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FILIPINO 2040
POWER SECURITY AND COMPETITIVENESS*

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Abstract

The Filipinos' vision for themselves by 2040 is for them to enjoy a stable and comfortable lifestyle, having enough for their daily needs and unforeseen expenses, so they can plan and prepare for their own and their children's futures. This paper looks at one major commodity that bears heavily on every Filipino consumer's expenses: electricity. By focusing on the generation sector, it presents two possible scenarios for the next 25 years and illustrates how policy reforms on fuel mix can potentially reduce blended generation charges that make up 47% of the total electric bill of households. This paper also provides an assessment of the power sector's performance and suggests broad key reforms and alternative pathways needed for the sector to contribute to the overall vision of a strong-growth economy and improved well-being of Filipinos by 2040.

Keywords: Electricity industry, scenario-building, reforms, Philippines

JEL: Q41, Q42, Q43, Q47, Q48

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Energy: Power Security and Competitiveness

M. Ravago, R. Fabella, R. Alonzo, R. Danao, and D. Mapa

INTRODUCTION

According to one set of official projections, if the Philippine economy were to grow at 7% per annum, close to the rate achieved in recent years, then by 2040 the country's per capita income would be PhP316,173 ($6,873) at constant 2000 prices[3]—a sharp increase from the 2015 level of PhP74,453 ($1,618). This is an optimistic forecast, given that annual per capita income growth over the past 25 years averaged only about 2%. The impressive growth attained during the period 2011-2016 was mainly driven by private and government consumption, which was, in turn, partly fueled by overseas Filipinos' remittances (BSP 2015).

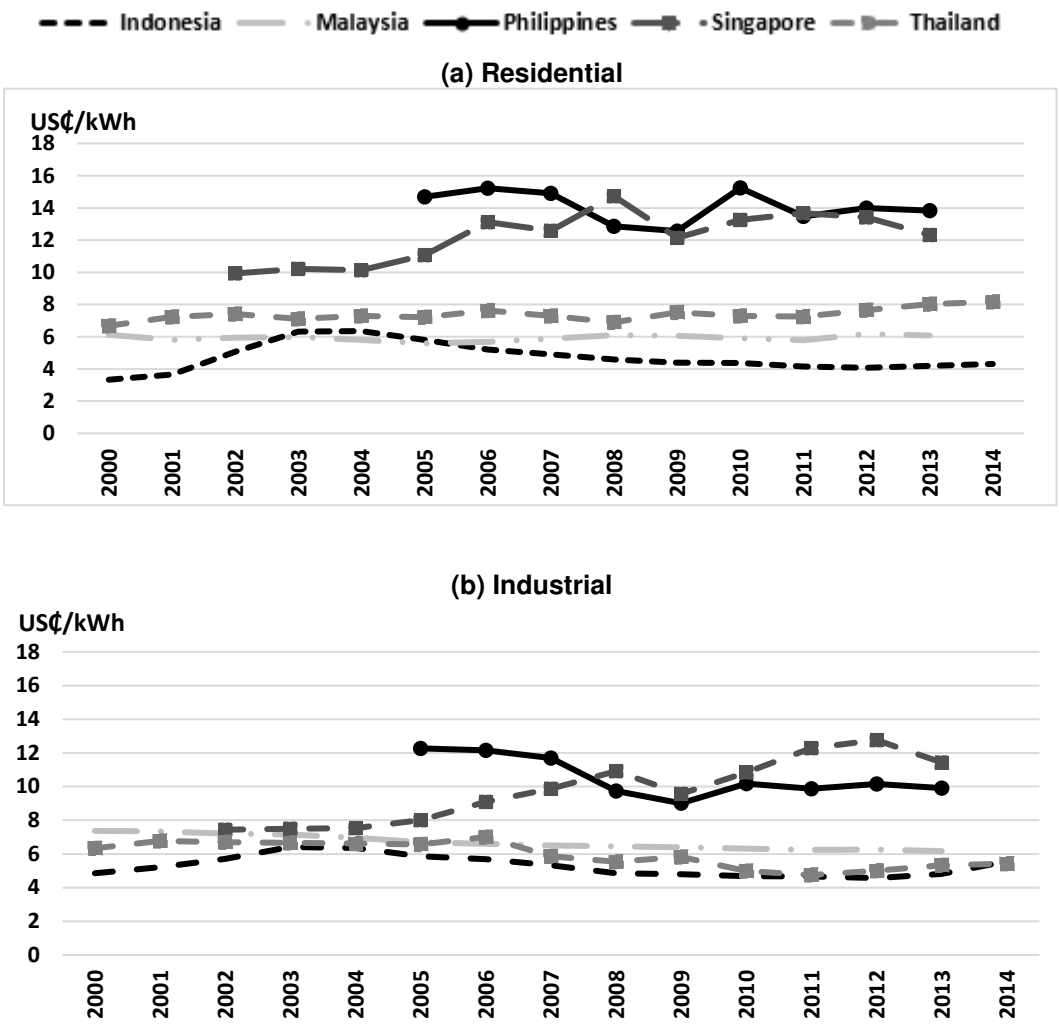
The sustainability of the recent growth remains tenuous. One constraint is the perennially high cost of power, as well as an inadequate power supply that cannot support the country's potential growth. The challenge lies in both the sourcing and timing of additional power supply to meet the growing demand and avert a recurrence of the power crisis that occurred in the early 1990s, while also reducing the cost of power. Energy supply and cost are central to an improved investment climate that in turn generates a higher productivity growth.

Philippine power costs are high by regional standards; within the Association of Southeast Asian Nations (ASEAN), it ranks second to Singapore. Thus, the country struggles to attract mobile capital, a reason why manufacturing growth has lagged in recent decades. We have elsewhere labeled the slower manufacturing growth compared to services as "development progeria" (Daway and Fabella 2015), where services forge ahead to developed-country levels in low-income countries. This translates into slow growth and slow poverty reduction.

Republic Act (RA) 9136, otherwise known as the Electric Power Industry Reform Act (EPIRA) of 2001, has the well-intentioned objective of opening up access to, and fostering competition in, the retail supply of electricity, so as to lower the price for consumers. However, electricity prices in the Philippines remain among the highest in Asia. Figure 1 shows the trend in electricity tariffs for residential and industrial customers in selected Asian economies. In 2013, for example, the Philippines' residential rate was $0.14/kWh, much higher than the rate in Singapore ($0.12/kWh), Thailand ($0.08/kWh), Indonesia ($0.04/kWh), and Malaysia ($0.06/kWh). The same trend is observed for industrial tariffs among these countries except for Singapore whose industrial rate ($0.11/kWh) is higher than the Philippines' ($0.10/kWh).

[3] For this paper, the currency exchange rate used is PhP46 = US$1.

Figure 1: Electricity Tariffs in Selected Asian Economies, constant 2005 US$



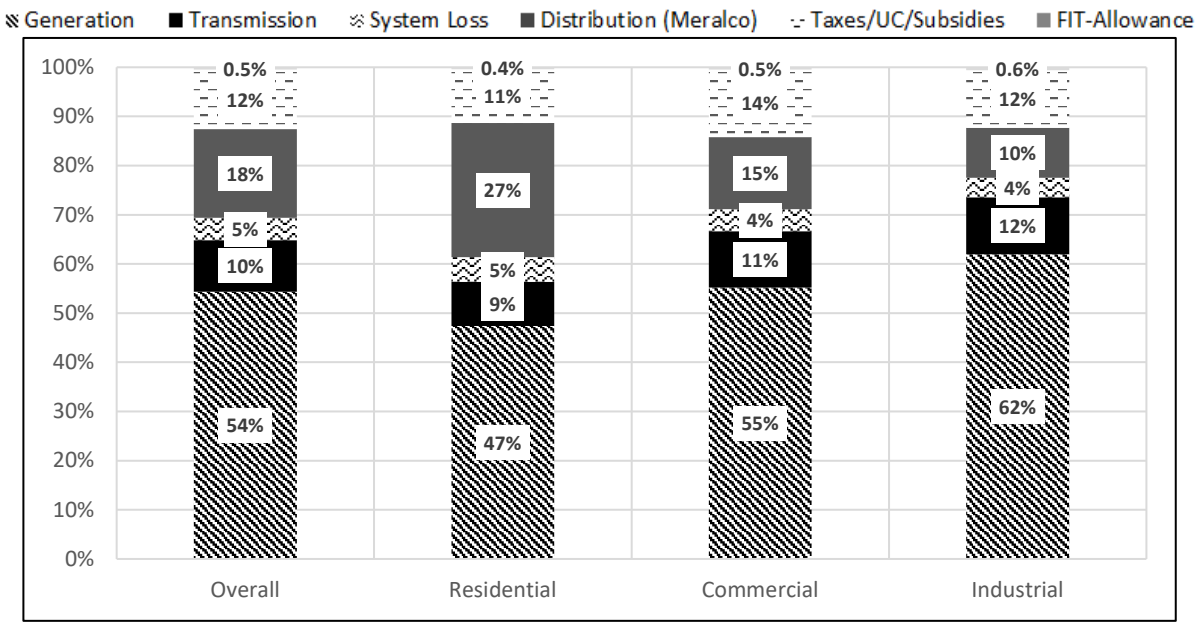
Source of basic price data: Enerdata. n.d. "Energy data."

Several factors explain the Philippines' high power cost despite the fact that 25-29% of its fuel source is from relatively lower-cost hydro and geothermal. As will be explained below, these include fuel mix, taxes and subsidies, low reserves and low generation capacity per capita, average size of generation plants, overall efficiency, volatility, and absence of competition in Power Supply Agreement (PSA) contracting (Fabella 2016).

The EPIRA mandates all industry participants to unbundle their own operations according to their functions and, consequently, unbundle their rates, charges, and costs. Figure 2 shows the breakdown of Meralco's (Manila Electric Company) tariff for its residential, commercial, and industrial customers. With regard to the retail price of electricity for residential consumers, a household that consumes about 200 kWh a month in Meralco's franchise area has a monthly bill of about PhP1,888 ($41), using the average price of PhP9.68/kWh in 2015. This household would typically have a refrigerator, electric fan, flat iron, TV set, and radio. For residential consumers, generation charges make up 47.4% of the bill, followed by distribution charges that include supply and metering at 27.2%. Transmission charges make up about 9%.

Transmission losses are about 5%. Taxes and subsidies are 11% and the feed-in tariff (FIT) allowance is 0.4%.

Figure 2: Manila Electric Company's (Meralco) Breakdown of Tariff



Source of basic data: Meralco, 2015, "Average Rates by Customer Class and Billing Component."

In this paper, we focus on the generation sector. We present two possible forward-looking scenarios running up to 2040 to illustrate how policy reforms with regard to fuel mix can potentially lower power rates. A significant reduction in the blended generation charges that make up 47.4% of the total bill will clearly improve the economic well-being of Filipino consumers. The numerical computation illustrates that to bring the price of power down, the fuel mix would not be constant over time but should exploit the opportunities opened up by less costly resources while taking environmental (including health) costs into account. We also provide an assessment of the power sector's performance and suggest broad key reforms and alternative pathways needed for the sector to contribute to the overall vision of a strong-growth economy.

