Comments of B-LEADERS

I. Executive Summary

The paper entitled Filipino 2040: Energy: Power Security and Competitiveness prepared by the Energy Policy and Development Program (EPDP) aimed to illustrate how policy reforms with respect to fuel mix can lead to lower power cost. The EPDP team focused on the generation component of the power bill, which reportedly account for 47% of the consumer's total power bill. The team, throughout the paper, claimed to have carried out a numerical exercise to illustrate this objective. Indeed, the exercises are simply numerical exercises since the paper ignored facts as well as realities in the Philippine electric power industry sector that may significantly impact electricity rates.

EPDP claimed that it is in the power cost that the Philippines loses out in the cost of doing business compared to its neigbors (page 7, 3rd para). Figure 1 showed trends in residential and electricity tariffs in selected Asian countries (page 8). EPDP ignored the potential outcome of retail competition and open access (RCOA) to contestable customers (1MW and up), which was implemented in 2012. These are the industries that are more relevant to be evaluated in relation to the government's desire to bring back manufacturing jobs to the country. EPDP cited rates that are not just outdated but may not be relevant since even the Energy Regulatory Commission (ERC) is no longer privy to the actual rates currently enjoyed by the contestable customers. EPDP did not even qualify its section on industrial rates to acknowledge that such industrial rates in the study as cited may not be truly representative of the power cost to the big industries.

Since the EPDP study was simply a numerical exercise that is not based on factual information, the scenarios presented do not have or have very little probative value as a foundation upon which future policy decisions may be based. It has no value from a policy setting perspective. The government will probably be best served if policy papers reflect actual information and best data available as of the time the paper is written so that the government may be able to identify course of actions designed to achieve the government's goals and objectives. Government policy decision makers should be presented with policy scenarios that are realistic doable and easily implementable cognizant of constraints prevailing in the sector.

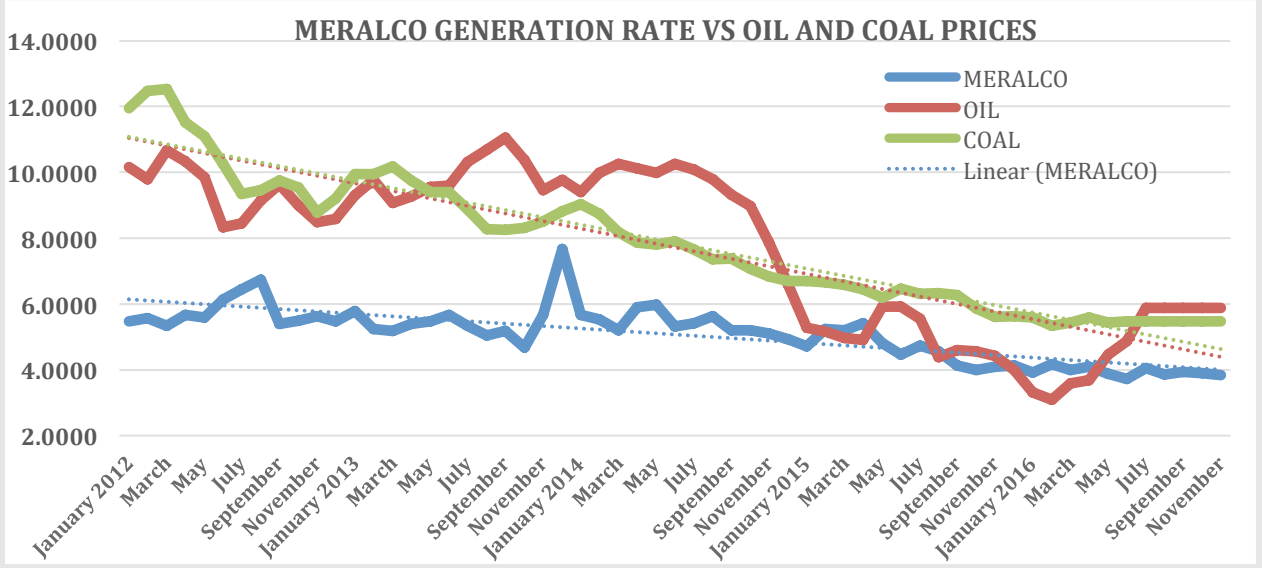
While the EPDP paper focused on the generation sector, it also ignored the fact that international-priced fuels dominate the Philippine electric power industry. The paper put forward the query on how power cost in the country can still be high despite the 25% to 29% share of hydro and geothermal energy in the country's fuel mix. It is common knowledge in the industry that the Philippines prices its indigenous fuels based on international fuel prices e.g. both indigenous natural gas and geothermal steam are priced as imported fuels.

