Pakistan Integrated Energy Model (Pak-IEM)

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Final Report Volume II

Policy Analysis Report

Prepared by
International Resources Group

for

Asian Development Bank

and

Ministry of Planning and Development
Government of Pakistan

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

AC	Air conditioning
ACTF	(Pak-IEM) Advisory Committee Task Force
ADB	Asian Development Bank
AEDB	Alternative Energy Development Board
BAU	Business As Usual (scenario)
CNG	Compressed Natural Gas
DGPC	Directorate General Petroleum Concessions
DISCO	Distribution (Electricity) Company
EIA	Energy Information Administration
ETSAP	Energy Technology Systems Analysis Programme
FBS	Federal Bureau of Statistics
GCISC	Global Change Impact Studies Center
GDP	Gross Domestic Product
GHG	Greenhouse gas
GoP	Government of Pakistan
GW	Gigawatts
GWh	Gigawatt hours
HDIP	Hydrocarbon Development Institute of Pakistan
HP	Horsepower
HSD	High Speed Diesel
IEA	International Energy Agency
IPP	independent power producers
IPCC	Intergovernmental Panel on Climate Change
IRG	International Resources Group
KESC	Karachi Electric Supply Corporation
KWh	Kilowatt hours
LDO	Light Diesel Oil
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
MEC	MEConsult
MW	Megawatts
MSW	Municipal Solid Waste
NED	University of Engineering and Technology, Karachi
NTDC	National Transmission & Despatch Company
NTRC	National Transport Research Center
OGRA	Oil and Gas Regulatory Authority
O&M	Operations and Maintenance
PAEC	Pakistan Atomic Energy Commission
Pak-IEM	Pakistan Integrated Energy Model
PEPCO	Pakistan Electric Power Company
PIEAS	Pakistan Institute of Engineering and Applied Sciences
PJ	Petajoules
RES	Reference Energy System

TA	Technical Assistance
T&D	Transmission and Distribution
TOR	Terms of Reference
UETL	University of Engineering & Technology, Lahore
UETT	University of Engineering and Technology, Taxila
USAID	United States Agency for International Development
VEDA	VErsatile Data Analyst (FE-Front End / BE-Back End)
WAPDA	Water and Power Development Authority

I. EXECUTIVE SUMMARY

Pakistan is at a critical crossroad. In order to attract the investment necessary to foster sustainable economic growth there must be a reliable and affordable supply of energy. Furthermore, as the past several years of load-shedding have demonstrated, it is not just the economy but the quality of life for the people of Pakistan that are at stake if the country is not able to identify a reliable roadmap for its energy future.

However, the options are many, and major decisions need to be made by policy makers. Does Pakistan utilize Thar coal, build Liquefied Natural Gas (LNG) terminals, exploit its hydropower resources, or pursue nuclear power? The issues surrounding each of these potential development paths are complex (e.g., Thar coal provides energy security benefits but increases climate change risks). Also, each path will require significant investment capital. How can Pakistan attract the necessary investor financing (both donor and private) for such projects? Fostering an environment which supports informed decision-making will be critical to the design of the best policies, programs, and practices to guide Pakistan's energy system evolution.

Examining the multiple technology options, resource supply constraints and opportunities, supply and demand-side investment tradeoffs, economic development goals and policy impacts requires an analytical framework that represents the national energy, economic and environmental systems. Seeing this need, the Asian Development Bank (ADB), at the request of the Pakistan Planning Commission, has supported the development, initial use, and transfer to the Energy Wing of the Pakistan Integrated Energy Model (Pak-IEM). This volume of the final report discusses the initial use of this model to examine a set of key issues identified by the Pak-IEM Advisory Committee. It is complemented by two other volumes: Volume I discusses the model structure, data sources, and assumptions (the Model Design Report), and Volume III, a Users' Guide, describes how to manage and use the model. Collectively they describe a robust policy assessment framework ready to provide insights for policy deliberations and formulation.

Section I of this report provides background information on the development of Pak-IEM, Section II presents the Reference scenario, which is based on an assumed continuation of current energy sector policies and practices, and Section III examines results of selective policy scenarios and sensitivity runs. These scenarios were combined into storylines that constitute plausible, but perhaps divergent, energy futures for Pakistan. The storylines illustrate the power and flexibility of Pak-IEM and create a more comprehensive picture of possible evolution of the country's energy system under varying future policies and possibilities. They are Storyline 1 – Pursue Best Practices and Storyline 2 – Challenges Persist.

The implications of these scenarios and storylines are discussed in terms of a suite of indicators highlighting their impact on resource requirements, energy diversity and security, power plant investment timing and costs, evolving sectoral fuel and device choices, CO_2 emissions, and changes in total energy system costs relative to the Reference scenario (e.g., see Table 6). These then serve as metrics against which to measure the merits of alternative choices and policies.

A. Summary Conclusions

Looking at the evolution of the Pakistan energy system over the next 20 years this initial application of Pak-IEM points to a number of critical conclusions, which are summarized here and discussed in detail in the rest of this report.

To sustain economic growth corresponding to 5.6% average GDP between now and 2030 will require a:

- Four-fold increase in electricity generation – 94,000 GWh to 410,000 GWh

- 82,000 MW of new power generation capacity additions
- Three-fold increase in consumption high value petroleum products – 6.2 Mtoe to 18 Mtoe

Without (quick) government action it will be difficult to avert a looming Energy Security crisis where, by 2030:

- Under current practices and policies proven conventional natural gas reserves will be depleted.
- Energy imports jump from 27% to over 45% of total supply.
- Delays in moving on critical energy projects will further exasperate the situation.

Significant annual savings can be achieved from Smart Policies (best practices):

- Eliminating load shedding avoids Rs. 524 billion in economic losses.
- Reducing electricity transmission and distribution losses by 7% saves Rs. 7.3 billion (gross).
- Improving end-use energy efficiency saves Rs. 41 billion (net).
- Successful exploration to deliver 20% more gas saves an additional Rs. 37 billion (gross).

Collectively, these Smart Policies delay and dampen the increased dependency on foreign energy sources by over 20 Mtoe a year beginning 2030. Exploitation of non-hydro renewables (e.g., wind, solar, municipal solid waste (MSW), bio-energy) can further enhance energy security by reducing total imports to 38% of total energy in 2030.

B. Possible Policy Evaluations

The Smart Policies analysis demonstrates that Pak-IEM is ready to be used to examine pressing issues facing Pakistan planners. Potential policy assessments that have been identified include those listed below.

- Transition plan for removal of energy sector subsidies
  - Sectoral gas allocation – most economic utilization
- Power and energy infrastructure priorities under funding constraints
- Short-term potential for energy efficiency
  - DISCO-level transmission and distribution (T&D) system improvement
  - Power plant rehab and upgrades
  - Gas processing and pipeline improvements
  - Residential and commercial buildings and appliances
  - Industrial processes and captive power generation
  - Transport mode shifts
- Strategic energy security (reducing imports and supply diversification)
- Support for climate change negotiations

C. Critical Factors for Success

Full engagement of the Planning Team continues to be an area of concern and a critical factor for the sustainable success of the project. While the model is operational, the national capacity to properly maintain, improve and apply Pak-IEM has not yet been achieved. However, the recent and continuing process to overcome staffing shortfalls in the Energy Wing, growing stakeholder interest and buy-in, and mandates to use the model (such as the study request from the Deputy Chair, Planning Commission (see Appendix C) are the critical next steps involving the points noted here.

- The Energy Wing of the Planning Commission, as the leader of the team, must guide and utilize the team resources to provide effective and useful analysis of Pakistan's future energy options and strategies.
- The Energy Wing is still in the process of adding new skilled staff, and only some of these staff received training in July and October 2010. The newest staff will need to be trained.
- The Planning Team continues to get strong contributions from the other engaged institutions, and their continued involvement is essential to long-term sustainable use of Pak-IEM.
- The Planning Team needs to be tasked by the Planning Commission and other ministries and stakeholders to conduct meaningful analyses of various policies and strategies, such as those identified in the section above.
- The project has created an Advisory Committee Task Force (ACTF) to facilitate involvement of the key Ministries, agencies, and private sector stakeholders to foster understanding and access to the best available energy sector data. Continuance of the ACTF beyond the term of the project is critical to insure the relevance and usefulness of Pak-IEM, and thereby the acceptance of the results arising from its use.
- Wider dissemination of model capabilities and results would also foster acceptance of Pak-IEM. The Project Team held a series of high-level briefings for key Ministries, agencies, and other energy sector stakeholders as part of the final mission. Various institutions indicated strong interest in understanding Pak-IEM and how it can be used, with several indicating a desire to gain access to and use Pak-IEM themselves.
- The Project Team has identified a few activities that will help to integrate Pak-IEM into the government's energy sector decision-making process. One of these is to begin development and publication of a "Pakistan Energy Sector Development and Investment Strategy" under the responsibility of the Planning Commission. The publication, which could be bi-annual, would feature Pakistan development pathways and requirements assessed using Pak-IEM for various scenarios and policies relevant to the pressing energy issues facing the country.
- Pak-IEM needs to be a living "tool," and must be continuously improved by incorporating new data and expanding the modeling of specific sectors. Suggested areas for improvement have been identified and discussed in Volume I of this Final Report: Model Design.

D. Next Steps

The Planning Team requires additional support, and IRG has submitted to ADB an outline plan for a wide range of follow-on support activities that could be considered for funding. In the meantime, IRG will remain committed to fielding questions from and providing guidance to the Planning Team.

II. INTRODUCTION

A. Background

The Asian Development Bank (ADB) supported Technical Assistance (TA) with Pakistan's Planning Commission to assist the Government of Pakistan (GoP) in developing an Integrated Energy Model (Pak-IEM) that will facilitate assessment of the impacts of various strategies for meeting the country's future energy needs in an optimal manner. The model integrates planning factors pertaining to financial investments, economic costs, energy supply, national resources, energy use, environmental impacts, technology improvement, energy efficiency, and conservation to assess the costs and benefits of policies that will shape the country for the coming decades. The TA is also designed to build the multi-institutional capacity that will allow various energy system policies and options to be examined in a clear and comparable manner so as to facilitate better communication and foster better cooperation between the various stakeholders on an ongoing basis.

This capability will provide the GoP with a framework for examining priority energy policy issues facing Pakistan, ranging from closing the current supply-demand gap to improving energy security by fully promoting energy efficiency and exploiting indigenous resources. Building this capacity within the GoP will create a solid analytic foundation for designing appropriate policies to guide the evolution of the energy system.

This report is Volume II of this TA Final Report and documents the results of the initial set of policy analyses examined using Pak-IEM. It is complimented by Volume I – Model Design, which discusses the model structure, data sources, and assumptions; and Volume III – Users' Guide, which describes how to manage and use the model. These analyses were carried out with the full engagement of the Planning Team, which is centered at the Energy Wing of the Planning Commission and supported by a network of key institutions in Pakistan as shown in Figure 1. The analyses were designed to illustrate the relevance and ability of the model to address important energy sector issues in Pakistan. They do not represent an official position of the ADB or the Planning Commission. *{Therefore, the results presented in this report should only be used for the purpose of reviewing the effectiveness of this TA.}*

Planning Team Composition	Sector Responsibilities
Energy Wing, Planning & Commission, Government of Pakistan	Demand Forecasting , Industry Supply & Resources, Transport & Agricultural Electricity, Residential & Commercial
Global Change Impact Studies Center (GCISC)	Emissions Transport & Agricultural
Hydrocarbon Development Institute of Pakistan (HDIP)	Emissions Supply & Resources
National Transport Research Center (NTRC)	Transport & Agriculture
Pakistan Atomic Energy Commission (PAEC)	Residential & Commercial Demand & Forecasting, Industry
Pakistan Electric &Power Company (PEPCO)	Electricity
Pakistan Institute of Engineering and Applied Sciences (PIEAS)	Transport & Agricultural Emissions
Pakistan Institute of Development Economics (PIDE)	Demand Forecasting Supply & Resources
University of Engineering and Technology, Karachi (NED)	Industry
University of Engineering & Technology, Lahore (UETL)	Electricity
University of Engineering & Technology, Taxila (UETT)	Industry Residential & Commercial

Figure 1: Institutional Composition of the Planning Team

B. Pak-IEM Design Overview

Pak-IEM utilizes the TIMES (The Integrated MARKAL/EFOM System) model generator, the successor to the MARKAL modeling framework, which has been conceived, developed, and continually supported by International Energy Agency – Energy Technology Systems Analysis Programme (IEA-ETSAP).[1] MARKAL/TIMES is the most widely used energy systems optimization model in the world today, deployed in some 70 countries in over 200 institutions. It has a 30-year track record of evolution and success. IRG team members have been involved in model development, capacity building, and policy analysis involving MARKAL/TIMES during much of that time.

Pak-IEM employs the VErsatile Data Analyst (VEDA) data and model management system to organize and handle the input data and process the results, thereby overseeing all aspects of working with the model. The development of the model input data is organized into a set of Excel workbooks (templates) that are managed by VEDA-FE (Front End), with VEDA-BE (Back End) handling the model results. The model base year is calibrated to 2006/2007 data (with intermediate calibration points up to 2010) and depicts development options for a Reference scenario out to 2030, and beyond (see Figure 2).

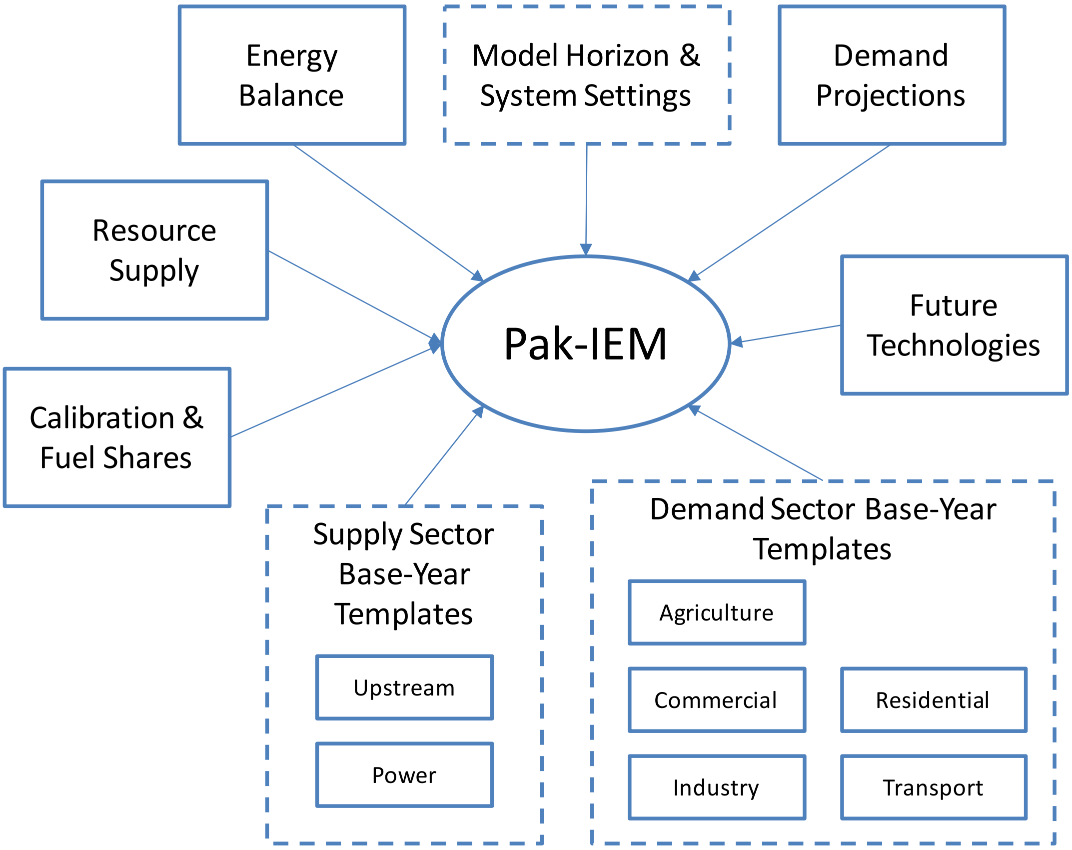

Figure 2: Structure of the Pak-IEM Data Inputs

A detailed description of Pak-IEM can be found in the Model Design Report (Final Report, Volume I). The Model Design Report describes Pak-IEM including its data sources, model structure by sector, demand drivers, and calibration of the model to the base year. In

[11] See www.etsap.org.

addition, a Pak-IEM Users' Guide, which is the third component of the TA Final Report (Volume III), describes the organization of the model components and how to use the Pak-IEM model with the VEDA framework.

This Policy Analysis Report presents the Reference scenario and initial Policy Analysis results as presented to the Advisory Committee in October 2010 at the Final TA Workshop. This report builds on the Interim Policy Analysis report, which was based on the results presented to the Advisory Committee in July 2010. Based on comments from that workshop, corrections and improvements were made to the model, and an updated Reference scenario and alternate scenarios results were generated. In this report, the alternate scenarios were combined into two possible future storylines as discussed in Section IV – Policy Analysis Results.

C. Recent Model Improvements

The following model improvements were implemented based on comments gathered at the July 2010 Policy Analysis Workshop:

1. All Power Plant discount rates were reviewed to ensure consistency.
2. More end-use efficiency and conservation options were developed, especially for the residential and industrial sectors, which are the largest demand sectors.
3. The handling of sector price adjustments for taxes and markups was refined and expanded.
4. A new imported LNG power plant option was added.
5. A “tight” natural gas resource was implemented based on new data from the industry association.
6. Updated Thar coal production costs and the power plant costs based on new information presented by the Thar Coal Development Board.
7. Improved refineries’ modeling based on improved data from the refineries regarding expansion options and clearer identification of which crude types are used.

The most influential of these was the reduction in the costs for Thar coal, which moved the Reference scenario from a balanced reliance on hydro, coal, and nuclear, to one which relies on hydro and coal with new nuclear only entering in 2030.

III. REFERENCE SCENARIO RESULTS

A. Planning Horizon Flexibility

The Reference scenario, which is intended to represent a business-as-usual evolution of the energy system in Pakistan, was run for the set of varying length periods as reported in Table 1. The initial (mostly annual) time periods provide a more detailed representation of the 2010 to 2016 time frame, while 5-year periods are used after 2020. The two 2-year periods are used to facilitate the mid-period reporting years shown in Table 1. The model runs were all made for the entire period of 2007 to 2040, but the results are reported up to 2030 only, using 5-year intervals starting in 2010. The TIMES framework allows full flexibility in terms of the year for which data is specified and the years for which the model is run. Thus, the modeling horizon and the run periods may be changed as the analysis requires.

Table 1: 2030 Reference Scenario Period Definitions

Period Indicator	Dates	Length
2007	Jul 2006 to Jun 2007	1 year
2008	Jul 2007 to Jun 2009	2 years
2010	Jul 2009 to Jun 2010	1 year
2011	Jul 2010 to Jun 2011	1 year
2012	Jul 2011 to Jun 2012	1 year
2013	Jul 2012 to Jun 2013	1 year
2014	Jul 2013 to Jun 2014	1 year
2015	Jul 2014 to Jun 2015	1 year
2016	Jul 2015 to Jun 2017	2 years
2020	Jul 2017 to Jun 2022	5 years
2025	Jul 2022 to Jun 2027	5 years
2030	Jul 2027 to Jun 2032	5 years
2035	Jul 2032 to Jun 2037	5 years
2040	Jul 2037 to Jun 2042	5 years

B. Technology Characterizations

All of the model data and assumptions are described in detail in the Model Design Report. But to support interpretation of the Pak-IEM results, some of the key data sources and assumptions are presented here.

- Oil & Gas Supply Reserves were provided by Directorate General Petroleum Concessions (DGPC), along with maximum projected annual extraction rates.
- Oil and gas resource costs were developed using both domestic and international sources, starting with the cost for a basket of Middle East crudes, adjusted for transportation charges to Pakistan, as shown in Table 2. Future costs are based upon International Energy Agency (IEA) projections for the growth in costs over time.
- Thar coal mining costs were based on the Shenhua Study of 2004, which predicted \$130/tonne investment cost with operating costs of \$3.7/million Btu.

- New power plant characteristics were developed from both domestic and international sources, and are presented in Table 3.
- Annual capacity addition rates were developed for each new power plant type to represent limits on the technical and institutional capacity in Pakistan. These limits were based on Planning Team experience and judgment, and they are presented in Table 4.
- The Reference scenario also contains constraints which are designed to prevent overly rapid change in the energy system. These include upper bounds on the degree of fuel switching in each demand sector (which are based on historical trends), and penetration limits on energy efficiency devices (upper bound of 10% of new devices can be high efficiency varieties by 2030).

Finally, Pak-IEM reflects the current situation with load shedding, which grows from zero in the base year to historical levels in 2010 and declines to zero again in 2013. The economic cost of load shedding was estimated at $0.60/KWh.

Table 2: Oil and Gas Prices, $/million Btu

Type	2008	2020	2030
Crude Oil	10.3	17.2	19.9
Domestic gas	2.5	3.8	4.4
Imported pipeline gas	11.7	12.8	14.7
Imported LNG	12.6	13.7	15.9
Imported heavy fuel oil	10.9	18.2	20.9

Table 3: New Power Plant Technology Characteristics

New Power Plant Option	Total Investment Cost (2007 $/kW)	Fixed O&M ($2007/kW)	Variable O&M ($2007 mills/kWh)	Efficiency	Availability	Start Date	Lead Time (Years)
Gas Turbine Open Cycle - Gas or Fuel Oil	709	11.79	3.47	32.7%	70%	2011	2
Heavy Oil Reciprocating Engines Combined cycle	1200	16.92	6.20	48.0%	70%	2010	3
Heavy Oil Steam turbine with Reheat Cycle	1000	17.52	2.40	40.0%	70%	2010	3
Coal Integrated Gasification Combined Cycle	2898	37.63	2.84	45.8%	75%	2016	4
Gas turbine Combined Cycle – Natural Gas and Diesel	1063	12.15	2.01	47.4%	70%	2011	3
Gas turbine Combined Cycle with Reheat - Natural Gas and Diesel	1200	15.84	3.00	54.0%	70%	2011	3
Nuclear Power Plant	4501	87.60	0.48	34.1%	85%	2011	6
Coal Supercritical Steam Turbine Power Plant	2560	26.79	4.47	37.1%	75%	2010	3
Hydro Power	1911	53.19	5.15	34.1%[a]	Note b	2016	4
Solar Photovoltaic Systems	6390	11.37	0.00	34.1%[a]	Note b	2011	1
Solar Thermal Power Systems	3500	19.08	2.40	34.1%[a]	Note b	2011	3
On Shore Wind Turbines – Classification 4-5	2500	63.24	0.40	34.1%[a]	Note b	2012	2
On Shore Wind Turbines – Classification 6	2750	63.24	0.40	34.1%[a]	Note b	2012	2
Off Shore Wind Turbines	3700	87.84	0.70	34.1%[a]	Note b	2012	3
Municipal Solid Waste	2809	111.18	0.00	25.0%	70%	2010	3

Note a: The efficiency of renewable energy technologies influences the investment cost and capacity factor, but Pak-IEM only uses it to calculate a fossil energy equivalent for renewable based electricity.

Note b: Capacity factors for each time-slice are used for each technology based on hydrological, meteorological and other data relevant to each resource.

Table 4: Upper Bounds to Annual Capacity Additions for Key Power Plant Types (GW)

Type	2020	2030
Nuclear	1	1
Oil	2.5	2.5
Gas	2.5	2.5
Coal	2.5	2.5
Hydro	1.5	1.5
Solar	0.002	0.005
Wind	0.2	0.2

C. Demand Projections

The Reference scenario results are largely driven by the demand projections developed in cooperation with the Planning Team, using the latest government forecast for GDP growth, and associated information. The GDP forecast is shown in Figure 3, broken down by the main sectoral components to GDP: agricultural, commercial services, and industry. The GDP projections are quite aggressive, particularly for the industry sector, peaking at 10% per annum in the 2020 to 2024 time frame. The average annual overall GDP growth for the 2007 to 2030 timeframe is 5.6%. More details on the development of the energy service demand projections for each sector are provided in the Model Design Report.

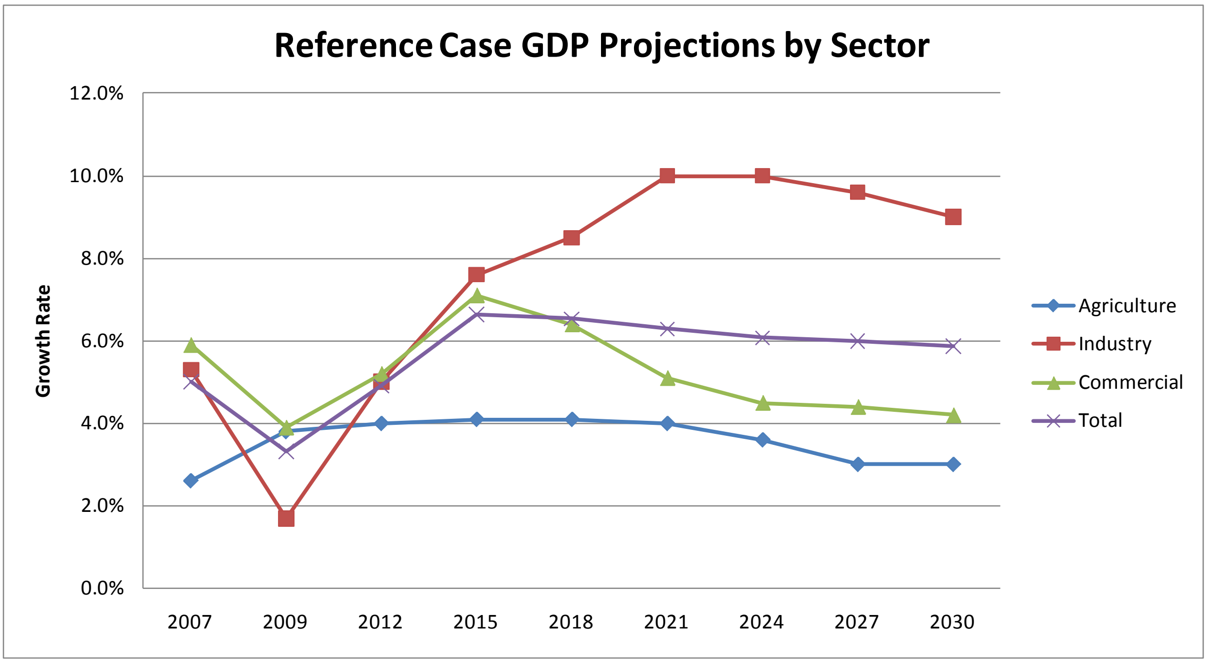

Figure 3: Reference Case GDP Projections by Sector

D. Primary Energy Use

Pak-IEM is calibrated to the 2006/07 energy balance for Pakistan, sourced from the Energy Year Book (EYB) 2007 (HDIP 2008). Two issues were identified with the Energy Balance, which resulted in adjustments to the overall energy balance used for the model relative to the Yearbook data.

- **High speed diesel (HSD)**. Based on bottom-up estimates of consumption across all end-use demand sectors, a shortfall was identified that was attributed to a significant amount of black market diesel not accounted for in the official energy balance. Based on expert judgment, a 10% increase in HSD has been assumed in 2006/07. This issue is discussed in detail in the transport section of the Model Design Report.

- **Non-commercial fuels**. Various forms of biomass are not present in the official Energy Balance due to a lack of statistics. Examples include wood, dung, and agricultural residue use in the residential sector and bagasse use in the sugar industry. Expert estimates of biomass use in the residential and sugar sectors have been made and included in the Pak-IEM base year energy balance.

Figure 4 summarizes the Pak-IEM base year energy balance data showing total primary energy supply and final energy consumption by sector. The non-commercial biomass consumption is included in the accounting of primary energy (under “renewables” category). Most other balances of primary energy use do not include this non-commercial energy use.

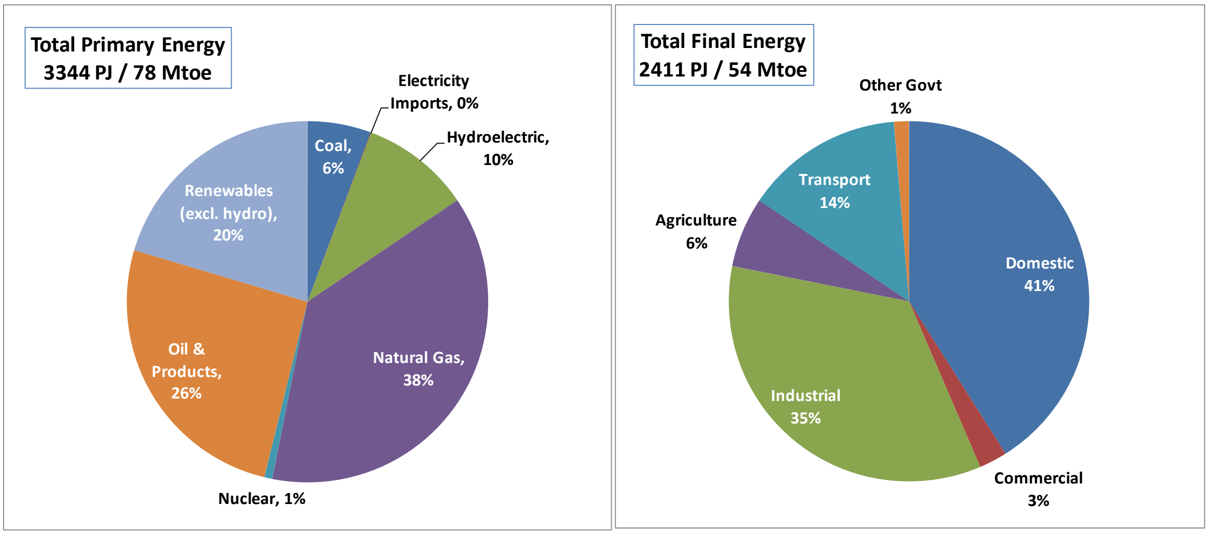

Figure 4: Primary Energy Production by Fuel type and Final Energy Consumption by Sector for 2006-07

Figure 5 shows that primary energy supply in the Reference scenario more than doubles over the next 20 years, largely coming from coal, hydropower, oil, and nuclear. The additions of hydropower, coal, and nuclear are due to the expansion of electricity generation, and the increase of refined oil products comes from transport sector growth. Per capita primary energy consumption increases by almost a factor of 2 from 0.42 Mtoe in 2007 to 0.74 Mtoe in 2030. However, even in 2030, Pakistan’s per capita primary energy use is 2.5 times below the 2007 world average.

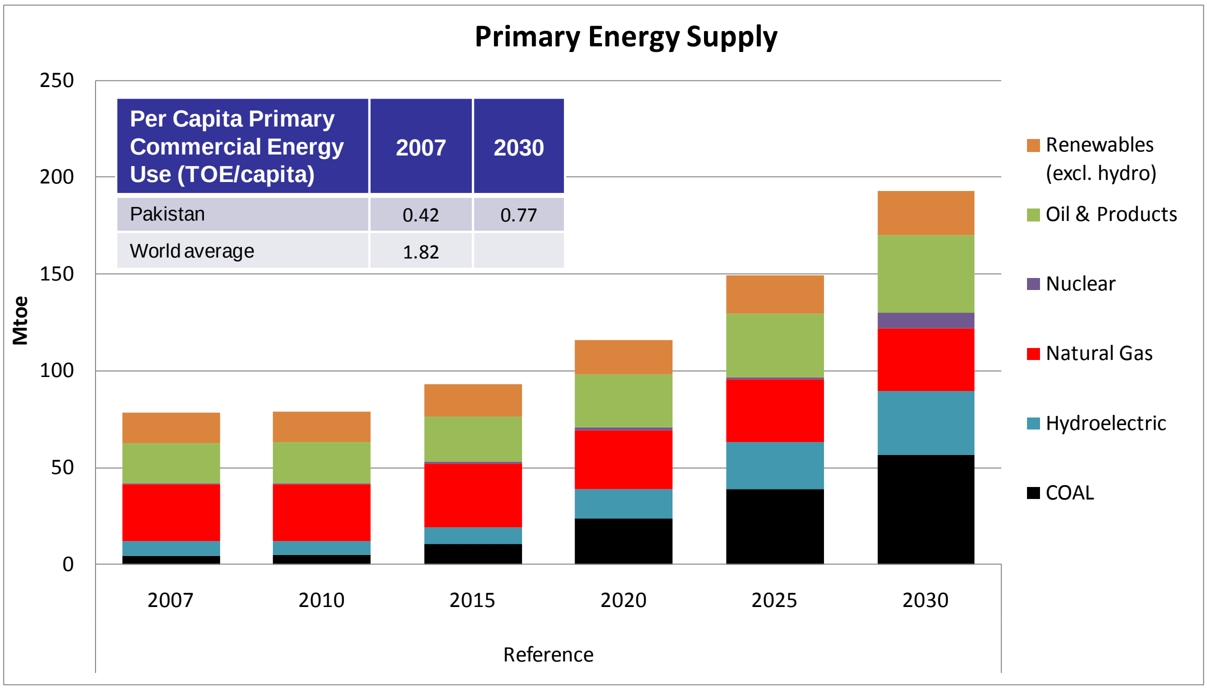

Figure 5: Primary Energy Supply – Reference Scenario

E. Fossil Fuel Supply

Figure 6 shows the projected requirement of all forms of fossil fuels under the Reference scenario. The fuels that show the most significant growth are imported oil, domestic coal (for power generation), and imported coal (for industry). The consumption of natural gas remains about the same, although the source of gas supplies changes significantly, as shown in Figure 7. What is most striking in Figure 7 is that the various domestic sources are depleted by 2030, at which time, the model invests in both LNG and pipeline imports. Although some LNG imports occur in 2015 for power generation only, the current low cost of domestic gas relative to imports ensures that domestic sources are used before turning to imports. While understandable, this does not necessarily reflect the best national policy.