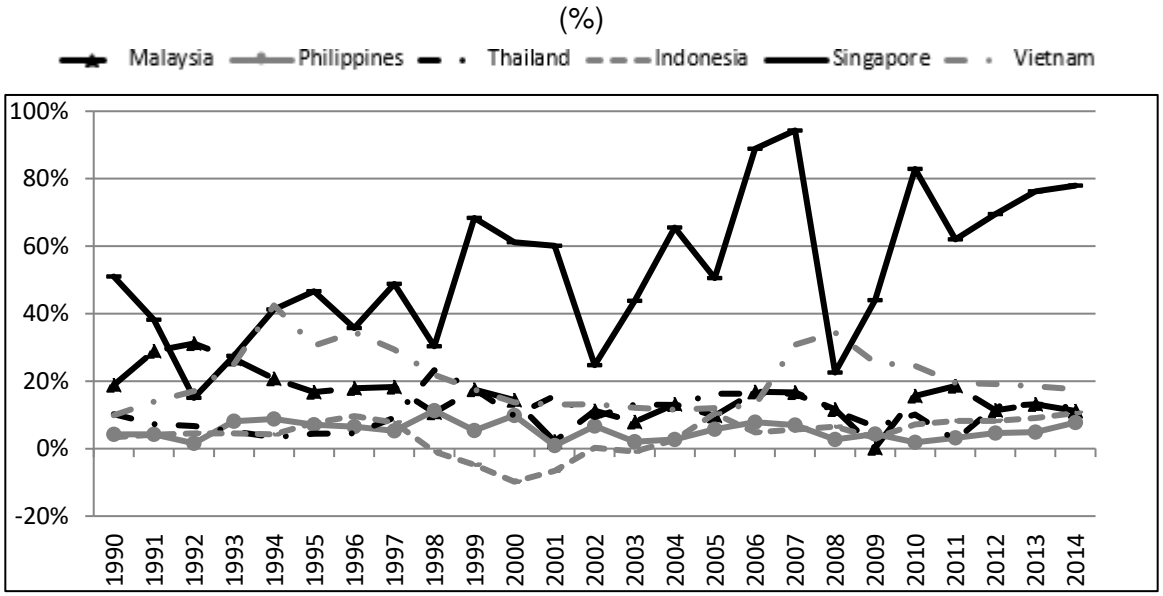
I. BASELINE ASSESSMENT OF POWER SECTOR PERFORMANCE

The sustainability of the economic growth during the last four years remains tenuous. The Philippine investment rate has remained at well below 25% of Gross Domestic Product (GDP) while the saving rate is now at 25% of GDP—making the Philippines a net lender to the world. Government investment, as percentage of GDP, remains at less than its target level of 5%. To achieve the *Filipino 2040* vision, growth must quickly become investment-driven with the investment rate at 25-27% of GDP. This would mean a government capital outlay of 6-7% and a private investment rate of 21-22%. This is an immense departure from the historical level of approximately 1.5% of GDP for government infrastructure spending and 17% for the private investment rate.

These investment targets have not been attained in the last quarter century. On the one hand, the government will be hard-pressed to try to reach this level of government capital outlay unless it addresses the causes of the spending gridlock and miserable absorptive capacity. This problem cannot be addressed by simply creating facile corruption-prone programs of entitlements (e.g. Priority Development Assistance Fund). An increase in Government Contracting Activity (GCA) is a way to address this. On the other hand, the private investment rate will not rise to desired levels unless the known traditional hurdles to investment are cleared: the almost unbearably lengthy, costly licensing procedures; the highly uncertain and sometimes inconsistent nature of regulation; the high cost of doing business; and the closing off of many areas (agriculture and mining) to large-scale investment projects.

One sizeable source of investment is Foreign Direct Investment (FDI) which the Philippines has repeatedly rebuffed. The country's share in total FDI in the ASEAN is only about 1% (Figure 3). Investment-friendliness is far from being the Philippines' competitive strength.

Figure 3: Philippine Share in Net Foreign Direct Investment into the ASEAN



Source of basic data: WDI-WB.

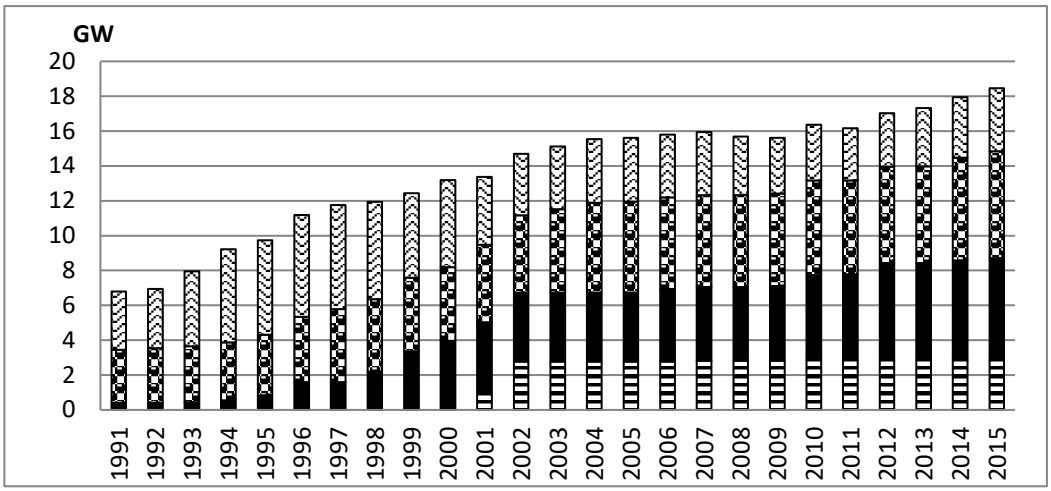
After the passage of the EPIRA in 2001, the power industry underwent a major shift in structure, from a predominantly government-led monopoly in generation and transmission to a private sector-led and more competitive environment. This has brought expectations that

electricity prices will eventually go down due to forthcoming new investments in power generation. Some 14 years after EPIRA (RA 9136) was passed, significant milestones have been achieved, including the establishment of the Wholesale Electricity Spot Market (WESM), the removal of some cross-subsidies and unbundling of functions to reflect their true costs, and the establishment of the Energy Regulatory Commission (ERC) and the Joint Congressional Power Commission to enhance oversight. However, delays in the privatization of assets and transfer of management of the contracted generation companies under Independent Power Producers (IPPs) to IPP administrators have pushed back the end-goal of establishing the Retail Competition and Open Access (RCOA) in the power sector.

A. Resource Availability and Power Consumption Mix

Figure 4 shows the trend in the country's installed capacity from 1991 to 2015. After the EPIRA, new investments in natural gas and additional coal came online, and the expansion of geothermal and hydro replaced some of the more expensive diesel. The passage of RA 9513 or the Renewable Energy (RE) Law in 2008 triggered the addition of wind and solar power generation sources into the country's installed capacity.

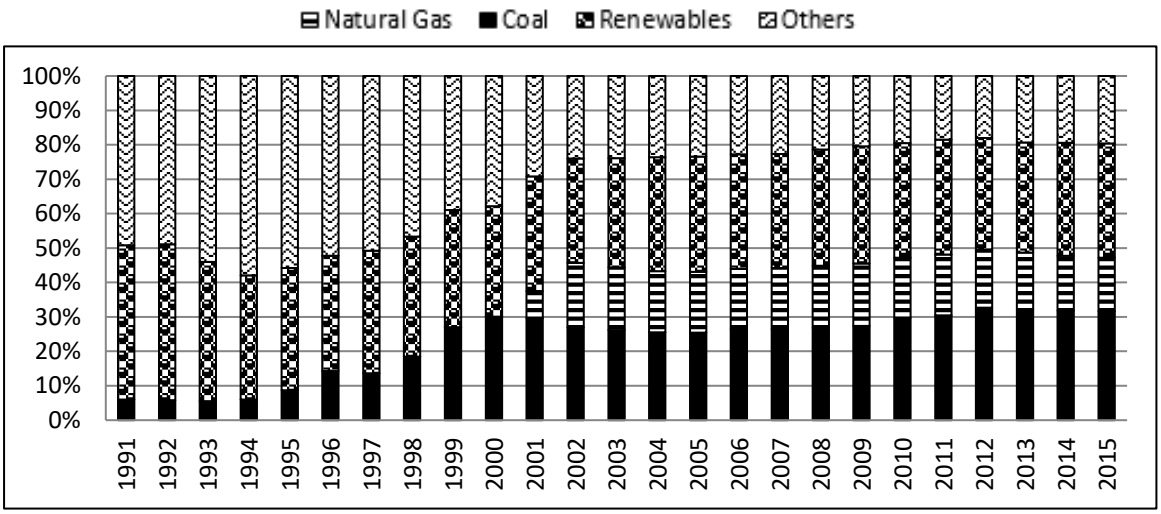
Figure 4: Installed Capacity* by Level, 1991-2015



Source of basic data: DOE.
*Installed capacity is the amount of power that a station is able to produce.
Note: "Renewables" include hydropower, geothermal, wind, solar, and biomass; "Others" include oil-based products, petroleum, and diesel.

For the past 20 years, the country has observed a good "green energy" share in its power consumption mix. Green energy refers to the combination of renewable energy sources and natural gas. Figure 5 shows the trend in installed capacity mix by fuel source from 1991 to 2015. In the early 1990s, the capacity mix was composed mostly of renewable energy and diesel. As new sources came online, the mix became more diverse and included natural gas after 2001. By 2015, coal constituted 32% of the mix, renewable energy 33%, natural gas 15%, and the remaining 20% consisted of diesel, bunker fuel, and other oil-based products. The RE Law of 2008 encouraged investments in renewable energy production in solar, wind, biomass, and run-off-river hydro, expanding the green energy share in generation capacity.

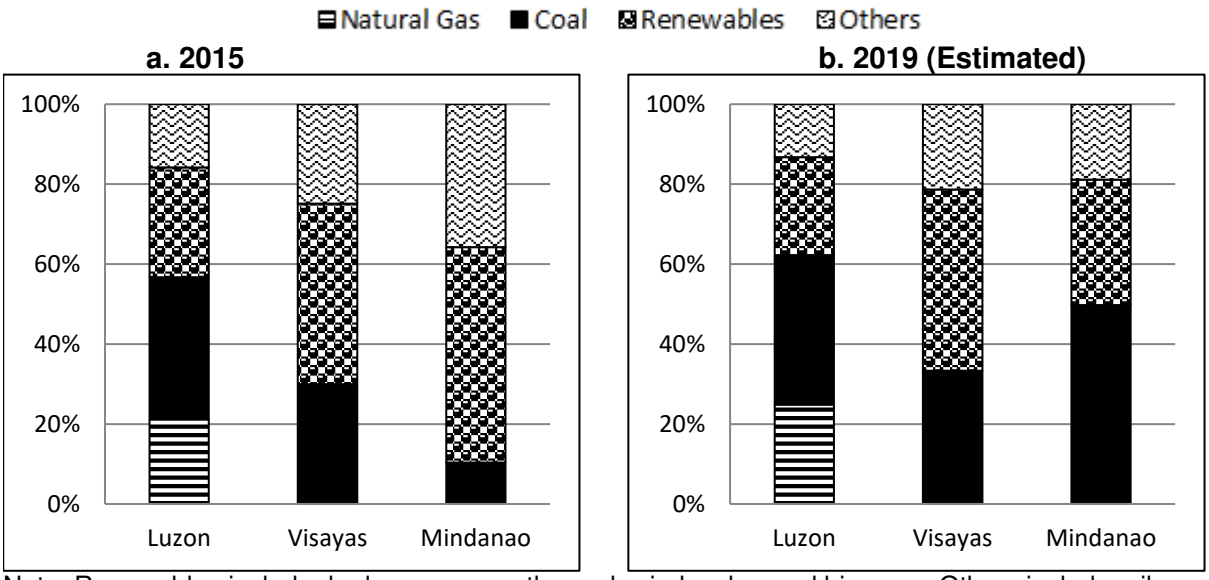
Figure 5: Installed Capacity by Percent Share, 1991-2015



Source of basic data: DOE
Note: "Renewables" include hydropower, geothermal, wind, solar, and biomass. "Others" include oil-based products, petroleum, and diesel. Off-grid generator not included in installed capacity.