It is also surprising that no analysis was done to understand the direct relationship between international fuel prices and movement in the generation costs over time to

truly determine the reason behind the alleged high power cost. B-LEADERS's graph and its explanation below provide an in-depth analysis between the direct relationship between international fuel prices and generation rates of the country.

Based on the 2015 fuel mix for energy, 88% of the fuel used for power generation is priced based on international markets. This makes the Philippines very vulnerable to spikes in global prices, which are beyond the control of the Philippines. Being tied to the global fuel market is also double-edged since the country can also benefit the Philippines when the international fuel prices are relatively low resulting in lower generation rates at the retail level. This pricing scheme is reflected in Power Supply Agreements (PSAs) not only for all imported fuels such as oil and coal but likewise for indigenous fuels such as geothermal steam which is priced based on coal markets and the Malampaya natural gas, which is priced based on oil markets.

An analysis of the changes in the MERALCO retail generation rates provides insight into the direct relationship between global fuel markets and the cost of generation, particularly in light of the significant amount of coal and natural gas fired generation in their fuel mix. The chart below shows the movement in the MERALCO generation rate compared to global commodity prices for oil and coal. As can be seen from the chart, the recent significant decrease in the MERALCO retail generation rates corresponds with similar decreases in the global price of oil and coal.



The declining international fuel prices led to a significant decrease in MERALCO's generation rate from a high of Php 7.67 per kWh (December 2013) to Php 3.72 per kWh (June 2016) or a more than 50% reduction. Data for the graph was tracked from the monthly publication of MERALCO's generation rates in its website. The generation rate for November 2016 was recorded at Php 3.84 per kWh. Given the sharp decline in MERALO's generation rate, EPDP's claim of perennially high cost of power seems unfounded (page 7, second para).

Global fuel markets respond to changes in supply and demand, consistent with what markets are designed to do. However, it must be remembered that this is a global market not a local market such as what the Philippines has with the Wholesale Electricity Spot Market (WESM). In a global market, a small player like the Philippines is a price taker not a price setter. As such, it is at times the beneficiary of lower prices while at other times it is the victim of high prices. The one thing that can always be counted on is change. This direct relationship between international fuel prices and the country's generation rate only underscores the high risk of price uncertainty for imported fuels. Any serious analysis of fuel mix policy must incorporate this risk factor in the possible future changes in global fuel prices.

Another layer of risk tied to imported fuel prices is the movement of foreign currencies i.e. the exchange rate between the US$ and the Philippine Peso. When the Philippine peso is weak, the cost of international-priced fuels will go up leading to increased electricity cost.

While electricity is an integral input to economic development, there seems to be no direct relationship between generation cost and economic growth. As shown in the table below, the country's Gross Domestic Product (GDP) grew at a high 7.7% in 2010 despite generation cost relatively higher at Php 5.18 per kWh compared to the Php 4.62 per kWh recorded for 2015. This only illustrates that it is important to impute in the study the drivers for economic growth in order to arrive at a meaningful conclusion that can be used for future policy directions.

Year	GDP Growth Rate, %	Generation Rate, MERALCO, Php/kWh
2010	**7.70**	**5.18**
2011	3.70	5.10
2012	6.80	5.75
2013	7.20	5.42
2014	6.10	5.44
2015	5.80	4.62

The EPDP study cited that the goal of Filipino 2040 is to improve the well-being of the Filipinos and identified electricity price as one indicator. B-LEADERS collated data on the share of electricity cost to the total household's (HH's) expenditure across selected countries around the world. Data on electricity expenses, however, are lumped with expenses for other utilities such as water and gas. The succeeding table shows that a Filipino HH spends roughly 8% for electricity, water and gas. Even if electricity cost

makes up the bulk of the 8% share in cost, it is quite clear that electricity price as an indicator may not lead to a solid conclusion with respect to a Filipino's well-being.