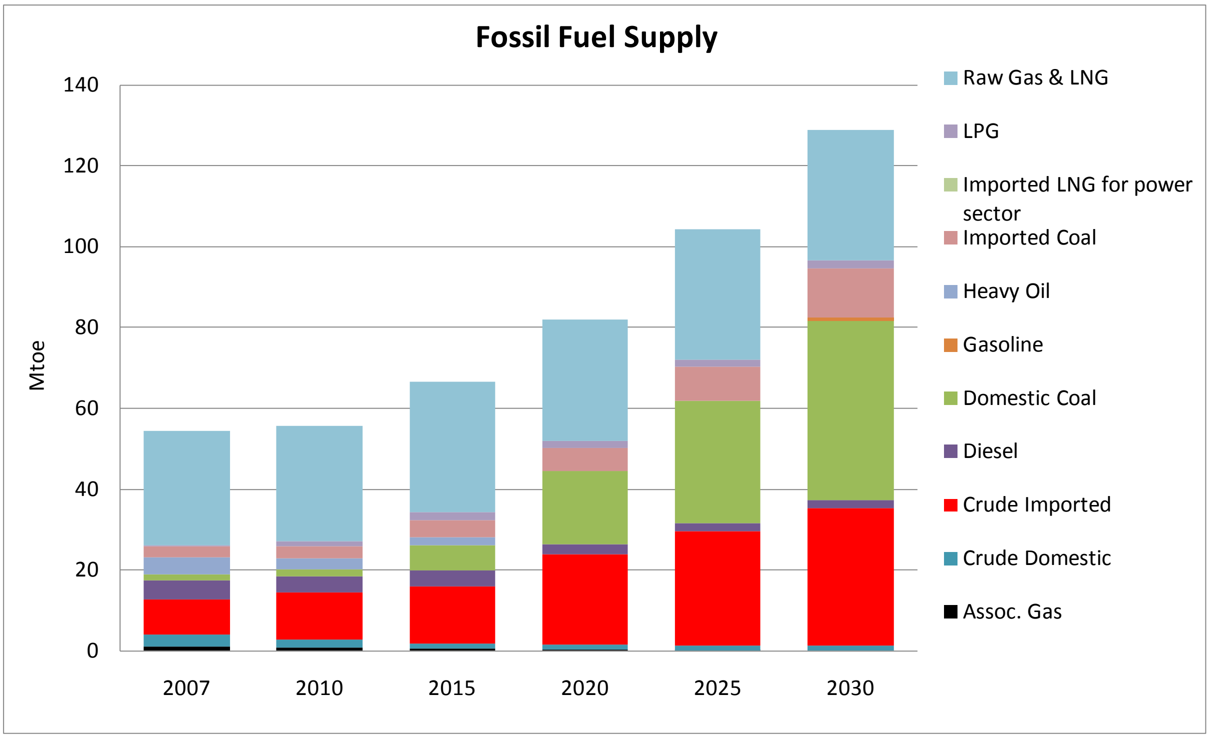

Figure 6: Fossil Fuel Supply – Reference Scenario

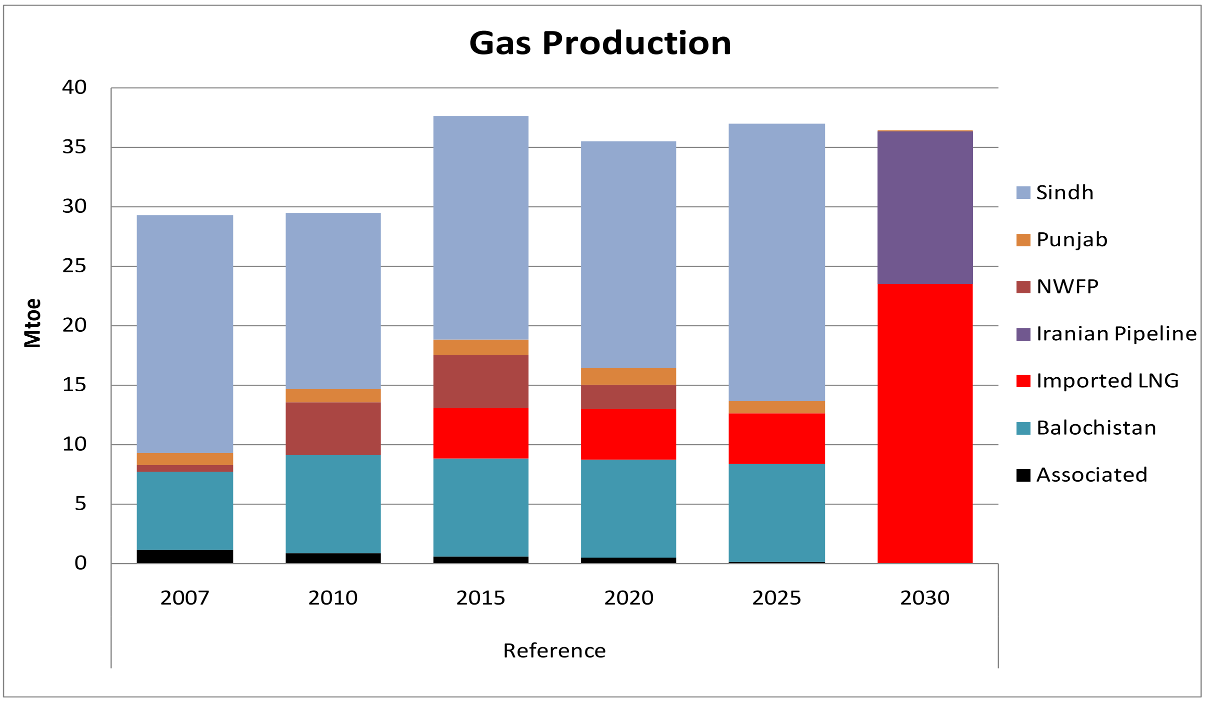

Figure 7: Natural Gas Supply by Source – Reference Scenario

F. Refinery Operation

Figure 8 shows that total refinery production is expected to grow through planned near-term refinery upgrades and undefined new refineries starting in 2020. Total refinery production is projected to triple due to the relative attractiveness of adding new, flexible refineries compared to importing refined oil products.

Following the presentation of similar preliminary results at the July 2010 Advisory Committee Task Force meeting, the refinery portion of Pak-IEM was updated to better represent details of refinery operation, particularly in regard to output flexibility of existing refineries and upgrade options for those refineries relative to investments in new flexible refineries. Further refinements have been made to the sector characterization concerning input crude / product output flexibility and new refinery build rates.

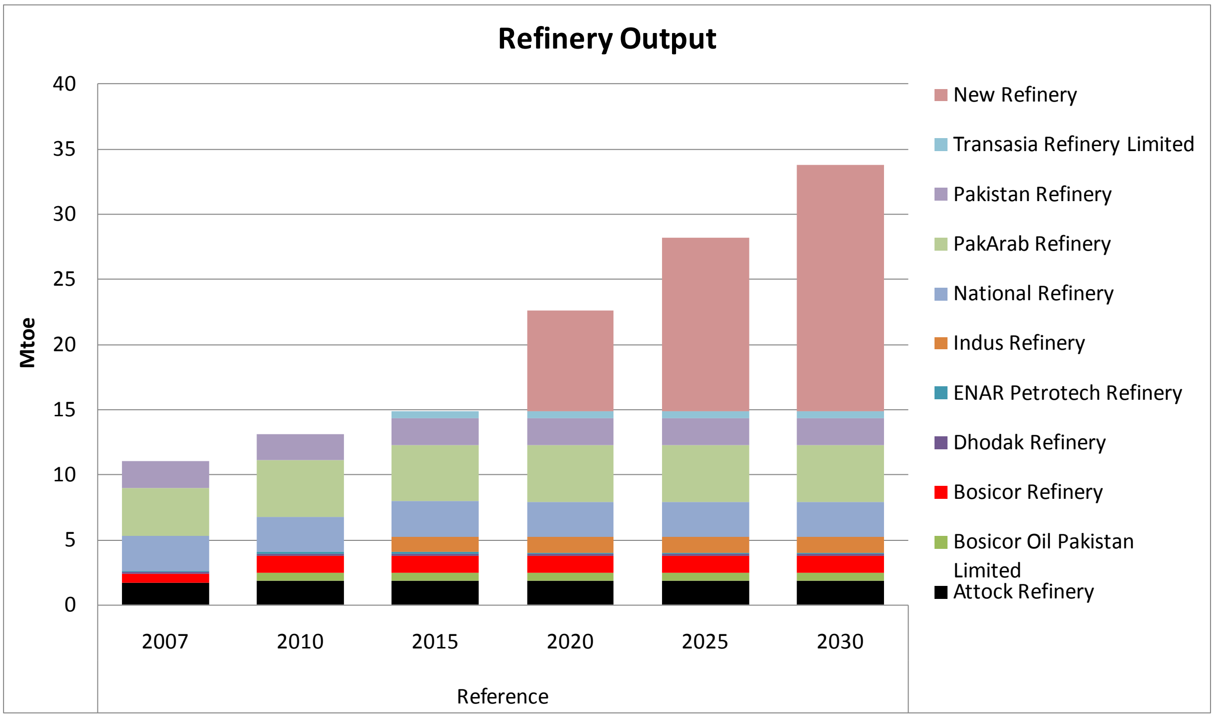

Figure 8: Refinery Capacity – Reference Scenario

The product slate demanded of the refineries is shown in Figure 9. Gasoline and diesel fuel use grow most dramatically, due to transport sector growth, while heavy fuel oil use diminishes by 2030, as the older fuel oil power plants are replaced.

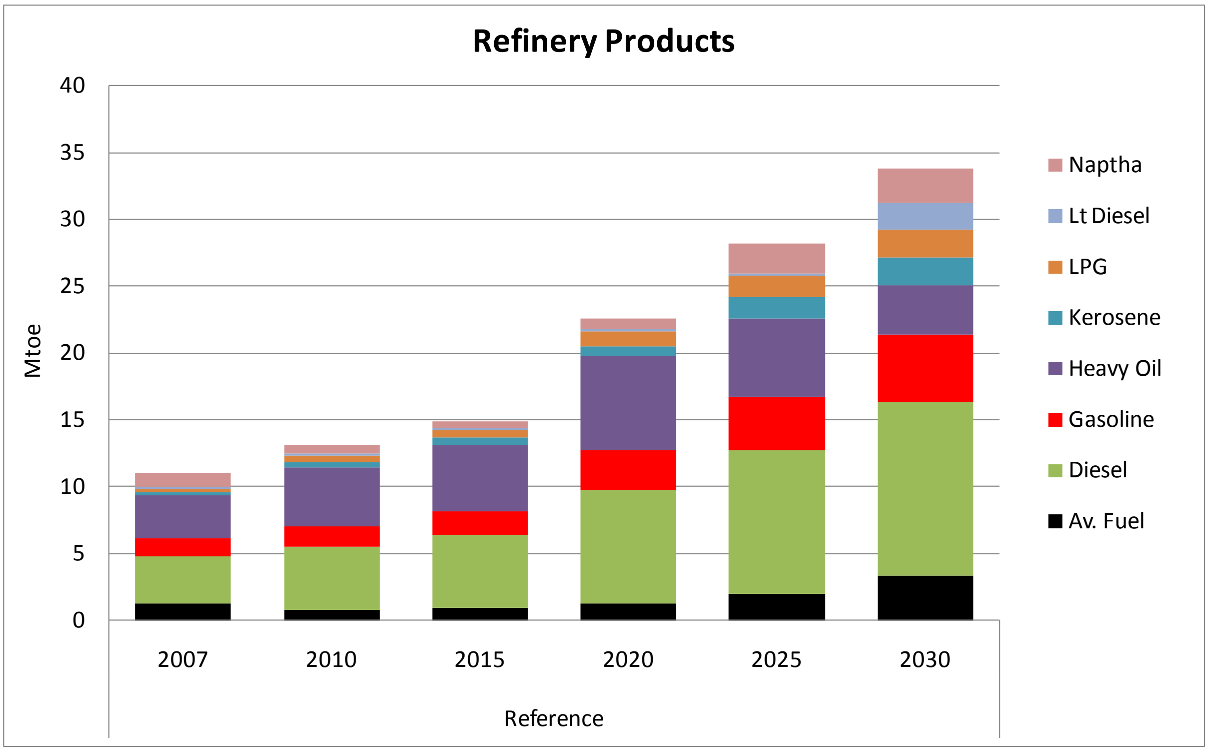

Figure 9: Refinery Outputs – Reference Scenario

G. Power Plant Electricity Output

Figure 10 shows that electricity generation is expected to quadruple by 2030, with hydropower and coal power plants growing to be the primary generators of electricity. Nuclear makes a significant contribution starting in 2030. Natural gas-fired power plants continue to generate over the long term, although their share declines, using dedicated imported gas (such as LNG).

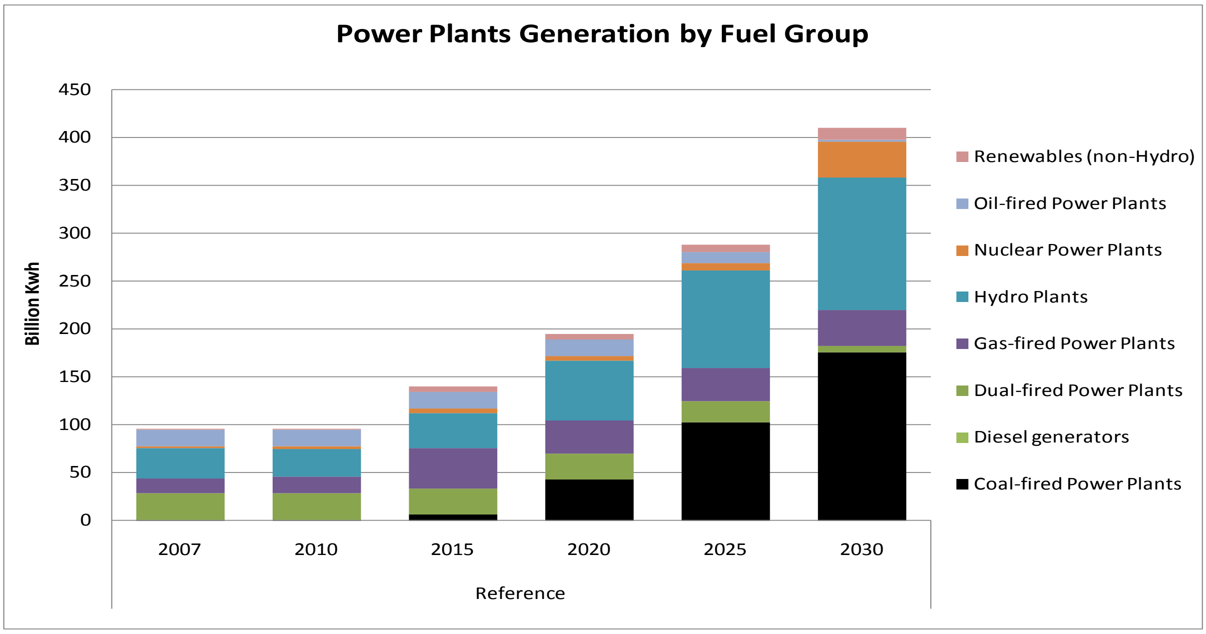

Figure 10: Power Plant Electricity Output - Reference Scenario

H. Additions to Power Generating Capacity

In the Reference scenario, almost 12 GW of new capacity is added to the system by 2015, of which over 8 GW is in planning (see Figure 11). Most of the planned builds are gas and oil-based generation, with some additional hydro and nuclear capacity. Beyond these planned near-term additions, new power plant additions come primarily from dedicated (coastal) gas LNG power plants, in 2013 and 2014. In the near term, the new renewable generation mostly comes from MSW.

In the longer term, new power plant additions come mainly from hydropower and coal, with nuclear growing post-2030. Both hydropower and coal grow at their permitted build rate limits in the outer years. To meet the Reference scenario electricity demand requirements a cumulative total of 82 GW of new power plant capacity is needed, with almost half coming from coal, and 30% from hydropower. Most longer term renewable additions are from wind.

The capacity additions that are required to meet the Reference scenario demand projection average about 2 GW per year between 2010 and 2017, but for the 2020 period (2018-2022) the annual amount of new capacity increases to about 3.5 GW, and reaches 5 GW per year by the 2030 period.

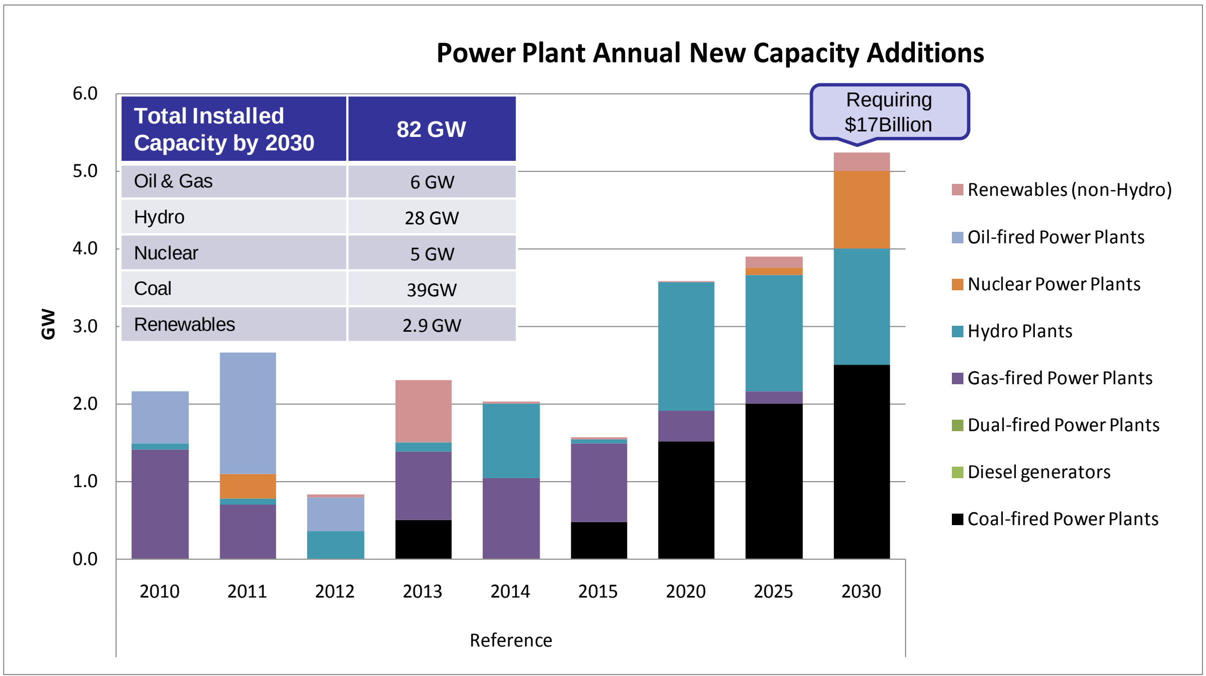

Figure 11: Annual Additions to Power Generating Capacity – Reference Scenario

Figure 12 shows the level of annual capital investment required to meet the additional generation capacity under the Reference scenario. The total investment requirements average about $4 billion per annum in the near term and increase to $17 billion by 2030.

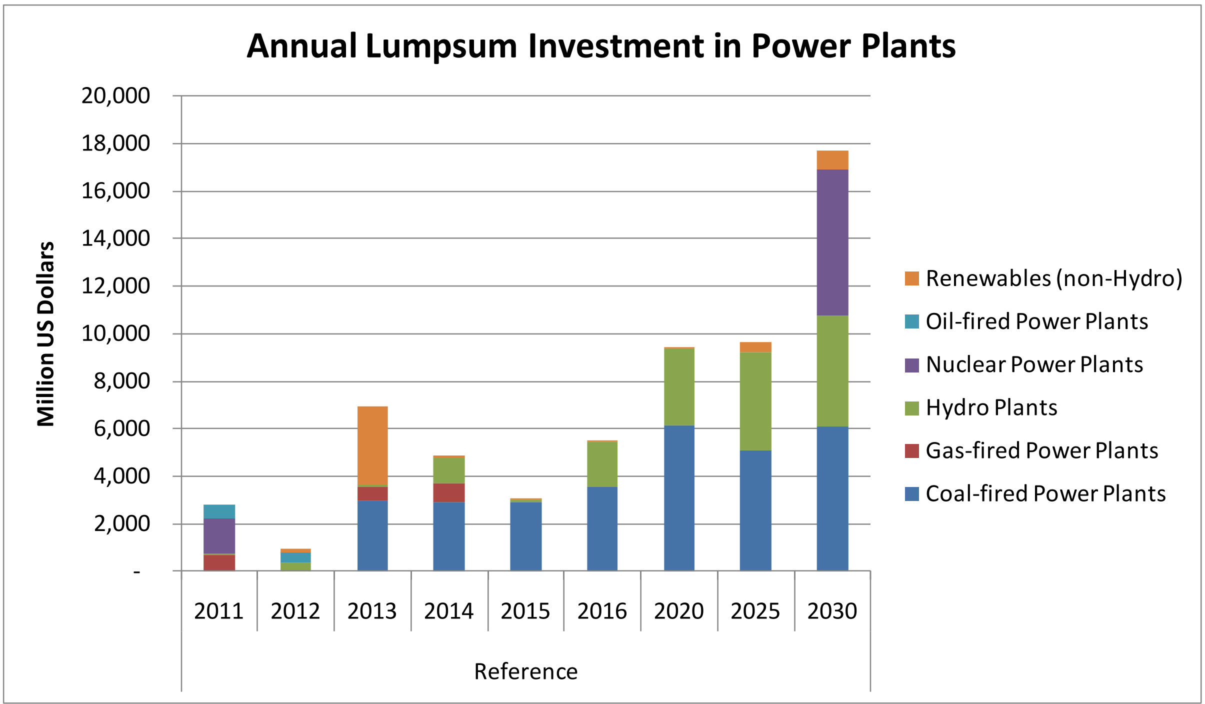

Figure 12: Annual Lumpsum Investment in Power Plants

I. Final Energy Consumption by Fuel

Figure 13 shows that natural gas and electricity account for most of the near term growth in final energy use. However, in the longer term, domestic supplies of natural gas are declining and imports are required to both maintain and increase supplies. By 2030 the most significant growth in final energy is based on electricity (which grows by a factor of 5) and oil products (growing by a factor of 4), driven particularly by industry demand. Natural gas use increases by 50% while coal use increases significantly, from 4 to 36 Mtoe due to use by industry. Renewable energy use, which is primarily traditional biomass (wood, agricultural residues, and dung), remains broadly flat due to resource constraints. Per capita electricity consumption, which increases from 457 kWh/yr to 1450 kWh/yr, remains lower than the 2007 world average of 2752 kWh/yr.

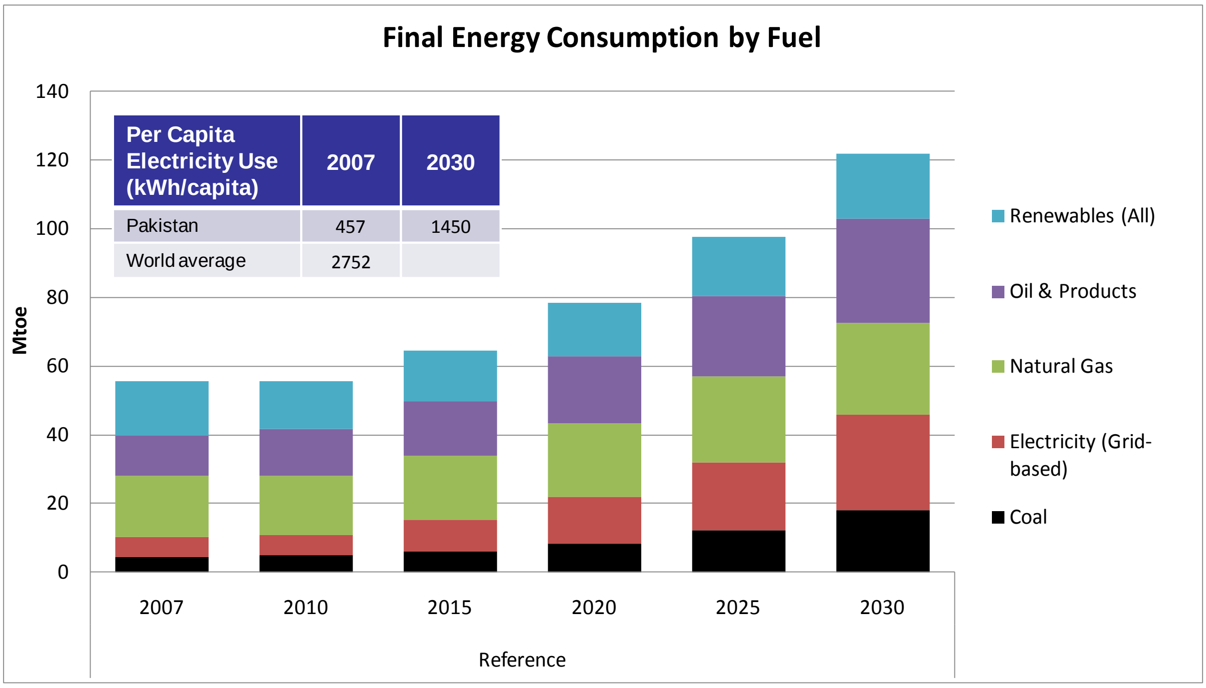

Figure 13: Final Energy Consumption by Fuel Type – Reference Scenario

J. Final Energy Consumption by Sector

Figure 14 shows that by 2030 overall final energy use more than doubles, while industrial energy use increases around a factor of 3 (driven by strong predicted GDP growth) and transport energy use almost quadruples. Residential energy use doubles, and continues to be the second largest component of final energy use in 2030. Agricultural and commercial energy use grows, but they remain small contributors to overall final energy consumption. This figure helps to identify where policies should be examined that can promote moderation of energy growth relative to GDP growth. Appendix A presents the sector level details of the Reference scenario results.

K. Import Dependency

Figure 15 shows that imports increase to over 30% by 2014, remain at that level until 2025, and then grow to over 45% of total supply by 2030. Besides the basic growth in energy demand discussed in the previous section, the continued depletion of domestic proven oil and gas reserves forces the increased use of imported energy, particularly in the final period.

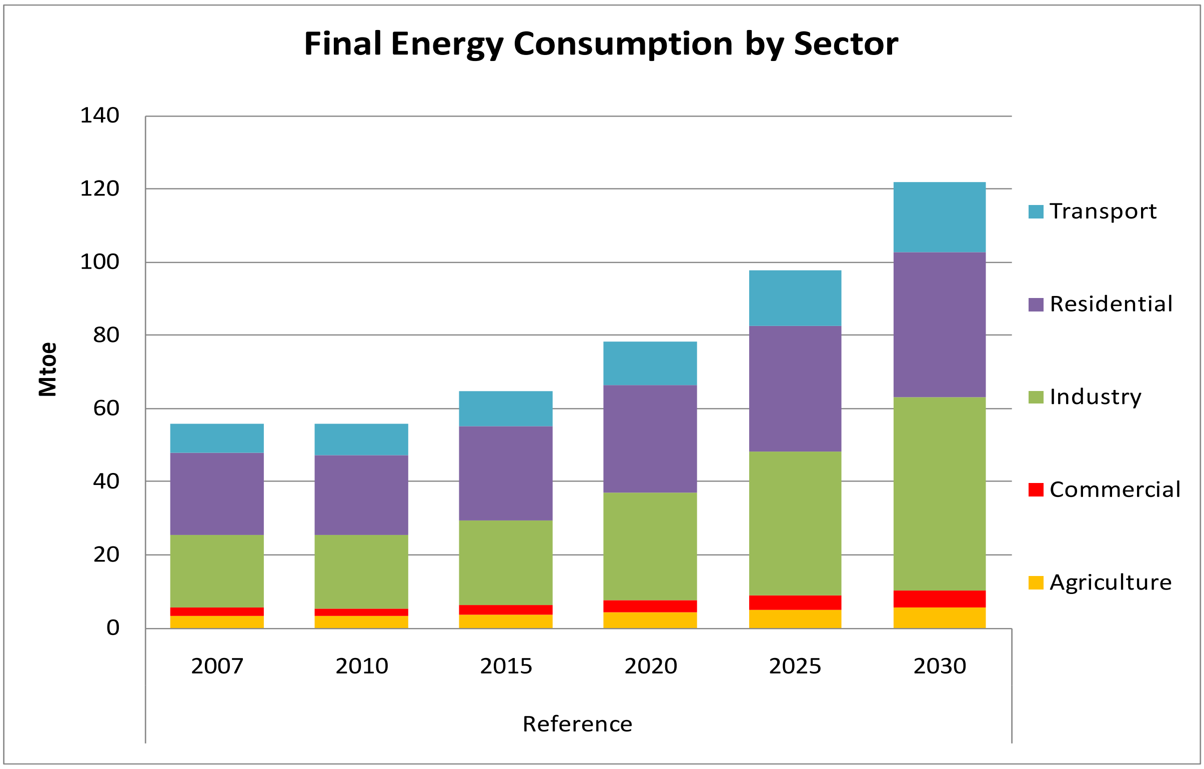

Figure 14: Final Energy Consumption by Sector – Reference Scenario

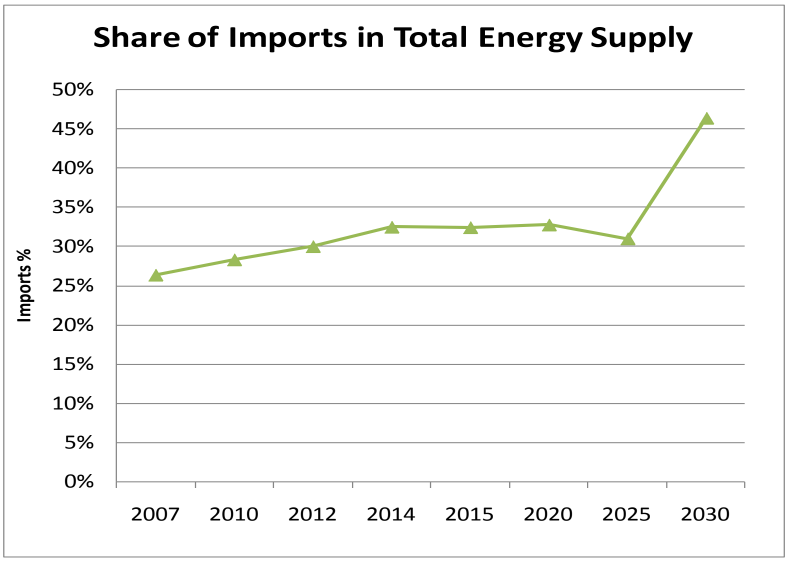

Figure 15: Import Dependency – Reference Scenario

L. Energy System Costs

Figure 16 shows a breakdown of the annualized energy system costs according to fuels (resource supply), new investments in power plants, refineries, and demand devices (e.g., cars, industrial boilers, light bulbs, etc.), and fixed and variable operations and maintenance (O&M) costs for all technologies. Fuel expenditures quadruple in 2030 relative to 2007 levels, and investments in all components of the energy system (supply and demand technologies in all sectors) grow to more than US$45 billion in 2030, approximately 40% of total system costs.

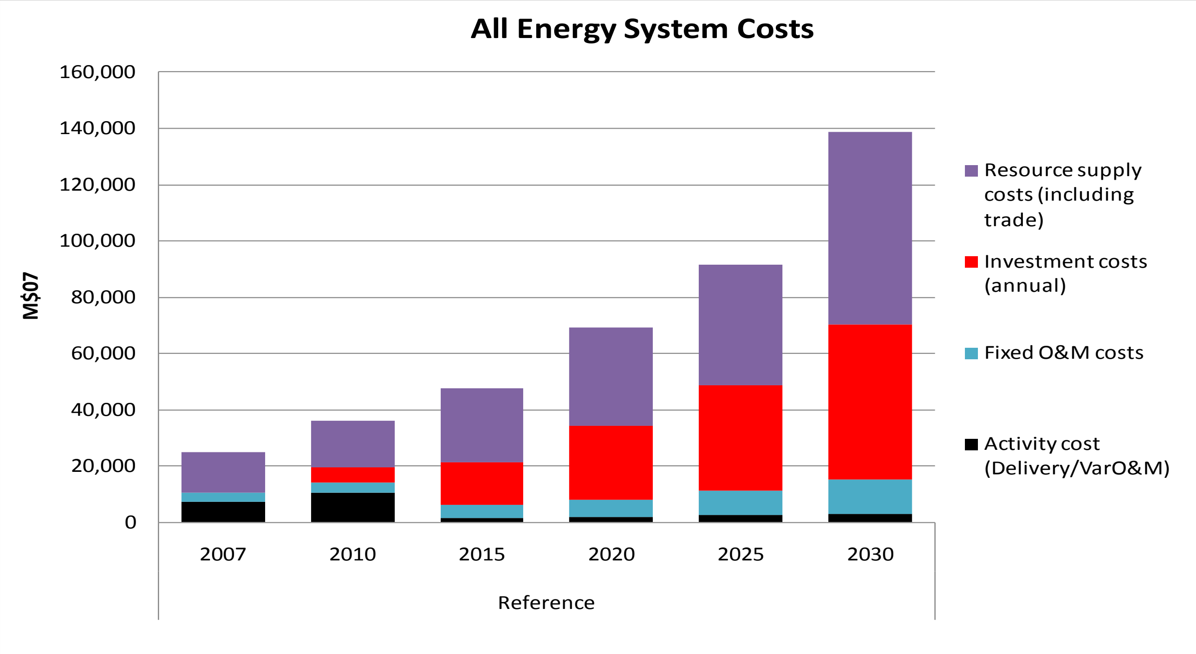

Figure 16: Breakdown of Energy System Costs – Reference Scenario[2]

M. CO_2 Emissions

Figure 17 shows CO_2 emissions from the entire energy system. The most growth in emissions comes from the power sector, but both the industry and transport sectors show steady and significant growth. Per capita CO_2 emissions increase from 858 kg/yr to 1650 kg/yr in 2030, but the 2030 value for Pakistan's energy sector remains about 3 times lower than the world average in 2007.

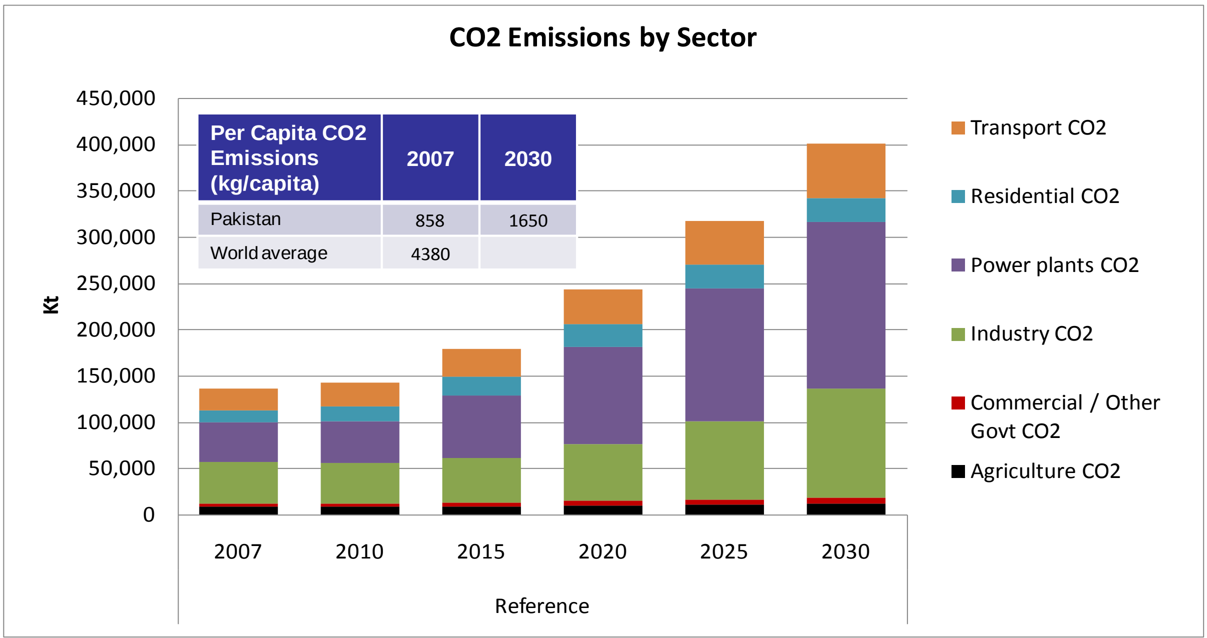

Figure 17: CO_2 Emissions by Sector

[2] Note that the sunk costs of existing power plants and demand devices are not included in the model.