By grid, the capacity mix varies as may be dictated by location and basic resource availability (see Figure 6a). Following the major island groupings of the country, the national electricity grid is divided into Luzon, Visayas and Mindanao. Natural gas production is found only in Luzon, and constitutes 41% of the grid capacity. Coal production is largest in the Luzon grid at 36%. In the Visayas grid, renewable energy, mainly geothermal, has the largest share at 36% of grid capacity. Coal also occupies a substantial share at 30%, followed by oil-based sources, including diesel and petroleum, at 25%. In Mindanao, renewables have the biggest share at 54%, with hydro dominating at 47% of the total grid capacity. Coal is small at 10%. Figure 6b shows the projected capacity mix in 2019, including the committed and indicative projects in the three grids. When the generation plants all go online, capacity mix on the three grids will be varied, especially in Mindanao where more coal will figure in the mix.

Figure 6: Fuel Capacity Mix by Grid and by Source
(% Share)



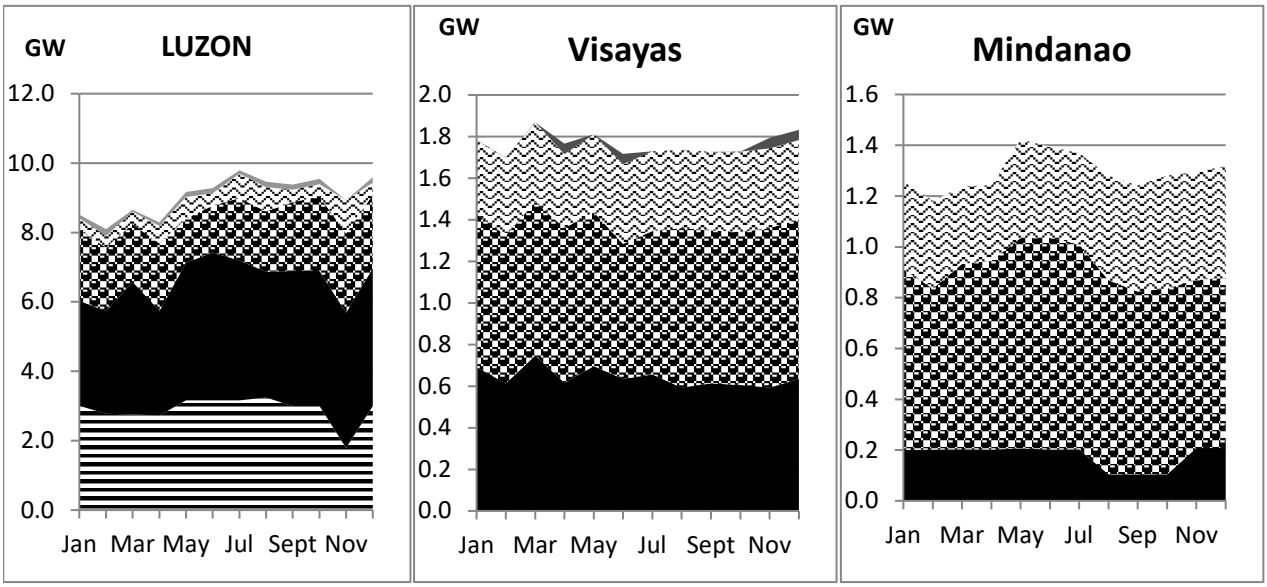
Note: Renewables include: hydropower, geothermal, wind, solar, and biomass. Others include: oil-based products, diesel, and petroleum.
Source of basic data: DOE

B. Load (Consumption) Profile

In terms of power consumption, Figure 7 shows the monthly load (consumption) curve in 2013, and Figure 8 shows the typical daily load curve in Luzon, Visayas, and Mindanao in 2014. For Luzon, demand usually peaks during the summer season, mainly driven by residential use of air-conditioning units and electricity consumption of industries. On a daily basis, power consumption on weekdays starts to rise at 7:00 a.m., as people prepare for their daily routine, then peaks at around 11 a.m.-12 noon. From the mid-day peak, consumption goes down and reaches a trough between 4:00-5:00 p.m., when people are traveling home, then peaks again at around 7:00 p.m. Daily off-peak is from 1:00-6:00 a.m.

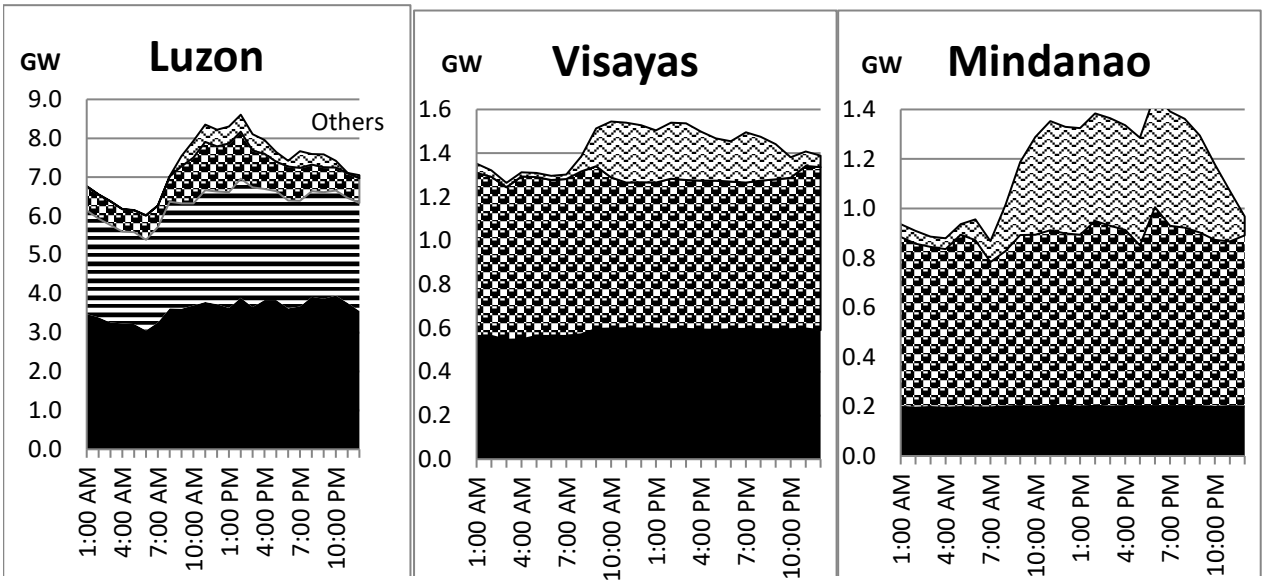
In Visayas, the typical trend is stable from January to December. Geothermal covers most of the base load in the Visayas. Interestingly, unlike Luzon where geothermal generation is constant, Visayas uses some of its geothermal power to meet its peak. Although the region occasionally imports power from Luzon, the direction of trade is usually from Visayas to Luzon. In Mindanao, consumption peaks during the summer and holiday seasons, when people from Mindanao working in either Luzon or Visayas make their way back home. Hydro generation comprises the base load of Mindanao.

Figure 7: Luzon, Visayas and Mindanao Monthly Load Curve, 2013



Sources of basic data: DOE. Luzon-Visayas Grid; National Grid Corporation of the Philippines (NGCP)-Mindanao Grid
Note: Imports are applicable only for the Luzon and Visayas grids.

Figure 8: LVM Hourly Load Curve on a Typical Day, 2014



C. Power Supply and Demand Indicators

Benchmarking power supply and demand indicators of the Philippines relative to other countries indicates that there is limited supply of power in the Philippines vis-à-vis consumption (Table 1). In 2014, the Philippines had 17.95 GW capacity serving 100 million Filipinos. In comparison, its neighbors, Thailand and Malaysia, had 44.83 GW and 32.46 GW of power capacity serving their populations of 68 million and 30 million, respectively. Electricity

consumption per capita in the Philippines is the lowest compared to other ASEAN countries. In contrast, the price per KWh is among the highest. It should be noted that Thailand, Malaysia, and Singapore trade in electricity and this potentially helps keep power costs low.

Table 1: Power Supply and Demand Indicators in Selected Asian Countries, 2014

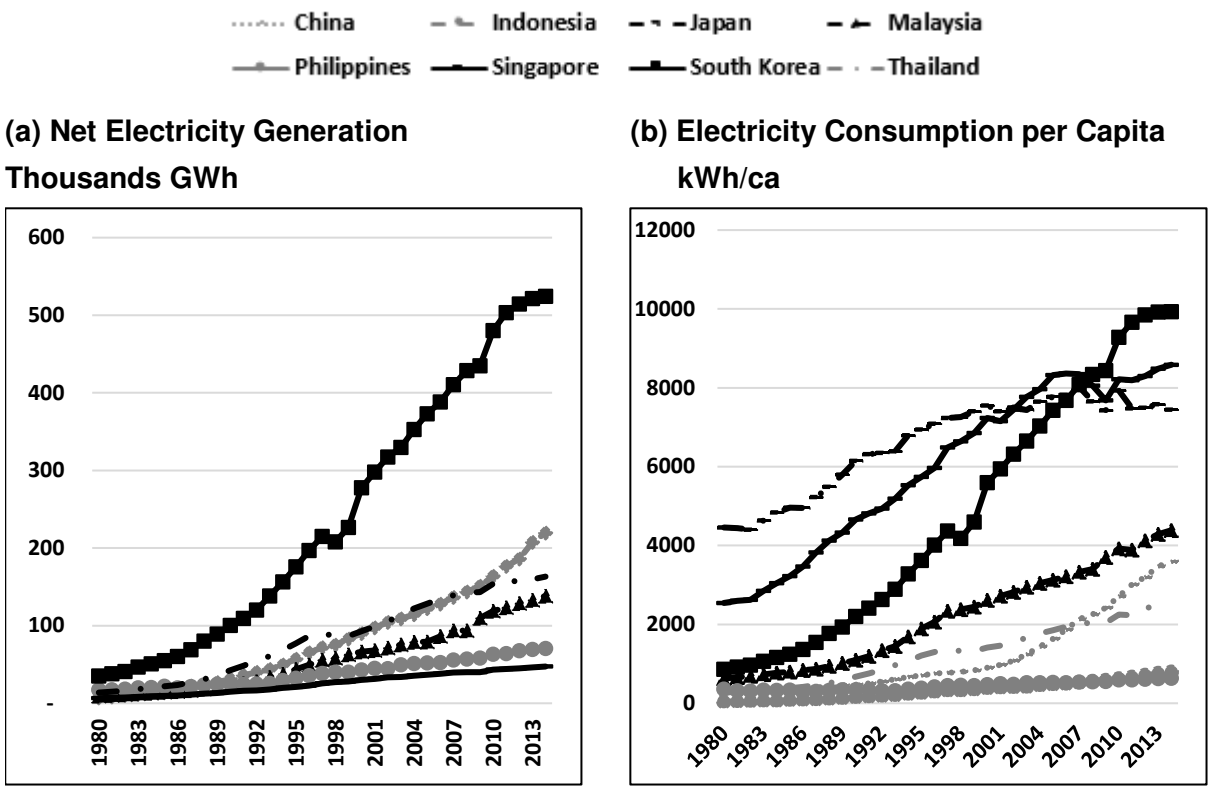
	Electricity Generation per capita[a] (kWh/cap)	**Per capita electricity consumption[b]** (kWh/cap)	**Installed Electricity Capacity[c]** (GW)	**Share of renewables in electricity capacities[d]** (%)	**Pop'n** (in millions) [e]	**Residential Prices[f]** (USc05/kWh) **(for 2013)**	**Industrial Prices[g]** (USc05/kWh) **(for 2013)**	**GDP per capita[h]** (constant 2005 US$)	Electricity T&D losses[i] (kWh/cap)
Philippines	772	633	17.95	32.86	100	13.84	9.91	1,650	73
Indonesia	901	789	53.87	12.25	253	4.19	4.82	1,878	85
Malaysia	4,773	4,388	32.46	20.06	30	6.07	6.17	7,295	193
Singapore	8,949	8,586	13.18	1.95	6	12.32	11.44	37,203	44
Thailand	2,523	2,508	44.83	18.05	67	8.03	5.33	3,457	157
China	4,153	3,590	1,405.03	30.94	1,364	4.55	6.38	3,826	239
Japan	8,066	7,444	311.53	26.88	127	22.60	16.26	37,607	367
South Korea	10,797	9,928	93.71	11.68	50	8.82	7.87	24,550	364

a. Net Generation is the "amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries. Note: Electricity required for pumping at pumped-storage plants is regarded as electricity for the station service and is deducted from gross generation" (Energy Information Agency or EIA, 2015).
b. Net Consumption is the "consumption of electricity computed as generation, plus imports, minus exports, minus transmission and distribution losses" (EIA, 2015).
c. Installed capacity
d. Renewables' share in electricity production or generation (Enerdata)
e. World Development Indicators
f. In real prices constant at 2005 US$ cents (Enerdata).
g. Constant 2005 US$ prices and exchange rate (Enerdata).
h. Constant 2005 US$ prices and exchange rate (Enerdata).
i. Transmission and Distribution Loss is "electric energy lost due to the transmission and distribution of electricity. Much of the loss is thermal in nature" (EIA, 2015)