Family/Household Income and Expenditure Survey-Data (in US$)					
Country	**Income**	**Expenditure**	**Electricity**	**Percent Share**	**Year**
Sri Lanka	318.80	282.10	11.89	4.21%	2012 (Monthly Average)
Pakistan	247.29	215.51	17.05	7.91%	2012 (Monthly Average)
Timor Leste	377.73	297.28	2.81	0.95%	2012 (Monthly Average)
Maldives	1104.69	876.77	199.90	22.80%	2009/2010 (Monthly Average)
Thailand	721.82	546.10	23.61	4.32%	2013 (Monthly Average)
Malaysia	1467.73	855.16	204.38	23.90%	2014 (Montly Average)
Japan	4477.86	3536.46	86.78	2.45%	2015 (Monthly Average)
United States of America	69629.00	55978.00	3885.00	6.94%	2015 (Annual)
Philippines	5537.48	4455.84	352.76	7.91	2015 (Annual)
South Africa	8827.43	7028.67	2252.60	32.00%	2011/2012 (Annual)

SOURCE: Data was sourced from different Household/Family Income and Expenditure Surveys from each respective nation indicated above. Parameters may vary from nation to nation.

II. Policy Scenarios

The EPDP presented 4 scenarios, all of which are not realistic enough to incorporate actual facts and best data as of the time of the study.

Policy 1: Balanced aspiration of 30% (coal), 30% (natural gas), 30% (renewable energy) and 10% (others).

It is unclear in the study how the country can attain a 30% share of natural gas in its fuel mix. The natural gas component never reached a 30% share of the generation mix since the power plants were constructed in the late 1990s. The table below shows that natural gas share ranged between a high of almost 18% in 2010 to a lower 15% in 2015 for the country.

Fuel Technology	**2000**	**2005**	**2010**	**2015**
Oil Based	37.8%	23.5%	19.5%	19.2%
Hydro	17.5%	20.6%	20.8%	19.2%
Geothermal	14.6%	12.7%	12.0%	10.2%
Coal	30.1%	25.4%	29.7%	31.8%
New RE	0.0%	0.2%	0.4%	4.3%
Natural Gas	0.0%	17.7%	17.5%	15.3%
Total	100.0%	100.0%	100.0%	100.0%

EPDP's claim of the 41% share of natural gas to Luzon's installed capacity is baseless (page 34, 1st para). Even with the addition of increased capacity for San Lorenzo natural gas power plant, the total installed capacity of this fuel technology stands at 2871 MW, or 20% of Luzon's installed capacity for the period January to June 2016. This data from the DOE (https://www.doe.gov.ph/electric-power/january-june-2016-power-situation-highlights) is shown in the table below:

Luzon Installed, Dependable and Available Capacity from January-June 2016 (in MW)

Luzon					
Fuel Type	Installed	Dependable	Available		
			Min	Max	Average
Coal	**5,247**	**4,928**	**2,419**	**4,848**	**3896**
Oil Based	**2,133**	**1,785**	**720**	**1,446**	**1,233**
Natural Gas*	**2,871**	**2,780**	**2,115**	**2,758**	**2,688**
Renewable Energy	**4,098**	**3,616**	**1,458**	**3,342**	**2,544**
Geothermal	*844*	*777*	*378*	*511*	*482*
*Hydro**	*2,537*	*2,271*	*1,058*	*2,280*	*1,827*
Wind	*337*	*293*	*1*	*286*	*82*
Biomass	*95*	*71*	*20*	*60*	*46*
Solar	*284*	*204*	*1*	*205*	*107*
TOTAL	**14,348**	**13,109**	**6,712**	**12,394**	**10,361**

The 30% share for natural gas cannot be achieved without taking into consideration possible entry of new natural gas technology like the LNG (liquefied natural gas) technology. However, such inclusion will significantly change the cost dynamics for fossil-based fuels. Based on current negotiations, LNG costs will include guaranteed payments for both capacity and fuel and will likely entail massive infrastructure costs to operationalize. To exclude the cost of LNG in this scenario is a flawed approach for future policy decisions with respect to the fuel mix.

EPDP likewise ignored the more than 4500 MW of coal-fired power plants that are expected to become commercially operating by 2020. Keeping the share of coal-fired power plants to 30% share even under a numerical exercise is impossible without any discussion on potential impact of stranded generating assets that have fixed capacity payment provision in power supply agreements.