Figure 18 shows Reference scenario annual CO_2 emissions from the power sector only. These emissions increase dramatically starting in 2020 due to generation from Thar coal power plant.

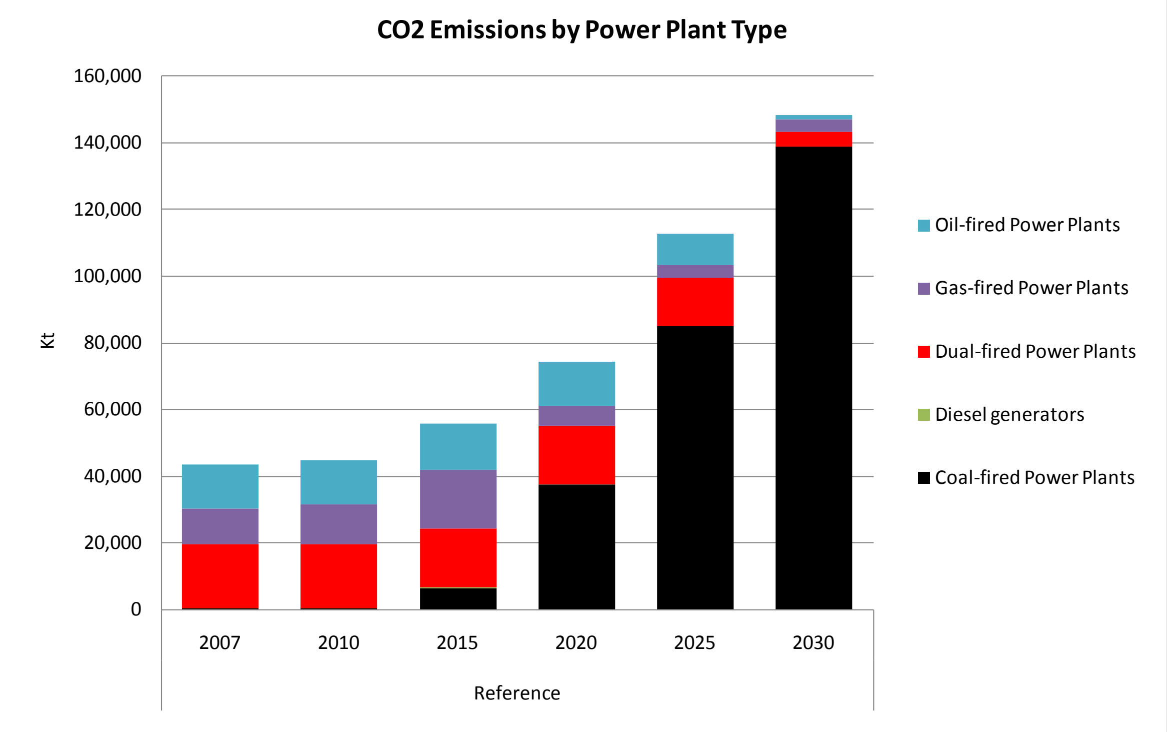

Figure 18: CO_2 Emissions by Power Plant Type

N. Summary Observations

These Reference scenario results are not intended as a prediction. They represent a least-cost development path for the Pakistan energy sector that supports the government's projections for GDP growth. It will serve as the comparison point for the scenario analyses and policy storylines to be presented in the next section.

These Reference scenario depend on many factors, such as the demand projections, the prices assumed for fuel, the cost and performance of the future technology options, the future characteristics of the existing and committed power plants, and demand sector end-use technology choices.

There are also Reference scenario technology and fuel share constraints which control the rate at which the system is permitted to change relative to the way basic energy choices are made today. These constraints are relatively "tight" in the Reference scenario, as significant changes, such as the adoption of cost-effective energy efficiency measures, are considered unlikely in Pakistan without specific policy intervention. The Policy Analysis section explores plausible alternate energy futures for Pakistan that could be shaped by circumstances, choices and policy options.

IV. POLICY ANALYSIS RESULTS

This section summarizes the general results from the scenario and sensitivity analyses presented in the Interim Policy Analysis Report and builds on those results to present two divergent policy storylines. The storylines combine several of the alternative assumptions to create a more comprehensive picture of possible energy futures for Pakistan.

A. Scenarios and Sensitivity Cases

The scenarios described in Table 5 were developed after the set of priority policy issues were identified by the Advisory Committee Task Force. These scenarios were also developed to illustrate the power and flexibility of the model. Each of the scenarios explores some adjustment to assumptions made in the Reference scenario. The results from the Interim Policy Analysis Report are reported in detail in Appendix B. Quantitatively, the interim results are no longer consistent with the current Pak-IEM Reference scenario. However, the results are still qualitatively valid and useful for illustrating the relative impacts of the various scenario and sensitivity analyses.

Table 5: Scenario Definitions and Groups

Scenario	Analysis Group	Description
Reference	All Groups	5.6% Overall GDP Growth 2007 to 2030
Medium Demand	G1: Economic Activity [Medium and Lower GDP Growth and Sector Prices]	5.0% Overall GDP Growth 2007 to 2030
Lower Demand		4.2% Overall GDP Growth 2007 to 2030
Sector Prices		Include fuel taxes and distribution charges
Low Energy Price	G2: Energy Prices and Security [Reduced Imports]	Decrease oil by $10/bbl in 2020 and $20/bbl in 2030
High Energy Price		Increase oil by $20/bbl in 2020 and $35/bbl in 2030
Reduced Imports		Limit imports to 25% of total primary supply
Hydro Delay	G3: Delay Power Projects [Hydro / Nuclear and No Thar Coal]	Delay Builds of new Hydro by 10yrs
Nuclear Delay		Delay Builds of new Nuclear by 10yrs
No Thar Coal		Prohibit the use of Thar coal
Hydro Cost	G4: Increase Power Plant Costs [Hydro / Nuclear / Thar Coal]	Increase Hydro Capital Cost by 10%
Nuclear Cost		Increase Nuclear Capital Cost by 10%
Thar Coal Cost		Increase Thar coal cost by 25%
Oil & Gas Reserve	G5: Reserves and Environmental [Oil & Gas Reserves / Renewable Electricity / Carbon Tax]	Increase Oil & Gas Cumulative Reserve by 20%
Renewables		Implement Renewable Electricity Target of 15%
CO2 Tax		Apply a tax of 20$/t in 2020 and $50/t in 2030

The primary qualitative results from these initial scenarios and sensitivity analyses are summarized below.

- **Lower economic growth** reduces both the future energy consumption and the investment required to meet the projected demand. However, the lower demand case has a 28% higher energy system cost per unit of GDP compared to the medium GDP growth case. This is because the system has a minimum energy requirement and because new technologies are generally more efficient than existing ones. Also, higher economic growth requires more investment in new technologies.
- **Lower energy prices** increase fuel consumption and result in a small additional investment in refineries.
- **Higher energy prices** increase nuclear power additions and promote more efficient power plants.
- **Reducing imports** requires the use of Thar coal and also encourages investment in more efficient end-use devices.
- **Hydropower** capacity additions remain essentially the same even in the lower economic growth scenario, and it reaches its maximum build rate in most periods. Hydropower is the least-cost power sector expansion option because the cost estimates attribute part of the total project cost to irrigation.
- **Nuclear and Thar coal** complete directly with each other, especially in the later periods, though with the most recent data for Thar coal supply and power plant investment (See Section III.B.), Thar coal is favored over nuclear.
- **With No Thar coal**, electricity is more expensive and direct use of fuels increases in the residential and industry sectors.
- **Increasing domestic oil and gas reserves** reduces system costs, but does not change the energy system mix of fuels and types of investments, other than delaying the need for large volume gas imports for a about a decade.
- **Renewable electricity target** increases system cost through investment in renewables displacing some of the coal and nuclear.
- **CO_2 tax** dramatically increases system cost by shifting investment away from coal and towards renewables, nuclear and increased gas consumption for power generation.

B. Policy Storylines

The scenarios and sensitivities described above were combined into storylines that constitute possible, but divergent visions of Pakistan's energy future. One assumes that Pakistan "Pursues Best Practices" while the other presumes that "Challenges Persist." These storylines are each presented in the next sections. They were developed to illustrate the power and flexibility of Pak-IEM and to provide a more comprehensive picture of how the framework can be used to advise policy evaluation and formulation.

1. Storyline 1 – Pursue Best Practices

The starting point for this storyline is the underlying premise for the Reference scenario:

- 5.6% average annual GDP growth
- Supply and power sector investment requirements are achieved
- Limited change in fuel or technology choices in demand sectors

The storyline follows the introduction of scenarios, which are dubbed the “best practice” energy policies and programs, and include:

- Electricity T&D efficiency improvements
- Increased potential for Renewable Energy (wind and solar thermal)
- Higher levels of Energy Efficient device deployment permitted in the demand sectors
- Expanded domestic Oil & Gas reserves

In addition, a CO_2 tax was added to this storyline to assess how the results might be influenced by the imposition of a CO_2 mitigation policy.

The primary observations arising (incrementally) from each scenario are summarized below.

- **T&D improvements**: Introduction of cost-effective measures to reduce electricity grid losses.
    - Reduce transmission losses from 6% to 4% by 2020
    - Reduce distribution losses from 19% to 14% by 2020
- **Renewable Energy**: Allows for more non-hydro power sector renewable energy, should policies dictate (e.g., increased energy security, emission reductions).
    - Increases the upper bound of the build rate for new wind installations to 700 MW per year in 2030
    - Increases the upper bound of the build rate for new solar installations to 200 MW per year in 2030
- **Energy Efficiency**: Allow for increased levels of energy efficiency in demand sectors, should policies to encourage their uptake materialize.
    - Permit up to 50% of new demand technology purchases in 2030 to be more efficient devices and industrial processes, rather than the 10% limit in the Reference scenario
- **More Domestic**: Assumes increased investment in oil and gas exploration will add to the proven reserves
    - Increase domestic oil and gas cumulative reserves by 20% (at the current price assumptions for domestic gas)
- **CO_2 Tax**: Assume international agreement that imputes a cost of CO_2 emissions (or a value to emission reductions).
    - Apply a tax of 20$/ton in 2020 and $30/ton in 2030 on CO_2 emissions

Figure 19 shows the total discounted energy system cost (in 2007) for the main components of Storyline 1. A savings of about $2.6 billion can be gained through T&D improvements. Energy efficiency measures save another $14.5 billion, while finding 20% more domestic gas resource realizes a total potential savings of $30 billion over the model horizon. Note that the renewable energy scenario saves less than $0.3 billion relative to the energy efficiency scenario, as much of the efficiency investment reduces the need for new power plants in general.

These are critical insights, and strongly indicate that pursuing Best Practices makes economic sense in the long term, taking account of all costs incurred out to 2030, discounted to the present day. This message is a challenging one for policy makers, who often only consider single investments in the near term rather than assess all investments together over the longer term.

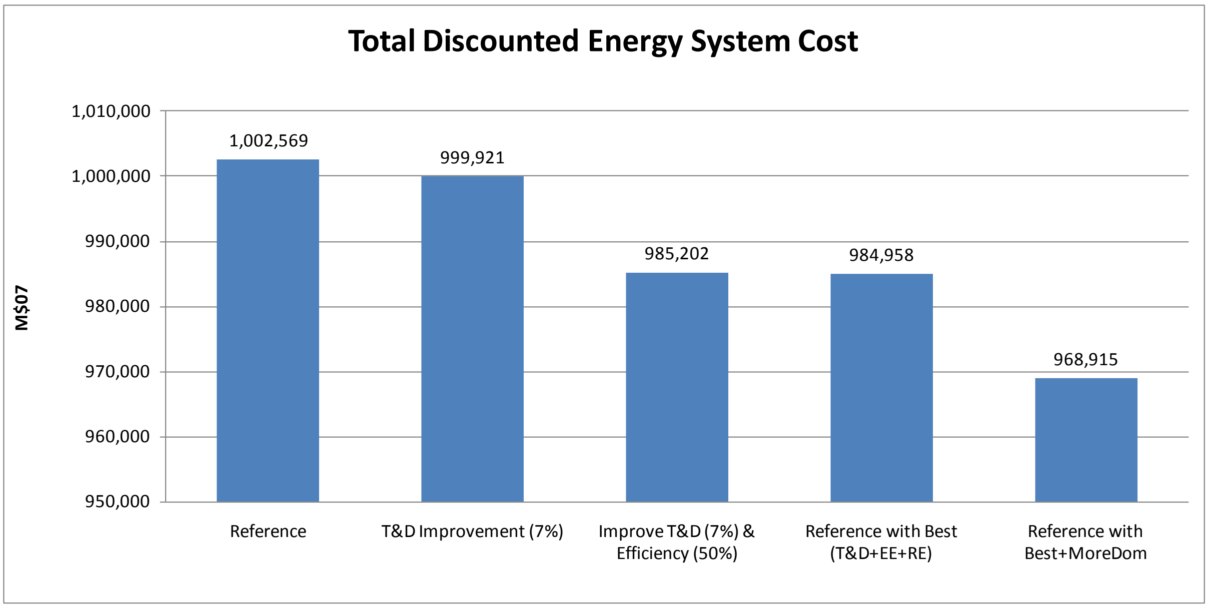

Figure 19: Storyline 1 – Change in Energy System Cost

Figure 20 provides a breakdown of the change in annual energy system investments for refineries (processes), power plants, and demand technologies compared to the Reference scenario. It shows that T&D improvements reduce power plant investments because of the higher percentage of output that can be delivered per unit of capacity. The best practice measures do require increased investment in more expensive demand devices; however, this is offset by lower power plant requirements (as well as reduced fuel expenditures). Finding more domestic oil and gas reduces slightly the investment required for the more energy efficient devices and increases the savings in power generation investments as more gas is consumed by the end-use sectors.

An issue that deserves further consideration is that these policy measures do not include all the additional costs that may be associated with their implementation. Specifically, neither the cost of reducing T&D losses nor the costs of new gas exploration are included in the analyses, so the benefits from these scenarios are gross benefits. The efficiency and renewables scenarios do include the higher investment costs associated with these technologies, but the cost of any incentive programs are not included.

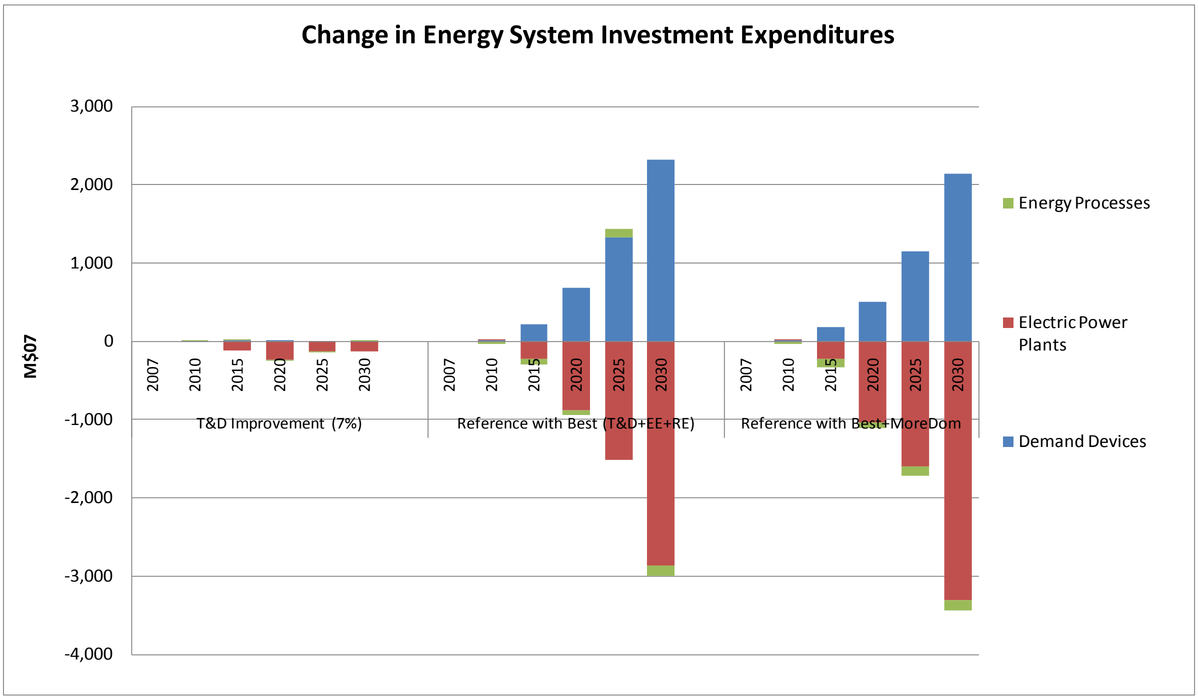

Figure 20: Storyline 1 – Change in Energy System Investments

Figure 21 provides a breakdown of power generation by power plant type. Best practice and More Gas cases result in a saving of about 50 to 60 billion KWh annually in 2030, and into the future. These policies also reduce the amount of new coal and nuclear power capacity, leading to significant investment savings.

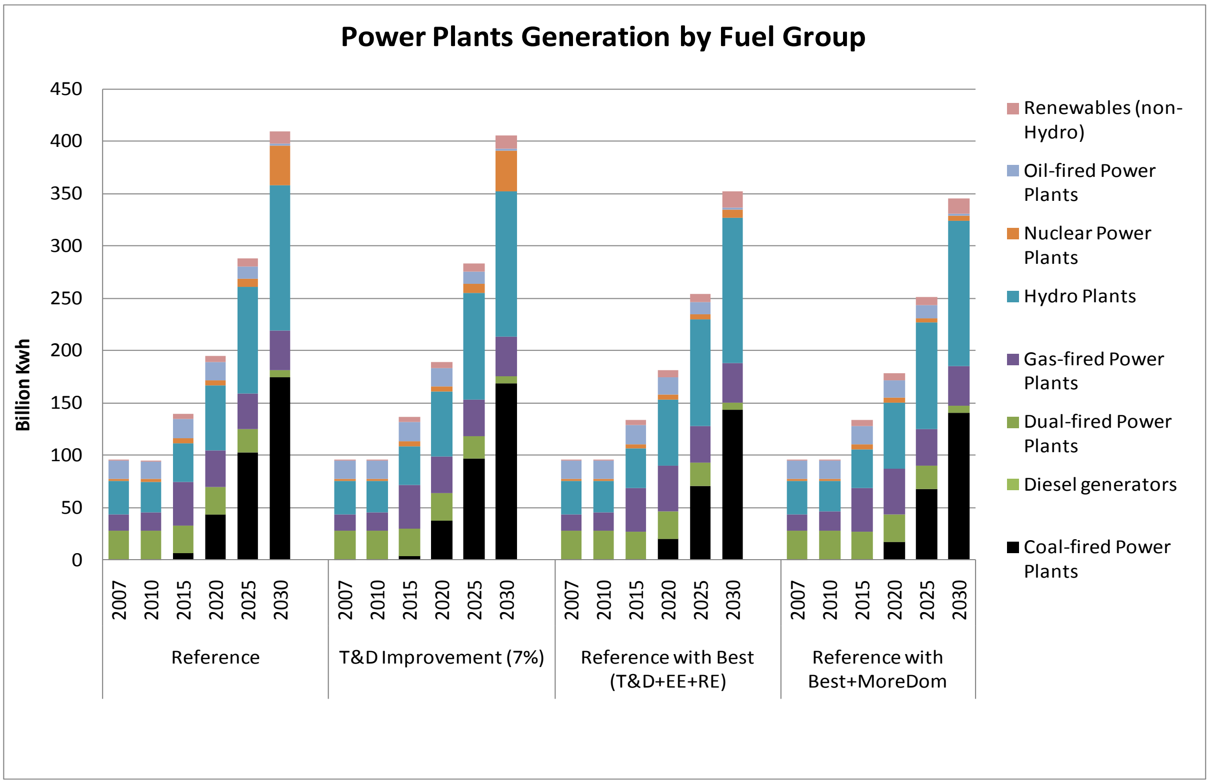

Figure 21: Storyline 1 – Power Plant Generation by Fuel Group

Natural gas production, as shown in Figure 22, does not change as a result of implementing best practices. Without additional finds, domestic gas reserves are depleted by 2030 and both LNG and imported pipeline supply options are developed – just as in the Reference scenario. Finding more domestic gas reserves (the MoreDom scenario) delays the need for the Iranian pipeline and reduces the size of the LNG infrastructure, while stretching out the availability of domestic gas for about ten more years. In all cases, LNG imports are needed to maintain overall gas consumption. Forcing the model to use Tight Gas or implement the Iranian pipeline before 2030 show similar behavior, but at a higher cost than first depleting all less expensive domestic reserves.

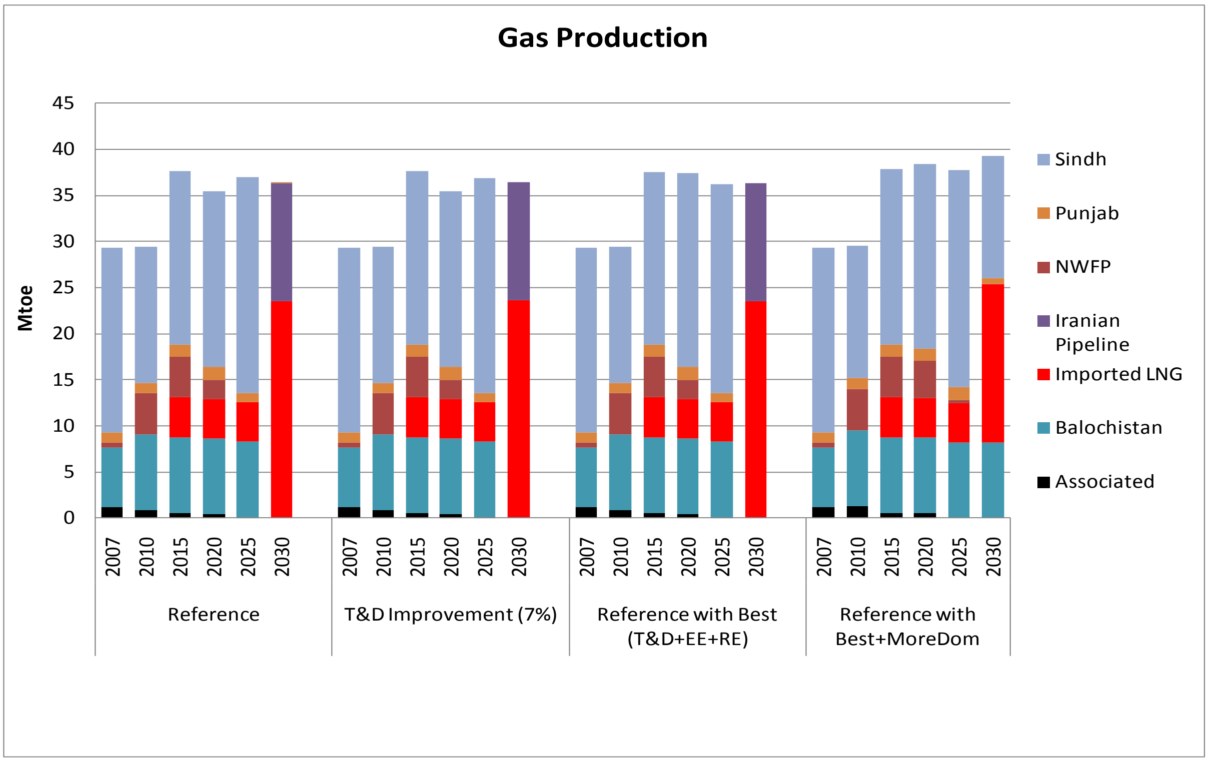

Figure 22: Storyline 1 – Natural Gas Production

Figure 23 shows the change in natural gas consumption. Implementing Best Practices reduces gas consumption in the residential sector due to energy efficiency measures, which also support increased gas consumption in the transport sector in compressed natural gas (CNG) vehicles. In the power sector, the reduction in overall electricity consumption defers some large coal plants and allows more generation from gas.

Finding more conventional domestic gas reserves encourages structural changes that facilitate increased gas use in residential, industry and transport sectors. In the residential sector, more gas is used in place of electricity for heating and cooking. In the industry sector, the additional gas is used for captive generation, and in transport, it powers more CNG cars.

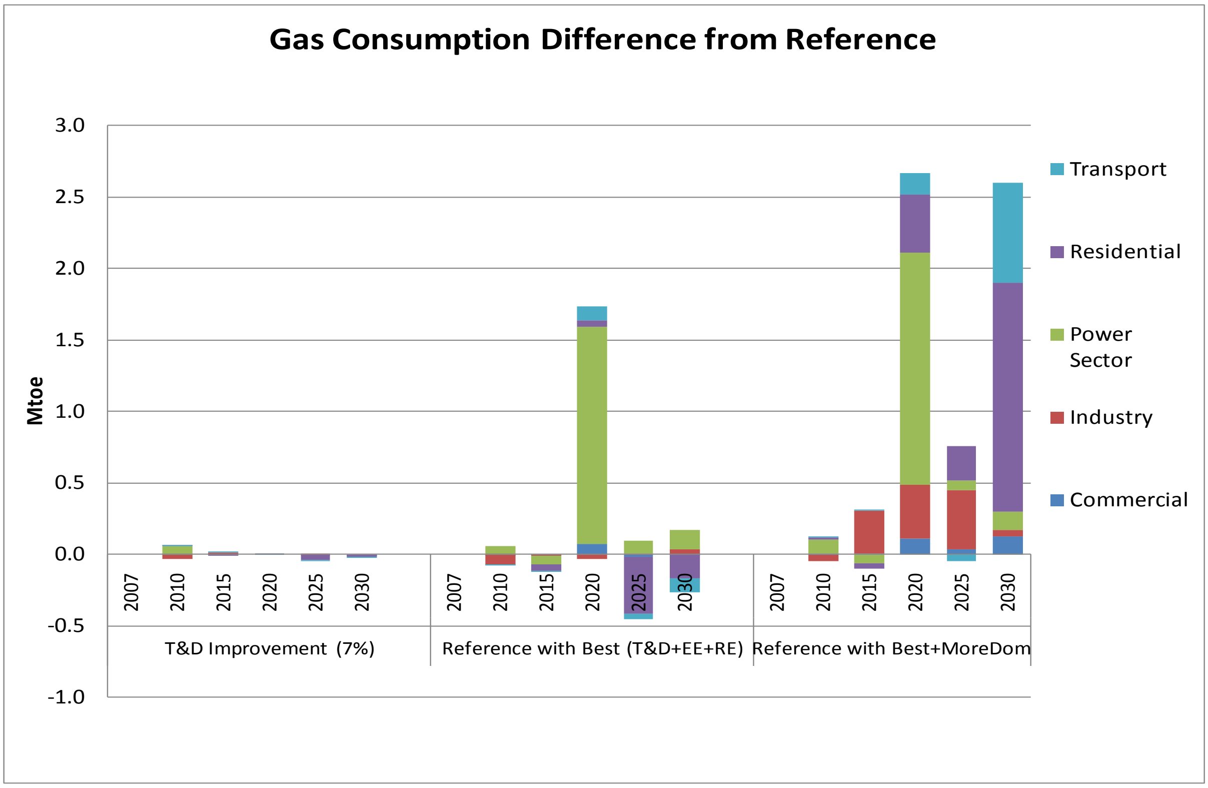

Figure 23: Storyline 1 – Change in Natural Gas Consumption

Figure 24 shows the change in final energy consumption by sector. Implementing Best Practices reduces electricity demand for residential lighting and cooling, agriculture irrigation, and industrial processes, along with biomass for cooking and gasoline for cars.

Finding more domestic gas reserves allows expanded direct consumption, including for captive power, and fuel switching from oil products.

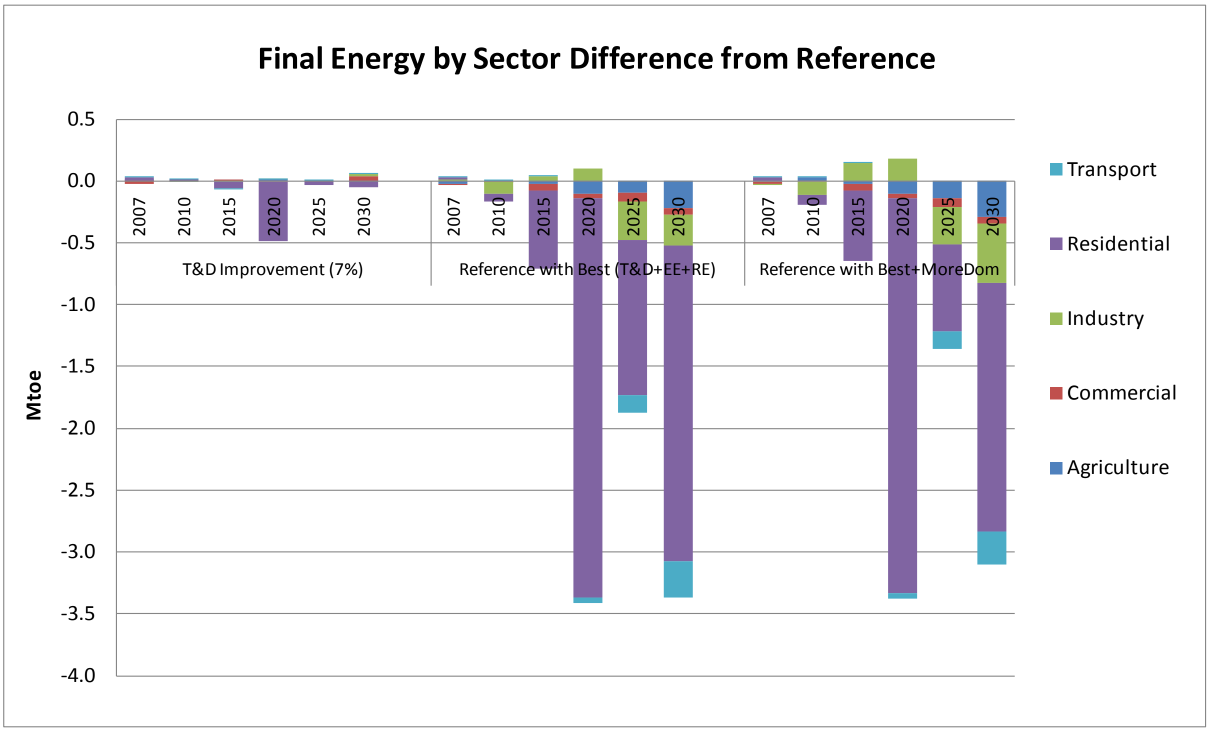

Figure 24: Storyline 1 – Change in Final Energy by Sector

Table 6 provides the summary metrics for Storyline 1, implementing best practices. These metrics are aggregate measures of the changes in each scenario relative to the Reference case. Specifically, energy efficiency and developing more domestic gas provide the biggest potential for driving the economy by reducing expenditures on the energy system by about $15 billion each (in aggregate between 2007 and 2030). Energy efficiency measures reduce fuel expenditures (as shown by the metric *Fuel Supply)* and investments in electricity generation (as shown by the metric *PP Builds).* Developing more domestic gas lowers imports, which are more expensive than domestic resources.

Pakistan will benefit on the energy security and environmental front as well. For example, imports and cumulative CO_2 emissions each are around 7% lower than observed in the Reference Scenario.

Table 6: Storyline 1: Pursue Best Practices – Summary Metrics with No CO_2 Tax

Scenario	System Cost		PP Builds		Fuel Supply		Imports		Final Consumption		CO2 Emissions	
	M$07	% Diff	GW	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mt	% Diff
Reference	1,002,569		135		5,933		2,290		3,899		12,099	
T&D Improvement (7%)	-2,648	-0.26%	0.88	0.65%	-23	-0.39%	4	0.16%	0	0.00%	-145	-1.21%
T&D Improve (7%) & Efficiency (50%)	-17,366	-1.73%	-12.90	-9.57%	-318	-5.36%	-40	-1.75%	-144	-3.68%	-854	-7.06%
Reference with Best (T&D+EE+RE)	-17,610	-1.76%	-7.05	-5.23%	-310	-5.22%	-38	-1.67%	-145	-3.73%	-894	-7.40%
Reference with Best+MoreDom	-33,653	-3.36%	-7.56	-5.61%	-311	-5.25%	-157	-6.86%	-137	-3.52%	-922	-7.62%

2. Storyline 1a - Pursue Best Practices in a CO_2 Limited World

A CO_2 tax was added to the Pursue Best Practices storyline to assess how the results might be influenced by the adoption of a CO_2 mitigation policy. A world price for carbon of 20$/t in 2020 and $30/t in 2030 on all energy sector CO_2 emissions was introduced. This has the effect of identifying where in the Pakistan energy system can reduce CO_2 for that price or less, and thereby indicate candidates for carbon financing.

Figure 25 shows that the impact of a CO_2 tax is about $70 billion, but implementing the Best Practices plus exploiting domestic gas reserves could reduce this impact in half – to only $36 billion, where the 2.5 billion tons abated could generate $50-60 billion for investment in the energy sector.

It is worth noting that the modeling does not take explicit account of the revenues generated by the tax. If these were recycled back into the energy system, for example through provision of renewable energy incentives, the additional costs due to the tax policy would be significantly lower.