The trend in net electricity generation[4] and consumption among selected Asian countries is shown in Figure 9. Relative to its neighbors, the Philippines has had low levels of both generation and consumption per capita since 1990. While generation has seen tepid growth, population growth has increased faster in the Philippines compared to its neighbors.

[4] Net electricity generation or production is the amount of gross generation less the electrical energy consumed at the generating station(s) for station service or auxiliaries (EIA, 2015).

Figure 9: Electricity Generation and Consumption



Source of basic data: Enerdata.

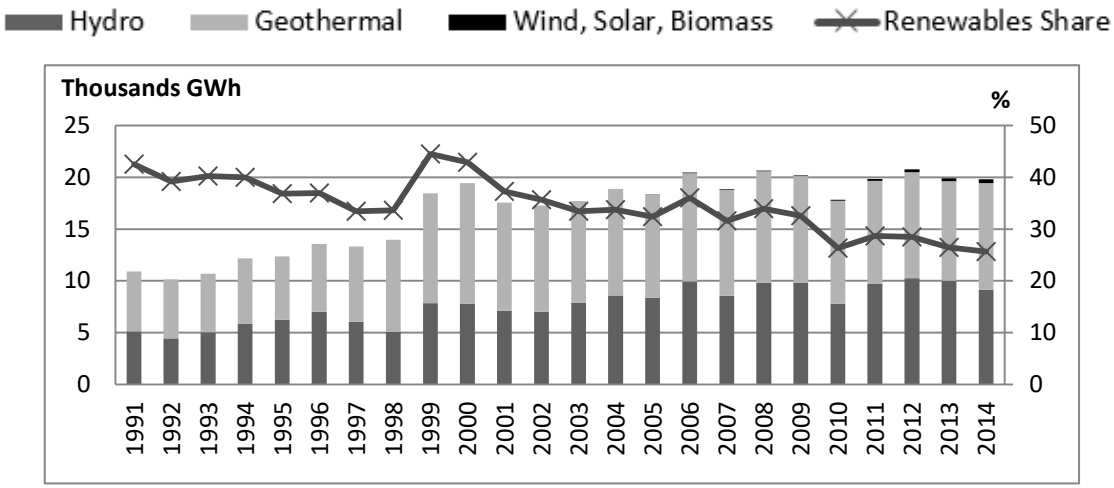
D. Energy and Climate Change

In 2008, RA 9513 or the Renewable Energy Act was passed mainly to (i) reduce dependence on fossil fuels, thus, insulating the country's exposure to price fluctuations in the international markets and (ii) increase the utilization and development of renewable energy resources as tools in preventing harmful emissions. To implement this law, the Department of Energy (DOE) released Circular 2015-07-0014, prescribing the policy for maintaining a fuel mix of 30-30-30-10, i.e., 30% coal, 30% renewables, 30% natural gas, and 10% others. The 30% share of renewable energy resources in the country's total power-generating capacity is facilitated through the implementation of the feed-in tariff (FIT) system.

Given this policy, what is the current status and where is the country heading, in terms of investments in generating capacity? Figure 10 shows the various renewable energy sources in the Philippines from 1991 to 2014. The graph shows that the biggest source is hydropower, followed by geothermal. Other renewable sources include wind, solar, and biomass. The share of renewable energy to total energy has been historically high for the Philippines. The share was about 38% in the 1990s and averaged about 33% in 2011-2014.

If, by 2040, technological innovation shall have driven down the cost of renewable energy (RE) relative to conventional sources, then the target 30% share of RE may be redundant and feed-in tariffs no longer necessary to encourage RE technologies for power generation.

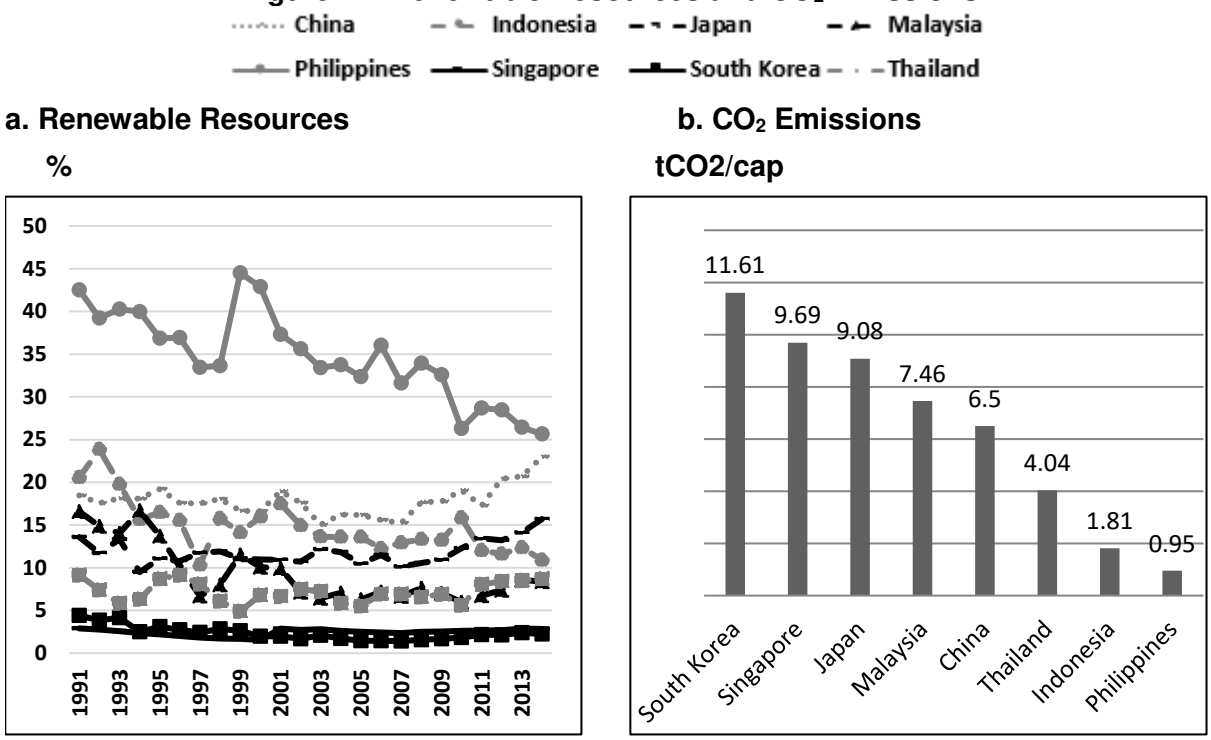
Figure 10: Renewable Resources, and Renewable Share to Total Energy
(Thousands GWh, %)



Sources of basic data: DOE and Enerdata.

With regard to the second objective of the Renewable Energy Act, even in the absence of a complete-participation-climate-change agreement, the Philippines' share of renewables in total energy source has been the highest relative to its Asian neighbors since 1991, as seen in Figure 11a. In 2014, the Philippines' share stood at 33%, China at 23%, Japan at 15%, and Indonesia at 12%. How does this translate in terms of carbon emissions? Figure 11b shows the carbon footprints of these countries relative to the highest two emitters. For the Philippines, the share of the renewables is very high while total carbon emissions are very small.

Figure 11: Renewable Resources and CO_2 Emissions



Source of basic data: Enerdata

Furthermore, power generation is not the only source of carbon gas emissions in the Philippines. Transport is another major source. Table 2 below shows that, in fact, in the last three decades of the 20th century, transportation was a heavier emitter of greenhouse gases than electricity. By 2012, however, power generation was releasing 60% more carbon dioxide than transport. The search for clean technologies, therefore, holds for these two sectors.

Table 2: Carbon Dioxide Emissions
(in Million Metric Tons)

Period	Electricity and Heat Production	Transportation
1971-1980	90.13	98.40
1981-1990	108.83	105.43
1991-2000	181.49	216.31
2001-2010	284.72	243.14

Source: World Resources Institute (WRI) (2014).

While the share of renewables may already be high, the prescribed target of 30% share for coal is already lower than the 32% share in installed capacity[5] in 2015 and the 42% gross

[5] Installed capacity is the maximum output, commonly expressed in megawatts (MW), that the generating equipment can supply to the system load, adjusted for ambient conditions (EIA, 2015).

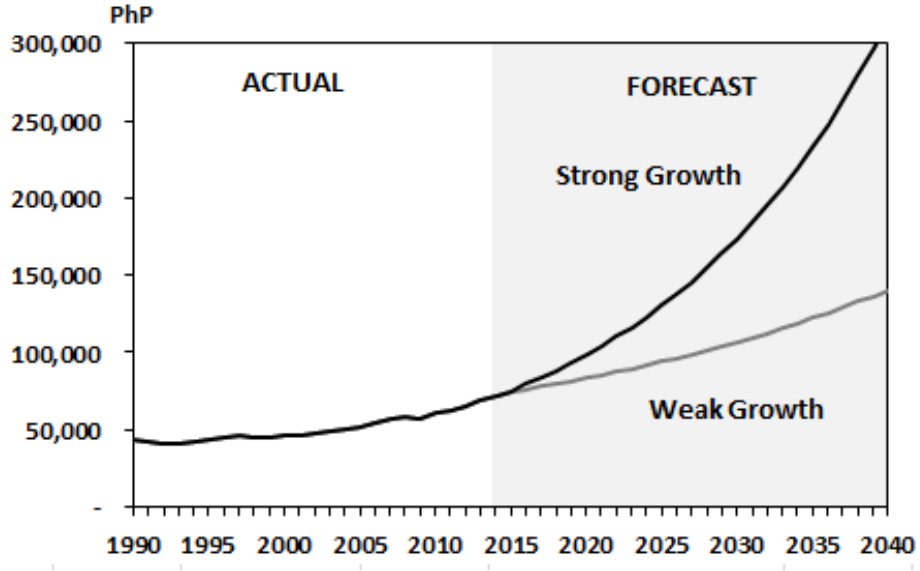
generation capacity[6] in 2014. These benchmarks will be higher since the new capacity said to be coming on-stream is largely coal (e.g., the Redondo Power Plant in Subic, Zambales). The Asian Development Bank (ADB, 2013) sees coal constituting about 70% of the fuel mix in the Philippines in 2035.