EPDP placed the coal share to 22% in Mindanao grid by 2020 despite the 1500 MW of coal fired power plants that will be operational by that year. In a presentation by the Mindanao Development Authority (MinDA) during the launching of the European Union (EU)-funded Access to Sustainable Energy Programme (ASEP), MinDA revealed a complete reversal in the grid's capacity mix from a predominantly-hydro run power

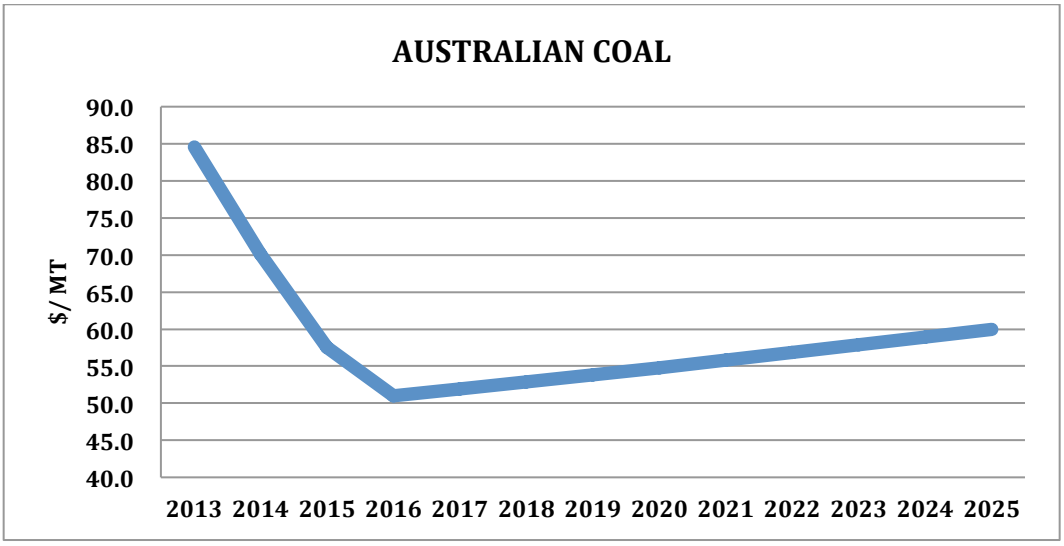
system to a grid dominated by coal estimated to be roughly 60% to 70% of the total grid's installed capacity.

Summarized below is a list of committed coal-fired power plants expected to be operating by 2020:

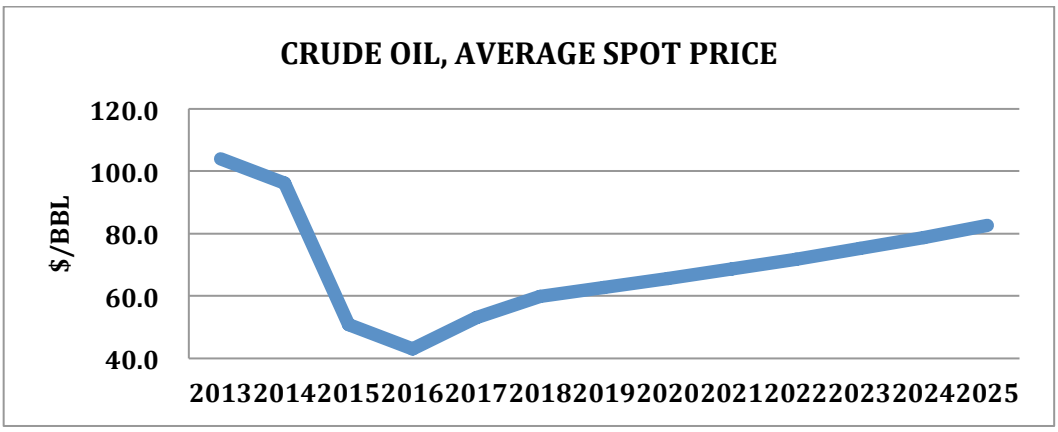
Committed Power Plants (Luzon)	Project Proponent	Start Year	MW
Limay Power Plant Project Phase I	SMC Consolidated Power Corporation	2016/2017	300
Pagbilao Coal-Fired Thermal Power Plant	Pagbilao Energy Corporation	2017	420
San Buenaventura Power Plant	MERALCO Power Gen Corporation	2018	500
Masinloc Expansion Project	AES Masinloc Power	2019	300
GN Power Dinginin Power Plant	Ayala Energy & Infrastructure Group	2019	1200
Total			2720
Committed Power Plants (Visayas)	Project Proponent	Start Year	MW
PEDC Expansion Project	Panay Energy Development Corporation (Global Business Power Corporation)	2016	150
Palm Concepcion Coal-Fired Power Plant	Palm Concepcion Power Corp. (Formerly DMCI Concepcion Power Corp.)	2018	135
Total			285
Committed Power Plants (Mindanao)	Project Proponent	Start Year	MW
SMC Davao Power Plant Project	San Miguel Consolidated Power Corporation	2016	300
FDC-Misamis Circulating Fluidized Bed (CFB) Coal-Fired Power Plant Project	FDC Utilities, Inc.	2016	405
Balingasag Thermal Circulating Fluidized Bed Combustion (CFBC) Coal-Fired Power Plant	Minergy Coal Corporation	2016	165
GNPower Kauswagan Clean Coal-Fired Power Plant	GN Power Kauswagan Ltd. Co.	2017	540
Southern Mindanao Coal Fired Power Station	Sarangani Energy Corporation	2018	100
Total			1510
Grand Total			4515
Data Source: DOE Private Sector Initiated Power Projects as of September 2016			

