***1.045***	***1.06***	***1.075***	***1.08***	***1.085***
Low Price Scenario	0.98	0.975	0.97	0.97	0.97	0.97	0.97
High Price Scenario	1.03	1.075	1.12	1.15	1.18	1.19	1.2
Advanced (B-t-L)	***1.12***	***1.0675***	***1.015***	***0.97***	***0.925***	***0.9075***	***0.89***
Low Price Scenario	1.12	1.035	0.95	0.89	0.83	0.815	0.8
High Price Scenario	1.12	1.1	1.08	1.05	1.02	1	0.98