[6] Gross generation capacity- the total amount of electric energy produced by generating units and measured at the generating terminal in kilowatthours (kWh) or megawatthours (MWh) (EIA, 2015).

II. THE PHILIPPINES IN 2040: STRONG VS. WEAK GROWTH

Two scenarios for the Philippine economy up to 2040 are identified in Figure 12. The first scenario, the strong-growth scenario, assumes an average GDP growth rate of about 7% annually from 2016 to 2040. With low population growth that ranges from 1.5% to 0.6% for 2016-2040 (see Table 3), per capita GDP growth would therefore average about 6%.

Figure 12: Strong and Weak Growth Scenarios of GDP per Capita, 2016-2040



Authors' calculations.
Note: GDP per capita (constant 2000 prices) from 1990 to 2015 (actual) and 2016 to 2050 (projected)

Accompanying this high economic growth is the well-known demographic dividend. That is, productivity rises due to the increased number of people in the workforce relative to dependents (Lee and Mason 2006). Strong reforms are needed to reduce fertility, including investment in human capital and expanded work opportunities. Reducing the fertility rate is the critical element for the demographic transition. (See Box 1 for notes on the population projections.) Strong political will is also needed to increase the contraceptive prevalence rate (CPR) from the current figure of 55% to 70%. Continuous investment in human capital is important, including the additional two years of schooling with the implementation of the K to 12 Program. The latter is particularly relevant for women, as increased education of women is a strong determinant of lower fertility. In turn, an increase in years of schooling may be expected to boost real wages, particularly for young workers.

Table 3: Strong Growth Scenario Projections for Real GDP, Population, GDP per Capita, and Electricity Consumption, 2015-2040

Year	Real GDP at 7% Growth Rate (PhP Billion)	Population		GDP Per Capita		Electricity Consumption (GWh)
		('000)	Growth Rate (%)	(PhP)	Growth Rate (%)	
2015	7,580	101,803	…	74,453	…	81,896
2016	8,110	102,273	1.46%	79,299	5.54%	85,434
2017	8,678	103,675	1.37%	83,702	5.55%	89,436
2018	9,285	105,056	1.33%	88,384	5.59%	93,549
2019	9,935	106,421	1.30%	93,358	5.63%	97,788
2020	10,631	107,771	1.27%	98,641	5.66%	102,165
2021	11,375	109,108	1.24%	104,253	5.69%	106,692
2022	12,171	110,429	1.21%	110,216	5.72%	111,382
2023	13,023	111,735	1.18%	116,553	5.75%	116,246
2024	13,935	113,027	1.16%	123,286	5.78%	121,296
2025	14,910	114,304	1.13%	130,442	5.80%	126,543
2026	15,954	115,567	1.10%	138,048	5.83%	131,998
2027	17,071	116,813	1.08%	146,135	5.86%	137,671
2028	18,265	118,039	1.05%	154,741	5.89%	143,576
2029	19,544	119,240	1.02%	163,906	5.92%	149,721
2030	20,912	120,411	0.98%	173,673	5.96%	156,121
2031	22,376	121,551	0.95%	184,088	6.00%	162,785
2032	23,942	122,658	0.91%	195,196	6.03%	169,728
2033	25,618	123,730	0.87%	207,050	6.07%	176,960
2034	27,412	124,765	0.84%	219,707	6.11%	184,496
2035	29,330	125,760	0.80%	233,225	6.15%	192,348
2036	31,384	126,714	0.76%	247,671	6.19%	200,531
2037	33,580	127,627	0.72%	263,113	6.23%	209,059
2038	35,931	128,498	0.68%	279,624	6.28%	217,946
2039	38,446	129,325	0.64%	297,282	6.32%	227,210
2040	41,137	130,110	0.61%	316,173	6.35%	236,865

Note: Real GDP and GDP per capita are at 2000 constant prices.

Box 1: Notes on the Population Projections

To project the population until 2100, the United Nations Population Division uses assumptions regarding future trends in fertility, mortality, and international migration. Because future trends cannot be known with certainty, a number of projection variants are produced.

The World Population Prospects 2012 Revision uses the same stochastic model for fertility projection as used in the 2010 revision with modifications. The AR1 model used for low-fertility countries is estimated using a Bayesian hierarchical model and future long-term fertility levels are more data-driven and country-specific. Two new stochastic models were also used to project life expectancy at birth for all countries not significantly affected by the HIV/AIDS epidemic. The first model, used for females, is a Bayesian hierarchical approach that models the rate of mortality improvement by level of life expectancy at birth; the second model is used for males, to project the gender gap conditionally on female mortality level.

The following projection variants were used to simulate the Philippine population up to 2100.

Projection Variant	Assumptions		
	Fertility	**Mortality**	**Migration**
Medium	Medium	Normal	Normal
Low	Low	Normal	Normal

The low projection variant is used for the strong growth scenario. The medium variant is used for the weak growth scenario.

- **Medium Fertility.** A country is assumed to have medium total fertility rate (TFR) if its rate has been declining but the estimated level is above the replacement level of 2.1 children per woman in 2005-2010. (The Philippines will reach a TFR of 2.12 in 2050–2055.)
- **Low Fertility.** A country is assumed to have low TFR if its rate is half a child lower than that of the medium variant. That is, countries with a TFR of 3 children per woman in the medium variant have a TFR of 2.5 children per woman in the low variant. (The Philippines will reach a TFR of 2.09 in 2025–2030.)
- **Normal Mortality.** For most countries where mortality was assumed to follow a declining trend starting in 2010, life expectancy was generally assumed to rise over the projection period. In contrast with fertility assumptions, only one variant of future mortality trends (median path) was used for standard projection.
- **Normal Migration.** Based on past international estimates and considered the policy stance on future international migration flows, the projected levels of net migration are generally kept constant over the next decades. After 2050, it is assumed that net migration will gradually decline and reach zero by 2100.

The following are the data sources in projecting the Philippine population:

- **Total Population:** National censuses from 1960 through 2010, and with estimates of the subsequent trends in fertility, mortality, and international migration.
- **Total Fertility:** Maternity-history data from the 1993 National Demographic Survey (NDS), and the National Demographic and Health Surveys (NDHS) of 1998, 2003, 2008, and 2013.
- **Infant and Child Mortality:** Estimates from the 1998, 2003, 2008, and 2013 NDHS; 2006 Family Planning Survey; and estimates from UNICEF as published in 2014.
- **Life Expectancy at Birth:** Infant and child mortality estimates from the 1998, 2003, 2008, and 2013 NDHS; 2006 Family Planning Survey; official estimates from a life table of 2006; and the West model of the Coale-Demeny Model Life Tables and the Lee-Carter method.
- **International Migration:** Estimates of net international migration derived as the difference between overall population growth and natural increase through 2010, and on information on Filipino emigrants admitted by the main countries of immigration.

The changing age structure due to a reduction in the country's TFR is a necessary but not a sufficient condition for harvesting the demographic dividend. Reforms must be made in the labor market to provide young workers with higher employment opportunities. The strong-growth scenario simulates increased employment rate, coupled with a lower fertility rate and increased years of schooling (that is, the additional two years). Under the strong-growth scenario, the "support ratio" will be higher than 0.50 starting 2025 and will be highest at 0.55 from 2055 to 2065. This scenario creates a relatively wider demographic window of opportunity. This means that, in 2025, 50 effective workers are supporting themselves and 50 effective consumers. By 2040, 54 effective workers are supporting themselves and 46 other effective consumers, thus providing the economy with additional savings.

The alternative "weak-growth scenario" assumes an average annual GDP growth of 4% from 2016 to 2040, similar to the average growth rate of GDP from 1990 to 2012. With this projected economic growth, implying per capita income growth of the country at 2.6%, per capita income is PhP140,791 ($3,061) by 2040 (see Table 4).

For the energy sector, the power subsector in particular, long-term visioning is of prime importance as investments in most new facilities for generation and transmission are lumpy in nature. It takes several years to put up a base load power plant, especially when environmental and social impact studies are required. Thus, it is critical to plan ahead and coordinate the power requirement and the corresponding generation and transmission that will support the vision of strong growth.

Forecasts of electricity consumption for 2040 under the two scenarios were obtained using a single-equation error correction model—a dynamic model that integrates short-run dynamics with a long-run relationship (see Danao and Ducanes 2016 for details of the model). In the present case, the short-run dynamics is modeled by relating annual growth rates of electricity consumption to growth rates of the predictor variables: GDP, electricity price, and temperature. The long-run relationship between electricity consumption and real GDP appears as an extra term in the model. Because there may be disequilibrium (referred to as "disequilibrium error") in the short run, this extra term is regarded as the error correction mechanism (ECM), which corrects for the disequilibrium. The ECM was estimated using annual data from 1992 to 2015. The forecast values were computed by assuming that electricity price and temperature follow their historical trends.

Figure 13 shows the trend in actual total electricity consumption[7] for 1990-2015 together with the forecasts for 2016-2040, both including transmission losses and utilities' own-consumption. The forecasted trend is the electricity consumption that supports the assumed GDP per capita growth under each scenario. Electricity consumption is expected to grow at an annual average rate of 4.3% under the strong-growth scenario but only 2.4% under weak-growth. We consider the forecasts as lower bounds, if we allow for the possibility of lower electricity prices and higher temperatures. However, electricity consumption will also be influenced by demand-side management through the use of more efficient appliances, lighting fixtures, and smart metering (see e.g. Strbac 2008; Moura and de Almeida 2010; EIA 2014). Thus, the net effect on electricity consumption is unclear. Since electricity consumption in the model is primarily driven by aggregate real GDP, it cannot reflect the effects of changes in GDP's components. Future modeling efforts should account for the structural changes within the economy, i.e., the gross value added share of agriculture, industry, and services.

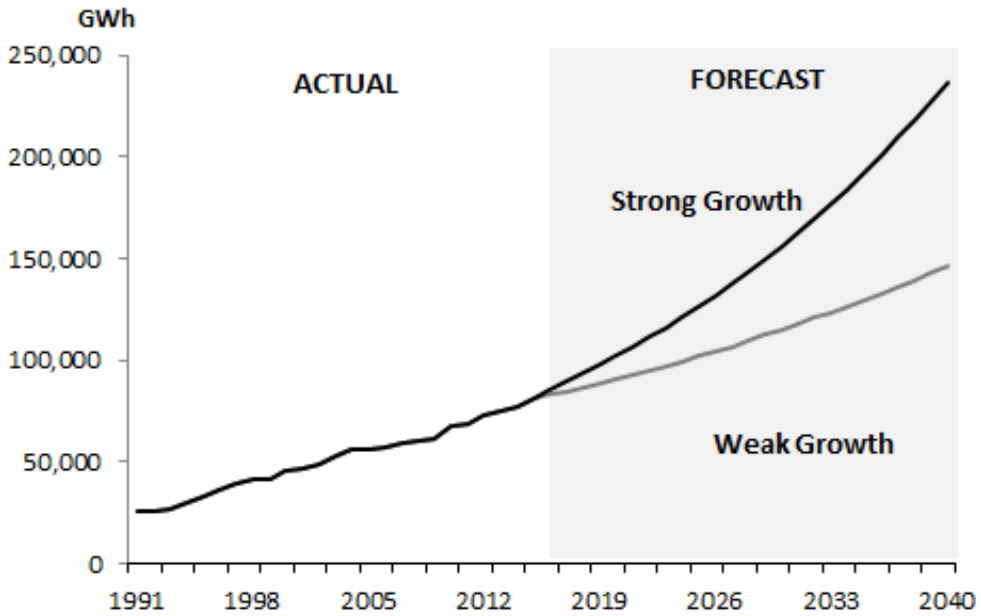
[7] Total electricity consumption includes transmission losses and utilities' own consumption.