EPDP also used 2015 average generation charges "in the absence of data to enable forecasting future price trends". This is a serious flawed assumption in the study particularly as the study is focused on reducing electricity costs and electricity price as an indicator for the improved well-being of a Filipino. There is a wealth of sources that can be used to forecast international fuel prices both for fossil-based and renewable energy sources.

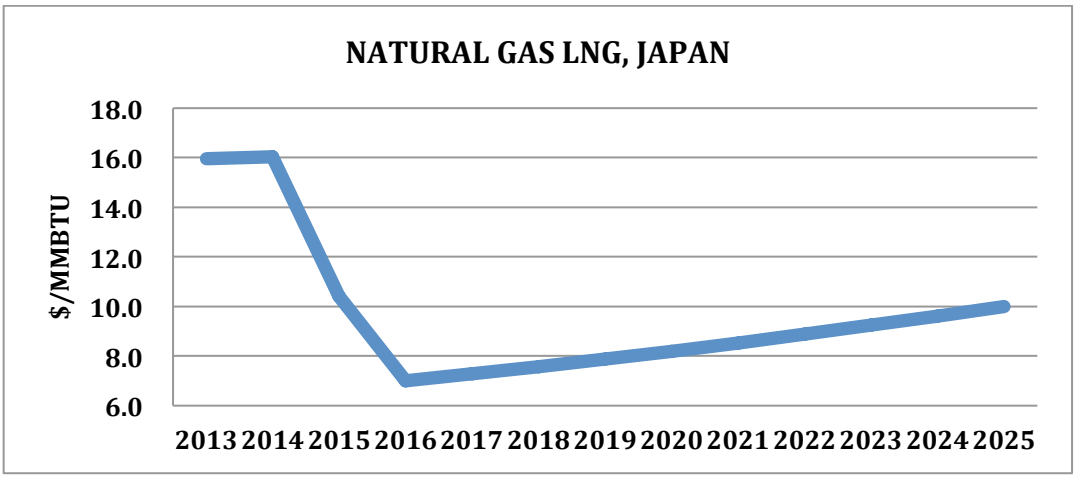
Keeping the price of fossil fuels to 2015 levels does not create a level playing field for cost analytics across the various fuel technologies particularly the diverging price trends for coal and LNG compared to wind and solar energy. The World Bank projects the price of Australian coal to increase gradually beginning 2019 and climbing up steadily up to 2025 as shown in the graph below. It should be noted that most coal-based power supply agreements use the Newcastle coal index in its fuel adjustment. It should also be emphasized that the country's geothermal steam cost is linked to the international price of coal; as such, when coal prices go up, steam cost is expected to increase as well.



A similar increasing price trend is noted by the World Bank for crude oil, which will have an impact on the price of indigenous natural gas.



If LNG technology is to be considered in the future, its fuel cost is also expected to go up beginning 2019 up to 2025.



In contrast, the prices for renewable energy notably wind and solar are projected to sharply decline.

The International Renewable Energy Agency (IRENA) in its June 2016 report entitled The Power to Change states that "*Indeed, by 2025 the global weighted average levelised cost of electricity (LCOE) of solar photovoltaics (PV) could fall by as much as 59%, the LCOE of concentrating solar power (CSP) could fall by up to 43%. Onshore and offshore wind could see declines of 26% and 35%, respectively".*

Other highly recognized international institutions such as the National Renewable Energy (NREL), US Energy Information Agency (USEIA), World Bank posit similar downward cost projections for solar and wind energy. In light of the diverging trajectory paths for the costs of fossil fuel compared to renewable energy, keeping 2015 prices constant up to 2040 is a serious flawed assumption that misleads and misinforms government policy decision makers.