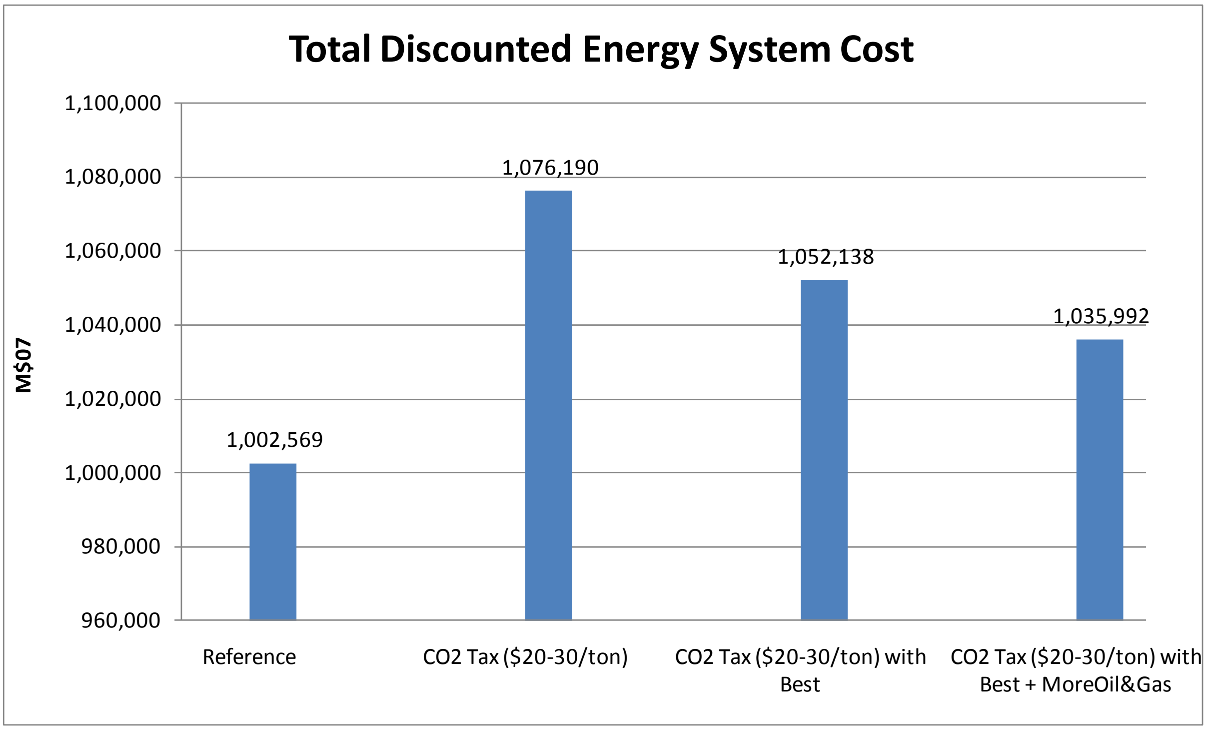

Figure 25: Storyline 1a – Best Practices with a CO_2 Tax

Figure 26 provides a breakdown of the change in energy system investments compared to the Reference scenario. It shows that a CO_2 tax alone increases investment mostly in more expensive clean power plants, while a CO_2 tax with the implementation of Best Practices also encourages efficient end-use device purchases. Finding more domestic gas reserves slightly reduces power plant investments due to increased direct consumption.

The change in power generation by power plant type is provided in Figure 27. The CO_2 tax alone increases both nuclear power and renewables to replace coal generation. Build limits on feasible additional nuclear capacity are reached, as is already the case with hydro. Implementing Best Practices with a CO_2 tax incentivizes the uptake of more renewable energy, which also reaches the upper bound of the build limits in an effort to further reduce coal use. In the more domestic gas reserves case, the additional gas is used to further reduce coal-fired power generation.

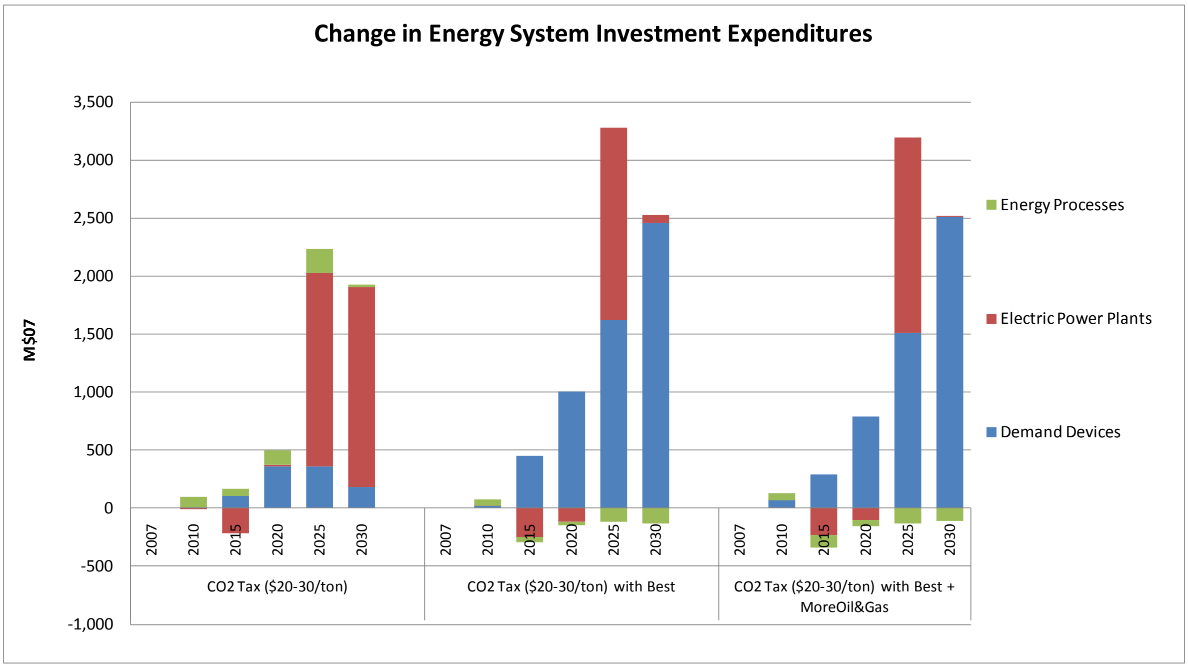

Figure 26: Storyline 1a – Change in Energy System Investments with a CO_2 Tax

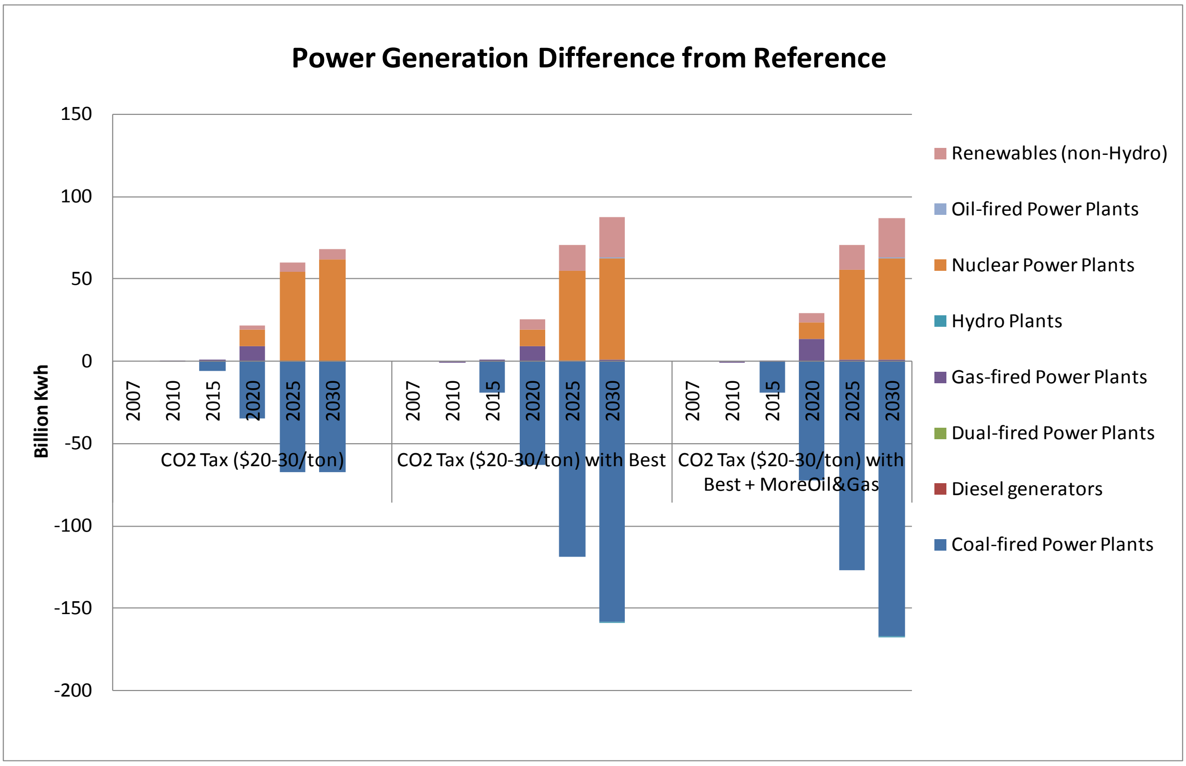

Figure 27: Storyline 1a – Power Plant Generation by Fuel Group with a CO_2 Tax

A lower carbon power sector presents some interesting trade-offs between investment choices. Implementing a domestic carbon tax disincentivizes coal plant investment, potentially reducing the ability of the power sector to deliver more affordable electricity. The opportunities to use international carbon finance to subsidize these more costly generation investments will be important to explore.

Figure 28 shows the change in final energy consumption by sector. A CO_2 tax increases the use of commercial biomass fuels in the residential sector (assuming the biomass is sustainably sourced and therefore carbon neutral). This change in final energy use persists with the implementation of best practices, but the traditional biomass fuels are pushed out when more domestic gas is available. More gas is used directly, primarily by industry. More efficient devices and fuel switching reduce electricity consumption in all demand sectors.

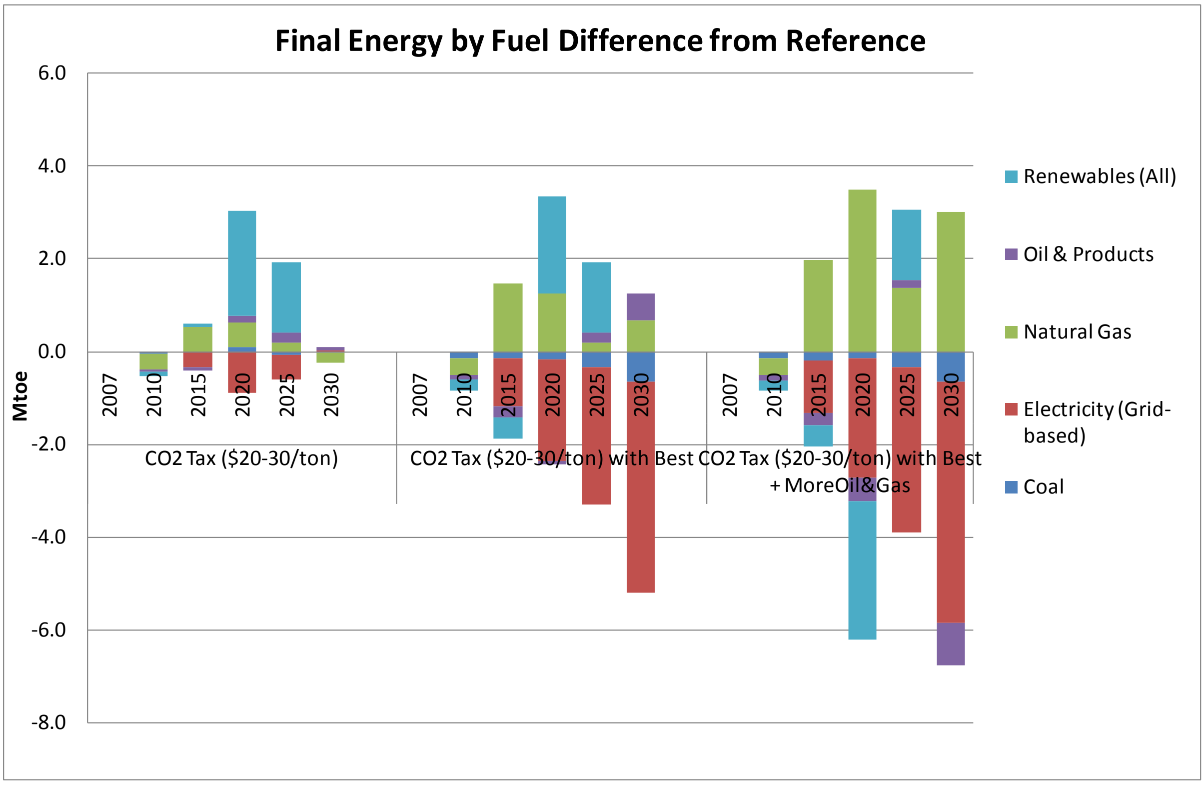

Figure 28: Storyline 1a – Change in Final Energy by Sector with a CO_2 Tax

Figure 29 shows the overall CO_2 emission levels for this storyline. The CO_2 tax alone reduces emissions by about 50 Mt in 2030, and achieves an 11% reduction in cumulative emissions relative to the Reference case. Also implementing Best Practices reduces CO_2 emissions by about 117Mt in 2030, with cumulative emissions dropping a full 22% by 2030.

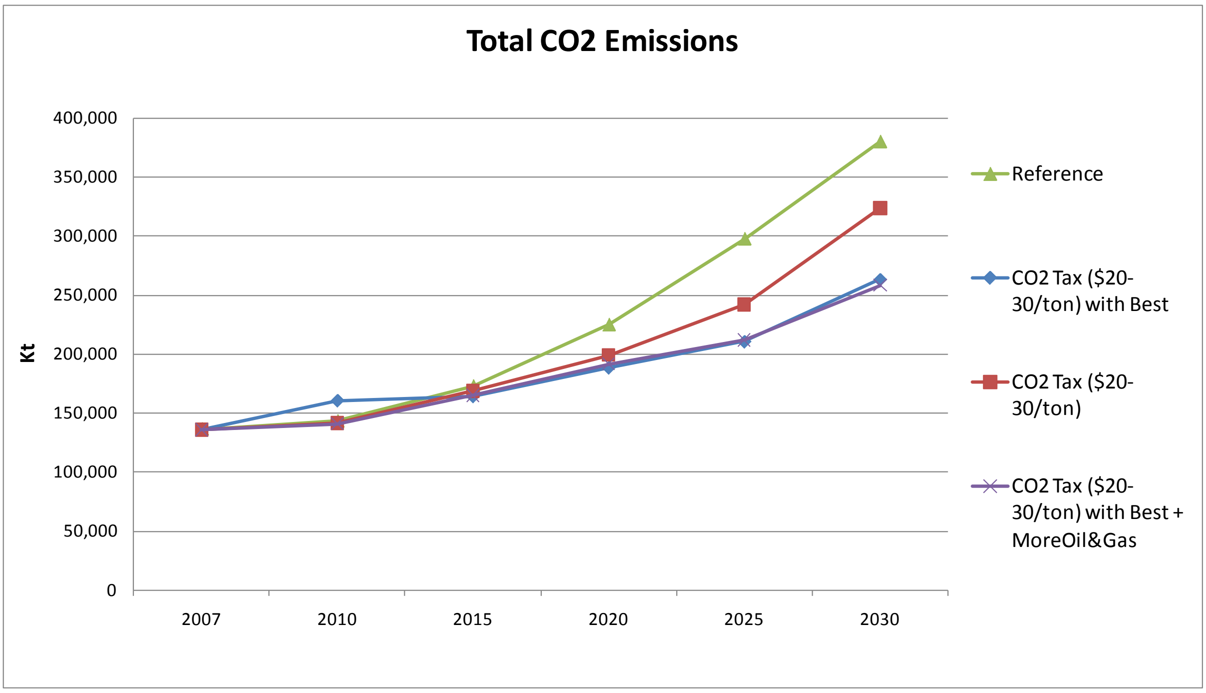

Figure 29: Storyline 1a – Change in CO_2 Emissions with a CO_2 Tax

Table 7 provides the summary metrics for Storyline 1a, implementing Best Practices with a CO_2 tax. CO_2 mitigation is not cheap; however, if the tax level was considered as a proxy for the finance that could be generated through carbon reduction credits on the international market (e.g. through CDM), at $20-30/ton, the 2.5 billion tons abated could generate $50-60 billion for investment in the energy sector.

The main structural change arising from a CO_2 tax occurs in the power sector where coal is replaced by nuclear and renewables, and the resulting higher electricity prices lead to more direct use of gas. From a policy perspective, the affordability of electricity would be a key issue to further consider, ensuring that negative impacts are not experienced by lower income groups.

Table 7: Storyline 1a: Pursue Best Practices – Summary Metrics with a CO_2 Tax

Scenario	System Cost		PP Builds		Fuel Supply		Imports		Final Consumption		CO2 Emissions	
	M$07	% Diff	GW	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mt	% Diff
Reference	1,002,569		135		5,933		2,290		3,899		12,099	
CO2 Tax ($20-30/ton)	73,622	7.34%	1.53	1.14%	61	1.03%	17	0.76%	25	0.65%	-1,312	-10.84%
CO2 Tax ($20-30/ton) with Best	49,569	4.94%	-6.23	-4.62%	-186	-3.14%	-34	-1.51%	-119	-3.05%	-2,676	-22.12%
CO2 Tax ($20-30/ton) with Best + MoreOil&Gas	33,423	3.33%	-6.37	-4.73%	-214	-3.60%	-154	-6.73%	-148	-3.79%	-2,772	-22.91%

3. Storyline 2 – Challenges Persist

The starting point for Storyline 2 is the Reference scenario, where the demand growth (5.6%) is achieved, but the underlying premise is that supply and power sector investments are not achieved. This storyline incrementally examines possible impacts if this lack of investment occurs, resulting in:

- Delay of Hydro and Nuclear investments by 5 years and No Thar Coal
- No Imported Coal port facilities and power plants
- No Imported Natural gas

The storyline was further elaborated to incrementally examine the introduction of Best Practice energy policies and More Domestic Gas reserves.

Figure 30 shows the impact of no investment for Thar coal and delays to hydro and nuclear plants. The total discounted energy system cost increases by about $37 billion, and the model compensates by importing coal for power plants. If we then restrict imported coal for power plants, the energy system cost increases another $2 billion. If we then try to restrict natural gas imports, the model can find no feasible solution. This analysis shows that failure to invest in indigenous resources could significantly increase costs in the longer term, due to higher import dependency. However, implementing Best Practices plus More Gas reduces the system cost by $12 billion below the Reference case. Interestingly, that amount is $21 billion above the Best Practices and More Gas case without delay (see the far right bar in Figure 19), indicating the value of those policies even in the event of delays to major power sector investments.

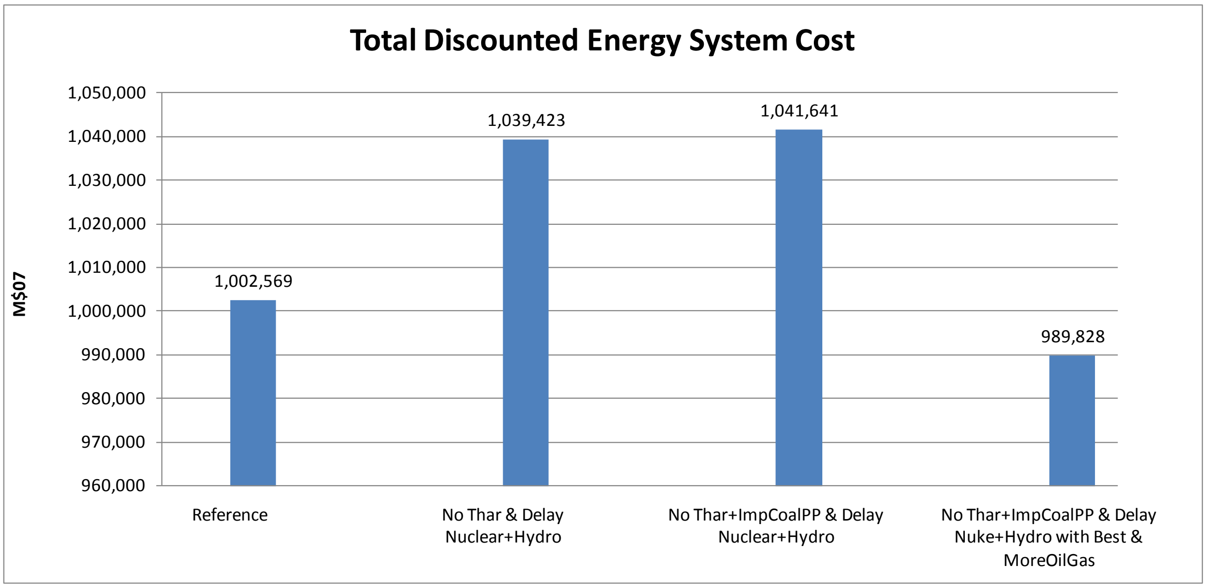

Figure 30: Storyline 2 – Challenges Persist

Figure 31 provides a breakdown of the change in annual energy system investments compared to the Reference scenario. It shows that not investing in Thar coal and delaying hydro and nuclear result primarily in higher fuel costs; first for imported coal then for imported gas. Implementing Best Practice and finding More Gas reserves counters the higher fuel costs with lower fuel consumption resulting in lower fuel expenditures.

When hydro and nuclear are delayed, hydro still rises to its build rate but with less new capacity able to be installed due to the delay. Therefore, increased investment in nuclear and renewables is required in later periods to reach the needed generating capacity.

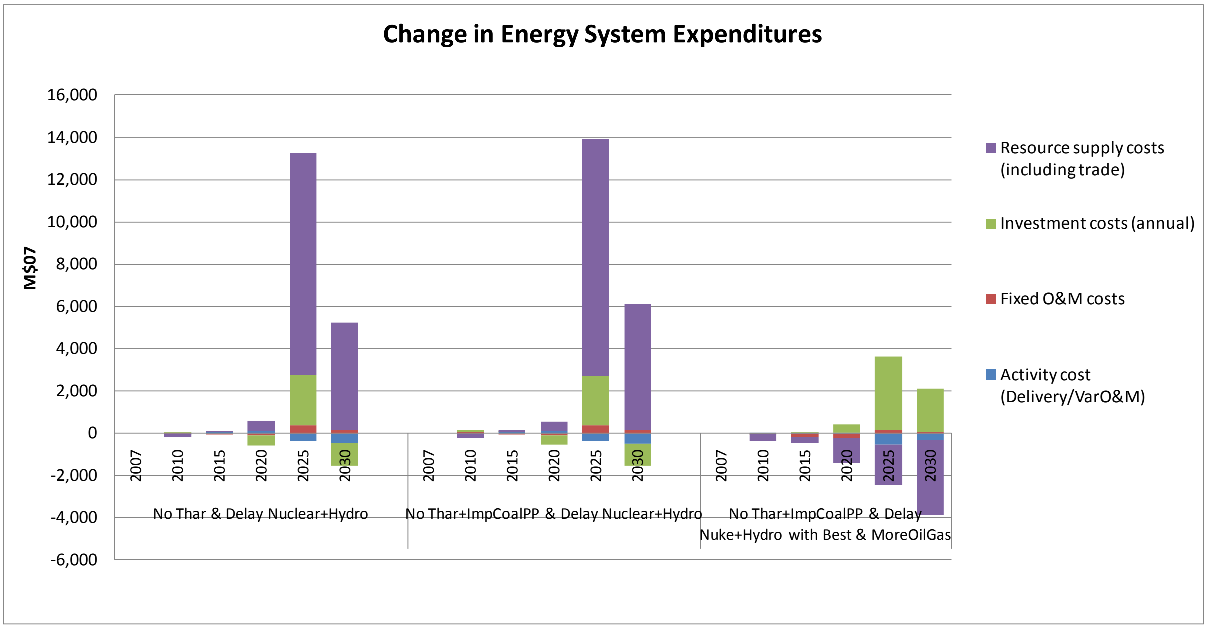

Figure 31: Storyline 2 – Change in Energy System Investments

Figure 32 shows the changes in imports when delays in new capacity additions occur. The main change is that gas imports start in 2025 rather than 2030, and at a significantly higher level. With No Thar coal and delayed hydro and nuclear, imported coal is used, and if that is deferred, then additional gas is imported. Implementing Best Practices and finding More Gas reserves reduces the need for the gas imports.

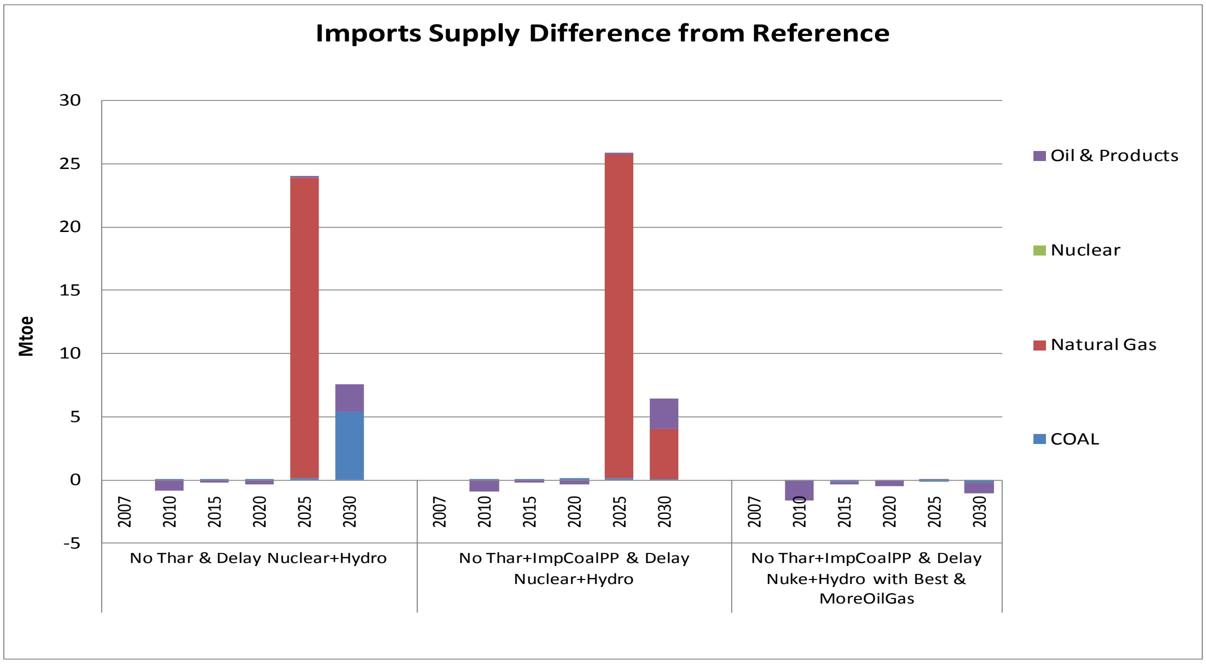

Figure 32: Storyline 2 – Change in Energy Imports

The power generation by power plant type is shown in Figure 33. No investment in Thar coal increases the need for nuclear power. Although its start is delayed to 2020, capacity grows faster from that time relative to the Reference case. Note that there is a reduction in total electricity generation, resulting from efficiency improvements and fuel switching (from electricity). Best Practices and More Gas further reduce the total electricity generation through investments in efficiency.

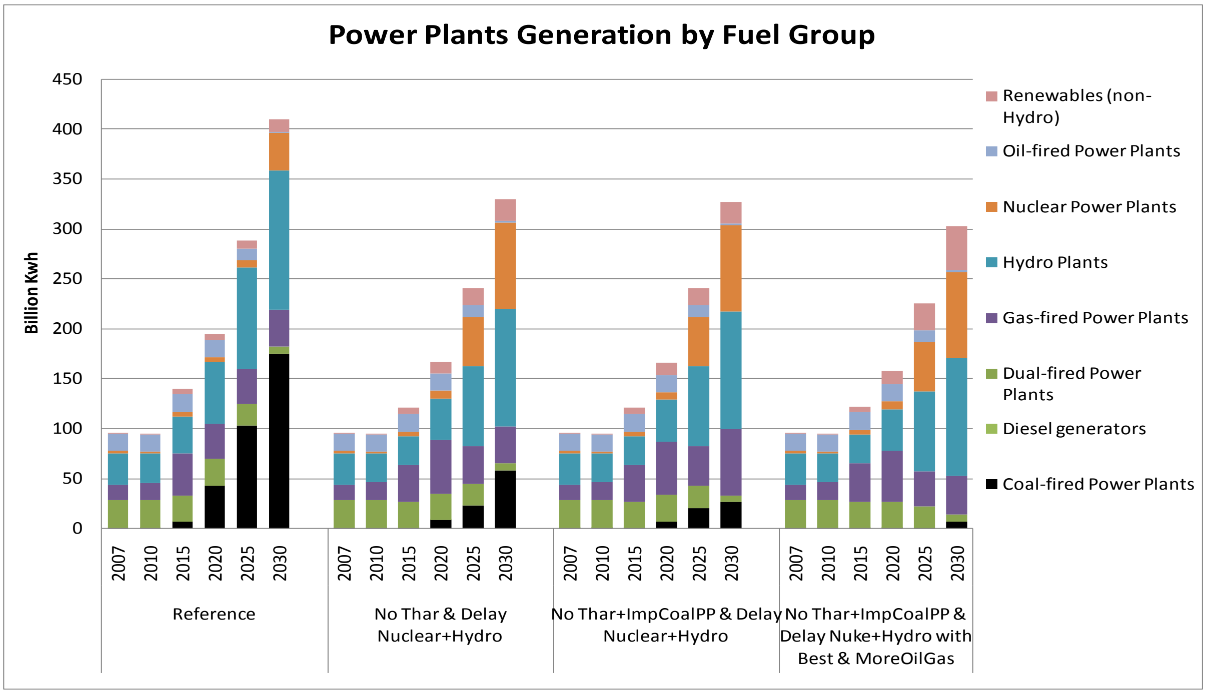

Figure 33: Storyline 2 – Power Plant Generation by Fuel Group

Figure 34 shows the change in final energy consumption by sector. With No Thar coal and delayed hydro and nuclear, electricity consumption is displaced by natural gas, biomass and oil products in the residential and industry sectors since the price of electricity rises. With Best Practice and More Gas, there is less demand for additional biomass and oil products.

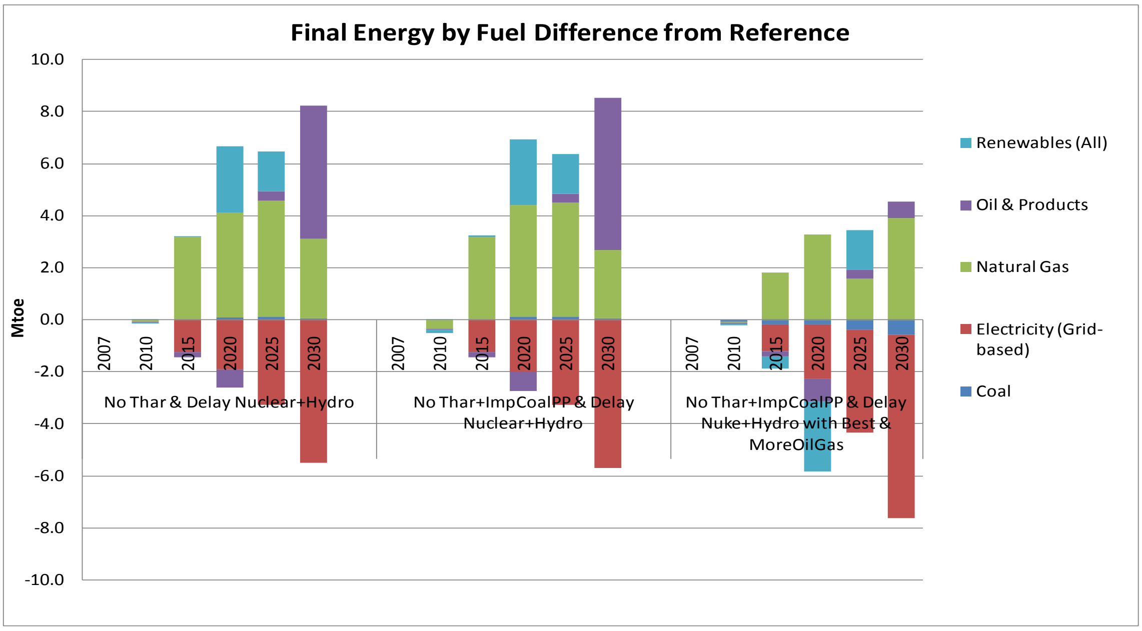

Figure 34: Storyline 2 – Change in Final Energy by Sector

Figure 35 shows the overall CO_2 emission levels for this storyline. Not building any Thar coal power plants results in a reduction of 80 million tons of CO_2 emissions in 2030, which is more than 20% of annual emissions in that year. No Thar coal reduces cumulative CO_2 emissions between 2010 and 2030 by 12%, which is a total reduction of over 1.4 billion tons relative to the Reference case. The implementation of Best Practices and finding More Gas reserves reduces emissions by another 42 million tons in 2030, which on a cumulative basis gives an overall reduction of 26%, or 3.2 billion tons of CO_2.

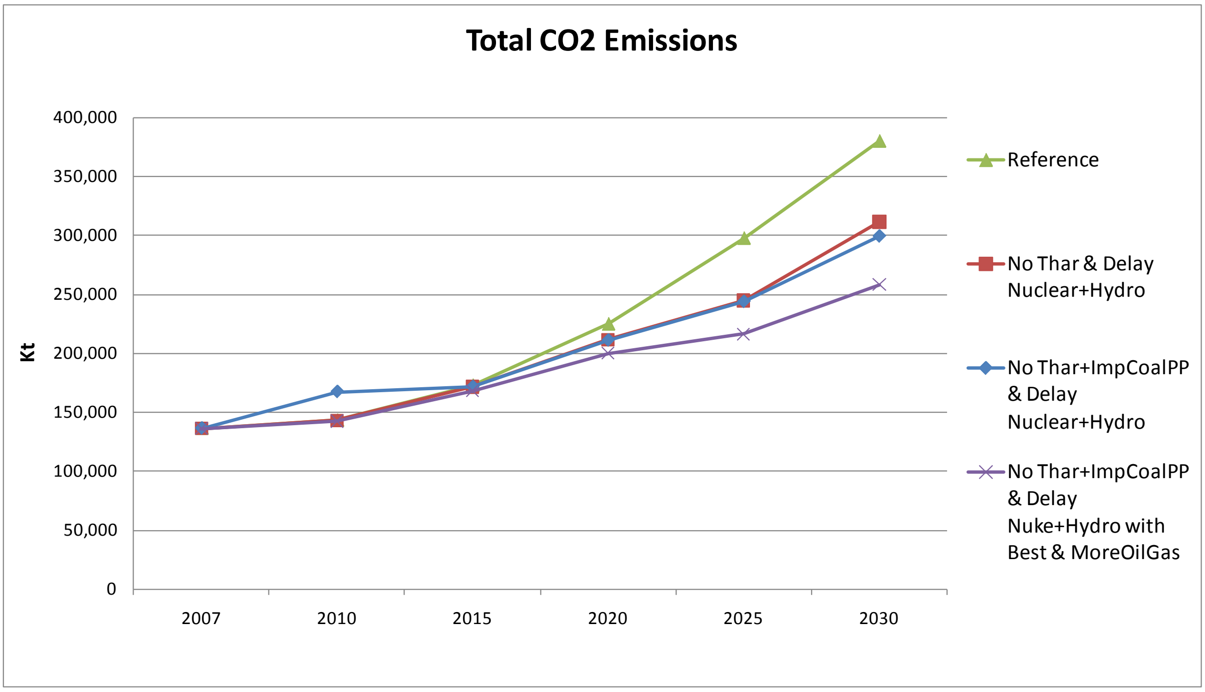

Figure 35: Storyline 2 – CO_2 Emissions

Table 8 provides the summary metrics for Storyline 2, Challenges Persist. It shows that the cost of inaction is significant, but it can be mitigated by policies that focus on efficiency, renewables, and expanded gas supply. Thus, policy makers have a crucial role in ensuring that the power sector is structured so that investments aren't delayed and investors can take long-term decisions (on whether to develop Thar coal, for example.) Without this, costs are going to rise, impacting on the ability of the system to deliver reliable and affordable energy services. As highlighted, these risks can be somewhat mitigated by moving towards best practice, and potentially through offsetting some of the additional costs through carbon finance.