Table 4: Weak-Growth Scenario Projections for Real GDP, Population, GDP per Capita, and Electricity Consumption, 2015-2040

Year	Real GDP at 4% Growth Rate **(PhP billion)**	Population		GDP Per Capita		Electricity Consumption **(GWh)**
		('000)	Growth Rate (%)	(PhP)	Growth Rate (%)	
2015	7,580	101,803	…	74,453	…	81,896
2016	7,883	103,509	1.68%	76,155	2.29%	83,204
2017	8,198	105,218	1.65%	77,914	2.31%	84,982
2018	8,526	106,934	1.63%	79,731	2.33%	86,852
2019	8,867	108,662	1.62%	81,602	2.35%	88,807
2020	9,222	110,404	1.60%	83,527	2.36%	90,843
2021	9,591	112,160	1.59%	85,508	2.37%	92,954
2022	9,974	113,926	1.57%	87,550	2.39%	95,137
2023	10,373	115,696	1.55%	89,659	2.41%	97,391
2024	10,788	117,462	1.53%	91,843	2.44%	99,713
2025	11,220	119,219	1.50%	94,109	2.47%	102,103
2026	11,668	120,964	1.46%	96,461	2.50%	104,560
2027	12,135	122,696	1.43%	98,904	2.53%	107,085
2028	12,620	124,413	1.40%	101,441	2.56%	109,676
2029	13,125	126,113	1.37%	104,075	2.60%	112,336
2030	13,650	127,797	1.34%	106,812	2.63%	115,063
2031	14,196	129,462	1.30%	109,656	2.66%	117,861
2032	14,764	131,107	1.27%	112,611	2.70%	120,729
2033	15,355	132,732	1.24%	115,682	2.73%	123,668
2034	15,969	134,336	1.21%	118,873	2.76%	126,681
2035	16,608	135,920	1.18%	122,188	2.79%	129,769
2036	17,272	137,482	1.15%	125,631	2.82%	132,932
2037	17,963	139,022	1.12%	129,209	2.85%	136,174
2038	18,681	140,541	1.09%	132,925	2.88%	139,495
2039	19,429	142,039	1.07%	136,784	2.90%	142,897
2040	20,206	143,516	1.04%	140,791	2.93%	146,383

Note: Real GDP and GDP per capita are at 2000 constant prices.

Figure 13: Strong and Weak Growth Scenarios of Electricity Consumption, 2016-2040 ('000 GWh)



What is the needed generating capacity that corresponds to the vision of strong growth and the possibility of weak growth, and at what electricity prices? The policies that the government takes are critical in influencing the outcome.

We did a numerical exercise to compute the required generating capacity at each projected electricity consumption level for the two scenarios. Formal modeling requires that supply and demand be determined simultaneously at each point in time. For illustration purposes, electricity consumption is modeled separately when computing the generation requirement.

A. Policy Regimes on Fuel Mix

To calculate the net generating capacity, estimates are needed for installed capacities from various fuel sources by grid in Luzon, Visayas, and Mindanao. This requires determining the optimal mix of fuel sources over time based on the least-cost rule while taking into account environmental and health concerns. Inasmuch as a fully theoretical and operational model of investment planning and coordination is yet to be developed for the Philippines, we do not compute the optimal fuel mix. We focus instead on the conceptual issues and illustrate how policies with regard to fuel mix might affect the growth trajectory of the country and the well-being of Filipinos– in particular, how fuel mix affects the blended generation charges that constitute 47.4% of the consumers' electricity bill.

For the two scenarios, strong- and weak-growth projections, we consider the policy of the government as stated in the Department of Energy's (DOE) Department Circular 2015-07-0014, "Guidelines for the Policy of Maintaining the Share of Renewable Energy (RE) in the Country." The policy statement in Section 2 of the circular is "to maintain the share of (RE) in power generation… by adopting at least 30 percent share of RE in the country's total power generation capacity…." For the numerical exercise, the fuel mix is pegged at 30% share of RE, 30% natural gas, 30% coal, and 10% others. The 30-30-30-10 fuel mix in the installed capacity is hereinafter referred to as **Policy 1**.

Under the strong-growth scenario, we present three other policy regimes on fuel mix. **Policy 2** favors increased utilization of the lower-cost resources but accounts for environmental costs. ADB (2013) forecasts coal, currently the cheapest fuel, being the main fuel source in Asia and the Pacific through 2035. For the Philippines, ADB (2013) forecasts coal to be about 70% of the fuel source in 2035 under their business-as-usual scenario. **Policy 3** and **Policy 4**, with an eye toward the objectives of RA 9513 or the Renewable Energy Act of 2008, consider a fuel mix that favors the increased use of renewables, both conventional and variable.

Moreover, our computation under the strong-growth scenario considers four policy regimes that target the following installed capacity fuel mix by 2040: 1) 30-30-30-10; 2) utilization of lesser-cost resource; 3) increased use of conventional renewables (hydro and geothermal); and 4) increased use of variable renewables (solar and wind) and biomass. Inasmuch as we do not model the optimal fuel mix, the policy regimes above are just four of the many possible configurations of fuel mix. A caveat is in order for Policy 3: the fuel share of conventional renewables in our assumption is for illustration purposes as the share may hit a hard constraint depending on the availability of natural reserves, e.g., water for hydropower.

Our assumptions about the fuel mix for the Philippines and the corresponding power consumption mix under the four policy regimes consider the type of load and geographical location (grid). For Luzon, fuels for baseload include coal, natural gas, geothermal, base hydro, and other renewables. These other renewables include the variable solar, wind, and run-off river hydro, which are considered “must-dispatch” together with biomass. Midmerit and peak loads include peaking hydro, peaking natural gas, and oil. For Visayas and Mindanao, fuels for baseload include coal, geothermal, base hydro, and the must-dispatch variable renewables while midmerit and peak loads include peaking hydro and oil.

B. Assumptions on Fuel Price

The evolution of power generation price for each type of fuel largely depends on how technology develops over time (see Viswanathan et al. 2006; ADB 2013; van Kooten 2013; and Knittel et al. 2015). One can think of many price trajectory possibilities. We use the following five cases with to differing generation price levels to illustrate the effects of these price trajectories on the blended generation charge:

Case 1: Baseline
Policy 1 - 2015 prices constant for the next 24 years
Policies 2,3,4 - 2015 prices plus emissions charges constant for the next 24 years
Case 2: Prices of RE incorporate FIT degression rates in policies 1 to 4
Case 3: Annual decrease in average RE prices by 3% in policies 1 to 4
Case 4: Annual decrease by 8% and 3% in the price of solar and RE, respectively, in policies 1 to 4
Case 5: All prices change simultaneously applying EIA projections on fuel prices in 2015 in policies 1 to 4

Case 1 is the baseline where the current 2015 average generation charges are assumed to remain constant in 2016-2040. The purpose is to determine the projected installed capacities and blended generation charges under the assumption that future fuel prices will remain the same. This is applied to policy regime 1 of 30-30-30-10. For policy regimes 2, 3, and 4 carbon emissions charges are added. The incorporation of emissions charges is an attempt to reflect the true social cost, albeit incomplete. The full social cost would have to incorporate local

pollution, including cost of particulates and sulfur dioxide. This may be larger than the emissions charges (see Roumasset et al., 2016 and Roumasset and Smith 1990) but an estimate for the Philippines is wanting. Cases 2,3, and 4 relax the constant price assumption of must-dispatch renewables only while all other fuel prices remain constant as in Case 1. Case 5 is where all fuel prices change simultaneously following the growth projections of the US Energy Information Agency (EIA). In all cases, policy regimes 2, 3, and 4 incorporate emissions and local pollution charges. The performance of each of the cases 2 to 5 is measured against the baseline case.

Table 5 presents the fuel prices for Case 1. Panel (a) shows the average generation charges in 2015 for each type of fuel source by grid in Luzon, Visayas, and Mindanao. These are the generation prices applied in Policy regime 1. These are adjusted to incorporate the negative externality from carbon emissions (Column b) to obtain generation charges for Policy regimes 2, 3, and 4 (Panel a+b). The generation charges are adjusted by imposing the appropriate emission charges per kWh of the corresponding CO_2 emissions.

Following Roumasset et al. (2016), we use a global social cost of carbon (SCC) ($25/MT of CO_2) obtained as the average of the SCC reported in Nordhaus (2011) and the United States Environmental Protection Agency or EPA (2013, revised August 2016). We assume that carbon-induced damages in the Philippines are 5% of worldwide damages and without a strong and binding global agreement, the Philippine carbon tax should be $1.25 per MT of CO_2. (See Box 2 for the conversion and computation of emission charges.)

Table 5: Fuel Prices for Case 1, 2015 Prices Constant for the Next 24 Years (PhP/kWh)

Fuel Type	Policy 1 (a)			Emissions Charge* (b)	Policies 2, 3, and 4 (a+b)		
	Luzon	Visayas	Mindanao		Luzon	Visayas	Mindanao
Coal	3.89	4.65	4.65	0.0566	3.95	4.71	4.71
Geothermal	4.52	5.01	5.01	…	4.52	5.01	5.01
Hydro	4.56	3.86	2.93	…	4.56	3.86	2.93
Must-Dispatch RE	7.16	7.16	7.16	…	7.16	7.16	7.16
Natural Gas	4.41	…	…	0.0317	4.44	…	…
Oil	10.18	6.79	8.24	0.0426	10.22	6.83	8.28

Sources of basic data: Meralco (2015), “Average Generation Charge by Fuel Type” for Luzon; kuryente.org (2015), “Power Supply Agreements”; Visayan Electric Company (VECO) 2016. “Generation Rates” for Visayas and Mindanao. See Box 2 on the computation of emission charges.

Box 2: Notes on carbon emissions

Since carbon emissions are a global public bad, the social cost of carbon (SCC) is the appropriate measure to use to incorporate its cost. SSC is the value of the long-term damage caused by a one-ton increase in global carbon emissions in a given year. A range of estimates is given by several studies, e.g., $25 per tC (Tol 2013), $12 per tCO_2 in 2005 dollars (Nordaus 2011), $36 per tCO_2 (Shelanki and Obstfeld 2015).

Is the value of SSC the appropriate charge to reflect the true cost in the Philippines? Gayer and Viscusi (2016) argue that the proper scope of domestic regulation for a public bad should consider the net "benefits of a policy across the political jurisdiction whose citizens will bear the cost of the policy" (p.2). They further note that without any binding world agreement regarding climate change mitigation, "there is no clear justification for one nation to include the benefits to other nations from policies for which the one nation incurs all of the costs" (p.13). Gayer and Viscusi (2016) suggest downscaling the SSC by the nation's share of world GDP as an appropriate scope of policy regulation regarding carbon emissions. Nordhaus (2015) argues that an efficient and politically feasible carbon tax for each country should be even less than that indicated by its share of world GDP. The Philippines share in world GDP is 0.44%. However, we use a 5% downscaling factor to reflect the Philippines' greater vulnerability to climate change (Roumasset et al 2016). The Philippine carbon tax should be much higher in the future according to the GDP share of countries participating in the new treaty (Nordhaus, 2015), if a stronger and more binding treaty than the Paris Agreement emerges.

Following Roumasset et al. (this volume), we use a global SCC ($25/MT of CO_2), which is obtained as a midpoint of the SCC reported in Nordhaus (2011) and the United States Environmental Protection Agency (2013, revised August 2016). Nordhaus reports an SCC of $12 per MT of CO_2 while the EPA reports an SCC of $37 per MT of CO_2. Absent a strong and binding global agreement and assuming that carbon-induced damages in the Philippines are 5% of worldwide damages, the Philippine carbon tax should be $1.25 per MT of CO_2, given a global social cost of carbon of $25 per MT of CO_2.