B-LEADERS collated data from 118 distribution utilities to establish the average generation cost for each fuel technology in 2015. The team segregated the cost for subcritical coal and circulating fluidized bed coal technology. Below is a summary of these fuel technologies for each grid:

2015 Average Generation Rate per Fuel Technology (In Php/kWh)							
	Geothermal	Hydro	Oil Thermal	Coal Subcritical	Coal CFBC	Diesel	Natural Gas
Luzon	5.39	5.01	9.93	4.23		12.11	4.41
Visayas	5.11	5.02	5.31	5.23	5.54	9.25	
Mindanao		3.45		4.00		6.20	
Total Philippines	5.12	3.73	7.65	4.30	5.54	7.27	4.41
Data Source: Uniform Reporting Requirements of DUs as submitted to the ERC							

It is not clear how EPDP developed its generation rates as shown on Table 4, page 21.

Policy 2: Temporary Utilization of the Lesser Cost Resource

Since EPDP kept 2015 generating costs all throughout the study until 2040, the outcome for this scenario is likewise misleading and should not even be considered for future policy decisions. This shortcoming should be highlighted in view of the increasing trends in projected costs for imported fuels. It should also be emphasized that electricity rates will also be adversely affected by the deteriorating currency exchange rate between the US$ and Philippine peso for imported fuels.

In the study, EPDP projects a reduction in electricity price of approximately 1.37% because it ignored the increasing trends for cost of imported fuels. A "real simulation, not simply a numerical exercise" including the potential impact of a weakening Philippine peso may indicate the opposite result – conventional fossil fuels may show increased levels compared to 2015 prices.

Policy 3: Increase Utilization of Conventional Renewable Energy (Hydro and Geothermal Resources)

EPDP ignored 2 very critical facts related to this policy scenario: a) DOE and the private sector admit that the country has very limited potential geothermal resource for future development and b) generation output from hydro power plants will be uncertain in light of the projected drier years for the Philippines in the next decade. EPDP, however, included a caveat in its paper for policy #3 as stated: " xxx the fuel share for conventional renewables is for illustration purposes only xxx" (page 15, 1st para). Given this caveat, government decision makers should not even find time to understand a policy scenario for illustration purposes only.

Policy 4: Increase Utilization of Variable Renewable Energy

EPDP assumed that Feed-in Tariffs (FiTs) would still be implemented until 2040 – reduced only annually by the degradation rate. This assumption is highly unrealistic and defeats the rationale behind FiTs, ignored the more than the degradation rate reduction between FiTs 1 and 2 for wind and solar and completely disregarded the significant reduction in the cost of technologies for these variable renewable energy.

Policy 4 could have been a window of opportunity to demonstrate best practices around the world on the implementation of FiTs. Summarized hereunder is a selection of such best practices:

COUNTRY	FEED-IN TARIFF POLICY	START	STATUS	END
Germany	2017 Amendment of the Renewable Energy Sources Act (EEG 2017)	2017 (January 1st)	In force (as EEG). *Note:* Original EEG was passed in 2000.	Not specified, although the 2017 EEG reform introduces public tender procedures for onshore wind, offshore wind, solar and biomass projects in country's efforts to shift from FIT support RE deployment to market orientated price finding mechanism. With that, projects will no longer be eligible for statuary FIT remuneration but will have to bid for it in public auction. Successful projects will receive contracts for duration of 20 years for sell of the produced electricity at the price that they bid during the auction process. The amendment stipulates capacity corridors for technology deployment in order to control capacity volumes commissioned each year.
Canada (Ontario)	Ontario Feed-in Tariff Programme	2009 (amended 2012)	In force	Not specified.
Mexico	N/A	N/A	FIT policy not yet passed	In lieu of FIT, Mexico has opted to implement reverse power auctions, the first of which launched at the end of March 2016
China	Feed-in tariff support for solar PV	2013 (last updated 2016)	In force	The feed-in tariff support is granted for period of 20 years.
China	Offshore wind power electricity price policy	2014 (June 5th)	In force	2017 (Dec 31st)
Spain	New tariff regulation for the production of photovoltaic electrical energy (Royal Decree 1565/2010)	2010 (adjusted 2011)	Ended	2014. Royal Decree 1565/2010 seeks to modify the support framework provided for RE projects by cutting financial support, especially to PV electricity production. Existing FITs for the installations under the previous framework will be cut down by: - 5% for small-size roof installations. - 25% for medium-size (21 to 100 kW) roof installation. - 45% for ground installations.