Table 8: Storyline 2: Challenges Persist – Summary Metrics

Scenario	System Cost		PP Builds		Fuel Supply		Imports		Final Consumption		CO2 Emissions	
	M$07	% Diff	GW	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mtoe	% Diff	Mt	% Diff
Reference	1,002,569		135		5,933		2,290		3,899		12,099	
No Thar & Delay Nuclear+Hydro	36,855	3.68%	9.76	7.25%	-74	-1.25%	486	21.22%	72	1.84%	-1,442	-11.92%
No Thar+ImpCoalPP & Delay Nuclear+Hydro	39,072	3.90%	-25.21	-18.71%	-195	-3.29%	367	16.02%	104	2.67%	-2,156	-17.83%
No Thar+ImpCoalPP & Delay Nuke+Hydro with Best & MoreOilGas	-12,741	-1.27%	-11.43	-8.49%	-322	-5.43%	31	1.37%	-111	-2.85%	-3,141	-25.96%

APPENDIX A: REFERENCE SCENARIO SECTOR-LEVEL DETAILS

This Appendix reports on the development of the various sectors of the energy economy under the Reference Scenario assumptions of 5.6% average GDP growth.

A. Agricultural Energy Consumption

The Agriculture sector accounted for about 6% of total final energy in 2007 and drops to about 5% in 2030. Figure 36 shows that final energy consumption in the Agricultural sector grows by about 30%, resulting from more consumption of diesel due to increased tractor use. Figure 37 shows that electricity use in the Agricultural sector almost doubles due to the increasing electrification of water pumping.

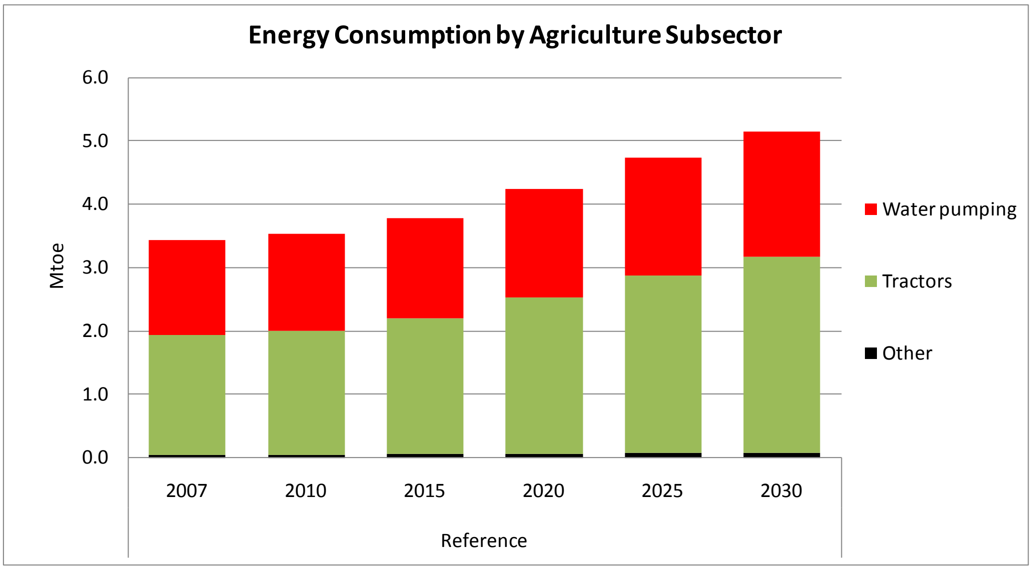

Figure 36: Agricultural Energy Consumption by Subsector

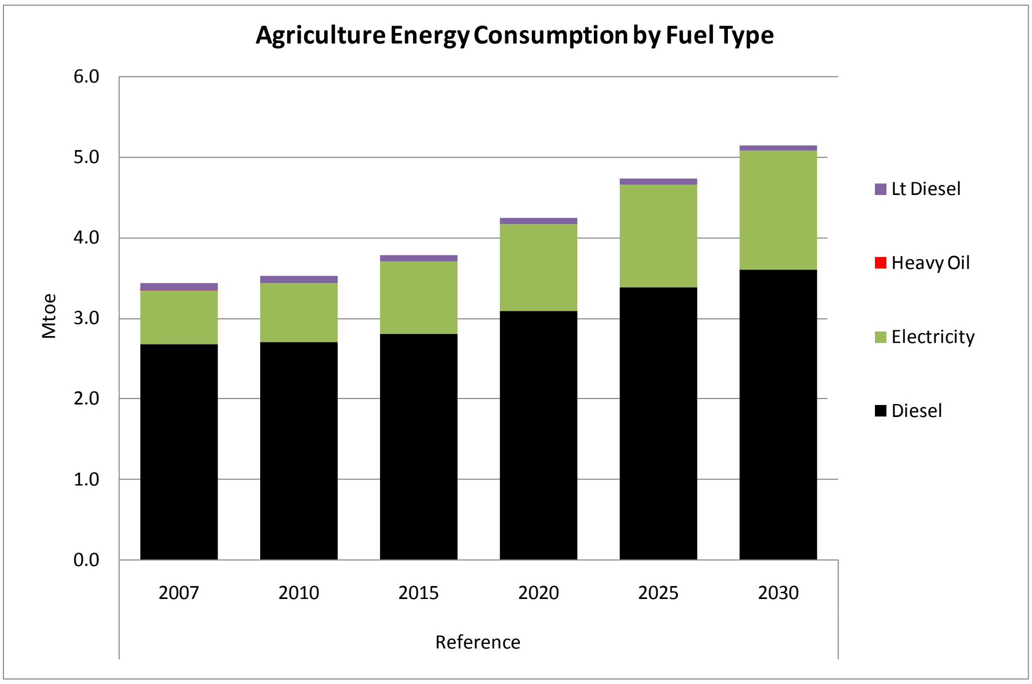

Figure 37: Agricultural Energy Consumption by Fuel Type

B. Commercial & Government Energy Consumption

The Commercial sector accounted for about 4% of total final energy in 2007 and remains at about 4% in 2030. Figure 38 shows that the Commercial sector energy use more than doubles, due largely to the growth in demand for cooking, air conditioning and other electric appliances, and the "other" category, which is largely military use and government.

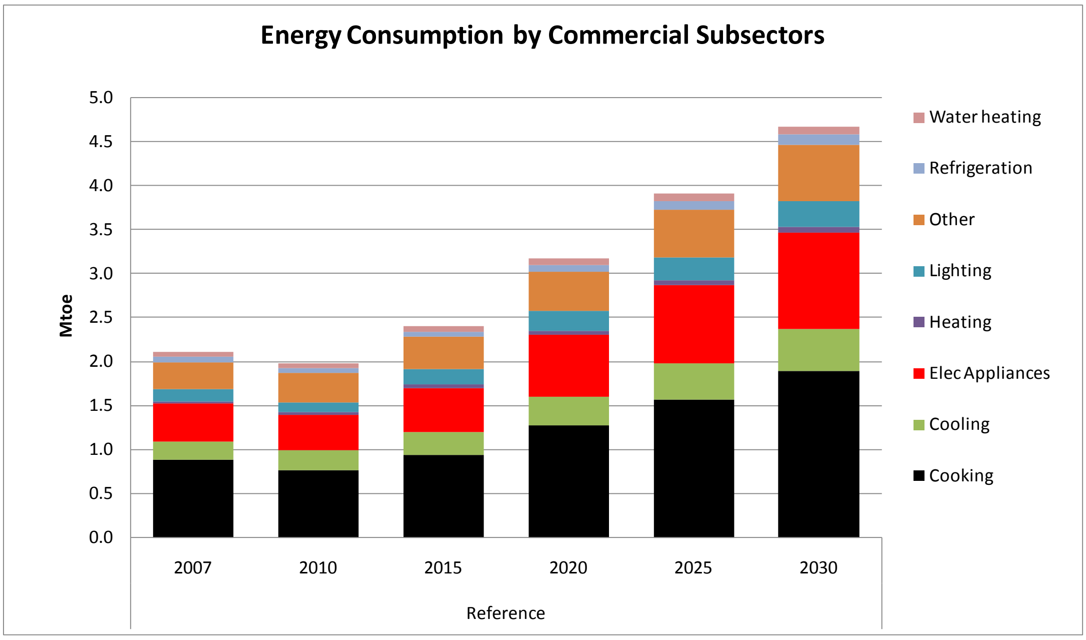

Figure 38: Commercial Energy Consumption by Subsector

Figure 39 shows that electricity consumption triples due to air conditioning and appliance demands, and that the growth in natural gas is primarily driven by the demand for commercial cooking and government buildings. LPG use increases in 2020 as natural gas supply is limited.

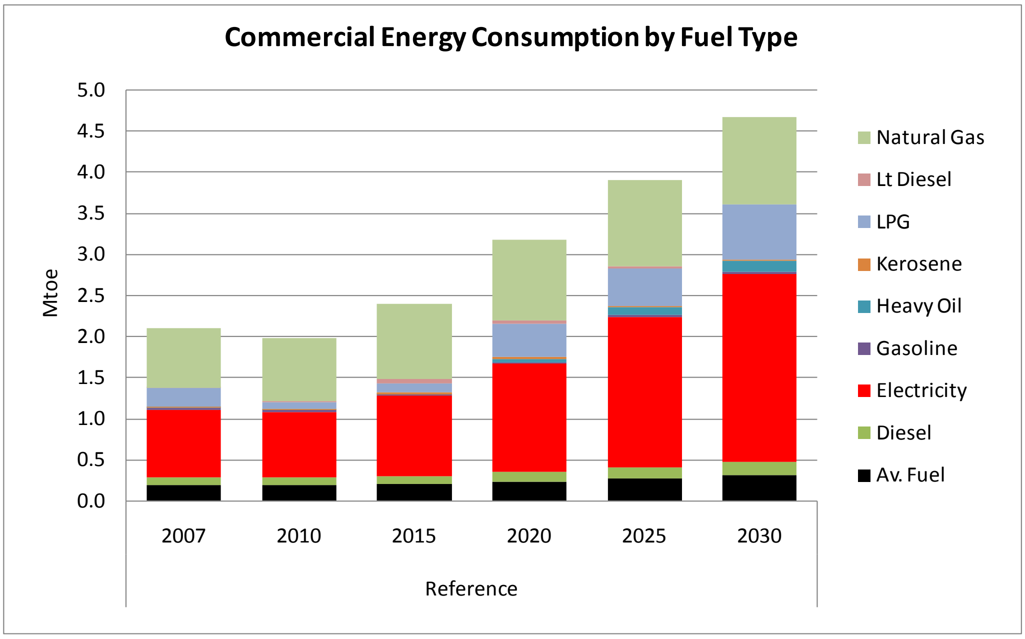

Figure 39: Commercial Energy Consumption by Fuel Type

C. Industrial Energy Consumption

The industry sector accounted for about 36% of total final energy in 2007 and increases to 43% in 2030. Figure 40 shows that overall industrial energy use grows by a factor of three with the most significant growth in the cement, textiles and light manufacturing (other) subsectors.

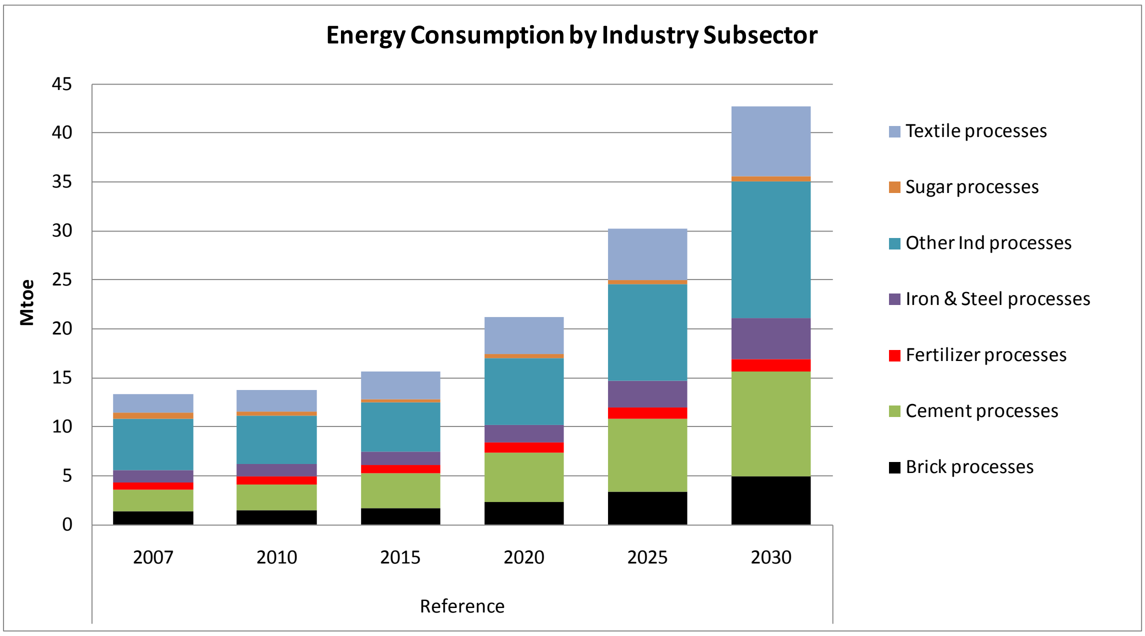

Figure 40: Industrial Energy Consumption by Subsector

Figure 41 shows that electricity and coal (domestic and imported) show the most growth in meeting industrial energy use. The electricity use is driven by growth in the textiles and other industry subsectors, while coal use is driven by growth in cement and brick kilns.

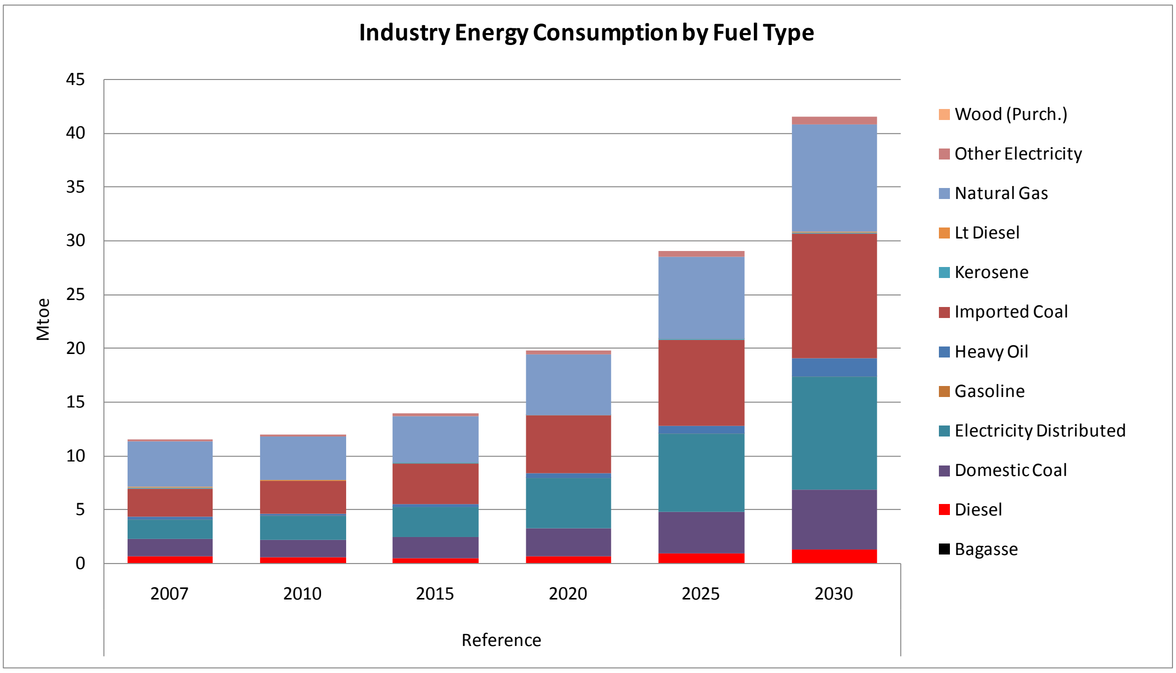

Figure 41: Industrial Energy Consumption by Fuel Type

D. Residential Energy Consumption

As a whole, the Residential sector accounted for about 40% of total final energy in 2007 and drops to 32% in 2030, in part because the growth in urban sector is offset by the lack of growth in the rural sector. Urban and Rural households are modeled as independent demands with distinct growth rates, available fuels and end-use device options.

1. Urban Residential Energy Use

Figure 42 shows that urban household energy use increases by a factor of two, with most growth coming from increased demand for air conditioning, cooking, and water heating. This is due both to the growing urban population but also the increased consumption per household, as incomes rise.

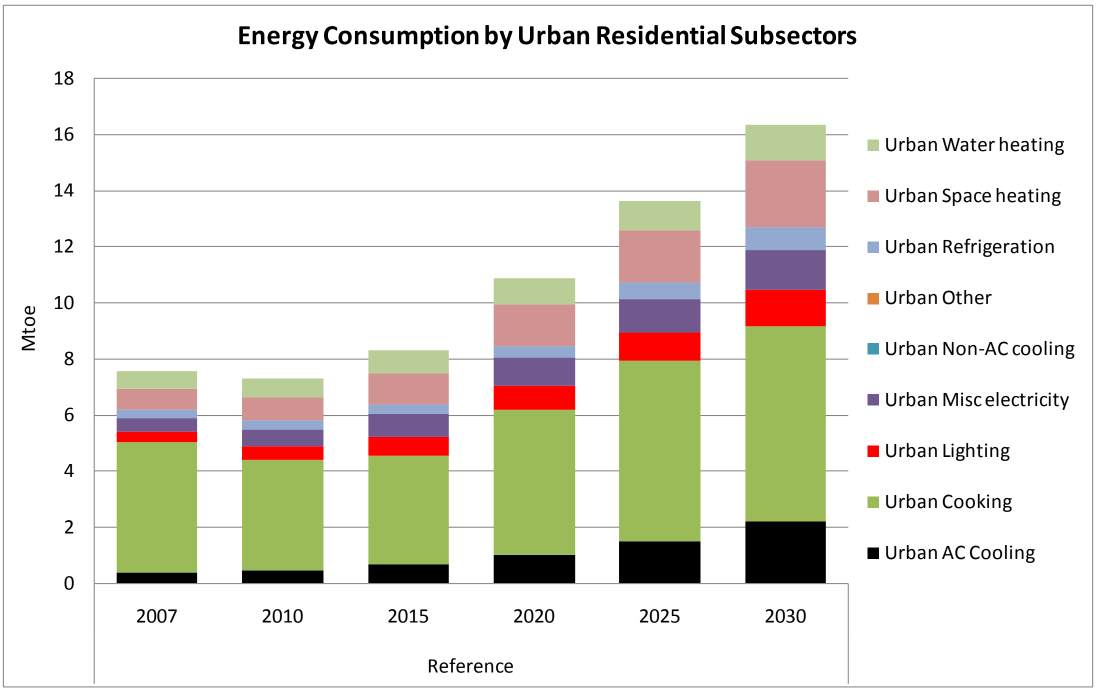

Figure 42: Urban Residential Energy Consumption by Subsector

Figure 43 shows that the growth in urban household energy use is provided primarily by electricity followed by natural gas. In 2030 there is a greater shift to electricity use as the natural gas supply switches to more expensive pipeline and LNG imports.

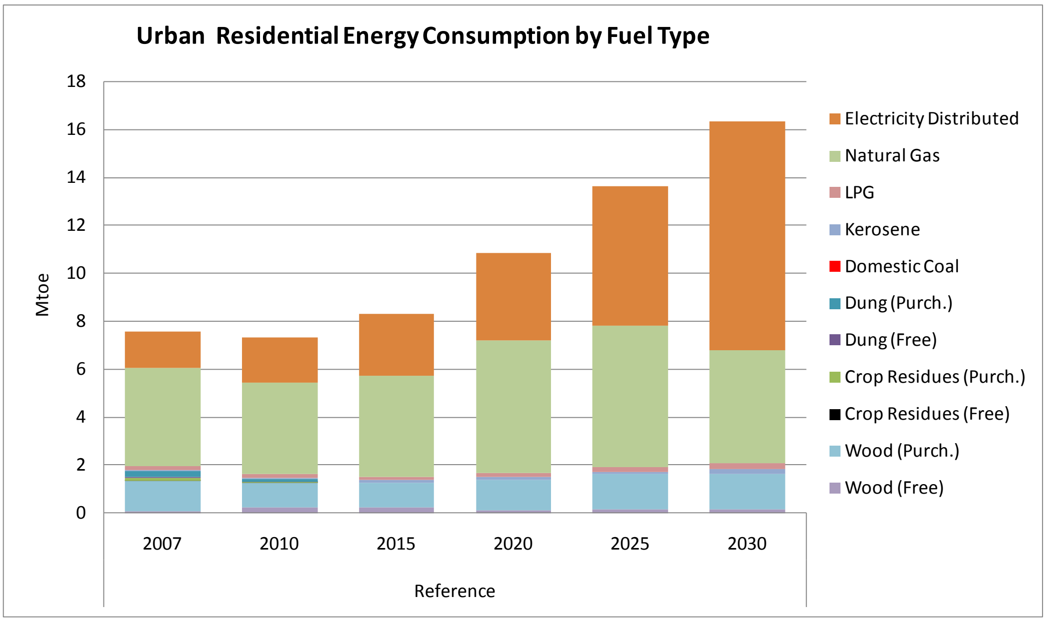

Figure 43: Urban Residential Energy Consumption by Fuel Type

2. Rural Residential Energy Consumption

Figure 44 shows that rural household energy grows by only 30% and is dominated by the demand for cooking. This low growth in energy use is because of the modest growth in the number of rural households and the adoption of more efficient cook stoves.

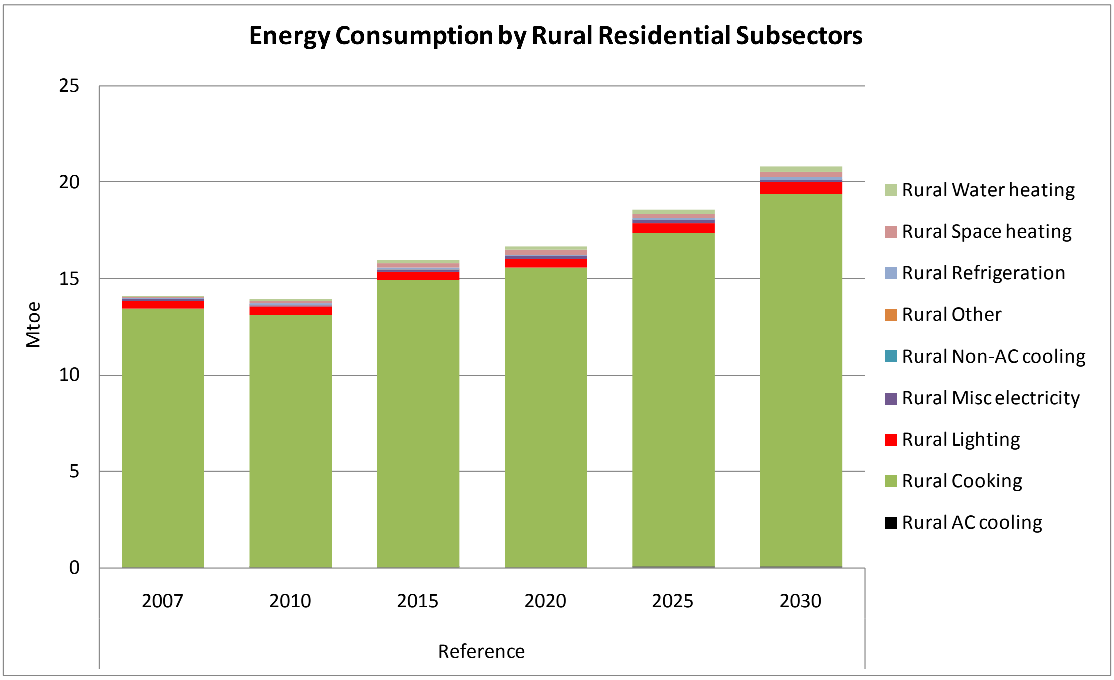

Figure 44: Rural Residential Energy Consumption by Subsector

Figure 45 shows that the pattern of rural fuels use is dominated by biomass fuels – both self-gathered (free) and purchased. Purchased biomass and LPG provide most of the growth in energy use in rural households.

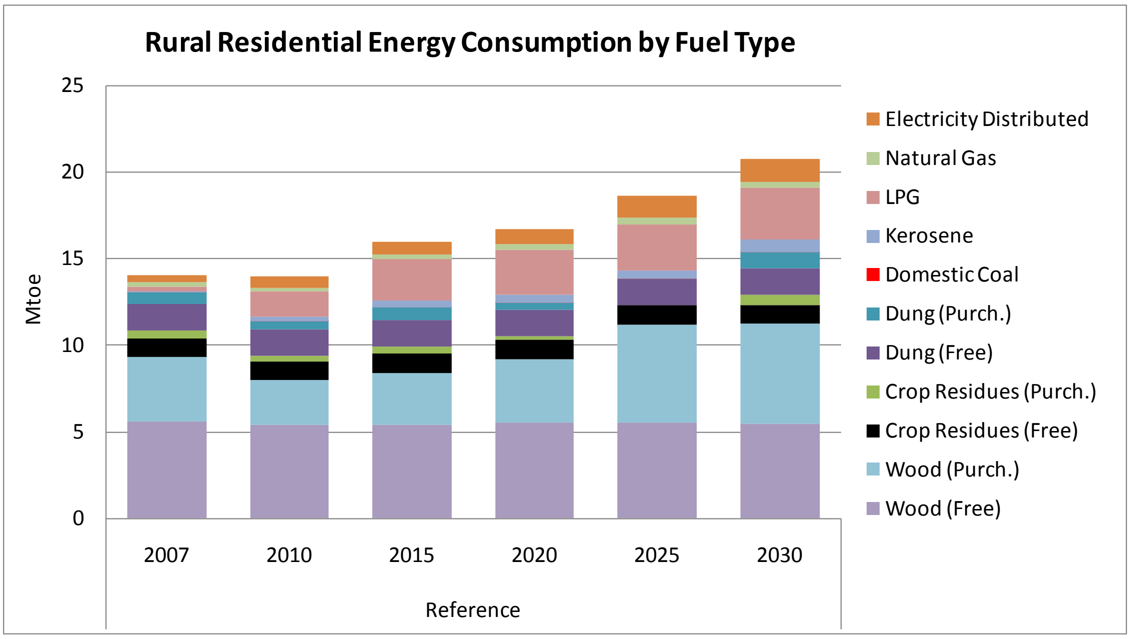

Figure 45: Rural Residential Energy Consumption by Fuel Type

E. Transportation Energy Consumption

Figure 46 shows that total fuel consumption for all modes of transport increases by a factor of 2.5 by 2030. The most significant growth is in gasoline consumption, followed by diesel, which is used primarily for road freight and rail transport.

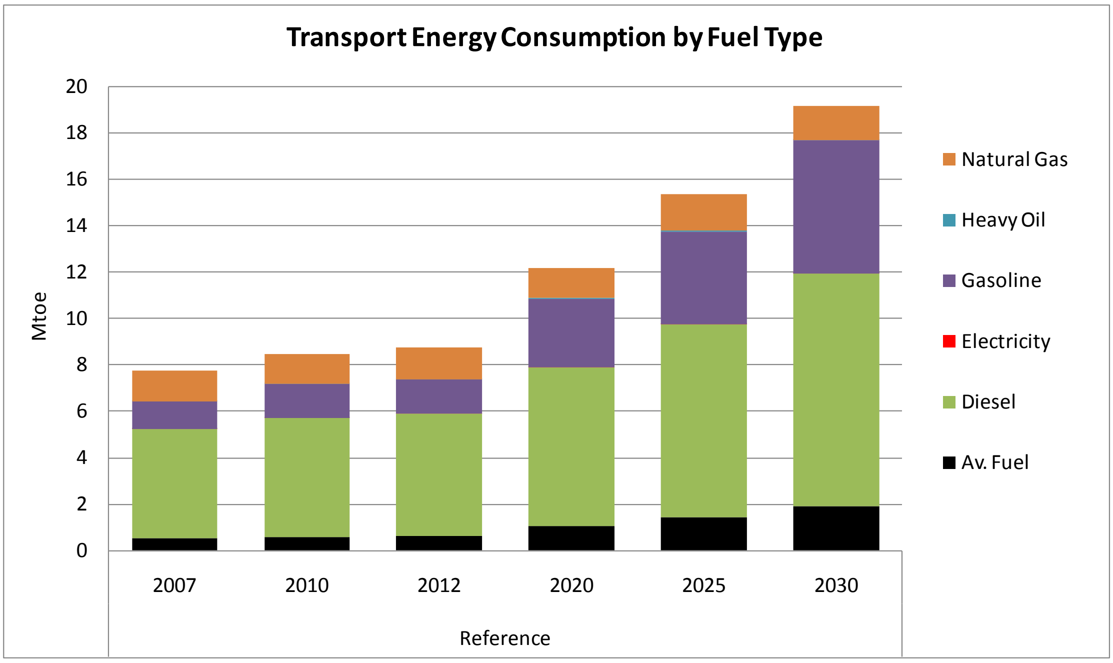

Figure 46: Transport Energy Consumption by Fuel Type

Figure 47 focuses on road transport, showing that most of the increase in energy consumption is due to the significant growth in cars and road freight vehicles.

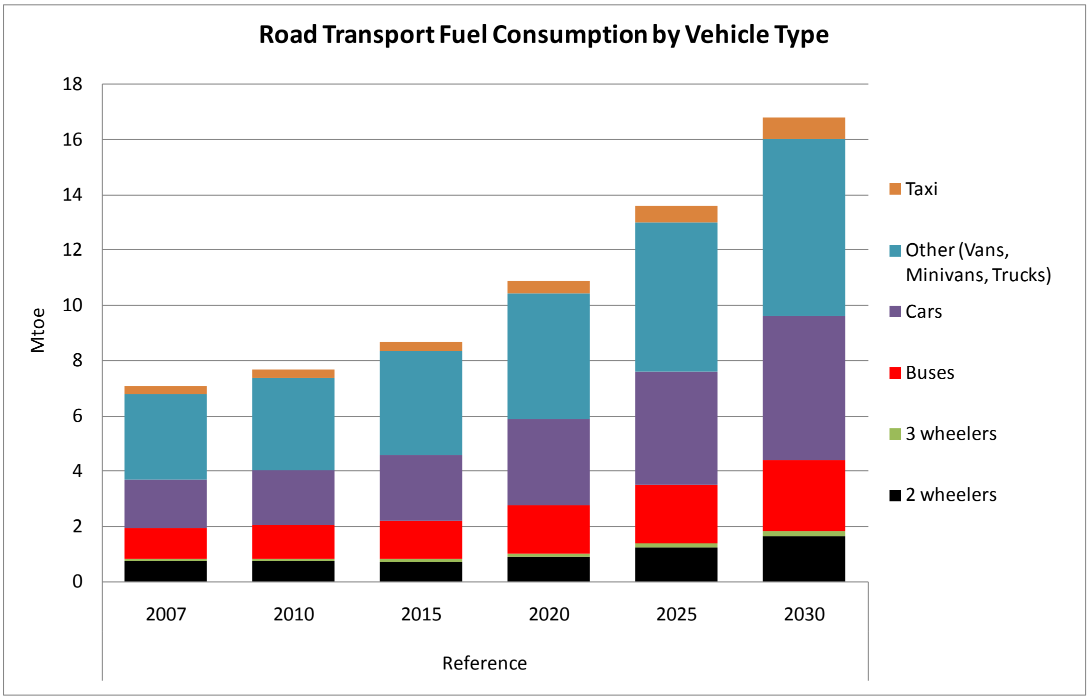

Figure 47: Road Transport Energy Consumption by Vehicle Type

APPENDIX B: INTERIM REPORT SCENARIO ANALYSES RESULTS

The scenarios described in Table 9 were fashioned after the set of priority policy issues identified by the Advisory Committee Task Force. These initial scenarios were also developed to illustrate the power and flexibility of the models. They are organized into five groups:

Group 1: Economic Activity, which includes medium and lower GDP growth and sector prices

Group 2: Energy Prices and Security, which includes reduced imports

Group 3: Delay Power Projects, which delays hydro and nuclear additions eliminates Thar coal as an option

Group 4: Increase Power Plant Costs, which increases the investment costs for hydro, nuclear and Thar coal

Group 5: Reserves and Environmental, which includes increased oil and gas reserves, a renewable electricity requirement, and a carbon tax

Table 9: Scenario Definitions and Groups

Scenario	Analysis Group	Description
Reference	All Groups	5.6% Overall GDP Growth 2007 to 2030
Medium Demand	G1: Economic Activity [Medium and Lower GDP Growth and Sector Prices]	5.0% Overall GDP Growth 2007 to 2030
Lower Demand		4.2% Overall GDP Growth 2007 to 2030
Sector Prices		Include fuel taxes and distribution charges
Low Energy Price	G2: Energy Prices and Security [Reduced Imports]	Decrease oil by $10/bbl in 2020 and $20/bbl in 2030
High Energy Price		Increase oil by $20/bbl in 2020 and $35/bbl in 2030
Reduced Imports		Limit imports to 25% of total primary supply
Hydro Delay	G3: Delay Power Projects [Hydro / Nuclear and No Thar Coal]	Delay Builds of new Hydro by 10yrs
Nuclear Delay		Delay Builds of new Nuclear by 10yrs
No Thar Coal		Prohibit the use of Thar coal
Hydro Cost	G4: Increase Power Plant Costs [Hydro / Nuclear / Thar Coal]	Increase Hydro Capital Cost by 10%
Nuclear Cost		Increase Nuclear Capital Cost by 10%
Thar Coal Cost		Increase Thar coal cost by 25%

Oil & Gas Reserve	G5: Reserves and Environmental [Oil & Gas Reserves / Renewable Electricity / Carbon Tax]	Increase Oil & Gas Cumulative Reserve by 20%
Renewables		Implement Renewable Electricity Target of 15%
CO2 Tax		Apply a tax of 20$/t in 2020 and $50/t in 2030

Each of these scenarios explores some adjustment to assumptions made in the Reference scenario. Their results, based on the analyses presented in the Interim Report, are presented in this Appendix. Quantitatively, these results are no longer consistent with the current Reference scenario, but the results are still qualitatively valid and are useful for illustrating the relative results of the scenario and sensitivity analyses.

A. Economic Activity [Group 1] Scenarios

Group 1 includes medium and lower energy demand scenarios, which are based in part on the medium and lower GDP growth projections. The sector prices scenario adds sector-based delivery mark-ups and taxes to the economic-based prices calculated in the model. Currently, these mark-ups and taxes distort the actual production price. However, for long-term energy planning it is important to fashion policy based upon “real” prices, and this sensitivity scenario shows how the imposition of the current mark-ups and taxes affects fuel choices and the system configuration.