Using conversion factor from the US Energy Information Administration (EIA) https://www.eia.gov/tools/faqs/faq.cfm?id=74&t=11, a megawatt hour of electricity from coal generates about 0.98 MT of CO_2 ($= \frac{2.17\ lbs\ CO_2}{kWh} \times \frac{1{,}000\ kWh}{1\ MWh} \times \frac{1\ MT}{2204.62\ lbs}$). The same formula is used for natural gas and oil but applying the corresponding pounds of CO_2 per kWh conversion factor.

The emissions charge on coal-generated power should be around $1.23/Mwh ($= {}^{\$1.25}/_{\mathrm{MT\ CO_2}} \times {}^{0.98\ \mathrm{MT\ CO_2}}/_{\mathrm{MWh}}$). In terms of pesos per Kwh, the emissions charge is PhP0.0566/Kwh ($= {}^{\$1.23}/_{1{,}000\ \mathrm{kWh}} \times {}^{\mathrm{PhP46}}/_{\$1}$).

NTRC (2016) has proposed emissions charges in the range of PhP 100 – PhP 1000 ($2.2 – 21.7 at PhP1=$46) per $MtCO_2$ following the range of carbon taxes being implemented in other countries. NTRC recognizes SSC but uses their suggested range in illustrating the revenue generated from the imposition of a carbon tax. A midpoint value of the suggested range of NTRC is $11.96 per $MtCO_2$. Following the same process of downscaling by 5%, the emission charge for the Philippines is $0.598 per MT of CO_2.

The other four cases are the "what-if" analyses relative to the baseline case. **Case 2** takes into account the degression rates in the feed-in-tariff (FIT), which is already in place as per ERC Case No. 2011-006 and ERC Resolution 10, Series of 2012. Incorporation of FIT will alter the price of must-dispatch renewables in policy regimes 1 to 4. The FIT degression rates are based on the adjusted 2016 rates as per ERC Case No. 2015-216 RC, where the FIT rates are PhP 7.0508 for biomass, PhP 6.4601 for hydro, PhP 8.69 for solar, and PhP 7.40 for wind.

The same circular notes that degression rates for solar and wind no longer apply. The degression rate for biomass and hydro is 0.5% two years after the effectivity of FIT.

Case 3 Is a scenario where prices of renewables decrease. This is a bottom-up exercise because we ask the question by how much, **at the minimum,** will prices of renewables have to go down for Policy 1 and 4 to perform better. This exercise results in a 3% annual decrease in the overall average price of the solar, wind, biomass, and run-off river hydro. This annual decrease in the average price of these renewables is reflected in policy regimes 1 to 4 under Case 3.

Case 4 considers the trend in the decrease in the price of solar. Feldman et al. (2014) reported that the prices of photovoltaic (PV) systems for the US have fallen by 6-8% per year on average since 1998. We use an 8% reduction in solar prices and a 3% reduction in other renewables as in Case 3 to further illustrate when policy regime 4 becomes superior to other policy regimes.

Table 6 presents the prices of must-dispatch RE under Cases 2, 3, and 4.

Table 6: Price Assumption of Must-dispatch RE under Cases 2, 3 and 4
(PhP/kWh)

	Case 1 (Baseline)	Case 2 Price of RE incorporating FIT degression rates	Case 3 Annual decrease in average RE prices by 3%	Case 4 Annual decrease by 8% in the price of solar and 3% in the RE price
2016	7.16	7.16	7.16	6.98
2022	7.16	7.06	5.96	5.36
2028	7.16	6.97	4.96	4.19
2034	7.16	6.88	4.14	3.33
2040	7.16	6.80	3.44	2.67

Case 5 illustrates what happens when all fuel prices change simultaneously. The evolution of generation charges for each type of fuel source largely depends on how technology develops over time. The heightened concerns over the environment and the energy crisis in the 1970s have since prompted research and development programs in finding ways towards increased efficiency of coal power plants (Viswanathan et al. 2006). Denmark, Germany, and Japan have been actively pursuing the development of an ultra-supercritical coal power plant that utilizes stronger high-temperature materials (World Coal Association 2015), enabling the power plant to utilize coal efficiently and thereby reducing carbon emissions. The shale gas boom and “fracking” technology would also affect the relative prices of fuel sources (Stephenson 2015). The glut of shale gas in the US that brought down the price of natural gas by almost 70% in 2008–2012 has provided incentives for generators to switch from coal to gas (Knittel et al. 2015). Technology on renewable sources is likewise evolving, including the development of batteries that address the intermittent nature of these sources (van Kooten 2013; IRENA 2015).

To capture the changes in technology, we apply the growth projections of EIA (2016 and 2017) on fuel prices in 2015 (from Table 5) to come up with a projection of fuel prices until 2040 for the Philippines. Table 7 presents the projection on fuel prices used under Case 5.

Table 7: Price Assumption under Case 5
(PhP/kWh)

Grid	Fuel	No emission charge					With emission charges				
		Policy 1					Policies 2, 3, and 4				
		2016	2022	2028	2034	2040	2016	2022	2028	2034	2040
Luzon	Coal	3.89	4.19	4.29	4.43	4.56	3.95	4.24	4.35	4.49	4.62
	Geothermal	4.52	4.52	4.89	5.29	5.72	4.52	4.52	4.89	5.29	5.72
	Hydro	4.56	4.56	4.50	4.44	4.38	4.56	4.56	4.50	4.44	4.38
	Must-Dispatch RE	7.16	7.46	7.14	6.84	6.55	7.16	7.46	7.14	6.84	6.55
	Natural Gas	4.41	7.42	8.54	8.46	8.29	4.44	7.46	8.57	8.49	8.32
	Oil	10.18	23.39	27.45	32.44	37.64	10.22	23.44	27.49	32.48	37.68
Visayas	Coal	4.65	5.00	5.12	5.29	5.45	4.70	5.06	5.18	5.35	5.50
	Geothermal	5.01	5.01	5.42	5.86	6.34	5.01	5.01	5.42	5.86	6.34
	Hydro	3.86	3.86	3.80	3.75	3.70	3.86	3.86	3.80	3.75	3.70
	Must-Dispatch RE	7.16	7.46	7.14	6.84	6.55	7.16	7.46	7.14	6.84	6.55
	Natural Gas	…	…	…	…	…	…	…	…	…	…
	Oil	6.79	15.60	18.30	21.63	25.10	6.83	15.64	18.35	21.67	25.14
Mindanao	Coal	4.65	5.00	5.12	5.29	5.45	4.70	5.06	5.18	5.35	5.50
	Geothermal	5.01	5.01	5.42	5.86	6.34	5.01	5.01	5.42	5.86	6.34
	Hydro	2.93	2.93	2.89	2.85	2.81	2.93	2.93	2.89	2.85	2.81
	Must-Dispatch RE	7.16	7.46	7.14	6.84	6.55	7.16	7.46	7.14	6.84	6.55
	Natural Gas	…	…	…	…	…	…	…	…	…	…
	Oil	8.24	18.93	22.21	26.25	30.46	8.28	18.97	22.25	26.29	30.50

Source of basic data: U.S. EIA (2016) and U.S. EIA (2017)

Given the generation price and the fuel mix assumptions under the four illustrative policy regimes and five cases of evolution of fuel price, the required installed capacities for strong- and weak-growth scenarios are calculated using our computation.

Table 8 provides the parameters, formulas, and assumptions used to estimate the projected installed capacity and gross generation for each grid: Luzon, Visayas, and Mindanao.

Summing up the corresponding values for all grids, we obtain the projected installed capacity and gross generation for the country. Using our forecast of electricity consumption (EC) for the Philippines in Figure 4, we allocate the consumption by grid (EC_G) using the historical average (a_G) (see Table 8, Lines 1-3).

The peak demand for each grid (PD_G) is computed by dividing EC_G by the grid load factor (LF_G) times 8760 hours (Table 8, Line 5). The load factor (LF_G) is taken from DOE's Philippine Energy Plan. We then compute the requirement for ancillary services, the regulating reserve $(RR_G$, 4% of peak demand), contingency reserve $(CR_G$, largest unit capacity online for the grid), and dispatchable reserve $(DR_G$, second largest unit capacity online) (IIEE 2014) (see Table 8, Lines 7-9).

The installed capacity by load net of maintenance and station service (NIC_{LG}) is obtained by multiplying the peak demand (PD_G) by the capacity factor (CF_{LG}) of each load, i.e., baseload, midmerit, and peaking for each grid (Table 8, Lines 10-11). We use capacity factors based on the DOE's Power Development Plan for base, midmerit, and peaking loads for each grid (see Table 8, Line 10). The DOE's capacity factor is based on "load duration curve (LDC) methodology."

The installed capacity for ancillary services NIC_{AG} (Table 8, Line 12) net of maintenance and station service is simply the sum of all reserves $(RR_G + CR_G + DR_G)$ by grid. The gross installed capacities for each load (GIC_{LG}) by grid and ancillary services (GIC_{AG}) for each grid are simply obtained by including the maintenance and station services (Table 8, Lines 13-16). From here, we get the gross installed capacity by grid (GIC_G), (Table 8, Line 17) by summing up GIC_{LG} and GIC_{AG}.

Table 8: Parameters and Formulas Used in the Computations

	Parameter	Variable	Unit	Formula	Description
1	Electricity Consumption	EC	GWh	…	Projected using error correction model (Figure 13). Equal to Gross Generation.
2	Share of Electricity Consumption by Grid	a_G	%		Historical average from 1991 to 2014: 74% for Luzon, 13% for Visayas, 13% for Mindanao.
3	Electricity Consumption by Grid	EC_G	MWh	$EC \times \frac{a_G}{100} \times 1000$	G refers to Grid: Luzon, Visayas, and Mindanao 1 GW = 1000 MW
4	Load Factor	LF_G	%		This is the average load divided by the peak load in a specified time period. Based on the DOE's Philippine Energy Plan assumptions per grid; 73% for Luzon, 69% for Visayas, 72% for Mindanao. Assumed constant for all years.
5	Peak Demand by Grid (Non-Coincident)	PD_G	MW	$\frac{EC_G}{\frac{LF_G}{100} \times 8{,}760 hrs}$	Based on the DOE's Power Development Plan computation of peak demand
6	Peak Demand (Non-Coincident)	PD		$\sum_G PD_G$	Summing the peak demand across grid to obtain the peak demand for the Philippines is based on the DOE Power Statistics (2014).