COUNTRY	FEED-IN TARIFF POLICY	START	STATUS	END
Spain	New regulation on electrical energy from wind and thermal electric technologies (Royal Decree 1614/2010)	2010	Ended	2014. The Royal Decree first adjusts electricity FITs allocated to wind generated power. The latest will be cut down by 35% as from early 2011. The aim of such a cut is to generated important savings and adapt to new market structures. It also establishes a share of equivalent generated hour per year. Once that limit is reached, the excess electricity generated by that particular installation during that particular year will not be entitled for any financial support.
Indonesia	Electricity Purchase from Small and Medium Scale Renewable Energy and Excess Power (No. 4/2012)	2012 (June 2nd)	In force	The Ministerial Regulation does not specify how long eligible renewable plants will benefit from introduced tariff. The policy introduces differentiated FIT levels in Indonesia, depending on the installation type, its location and voltage of grid interconnection. Following technologies benefit from the scheme: Biomass, biogas, municipal waste and hydropower plants below generation capacity of 10 MW.
Malaysia	Renewable Energy Act establishing feed-in tariff (FIT) system	2011 (last updated 2016)	In force	The policy established Malaysia's FIT system with an annual installed capacity caps to 2030. FITs are ranging over a 21 year period for PV and mini hydro and 16 year period for biomass and biogas.
Thailand	Feed-in premium for renewable power	2007 (modified 2009)	In force, but superseded in the case of Very Small Power Producers (VSPP)	Provided for between seven to ten years, with a "special adder" provided for Thailand's three southern provinces or remote areas.
Thailand	Feed-in Tariff for Very Small Power Producers (VSPP), excluding solar PV	2014 (Dec 15th)	In force	The new FIT will be granted for 20 years, an exception being power systems fuelled by landfill gas which will receive support for 10 years only. The FIT rates differ greatly on power plant size and fuel types and different bonuses are being granted for certain systems.
South Africa	Renewable Energy Feed-in Tariff (REFIT)	2009 (modified 2011)	2011 March	In 2011, the South African Department of Energy revised its renewable energy strategy, switching from the REFIT remuneration system to a procurement process based on price competition.

Armed with the knowledge of decreasing cost technologies for wind and solar energy complemented with best practices around the globe Policy 4 could have been used to illustrate the future pathway for FiTs in the Philippines. The study could have

proposed an end to FiTs regime by 2019 and shifting to other best practices such as reverse auctions (Mexico) and price challenges (South Africa).

III. Carbon Tax

The cost benefit analysis (CBA) study, which became the integral input to the country's formulation of its Intended Nationally Determined Contribution (INDC) provided benchmark levels for health co-benefits that can be used as basis for future carbon taxes.

Below is an excerpt from the CBA on co-benefits for selected mitigation actions:

Mitigation Option	Co-benefits Compared to Baseline (Cumulative 2015-2050) [Billion 2010 USD] Discounted at 5%				Cost per Ton Mitigation (2015-2050) [2010 USD]
	Health	Congestion	Income Generation	**Total Co-benefit**	*co-benefits only*
Biomass Co-firing	4.7			5	-66
Cement Waste Heat Recovery	0.06			0.06	-5.80
Gas for Coal	14.9			15	-98
NREP Biomass	0.1			0.10	-6.35
NREP Geothermal	3.0			3.02	-15.94
NREP Large Hydro	3.6			3.57	-12.43
NREP Ocean	0.2			0.16	-18.39
NREP Small Hydro	0.7			0.72	-16.15
NREP Solar	0.1			0.13	-15.53
NREP Wind	1.8			1.82	-18.76
Street Lighting - Efficient High Pressure Sodium	0.06			0.06	-5.12
Street Lighting - Light Emitting Diode	0.15			0.15	-10.20

The carbon tax shown in the EPDP study seems very low and insignificant. It is also not clear if the methodology is internationally accepted.