The top part of Figure 48 shows the total discounted energy system cost for this group of scenarios, and the bottom portion shows the percentage change in the system cost relative to the Reference case. Economic growth directly impacts energy system requirements and costs, but not proportionally. The lower economic growth case has a 28% higher energy system cost per unit change in GDP compared to the medium GDP growth case. The addition of delivery mark-ups and taxes in the sector prices scenario can be seen to increase the energy system cost by 6%.

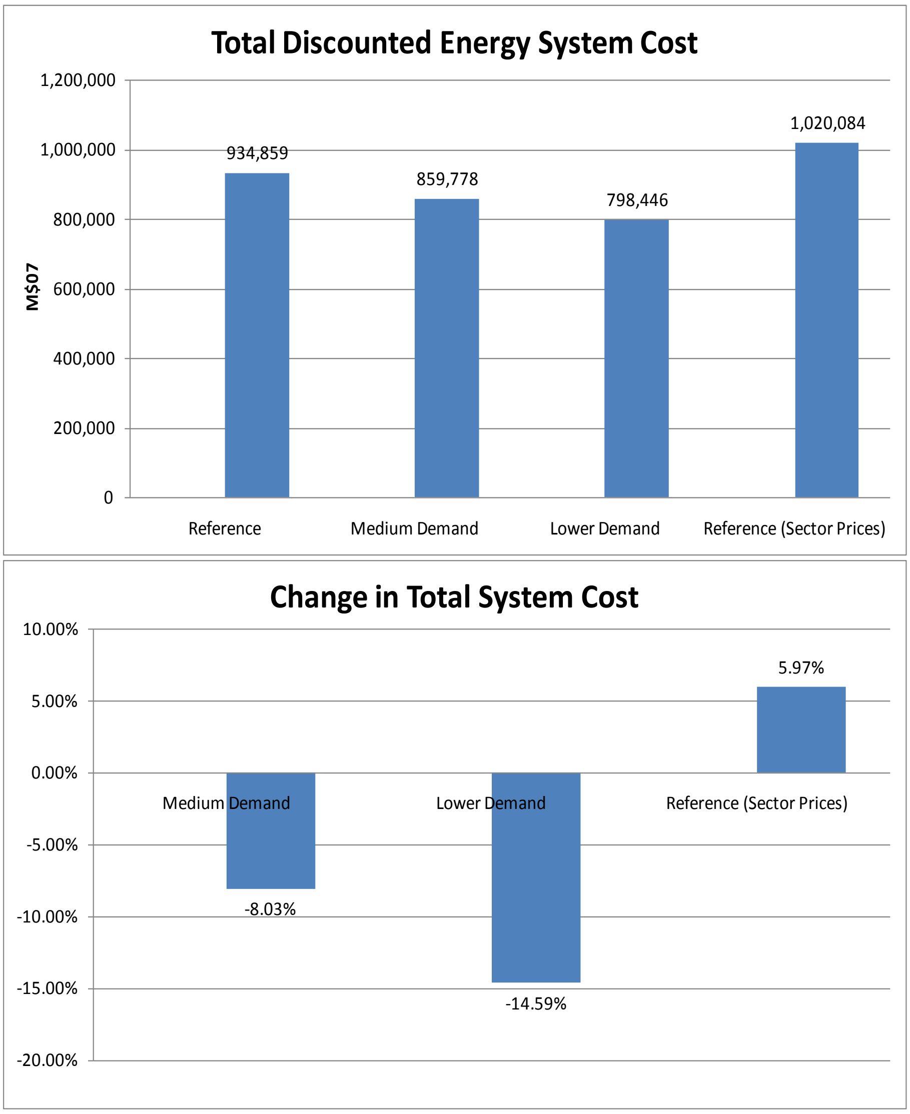

Figure 48: Energy System Cost – Group 1 Scenarios

Less economic growth will obviously require less expenditure on the energy system infrastructure, as can be seen in Figure 49 where the biggest reductions are in investment requirements, followed by fuel costs and O&M costs. Whereas the increased system cost in the sector prices scenario is almost entirely due to the additional fuel taxes and distribution charges, which produce a shift away towards more electricity and less direct use of natural gas and oil products by consumers.

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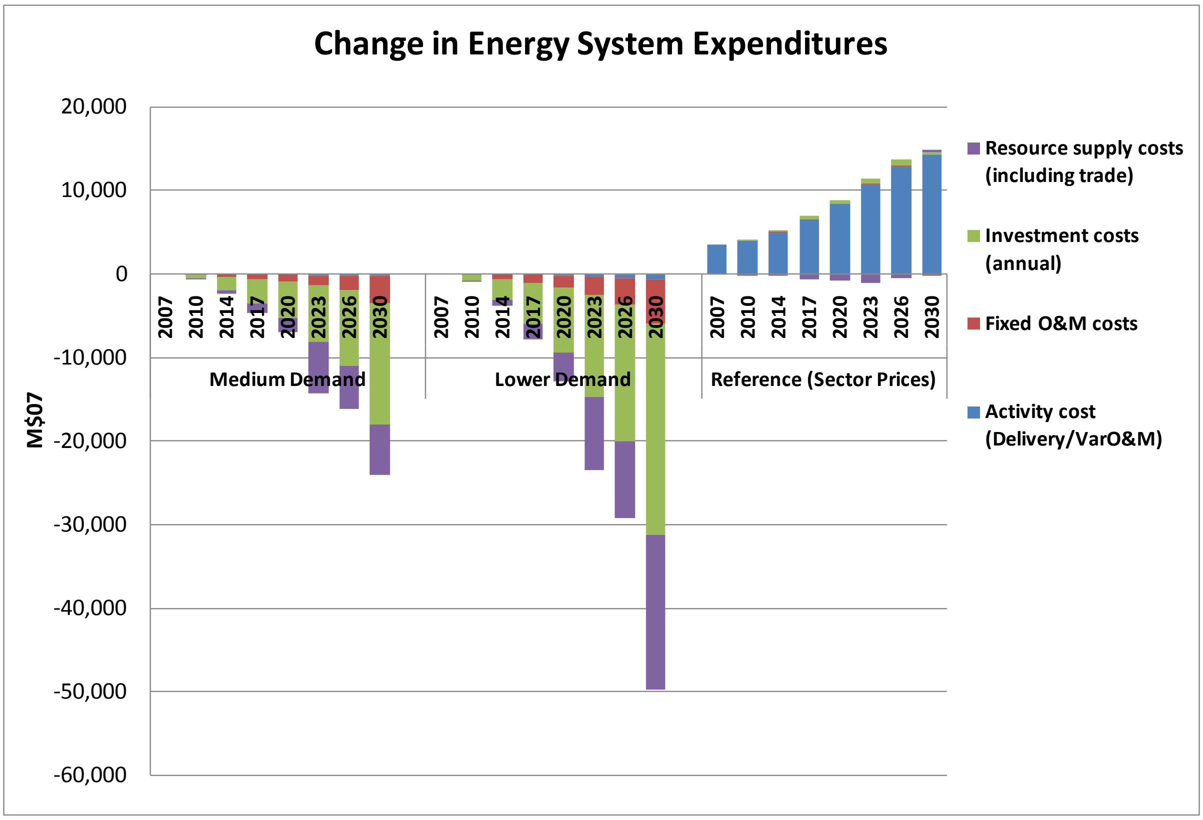


Figure 49: Annual Energy System Expenditures – Group 1 Scenarios

Figure 50 shows primary energy supply for the Group 1 scenarios. Hydropower supplies remain essentially the same even in the lower economic growth scenarios. In all these scenarios, hydropower is developed to the upper limit of its build rate because of its economic attractiveness, as the impoundment portion of the investment cost is allocated to agricultural irrigation needs. Other forms of primary energy decrease, except for the non-hydro renewables.

The change in primary energy use (see Figure 51) shows the significant decrease in natural gas consumption in the medium and lower demand cases, which results in less imported gas relative to the Reference scenario. Therefore, these lower demand scenarios show higher biomass use in the residential sector because imported gas is not available – as in the Reference scenario – to displace some biomass use in 2030.

Interestingly, the sector prices can be seen to distort the market, resulting in a scenario with higher primary energy consumption than the Reference case, which can be seen more clearly in Figure 51. The figure also shows the increased use of natural gas and oil, which goes to power generation to support the increased electricity consumption.

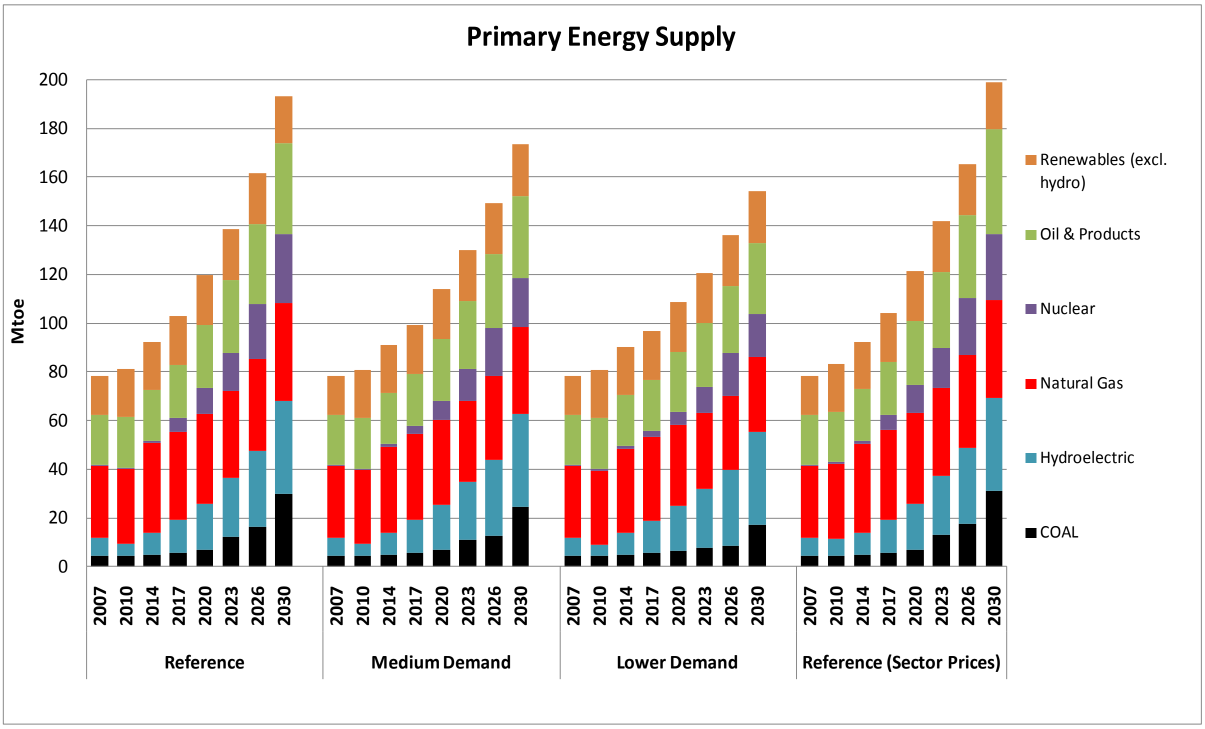


Figure 50: Primary Energy Supply – Group 1 Scenarios

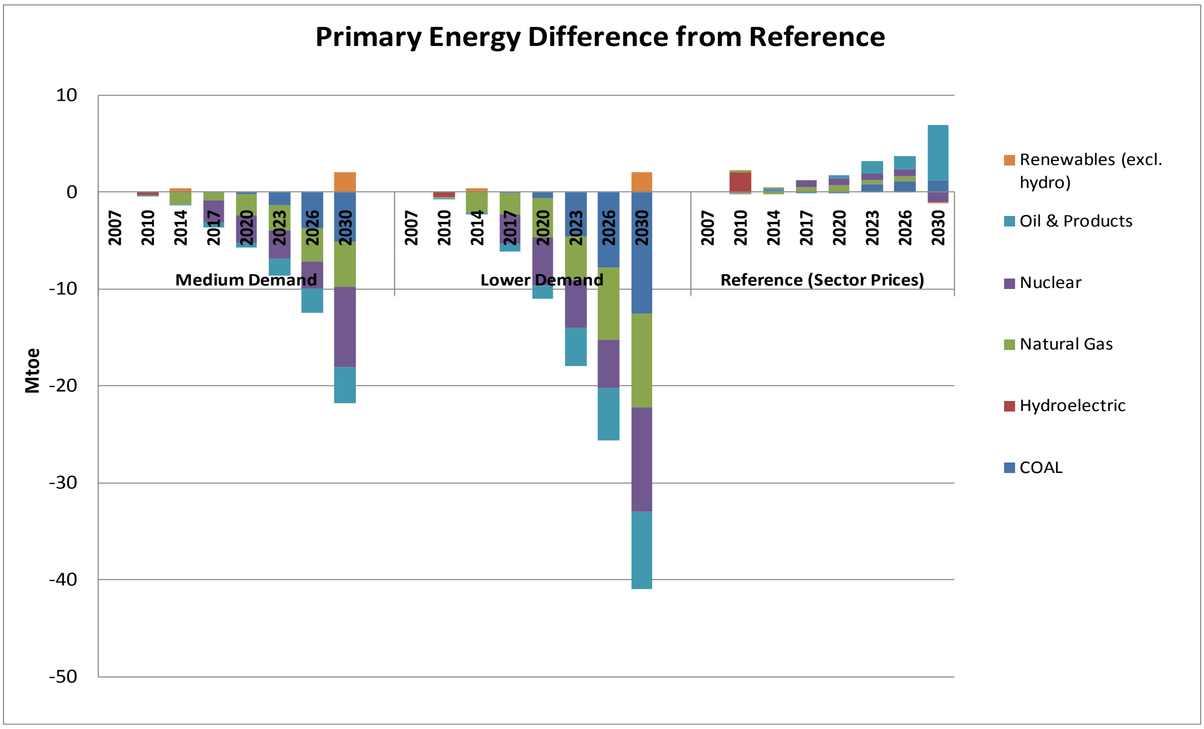


Figure 51: Change in Primary Energy Supply – Group 1 Scenarios

Figure 52 shows the change in new power plant builds for the Group 1 Scenarios. In the Medium and Lower growth scenarios fewer major projects are undertaken, particularly nuclear, which declines by 4.4 GW and 5.8 GW (in cumulative terms), respectively and coal, which declines by 2.0 GW and 5.8 GW, respectively. Sector prices result in earlier investments in nuclear and coal to avoid the higher oil costs that result from the additional fuel taxes and distribution charges and support the shift to more electricity consumption.

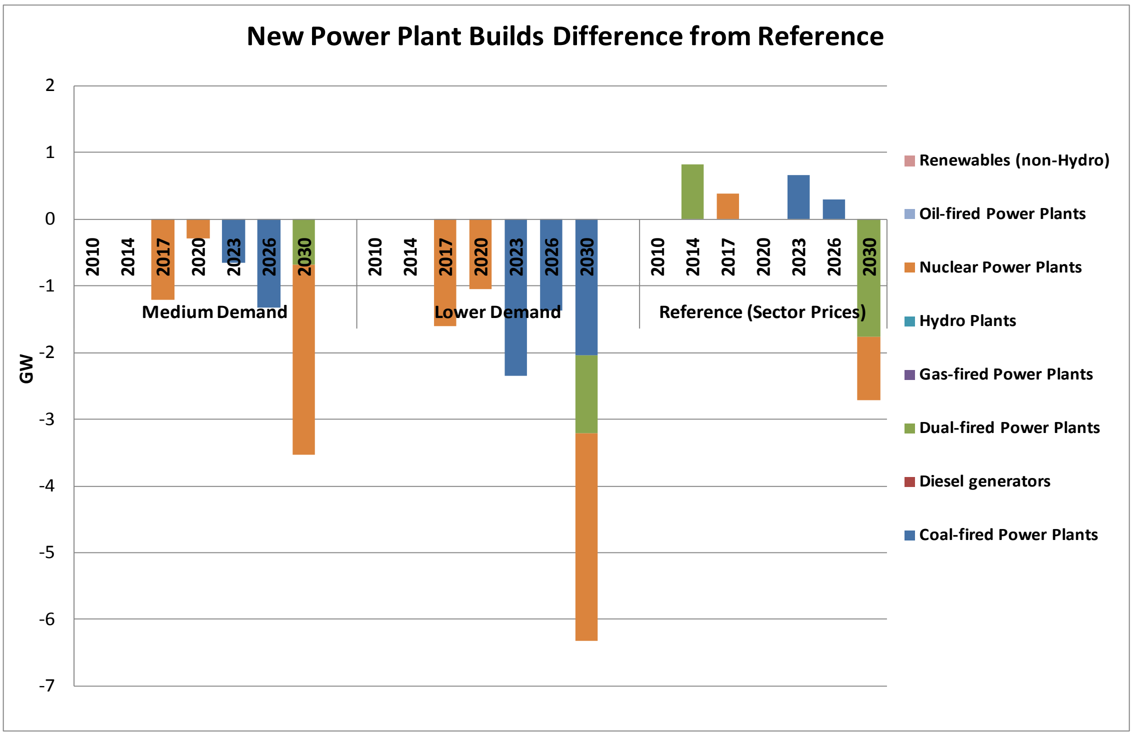


Figure 52: Power Plant New Builds – Group 1 Scenarios

Figure 53 shows the final energy intensity, defined as total Final Energy / GDP, for the Group 1 Scenarios. In the Reference case, intensity of final energy use decreases at an average rate of 2.2% per annum from 2007 to 2030. The Lower demand scenario has slightly higher energy intensity, but the other scenarios do not show much change to the energy intensity improvement.

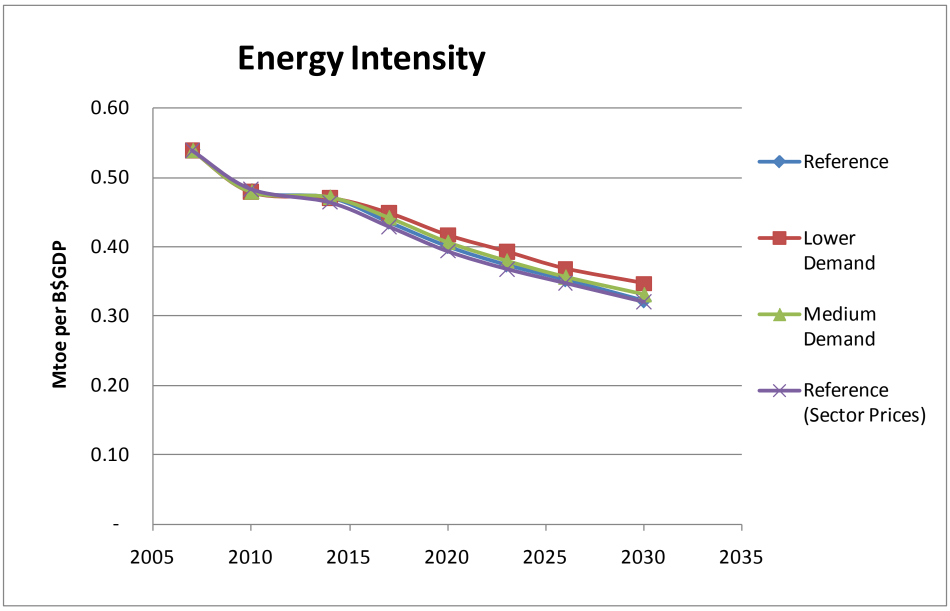


Figure 53: Final Energy Intensity – Group 1 Scenarios

Table 10 provides summary metrics for the Group 1 scenarios. These metrics are the differences from the Reference scenario, and cover cumulative change in system cost, fuel supply, imports, power plant (PP) builds, final energy consumption, and CO_2 emissions.

Table 10: Summary Metrics – Group 1 Scenarios (Difference from Reference)

Scenario	System Cost B$ (%)	Fuel Supply M$ (%)	Imports (%)	PP Builds GW (%)	Final Cons. (%)	CO_2 Emissions (%)
Medium Demand	-75.1 (-8%)	-64.4 (-8.3%)	-6%	-7 (-11.6%)	-6.3%	-8.2%
Lower Demand	-136 (-15%)	-146.7 (-18.9%)	-11%	-12.7 (-21.1%)	-12.9%	-17.4%
Sector Prices	85.2 (6%)	9.1 (1.2%)	2%	-0.55 (-0.9%)	-1.2%	-0.6%

B. Energy Prices & Security [Group 2] Scenarios

Group 2 includes low and high energy price scenarios and a reduced imports scenario. The low energy price scenario uses $90-100/bbl oil in 2020-2030, with imported & domestic gas at 90-50% of oil prices on an energy basis. This compares to $100-115/bbl oil in 2020-2030 for the Reference case. The high energy price scenario uses $120-150/bbl oil in 2020-2030, with imported & domestic gas at 90-50% of oil prices. The reduced imports scenario limits imports to 25% of total primary supply (15% lower than the Reference case.)

Figure 54 shows the change in total energy system cost for the Group 2 scenarios. The changes in oil & gas price assumptions have the anticipated impact on overall system cost – reducing and increasing system costs by 2.8% and 3.9%, respectively. Reducing the import share of primary energy has a more substantial impact on the overall system cost (6% increase) because nuclear fuel is categorized as an imported energy source.

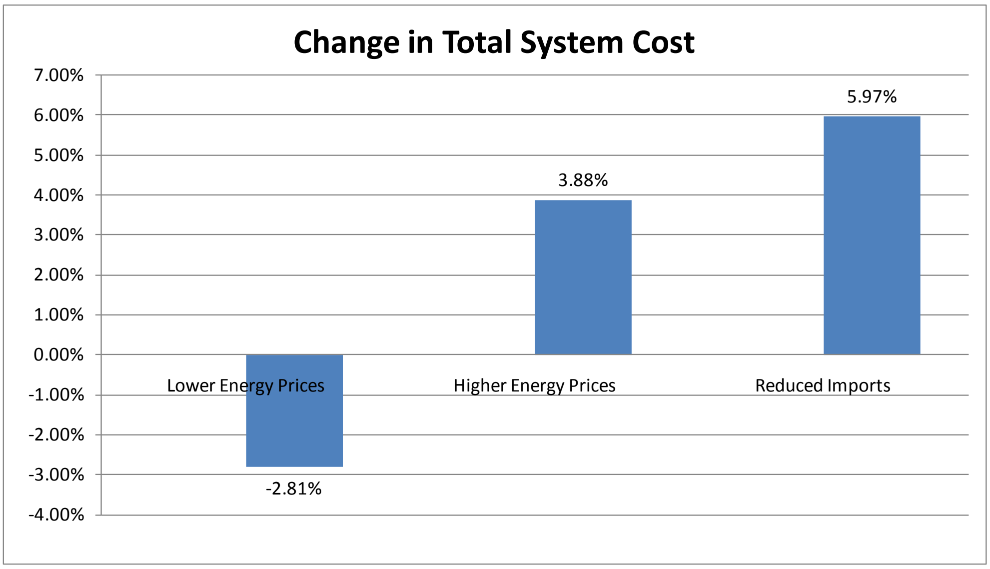


Figure 54: Change in Energy System Cost – Group 2 Scenarios

Figure 55 shows the change in primary energy supply for the Group 2 scenarios. At the lower oil and gas prices, modest amounts of gas substitute for coal in power generation and industry. At higher oil and gas prices, nuclear rises to its build rate limit in response. Reducing imports shows that 20 Mtoe of Thar coal is required to replace a portion of the oil and nuclear fuel used in the Reference case. About 2 Mtoe of renewables are added in the 2030 period.

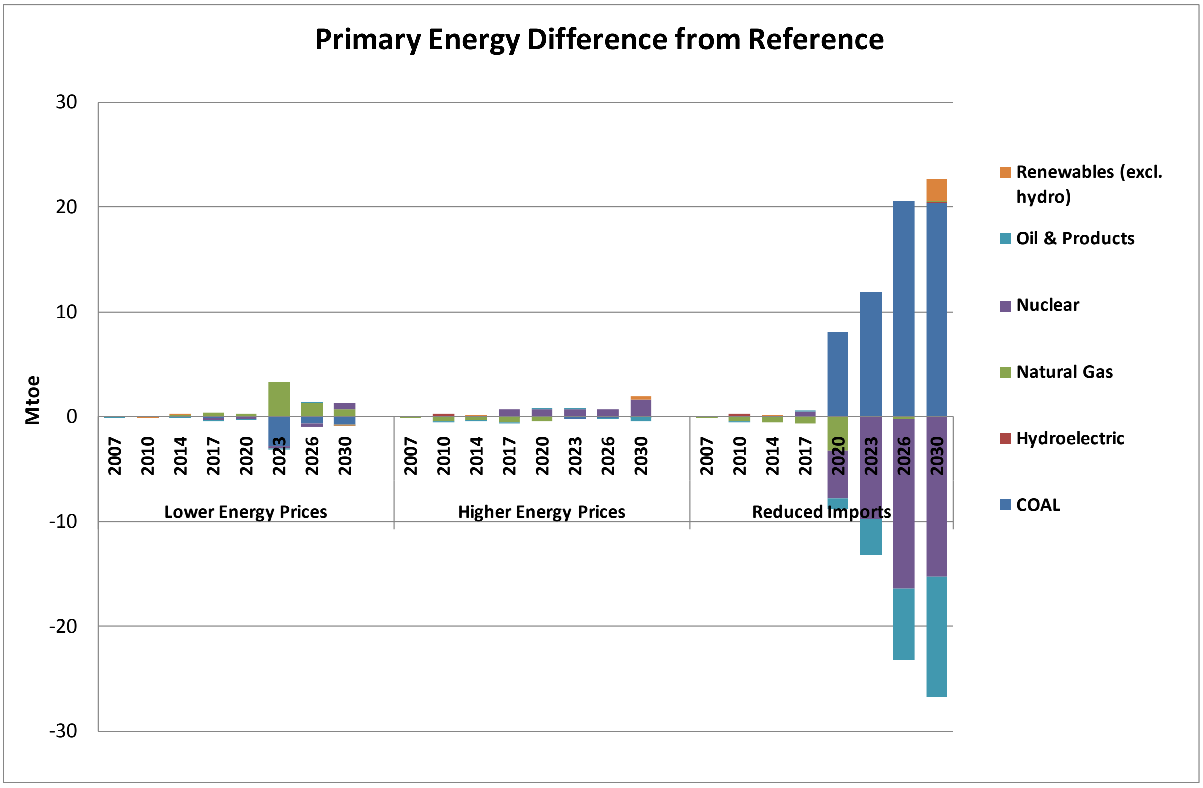


Figure 55: Change in Primary Energy Supply – Group 2 Scenarios

Figure 56 shows the change in electric generation for the Group 2 scenarios. The low and high oil price scenarios have relatively little impact on power generation choices. However, reducing imports requires significant generation from new coal plants, replacing nuclear, which is treated as an imported fuel, and some oil & gas-fired electricity.

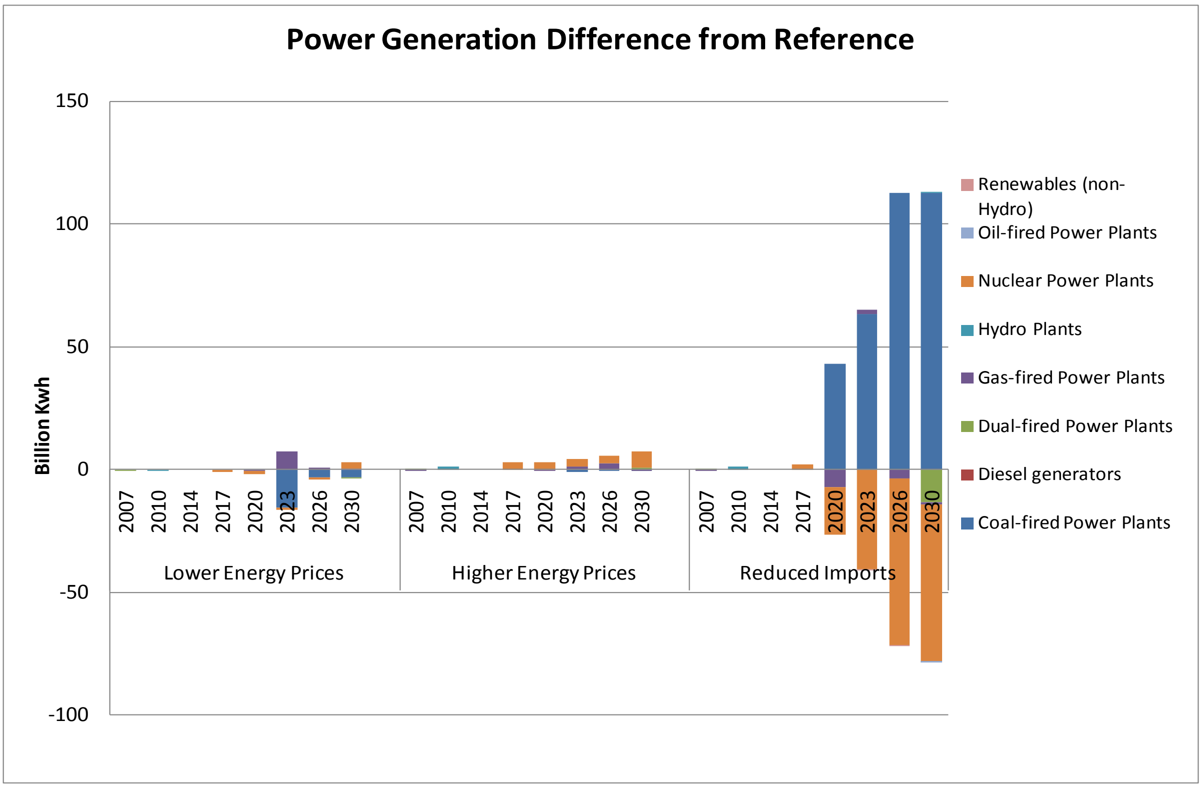


Figure 56: Change in Electric Generation – Group 2 Scenarios

Figure 57 shows the change in annual energy system expenditures for Group 2 scenarios. Lower oil & gas prices reduce fuel expenditures and result in a small increased investment in refineries. Higher oil & gas prices increase fuel expenditures and promote more efficient power plants. Limiting imports encourages investment in more efficient end-use devices.

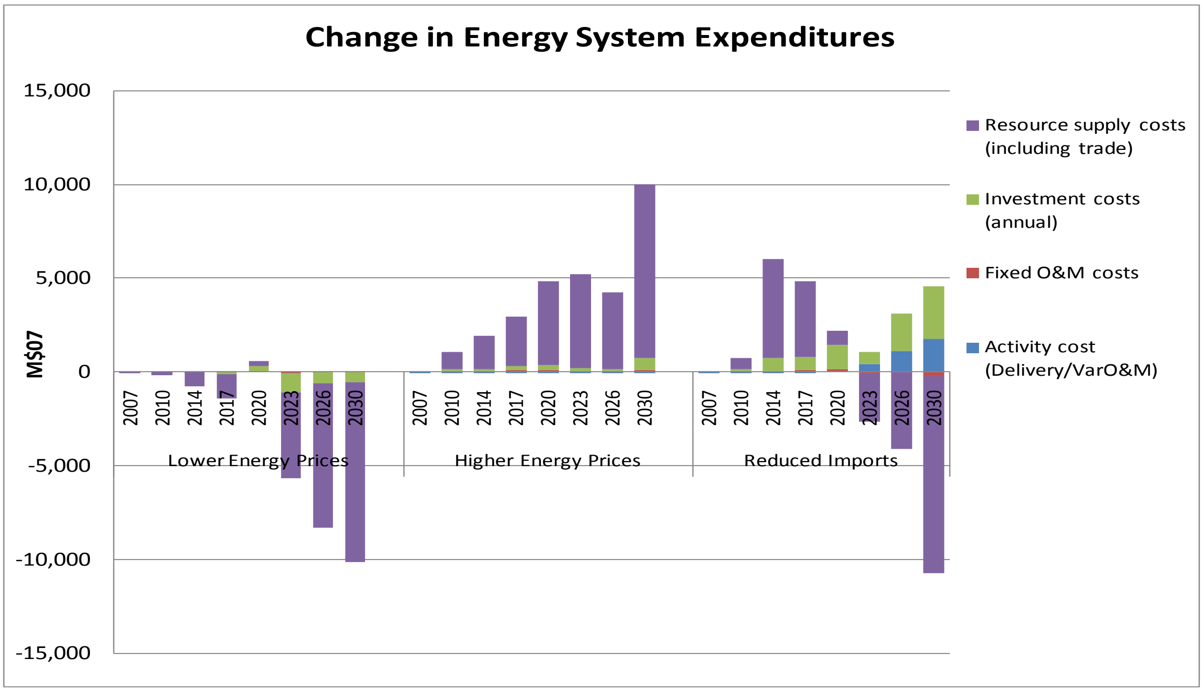


Figure 57: Change in Annual Energy System Expenditures – Group 2 Scenarios

Table 11 provides summary metrics for the Group 2 scenarios. These metrics are the differences from the Reference scenario, and are the cumulative change in system cost, fuel supply, imports, power plant (PP) builds, final energy consumption, and CO_2 emissions.

Table 11: Summary Metrics – Group 2 Scenaros (Difference from Reference)

Scenario	System Cost B$ (%)	Fuel Supply M$ (%)	Imports (%)	PP Builds GW (%)	Final Cons. (%)	CO2 Emissions (%)
Low Energy Price	-75.1 (-2.8%)	-88.7 (-3.9%)	-2.1%	-0.14 (-0.2%)	1.2%	16.4
High Energy Price	36.3 (3.9%)	99.8 (11.8%)	-0.8%	0.9 (1.6%)	-0.3%	-0.7%
Reduced Imports	16.9 (5.97%)	-33.1 (-3.9%)	-10.4%	+5.2 (8.7%)	0.0%	14.7%

C. Delay Power Projects [Group 3] Scenarios

Group 3 scenarios investigate the impact of delaying or prohibiting the construction of hydropower, nuclear and Thar coal power plants. The hydro and nuclear delay scenarios delay the start date of new hydro and new nuclear power plants by 10 years. For nuclear, which has a 7 year lead time, this is tantamount to prohibiting its use until 2030. The no Thar coal scenario prohibits the use of Thar coal for power generation or any other use.

Figure 58 shows the energy system costs for the Group 3 scenarios. Delaying new hydropower plants has a more significant impact because of its lower investment cost and no fuel cost. The investment cost is attractive because dam costs are partly attributed to irrigation water supply. Nuclear power and Thar coal power plants compete at the margin in the power sector, so the system cost impacts of delaying either are similar.

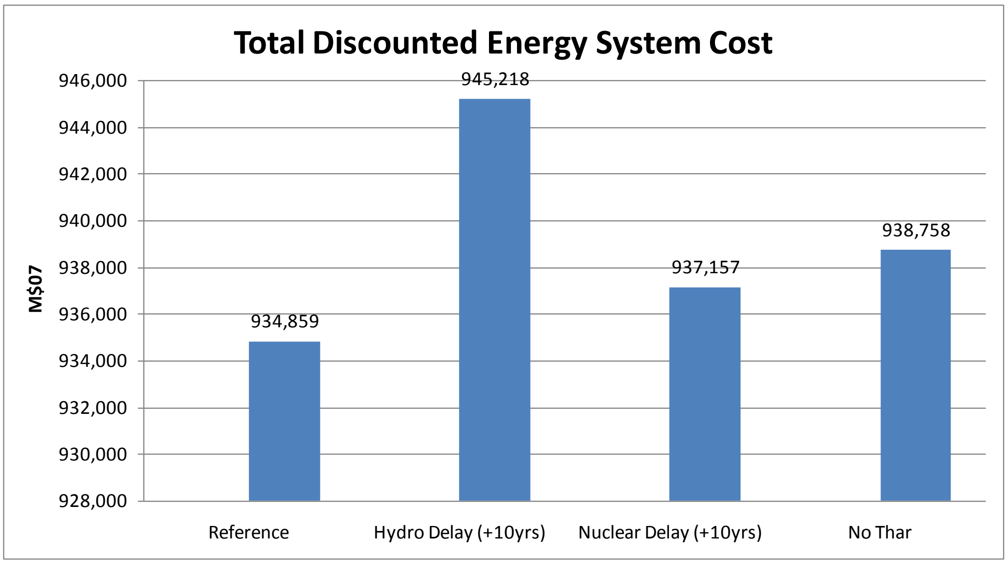


Figure 58: Energy System Cost – Group 3 Scenarios

Figure 59 shows the primary energy supply for the Group 3 scenarios. Delaying the start of either new hydropower or new nuclear power plants results in increased use of coal power plants; primarily from the Thar coal resource.

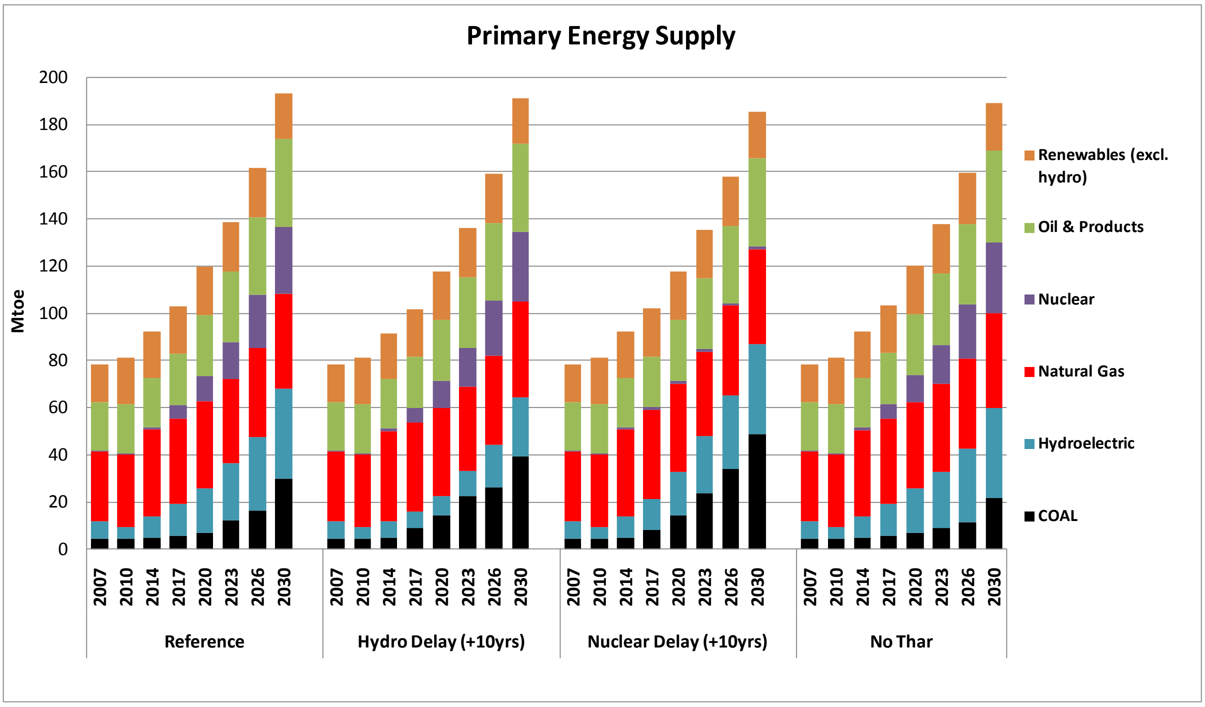


Figure 59: Primary Energy Supply – Group 3 Scenarios

Figure 60, which shows the change in primary energy supply, illustrates that in the no Thar coal scenario, imported coal is used for electricity generation, as well as some additional oil, nuclear and renewable energy supplies.

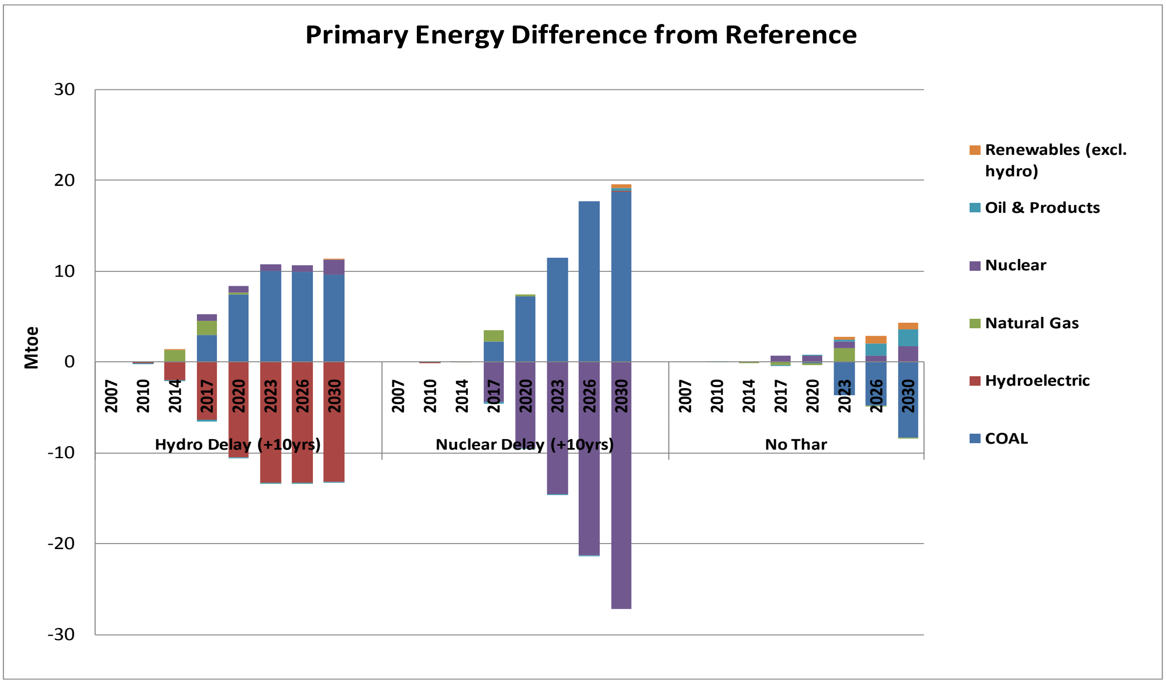


Figure 60: Change in Primary Energy Supply – Group 3 Scenarios

Figure 61 shows fossil fuel supply for the Group 3 Scenarios. Overall fossil fuel use increases as Thar coal substitutes for hydropower and nuclear, but fossil fuel use drops when Thar coal is not available due to the additional power from nuclear and renewables. Also, in the no Thar coal scenario imported coal is used for electricity generation, but not until 2030.

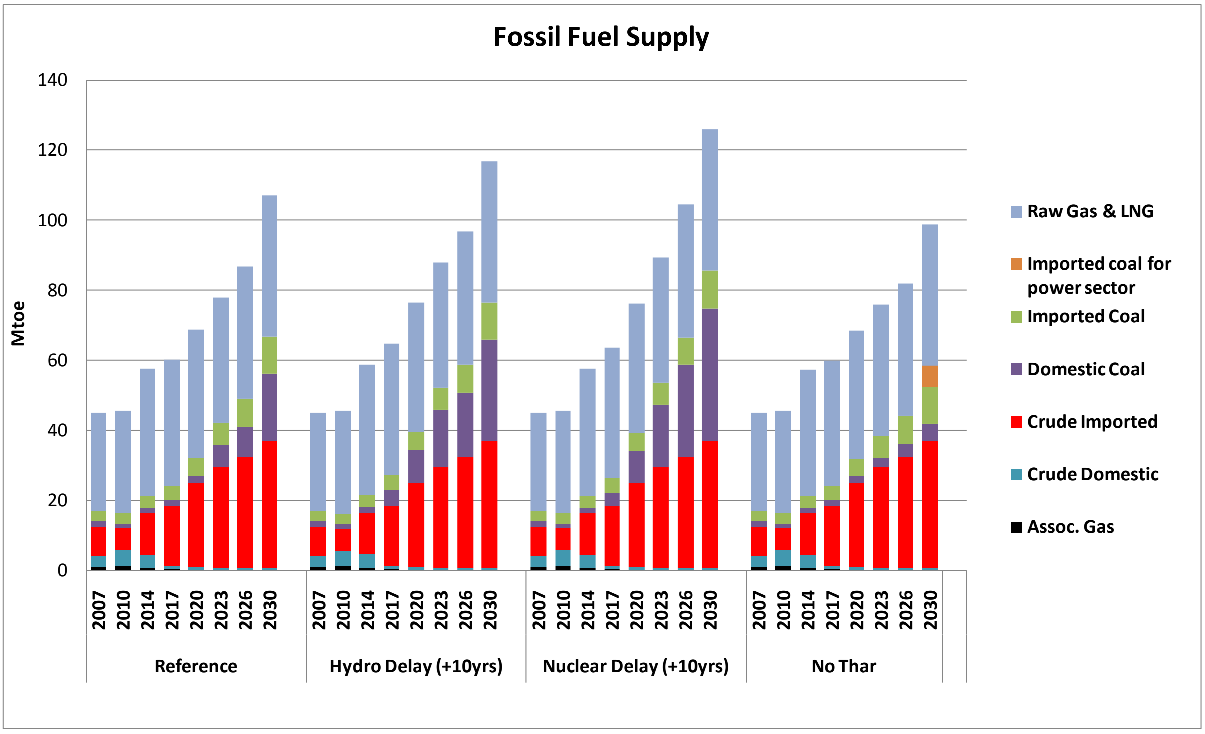


Figure 61: Fossil Fuel Supply – Group 3 Scenarios

Figure 62 shows the additions of new power plant capacity in each period. Delay of new hydro results in more Thar coal plants. When nuclear is delayed Thar coal plants are built at their anticipated maximum build rate. In both cases, a small amount of gas-fired generation is also displaced. In the No Thar case, hydro and nuclear reach their build limits, resulting in new imported coal-based power plants as well as dual-fired and renewable power plants in the later periods. The latter point is further illustrated in Figure 63.

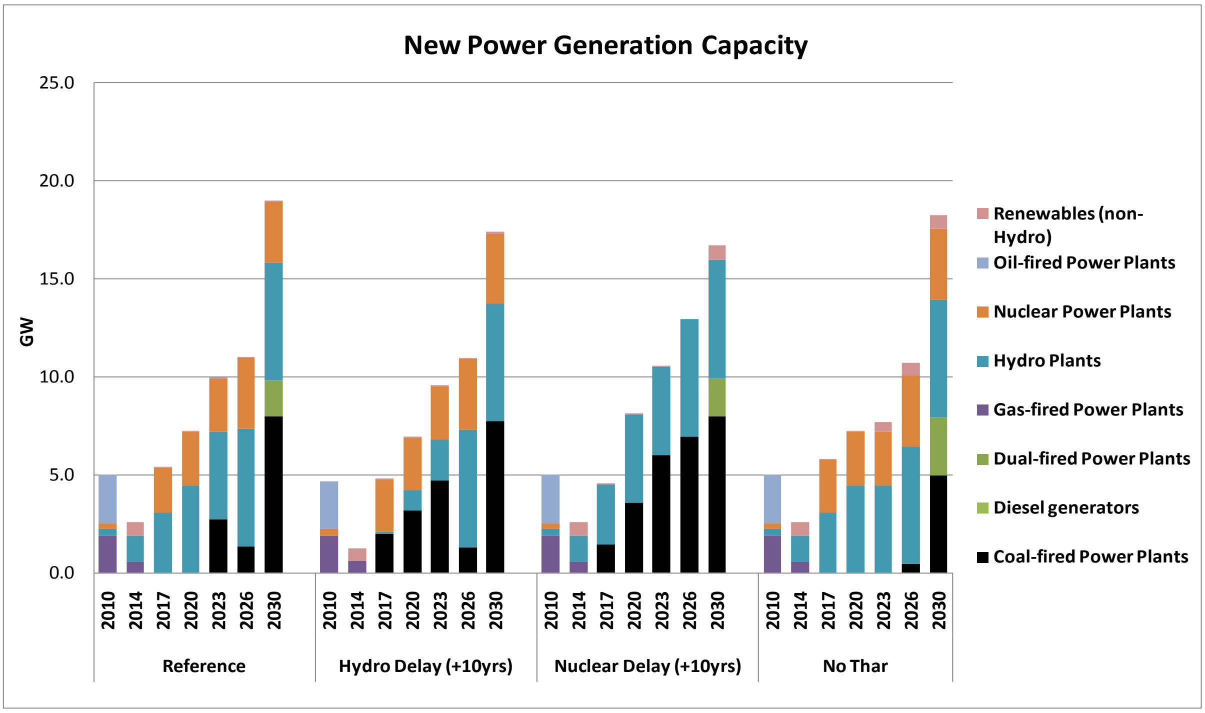


Figure 62: Power Plant New Builds – Group 3 Scenarios

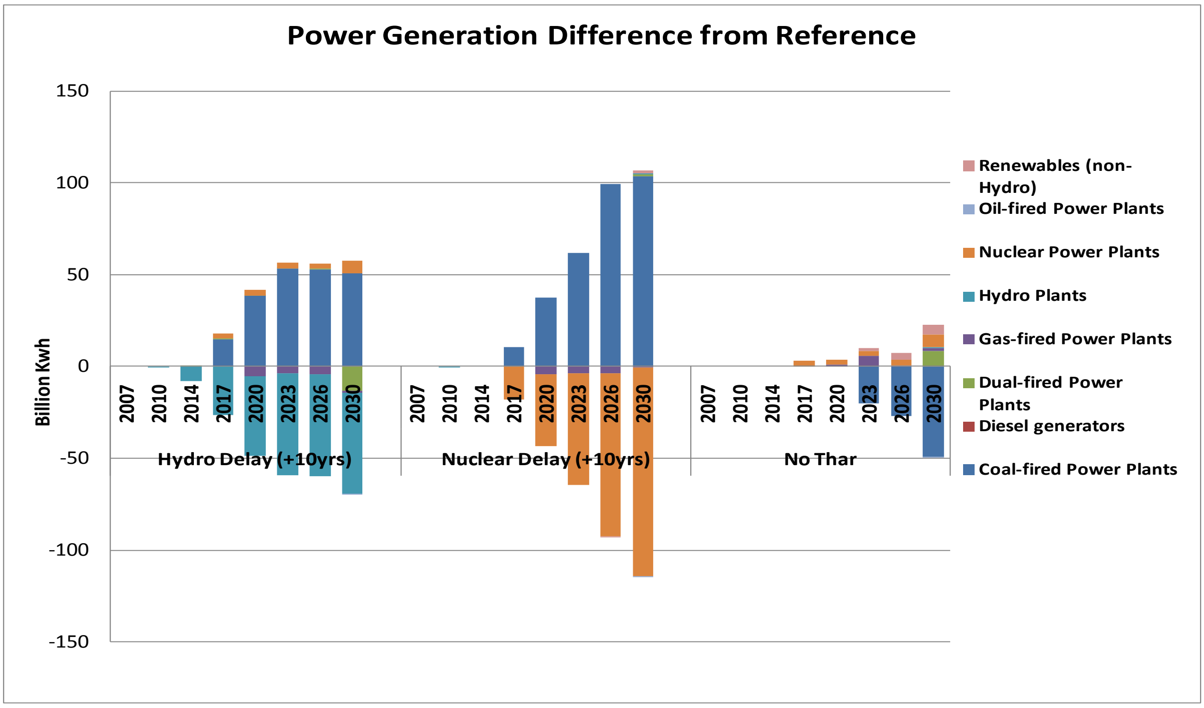


Figure 63: Change in Power Plant Generation – Group 3 Scenarios

Figure 64 shows the change in final energy consumption for the Group 3 scenarios. Delaying the hydro or nuclear power plants produce higher electricity prices and results in increased direct consumption of natural gas. With no Thar coal, more natural gas is used for power generation because the hydropower plants are already at their build limit and only limited additional nuclear capacity can be added before it reaches its build limit. The additional consumption of gas in the power sector results in more direct consumption of oil products in the demand sectors.

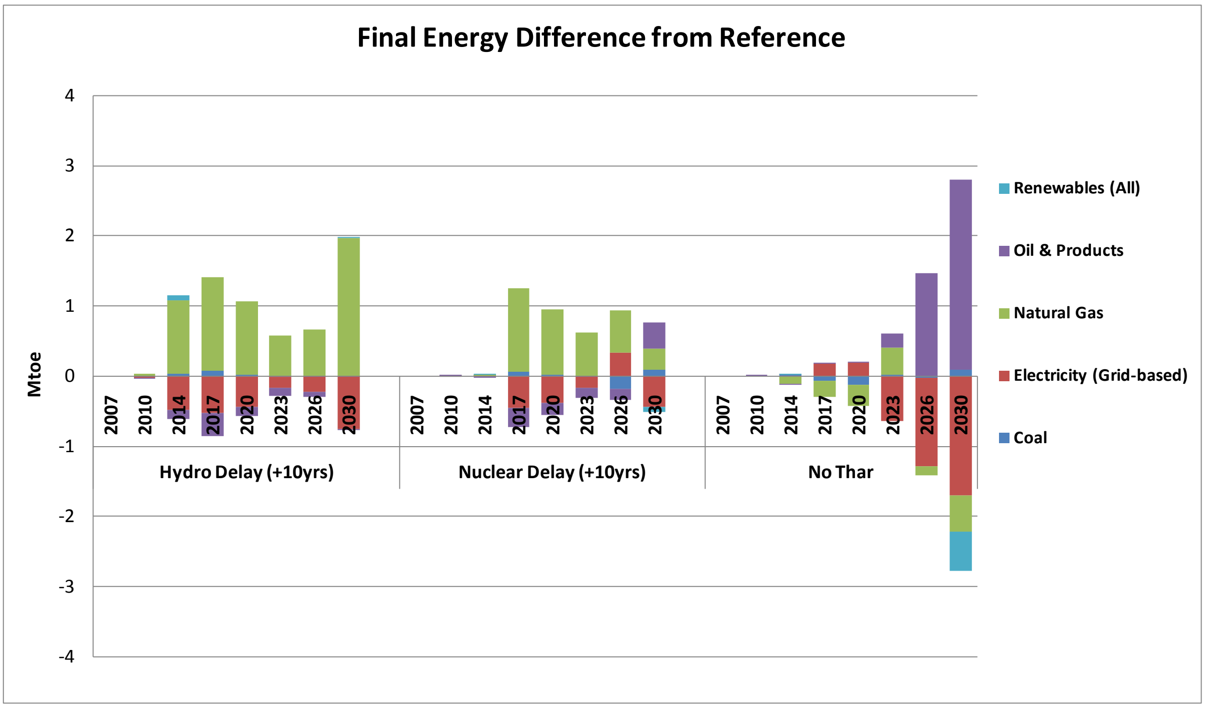


Figure 64: Change in Final Energy Consumption – Group 3 Scenarios

Figure 65 shows the change in annual energy system expenditures for the Group 3 scenarios. Hydro delay results in higher investment and fuel costs because the Thar coal plants are more expensive to build and operate than the hydropower plants. Nuclear delay results in lower investment and O&M costs due to relatively cheaper Thar coal plants. However, this savings is offset by the higher fuel and delivery costs. The no Thar case shows very high fuel costs from imported coal plants and a corresponding decrease in the investment costs due the lower cost of building the imported-coal power plants. However, there is an early albeit slight increase in investment costs for the additional nuclear build.

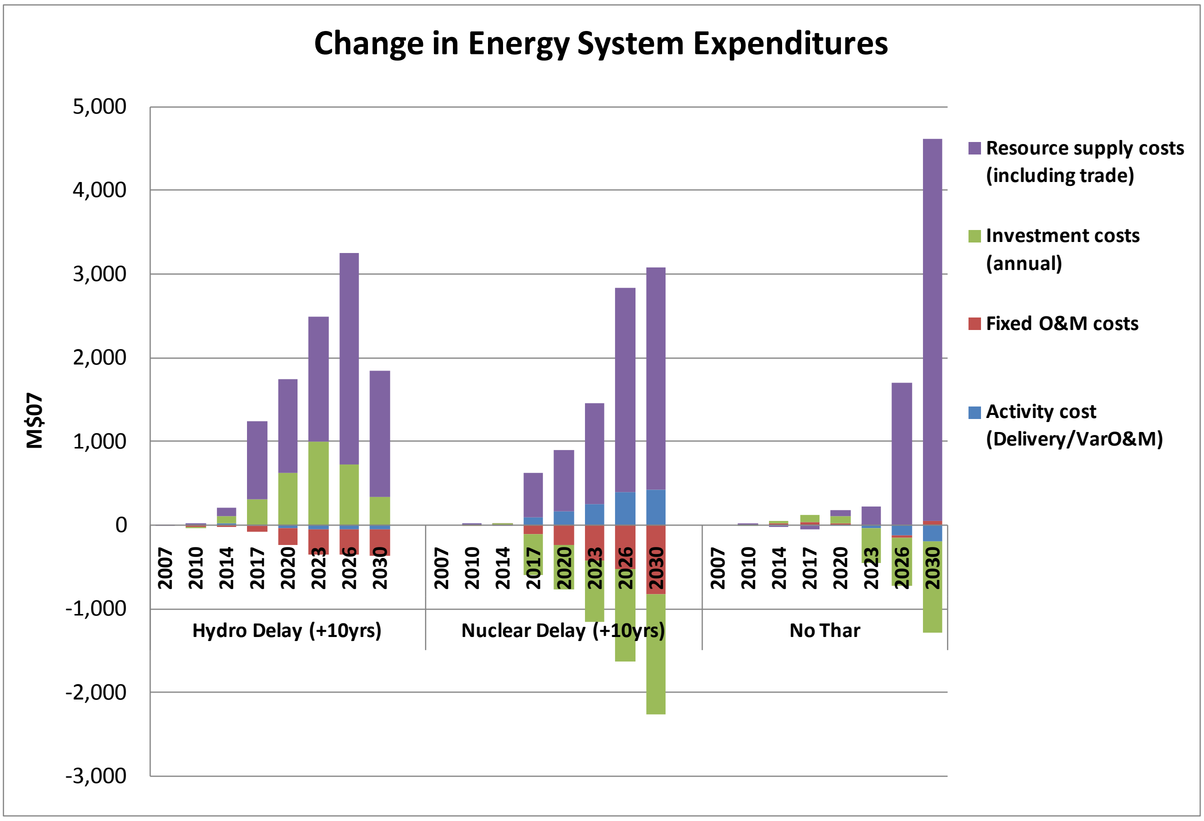


Figure 65: Change in Annual Energy System Expenditures – Group 3 Scenarios

Figure 66 shows the CO_2 emissions for the Group 3 scenarios. The level of CO_2 emissions is directly related to whether or not the Thar coal resource is exploited.

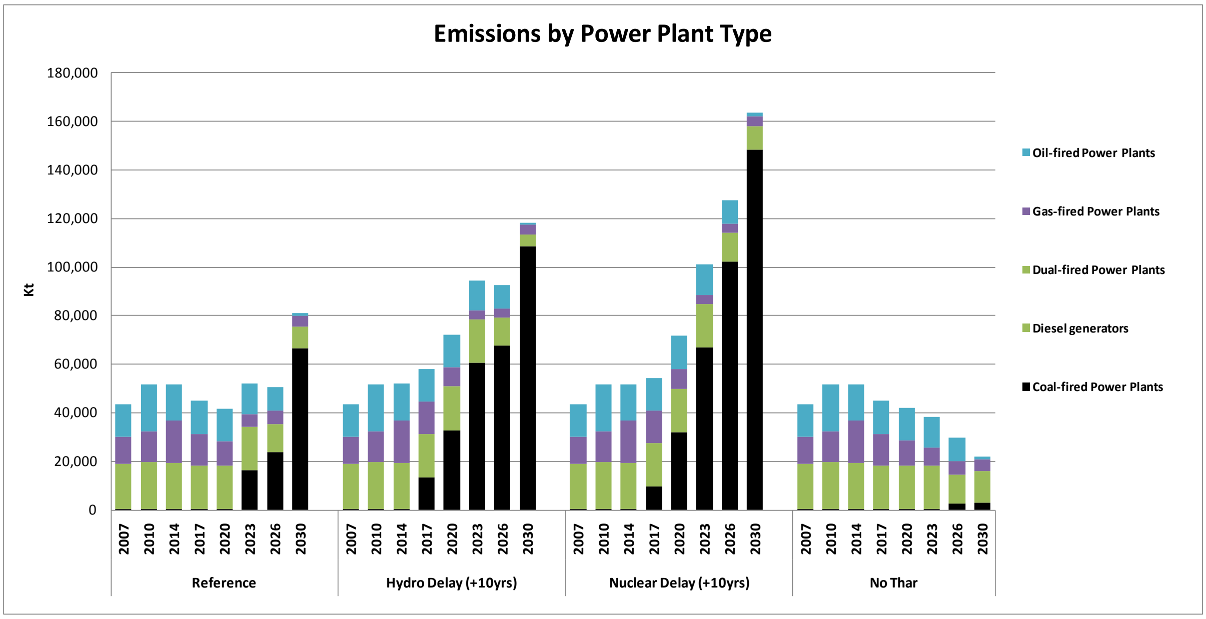


Figure 66: CO_2 Emissions – Group 3 Scenarios

Table 12 provides summary metrics for the Group 3 scenarios. These metrics are the cumulative differences from the Reference scenario, and cover change in system cost, fuel supply, imports, power plant (PP) builds, final energy consumption, and CO_2 emissions.

Table 12: Summary Metrics – Group 3 Scenarios (Difference from Reference)

Scenario	System Cost B$ (%)	Fuel Supply M$ (%)	Imports (%)	PP Builds GW (%)	Final Cons. (%)	CO2 Emissions (%)
Hydro Delay	10.4 (1.1%)	27.1 (3.2%)	0.9%	-4.6 (-7.6%)	0.56%	0.0%
Nuclear Delay	2.3 (.25%)	27.8 (3.3%)	0.4%	0.2 (.4%)	0.33%	0.2%
No Thar Coal	3.9 (.42%)	25.9 (3.1%)	3.2%	-2.9 (-4.9%)	-.04%	-0.4%

D. Increase Power Plant Costs [Group 4] Scenarios

Group 4 investigates the impact of increased investment costs for hydro, nuclear and Thar coal power plants. For hydro and nuclear, the capital cost was increased by 10%. In the case of Thar coal, the capital cost was increased by 25%.

Figure 67 shows the change in energy system cost for the Group 4 scenarios. There is little impact of increasing the cost of hydro or nuclear; even increasing the cost of Thar does not dramatically increase the energy system cost.

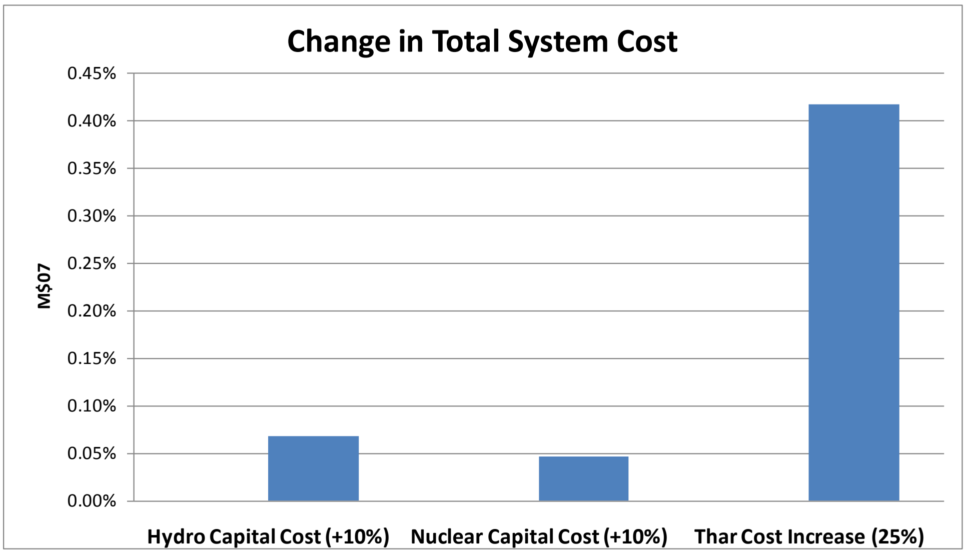


Figure 67: Total Energy System Cost – Group 4 Scenarios

Figure 68 shows the new power plant additions for the Group 4 scenarios. The 10% increase in the hydropower capital cost is not sufficient to make any difference, as it is so cost competitive owning to the irrigation "sharing" of the capital costs. The increases to the nuclear power plant capital cost and the Thar coal power plant cost result in nuclear and Thar coal substituting for each other, but the amount is relatively small as these are nearly cost neutral power plant options, and the impact is marginal.

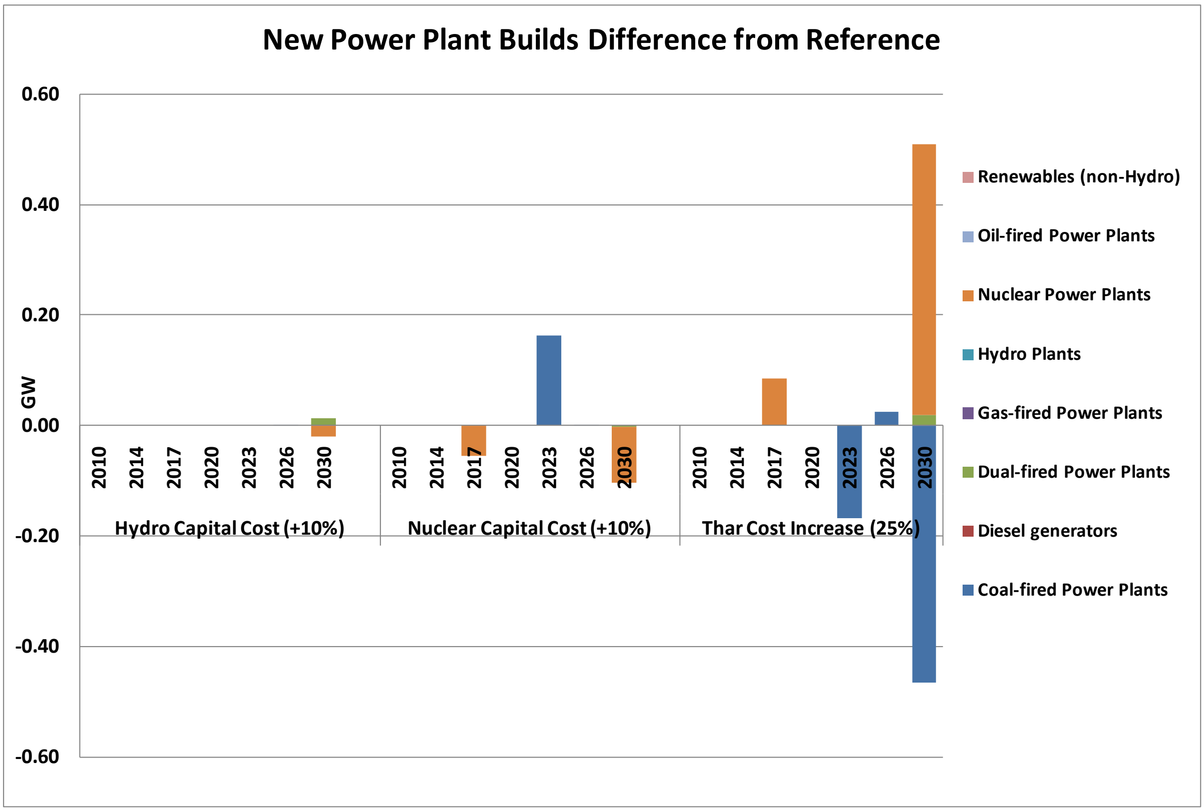
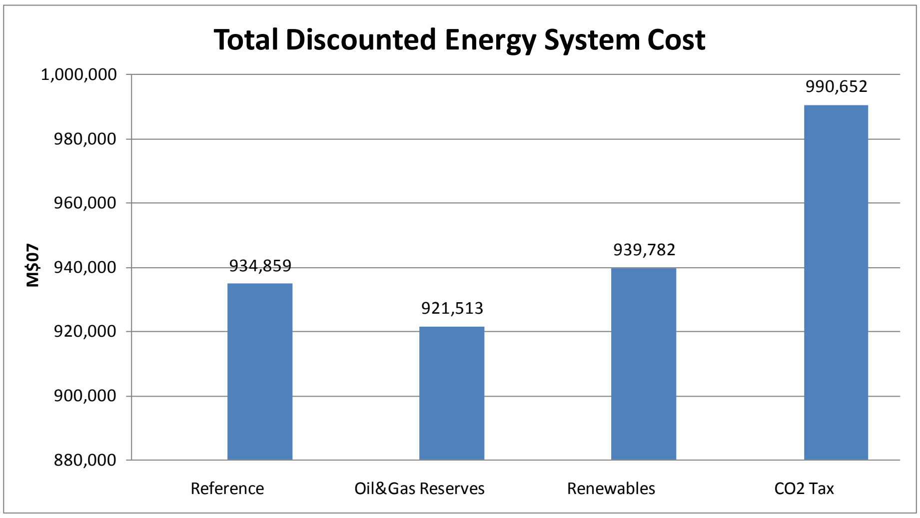


Figure 68: Power Plant New Builds – Group 4 Scenarios

E. Reserves and Environmental [Group 5] Scenarios

Group 5 includes an oil & gas reserves scenario, which assumes an increase to domestic oil & natural gas cumulative reserves by 20%. The renewable electricity scenario imposes a renewable electricity target of 15% by 2030, and the CO_2 tax scenario apply a tax of 20$/ton in 2020 and $50/ton in 2030.