IV. Energy Security

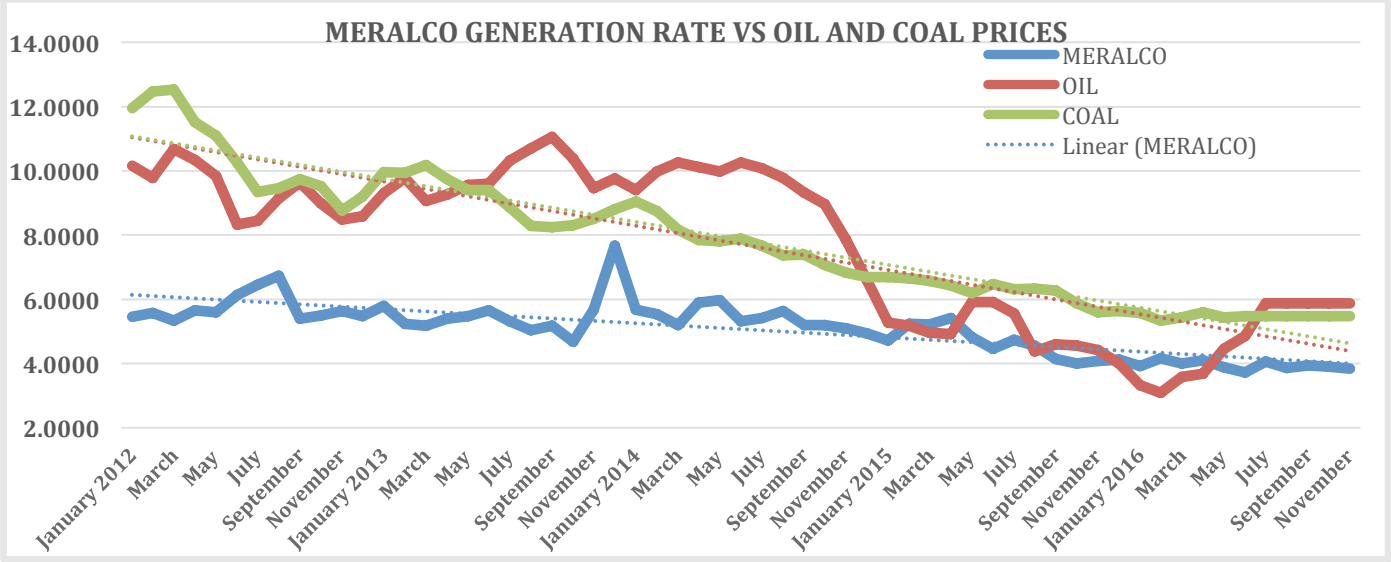
EPDP defined the following parameters as components of energy security:

A. Accessibility

It has to be noted that not all fuel technologies can be applicable to use for isolated and remote islands to increase energy access. Aside from line extension, which may be uneconomical in the long-run, only specific hybrid technologies (fossil/RE) may have the capability to service unserved areas at the moment due to remoteness and isolation. Diesel is the most favored fuel technology but is at the highest in the cost hierarchy of fuels. With solar technology going down significantly, complemented with improved technological innovation, it is highly likely that diesel/solar or natural gas/solar or even a hybrid of renewable energy may be the most economical energy solutions for rural communities.

B. Affordability

EPDP states that the indicator for affordability is the price that consumers pay (page 38, 1st para). Yet, the study ignored price risks arising from imported fuel and the uncertainty international fuel prices bring into the Philippine electric power industry. Shown again below is the chart that clearly indicates how the Philippine generation rates are impacted by international fuel prices. As such, it is too difficult to even claim that fossil fuels present the least cost resource for the country particularly in light of the fast decreasing cost for variable renewable energy such as solar and wind.



C. Reliability

This is the last parameter for energy security. It has to be emphasized that reliability has a price; a target loss of load expectation (LOLE) of 1.1 days a year (page 39, 1st para) may come at a steep cost. EPDP should not compare the Philippines' LOLE to the LOLEs of developed economies such as the US and Europe. These countries have neighbors from which they can "borrow" or import energy. As such, improving their respective LOLEs need not come at a price but may be the

product of better coordination with their neighbors. The Philippines, on the other hand, is an archipelago, made up of separate islands. Aspiring for a higher reliability may not be consistent with keeping electricity rates lower since reliability can only mean redundancy in power supply in anticipation of forced outages.

V. Conclusion

EPDP concludes that the government should not prescribe a fuel mix policy but make the markets work. Markets for us do not necessarily mean domestic markets but likewise heavily involves international markets particularly for fuel. While government should not prescribe a fixed fuel mix policy, the government should provide the signal on the type of fuel technology that the energy sector needs to achieve its economic goals.

If keeping the costs down is paramount to this study, EPDP should have focused on the capacity factors of power plants, particularly of base load power plants. Operating these power plants at below their maximum plant factors lead to higher costs and the government should determine the reasons and eventual solutions to maximize the operations of the supposedly cheaper base load power plants.