Figure 69 shows the total energy system cost and the percent change in energy system cost for the Group 5 scenarios. Increasing oil & gas reserves by 20% reduces the energy system cost by $13 billion, while a renewable electricity target would cost $4.9 billion and a CO_2 tax of $50/ton in 2030 could cost more than $50 billion over the 25 year planning horizon,



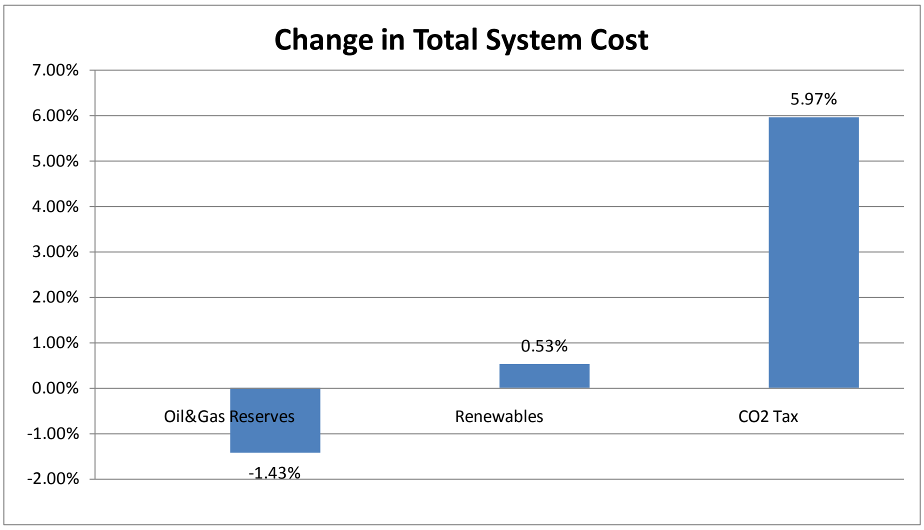


Figure 69: Total Energy System Cost – Group 5 Scenarios

Figure 70 shows the primary energy supply for the Group 5 scenarios. Total primary energy consumption does not change significantly except for more renewable energy and less nuclear in the renewable target scenario, since the increased domestic reserves simply displace (at somewhat less cost) indigenous for imported crude and oil products. Figure 71 shows the change primary energy supply and highlights the fact that the additional domestic oil and gas reserves does not change the utilization of oil and gas very much, while the renewables target case replaces some nuclear and oil products with renewable energy. The CO_2 tax increases renewable and nuclear generation and decreases coal consumption.

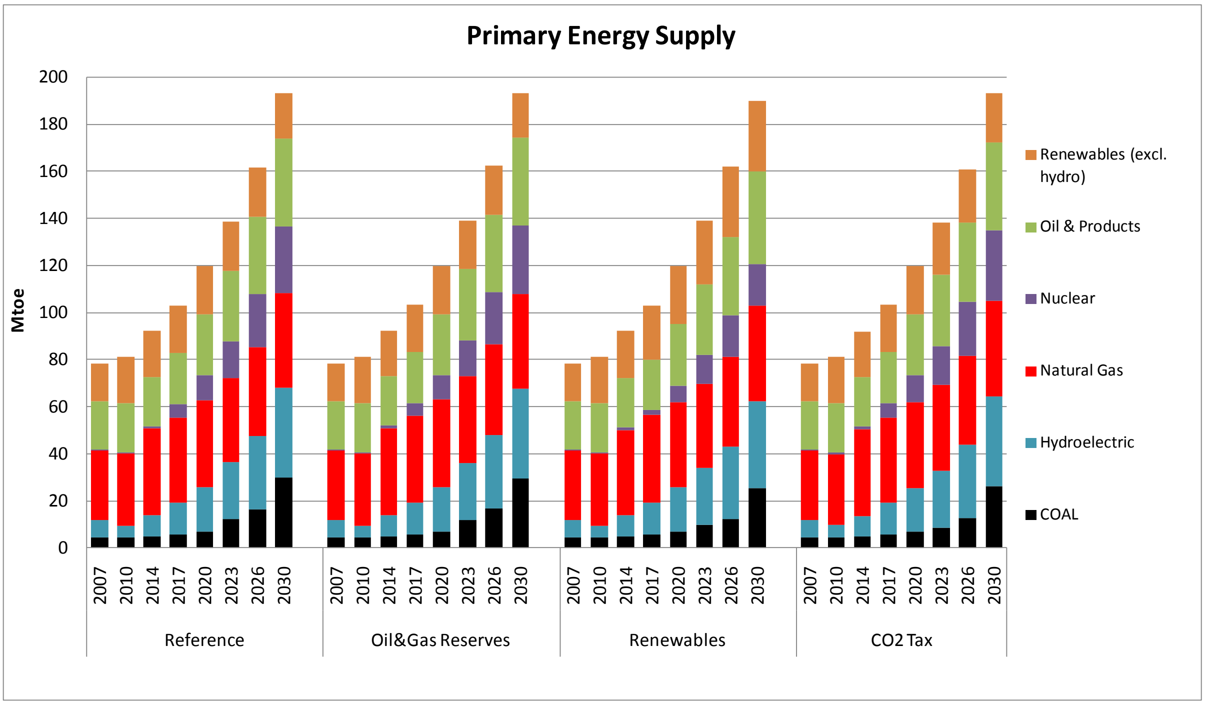


Figure 70: Primary Energy Supply – Group 5 Scenarios

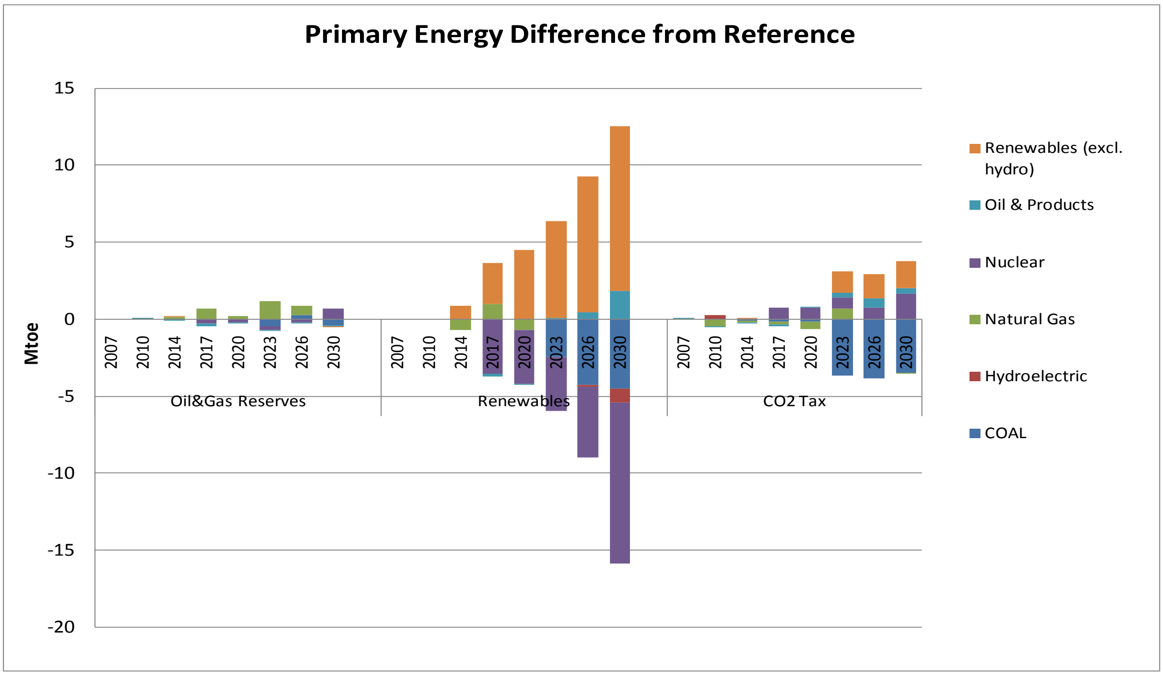


Figure 71: Change in Primary Energy Supply – Group 5 Scenarios

Figure 72 shows the change in fossil fuel supply for the Group 5 scenarios. Increased oil & gas reserves clearly shows the switch of domestic for imported supply along with a modest drop in domestic coal use, while both the renewables target and CO_2 tax scenarios decrease domestic coal use by 25% over the planning horizon.

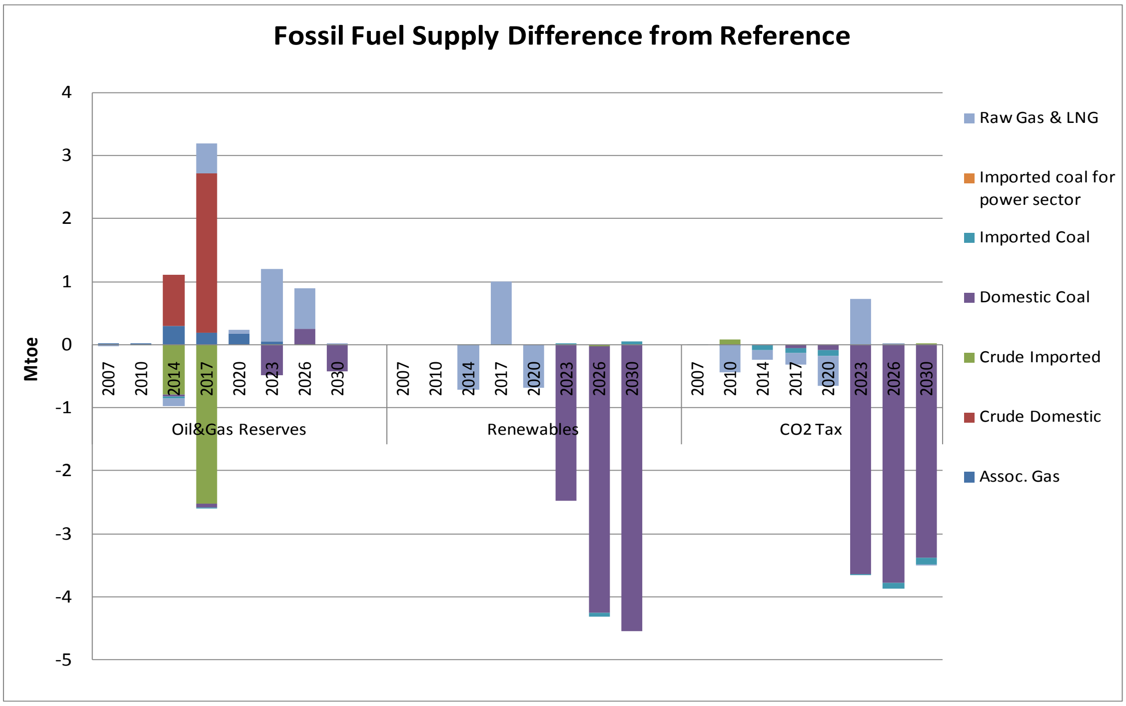


Figure 72: Change in Fossil Fuel Supply – Group 5 Scenarios

zFigure 73 shows the share of imports in the total energy supply. Imports are 5 to 6 percentage points lower in the oil & gas reserves scenario, while the other scenarios are basically the same as the Reference.

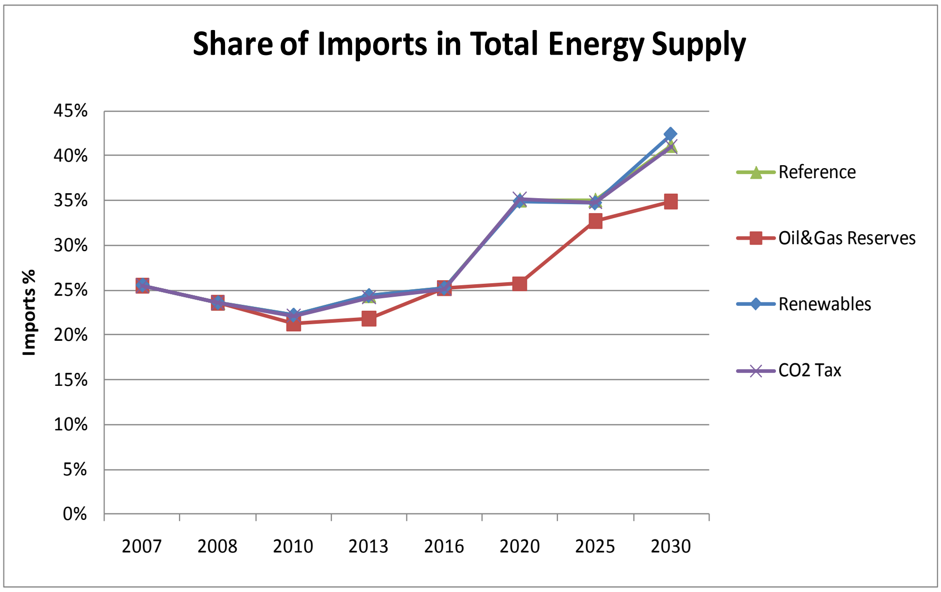


Figure 73: Import Dependency – Group 5 Scenarios

Figure 74 shows the change in new power plant capacity additions for the Group 5 scenarios. The oil and gas reserves scenario shows almost no change, but the renewables target scenario has additional new renewable generation (MSW, wind and solar thermal) displacing 560 billion kWh of nuclear and coal capacity over the 2014 to 2030 time period. The CO_2 tax scenario adds nuclear and renewables and reduces electricity from coal. It also switches the remaining coal use to coal gasification with carbon capture and sequestration.

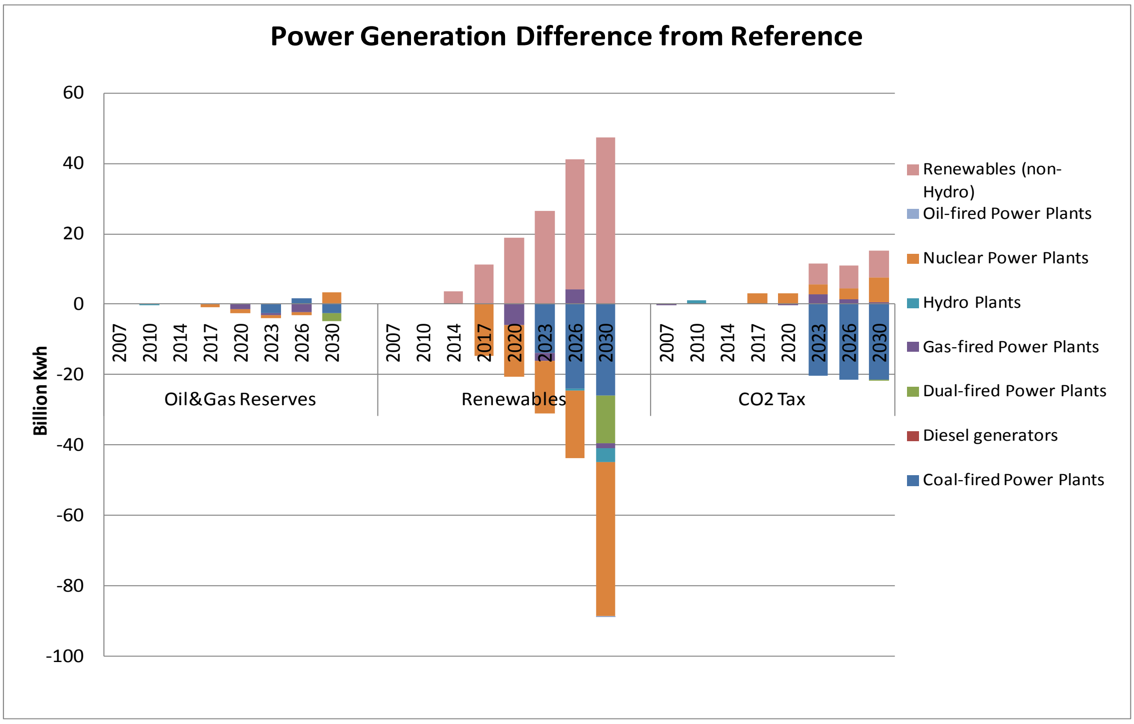


Figure 74: Change in Power Plant Generation – Group 5 Scenarios

Figure 75 shows the CO_2 emissions for the Group 5 scenarios, and Figure 76 shows the change from the Reference scenario. The renewables target scenario reduces cumulative CO_2 emissions by 3% while the CO_2 tax scenario reduces cumulative emissions by 8%, with the most dramatic improvement in 2030. In both cases, emissions reductions come from eliminating coal-fired electricity generation unless CCS is employed.

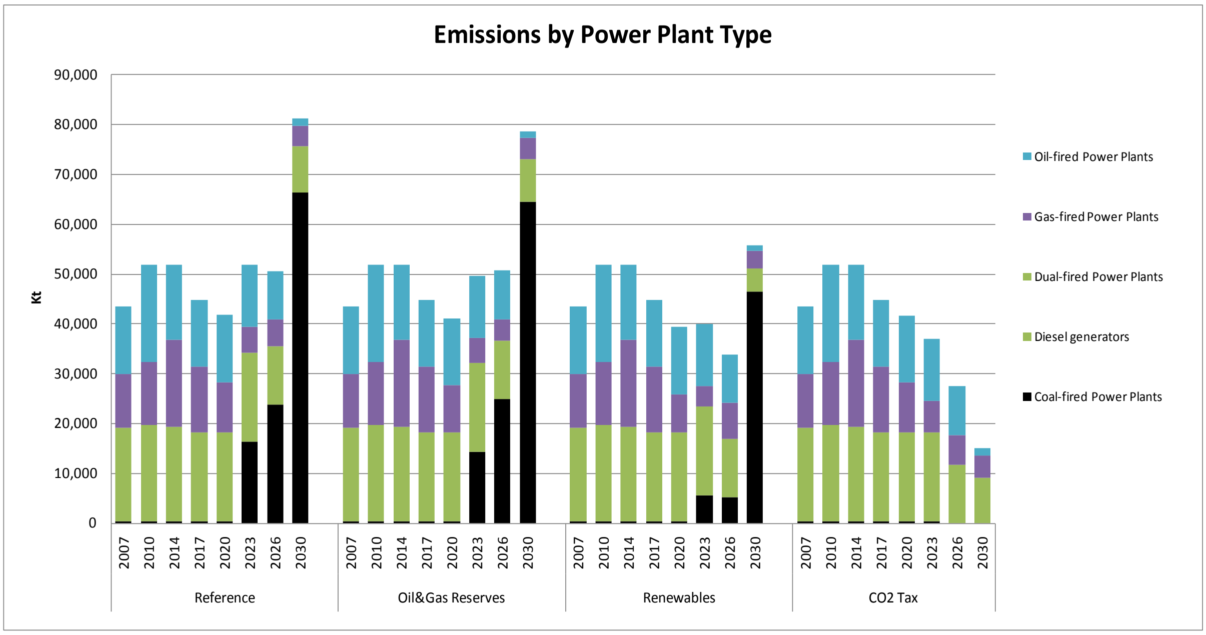


Figure 75: CO_2 Emissions – Group 5 Scenarios

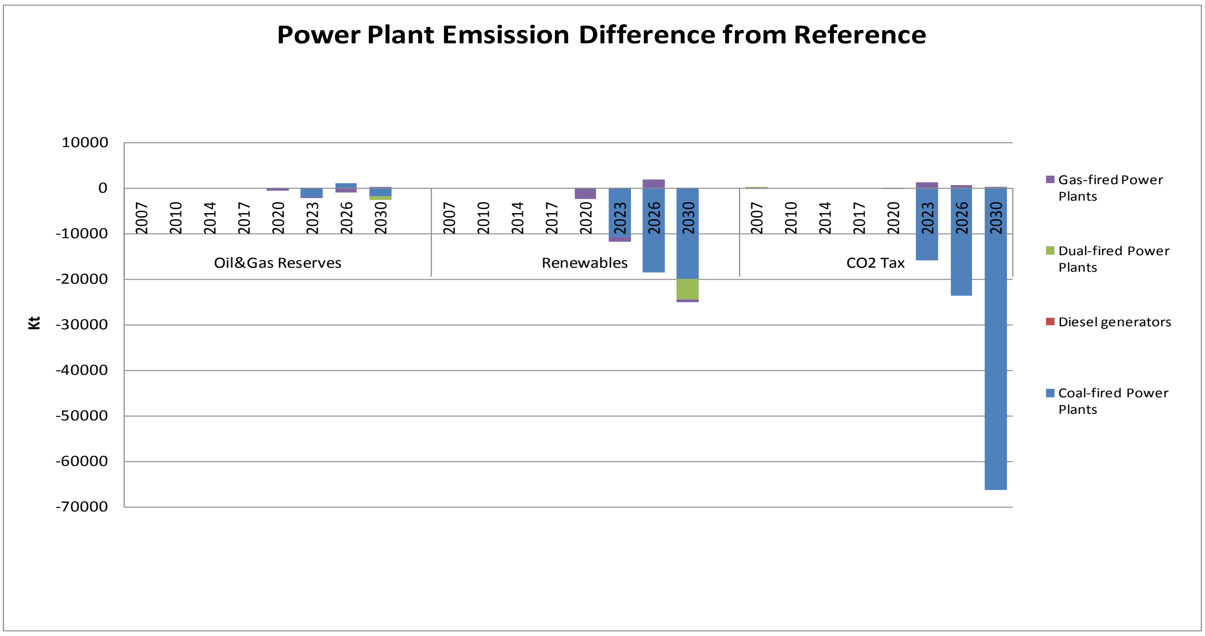


Figure 76: Change in CO_2 Emissions – Group 5 Scenarios

Table 13 provides summary metrics for the Group 5 scenarios. These metrics are the differences from the Reference scenario, and cover change in system cost, fuel supply, imports, power plant (PP) builds, final energy consumption, and CO_2 emissions.

Table 13: Summary Metrics – Group 5 Scenarios (Difference From Reference)

Scenario	System Cost B$ (%)	Fuel Supply M$ (%)	Imports (%)	PP Builds GW (%)	Final Cons. (%)	CO2 Emissions (%)
Oil & Gas Reserves	-13.3 (-1.4%)	-44.8 (-5.3%)	-10.7%	-0.44 (-0.7%)	0.2%	-0.1%
Renewable Electricity	4.9 (+0.5%)	3.3 (0.4%)	+0.3%	3.1 (+5.5%)	0.3%	-3.0%
CO2 Tax	55.8 (+6.0%)	-1.5 (-0.2%)	-0.4%	-0.19 (-0.3%)	-0.3%	-8.0%

F. Pak-IEM Primary Results Metrics

Table 14 provides summary metrics for the Group 5 scenarios. These metrics are the differences from the Reference scenario, and cover change in system cost, fuel supply, imports, power plant (PP) builds, final energy consumption, and CO_2 emissions.

Table 14: Summary Metrics – All Scenarios (Difference From Reference)

Scenario	Savings (M$ / %)	Exp. Fuel (M$ / %)	Imports (PJ / %)	PP Builds (GW / M$)	Final Cons. (PJ / %)	CO2 (%)
Medium Demand	-75.1 (-8%)	-64.4 (-8.3%)	-6%	-7 (-11.6%)	-6.3%	-8.2%
Lower Demand	-136 (-15%)	-146.7 (-18.9%)	-11%	-12.7 (-21.1%)	-12.9%	-17.4%
Sector Prices	85.2 (6%)	9.1 (1.2%)	2%	-0.55 (-0.9%)	-1.2%	-0.6%
Low Energy Price	-75.1 (-2.8%)	-88.7 (-3.9%)	-2.1%	-0.14 (-0.2%)	1.2%	16.4
High Energy Price	36.3 (3.9%)	99.8 (11.8%)	-0.8%	0.9 (1.6%)	-0.3%	-0.7%
Reduced Imports	16.9 (1.81%)	-33.1 (-3.9%)	-10.4%	5.2 (8.7%)	0.0%	-0.8%
Hydro Delay	10.4 (1.1%)	27.1 (3.2%)	0.9%	-4.6 (-7.6%)	0.56%	0.0%
Nuclear Delay	2.3 (.25%)	27.8 (3.3%)	0.4%	0.2 (.4%)	0.33%	0.2%
No Thar Coal	3.9 (.42%)	25.9 (3.1%)	3.2%	-2.9 (-4.9%)	-.04%	-0.4%
Oil & Gas Reserve	-13.3 (-1.4%)	-44.8 (-5.3%)	-10.7%	-0.44 (-0.7%)	0.2%	-0.1%
Renewables	4.9 (+0.5%)	3.3 (0.4%)	+0.3%	3.1 (+5.5%)	0.3%	-3.0%
CO2 Tax	55.8 (+6.0%)	-1.5 (-0.2%)	-0.4%	-0.19 (-0.3%)	-0.3%	-8.0%

APPENDIX C: AN ECONOMIC EVALUATION OF NATURAL GAS USE

This study was prepared by the Energy Wing of the Planning Commission and International Resources Group at the request of the Deputy Chairman. It is an illustration of the types of policy analyses that are possible with Pak-IEM.

A. Study Goal, Approach, and Conclusion

The goal of this study is to examine the economic impacts of changing gas priority between fertilizer feedstock and power generation. Two approaches were used: An energy system economic analysis, and a plant-level comparison. Both approaches give a similar result, which is that natural gas has a higher economic value for fertilizer production. The energy systems analysis shows that reducing gas to fertilizer and increasing gas to power both increase energy system costs. The plant-level analysis shows that importing fertilizer has a greater economic cost than that of importing heavy fuel oil for power generation.

B. Major Assumptions

- Natural Gas Allocation and Management Policy 2005
- 2010 Consumer Prices of Gas
- Fertilizer imports priced at Rs 37,200 ($430) per ton including transport and distribution costs
- Investment cost for new fertilizer plants estimated at Rs 43B ($500M) for 0.5 million tons per year capacity
- Economic model was allowed to reallocate gas on a least-cost basis, including shifting supply into the future
- Economic model was required to generate the same amount of electricity even when gas supply was constrained

C. Economic Assessment

Using the Pakistan Integrated Energy Planning Model (Pak-IEM), a Reference scenario was developed that had full allocation of gas to the fertilizer sector and historical allocations of gas to the power sector. Two alternative scenarios were created and the relative change in total energy system costs was used as the measure of the economic impact of the alternatives. The first scenario reduced gas supply to fertilizer sector by 10%, 20% and 30% relative to the Reference case. The other increased gas supply to the power sector by 10%, 20% and 30% relative to the Reference case. The total energy system cost is the discounted sum of all investments in technology, expenditures for fuel and costs for operation and maintenance of all technologies throughout the entire energy system.

1. Economic Impact of Less Gas to Fertilizer

The figure below shows the model results in terms of the reduction in gas to the fertilizer sector with the change in total discounted energy system cost superimposed. On a per unit energy basis, reducing gas to the fertilizer sector costs the energy system Rs. 196 million per MMCFD. Gas diverted from fertilizer production is mostly used to increase power generation in existing plants – both utility and captive power – while overall gas production is reduced, conserving the gas for future use.

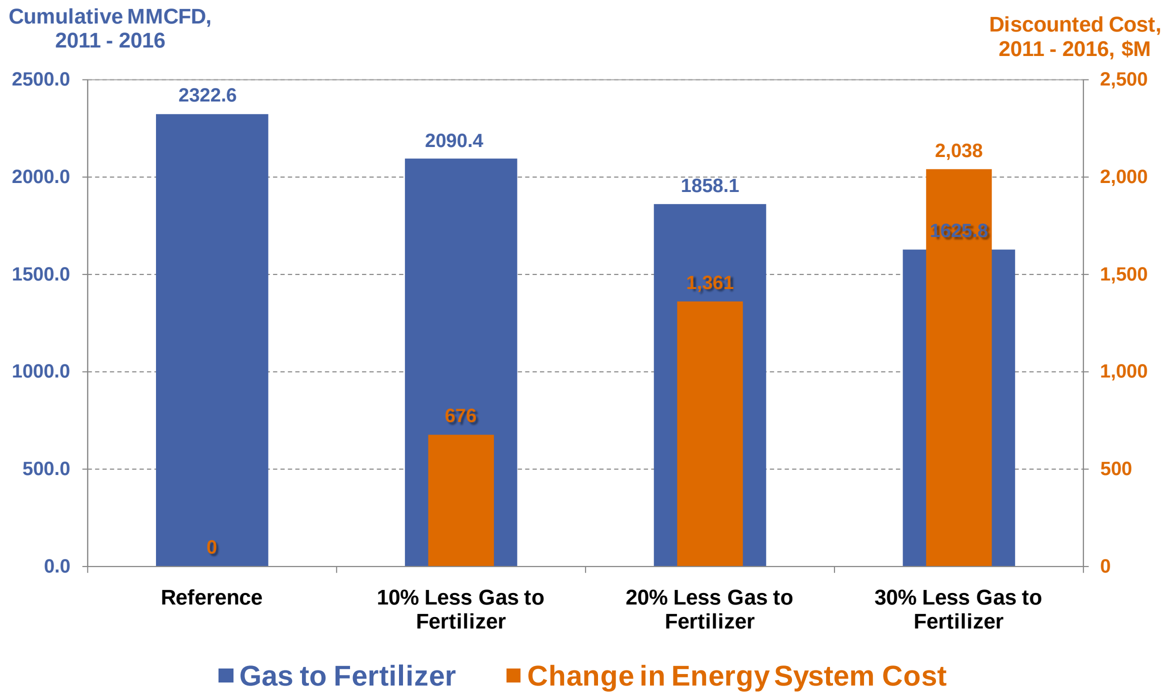


Figure 77: Impact of Less Gas to Fertilizer

2. Economic Impact of More Gas to Power Sector

The figure below shows the model results in terms of the increase in gas to the power sector with the change in total discounted energy system cost superimposed. While gas production goes up slightly, the additional gas to power comes mostly from general industry through fuel switching from direct gas use to electricity, and a small amount comes from domestic use through replacement of gas with LPG. On a per unit energy basis, increasing gas to the power sector costs the energy system Rs. 98 million per MMCFD.

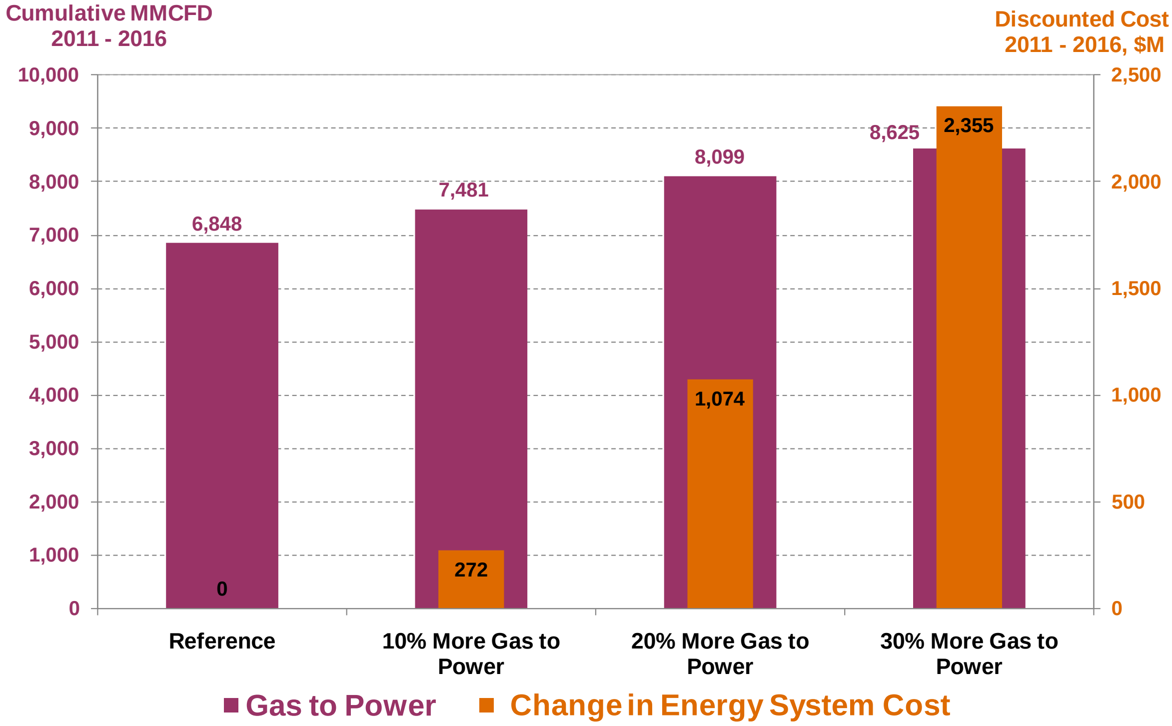


Figure 78: Impact of More Gas to the Power Sector

D. Plant Level Assessment

The plant-level assessment is based on the usage of 100 MMCFD of gas for either fertilizer production or power generation.

In a fertilizer plant, 100 MMCFD of gas can yield 1.43 Mt/yr of fertilizer with 75% of the gas being feedstock and 25% being fuel for the process. The value of the fertilizer in the domestic market (price to the farmer) is Rs. 22.3 billion. The alternative for the farmer is imported fertilizer priced at Rs 37,200 ($430) per ton including transport and distribution costs, which is a total cost of Rs. 51.7 billion. The savings from domestic fertilizer production versus imports is the difference, which is Rs. 29.4 billion.

In a 220 MW thermal power plant, 100 MMCFD of gas generates 11.1 GWh of electricity, which has a fuel cost of Rs. 3.5 billion based on natural gas priced at Rs 394 per million Btu. A 220 MW thermal power plant requires 0.22 million tons of heavy fuel oil priced to generate the same amount of electricity. At Rs 44,680 per ton, the fuel oil plant has a fuel cost of Rs. 9.9 billion. The savings from using domestic natural gas rather imported heavy fuel oil is the difference, which is Rs. 6.4 billion.

E. Conclusions

Gas has a higher economic value for fertilizer production compared to power sector.

The System Level Economic Valuation indicates that reducing gas to the fertilizer sector costs the economy Rs 196 million per MMCFD, while increasing gas to the power sector costs the economy Rs 98 million per MMCFD.

The Plant Level Comparison shows that using 100 MMCFD for fertilizer saves Rs. 29.4 billion compared to fertilizer imports, while replacing 100 MMCFD for power saves Rs. 6.4 billion compared to heavy fuel oil imports.

Thus, using natural gas for fertilizer has a higher savings relative to using it for power generation by Rs. 23 billion. This compares well with the value from the economic model, which for use of 100 MMCFD in the fertilizer sector gives a net benefit of Rs. 19.6 billion.

Additional Insights from Integrated Model Results

Gas diverted from fertilizer plants is partly used to increase power generation in existing plants – both utility and captive power, and is partly conserved for future use. However, gas directed to power generation comes mostly from general industry through switching from direct gas use to electricity consumption with some coming from domestic use through replacement of gas with LPG.

Gas diverted from power generation goes to industry for captive power generation and incentivizes more efficient power generation through rehabilitation and retirements of old plants.

Relative Benefits of the Integrated Energy Planning Model

While the economic value produced by the two approaches is similar, the integrated energy planning model provides additional benefits relative to the plant-level analysis. First, having two approaches that produce similar answers adds credibility to the efficacy of the result. Second, the integrated model provides additional insights regarding implications of changes to other sectors of the energy system that the plant level analysis cannot provide. Third, as the questions being asked become more complex, the integrated model can provide answers even when no plant level comparison can be used to address the question.