7	Regulating Reserve	RR_G	MW	$PD_G \times .04$	Assists in frequency control by providing automatic primary and/or secondary frequency response, equivalent to 4% of peak demand.
8	Contingency Reserve	CR_G	MW	…	Intended to take care of the loss of the largest synchronized generating unit or the power import from a single grid interconnection, whichever is larger. The Sual Power Plant Unit 1 with 0.647 GW capacity is assumed to serve as CR_G; Kepco-Salcon Unit 1 with 0.100 GW capacity for Visayas; a coal- fired power plant with 0.105 GW capacity for Mindanao.
9	Dispatchable Reserve	DR_G	MW	…	2nd largest unit capacity online. The Sual Power Plant Unit 2 with 0.647 GW capacity is assumed to serve as DR_G; Kepco-Salcon Unit 2 with 0.100 GW capacity for Visayas; a coal fired power plant with 0.105 GW capacity for Mindanao.
10	Capacity Factor by Load (Load L: Base, Midmerit, Peaking)	CF_{LG}	%	…	Based on the DOE's Power Development Plan capacity share assumptions by grid for base, midmerit, and peaking loads respectively for all grids: 67%, 23%, 10%
11	Net Installed Capacity by Load	NIC_{LG}	MW	$PD_G \times CF_{LG}$	Required installed capacity by base, midmerit, and peaking load net of maintenance and station service.
12	Net Installed Capacity for Ancillary	NIC_{AG}	MW	$RR_G + CR_G + DR_G$	Required installed capacity to satisfy ancillary services net of maintenance and station service.
13	Maintenance Capacity Factor	b	%		Assumed to be 90% of gross installed capacity.
14	Station Service Capacity Factor	c	%		Assumed to be 90% for base and 95% for midmerit, peaking, and ancillary services of gross installed capacity + maintenance service.
15	Gross Installed Capacity by Grid by Load	GIC_{LG}	MW	$\frac{NIC_{LG}/b}{c}$	Required installed capacity by base, midmerit, and peaking load plus maintenance and station service.
16	Gross Installed Capacity for Ancillary by Grid	GIC_{AG}	MW	$\frac{NIC_{AG}/b}{c}$	Required installed capacity to satisfy ancillary services plus maintenance and station service
17	Gross Installed Capacity by Grid	GIC_G	MW	$GIC_{LG} + GIC_{AG}$	Required installed capacity by grid: Luzon, Visayas, and Mindanao
18	Gross Installed Capacity	GIC		$\sum_G GIC_G$	Required installed capacity for the Philippines
19	Share of Installed Capacity by Load by Grid	θ_{LG}	%	$\frac{GIC_{LG}}{GIC_G}$	Note: $\sum_L \theta_{LG} = 100\%$ For simplicity, we lumped together midmerit, peaking, and ancillary loads as one. Thus, loads (L) are

					reduced to two: (1) base and (2) midmerit-peak-ancillary.
20	Fuel Source (Technology)	F	…		Fuel sources include coal, natural gas, conventional renewables, variable renewables, and oil. Conventional renewables include geothermal and hydro. Variable renewables include the must-dispatch solar, wind, biomass, and run-off river hydro.
21	Fuel Share by Load by Grid as Percent of Installed Capacity	β_{FLG}	%		Share in the fuel mix by grid is given in Box 3 as percent of installed capacity. Note that not all fuel sources or technologies are suitable for all types of load. Geographical location also matters. The following list the technologies by load and by grid: *1.* Luzon - Baseload: coal, natural gas, geothermal, base hydro and the must-dispatch variable renewables. Note: $\theta_{LG} = \sum_F \beta_{FLG}$ - Midmerit-peak-ancillary: peaking hydro, peaking natural gas, and oil *2.* Visayas and Mindanao - Baseload: coal, geothermal, base hydro and the must-dispatch variable renewables - Midmerit-peak-ancillary: peaking hydro, and oil
22	Per-unit Energy by Load by Grid	ρ_{LG}	%		Per-unit energy of baseload is assumed 67% for all grids. Per-unit energy of midmerit-peak-ancillary is assumed 5% for Luzon and Mindanao; and 2% for Visayas.
23	Power Consumption by Load by Grid	δ_{LG}	%	$\frac{\rho_{LG}}{LF_G}$	Per-unit Energy by Load/ Load Factor This is the percentage share of power consumption for each type of load.
24	Sum of Load in Peak Demand	d	%		The parameter (d) is based on the load duration curve in 2014 actual utilization of the different fuel sources. Based on DOE's data, the shares in peak demand of base, midmerit, and peaking are 67%, 23%, and 10% respectively. Mark-up for ancillary services is 15% of peak demand computed as $\frac{NIC_{AG}}{PD_G}$. Thus, sum total of load in peak demand, $d = 115\%$

25	Fuel Share by Percent of Electricity Power Consumption	μ_{FLG}	%	$\frac{\beta_{FLG} \times d}{\delta_{LG}}$	Share in the fuel mix by grid is given in Box 3 as percent of Power Consumption Mix. Computed as fuel share (installed capacity) by load multiplied by the sum total of load share in peak demand (d) taken as a share of energy consumption by load divided by the share of energy consumption by load.
26	Generation by Fuel Source by Grid	G_{FG}	kWh	$EC_G \times \mu_{FLG} \times 1000$	
27	Fuel Price by Grid	GP_{FG}	PhP/ kWh		Given in Tables 5-7.
28	Generation Cost by Fuel Source by Grid	GC_{FG}	PhP	$G_{FG} \times GP_{FG}$	
29	Blended Generation Charge by Grid	BGC_G	PhP/ kWh	$\frac{\sum_F GC_{FG}}{\sum_F G_{FG}}$	
30	Blended Generation Charge	BGC	PhP/ kWh	$\frac{\sum_{FG} GC_{FG}}{\sum_{FG} G_{FG}}$	

The next step is to compute the percent share of installed capacity (θ_{LG}) for each load for the three grids (Table 8, Line 19). For simplicity, we lumped together midmerit, peaking, and ancillary loads as one. Thus, loads (L) are reduced to two: (1) baseload and (2) midmerit-peak-ancillary. The percent share of installed capacity for these two loads for each grid (θ_{LG}) is just GIC_{LG} divided by GIC_G. The computed percent share of installed capacity (θ_{LG}) is given in Box 3.

Box 3: Assumption on the Share Allocation for Installed Capacity by Load and by Grid (θ_{LG}) (%)

	Strong Growth Scenario		Weak Growth Scenario	
	Baseload	Midmerit, Peak, Ancillary	Baseload	Midmerit, Peak, Ancillary
Luzon				
2016	59	41	58	42
2022	60	40	59	41
2028	61	39	60	40
2034	62	38	61	39
2040	63	37	61	39
Visayas				
2016	60	40	59	41
2022	61	39	60	40
2028	62	38	61	39
2034	63	37	61	39
2040	63	37	62	38
Mindanao				
2016	59	41	59	41
2022	61	39	60	40
2028	62	38	60	40
2034	62	38	61	39
2040	63	37	62	38

*Sum not equal to 100 due to rounding

Our assumptions on the percent share of installed capacity for each fuel (β_{FLG}) representing the four policy regimes are given in see Box 4a-d. β_{FLG} takes into account θ_{LG}. Not all fuel sources or technologies are suitable for all types of load. Geographical location also matters. For the Luzon grid, the baseload consists of coal, natural gas, geothermal, base hydro and the must-dispatch variable renewables. Thus, we have $\theta_{LG} = \sum_F \beta_{FLG}$, i.e., the share of installed capacity when L =baseload is the sum of the shares of the fuel mix (Σ_F) appropriate for meeting baseload requirement (Table 8, Line 21). The midmerit-peak-ancillary capacity components for Luzon consists of peaking-hydro, peaking natural gas, and oil. For the Visayas and Mindanao grids, the baseload consists of coal, geothermal, base hydro and the must-dispatch variable renewables. Their midmerit-peak-ancillary capacity components comprises peaking-hydro, and oil.

The percent share of energy consumption (δ_{LG}) by load per grid (Table 8, Line 23) is computed by dividing per-unit energy (ρ_{LG}) for each load (Table 8, Line 22) by the load factor for each grid, i.e., $\delta_{LG} = \frac{\rho_{LG}}{LF_G}$. Per-unit energy of baseload is assumed 67% for all grids. Per-unit energy of midmerit-peak-ancillary is assumed 5% for Luzon and Mindanao; and 2% for Visayas. The computed values for δ_{LG} is given in Box 5.

Our assumption on the percent share of power consumption for each fuel (μ_{FLG}) under the four policy regimes takes into account δ_{LG} and β_{FLG}. This is equal to the percent share of installed capacity by fuel multiplied by a parameter (d), then divided by the percent share of energy consumption by load, i.e., $\frac{\beta_{FLG} \times d}{\delta_{LG}}$ (Table 8, Line 24-25). The parameter (d) is obtained

from the load duration curve based on the 2014 actual utilization of the different fuel sources. Based on DOE's data, share in peak demand of base, midmerit, and peaking loads are 67%, 23%, and 10% respectively. Ancillary load is 15% computed as $\frac{NIC_{AG}}{PD_G}$. Thus, the sum total of load share in peak demand is given by $d = 115\%$ (Line 25). The computed values for μ_{FLG} is given in Box 4a-d.

Box 4a: Assumptions on Fuel Mix by Grid
(%)

Policy 1: 30-30-30-10

	Installed Capacity Mix (β_{FG})					Power Consumption Mix (μ_{FG})				
	Coal	Natural Gas	Conventional RE	Variable RE	Others	Coal	Natural Gas	Conventional RE	Variable RE	Others
Luzon										
2016	39	21	25	4	12	50	27	20	1	3
2022	33	32	22	3	10	41	41	15	1	2
2028	30	38	22	3	7	38	46	13	3	1
2034	30	40	21	3	6	38	47	10	4	1
2040	30	41	21	3	5	39	47	8	5	1
Visayas										
2016	29	0	36	10	25	34	0	62	1	3
2022	25	0	40	10	25	29	0	66	3	2
2028	24	0	40	10	26	28	0	65	5	2
2034	23	0	40	10	27	27	0	64	7	2
2040	23	0	40	10	28	27	0	62	9	2
Mindanao										
2016	16	0	49	2	33	20	0	74	1	6
2022	22	0	44	3	31	27	0	67	1	5
2028	30	0	41	3	26	37	0	56	3	5
2034	35	0	39	3	23	44	0	48	4	4
2040	38	0	39	3	20	48	0	44	5	4

*Sum not equal to 100 due to rounding.
Note: The numbers shown in this tables sums up the shares for all loads.

Box 4b: Assumptions on Fuel Mix by Grid

(%)

Policy 2: Utilization of the lesser-cost resource										
	Installed Capacity Mix (β_{FG})					Power Consumption Mix (μ_{FG})				
	Coal	Natural Gas	Conventional RE	Variable RE	Others	Coal	Natural Gas	Conventional RE	Variable RE	Others
Luzon										
2016	39	21	25	4	12	50	27	20	1	3
2022	42	20	25	2	12	52	29	16	1	2
2028	44	21	25	2	8	55	27	16	1	2
2034	47	20	25	2	6	60	23	16	1	1
2040	53	18	24	2	3	68	15	15	1	1
Visayas										
2016	29	0	36	10	25	34	0	62	1	3
2022	30	0	37	8	25	35	0	62	1	2
2028	32	0	39	6	23	37	0	60	1	2
2034	34	0	39	6	21	40	0	57	1	2
2040	35	0	40	6	19	43	0	55	1	1
Mindanao										
2016	16	0	49	2	33	20	0	74	1	6
2022	23	0	46	2	30	28	0	66	1	5
2028	28	0	44	2	27	34	0	60	1	5
2034	36	0	39	1	24	45	0	50	1	4
2040	44	0	34	1	21	56	0	40	1	4

*Sum not equal to 100 due to rounding.

Note: The numbers shown in this tables sums up the shares for all loads.

Box 4c: Assumptions on Fuel Mix by Grid

(%)

Policy 3: Increased utilization of conventional renewables (hydro and geothermal)

	Installed Capacity Mix (β_{FG})					Power Consumption Mix (μ_{FG})				
	Coal	Natural Gas	Conventional RE	Variable RE	Others	Coal	Natural Gas	Conventional RE	Variable RE	Others
Luzon										
2016	39	21	25	4	12	50	27	20	1	3
2022	35	21	30	4	10	43	28	25	2	2
2028	33	21	31	8	7	41	23	30	4	1
2034	30	21	33	12	4	38	21	33	7	1
2040	28	21	34	14	3	36	20	33	10	1
Visayas										
2016	29	0	36	10	25	34	0	62	1	3
2022	24	0	41	10	25	28	0	67	4	2
2028	24	0	38	13	25	28	0	62	8	2
2034	24	0	36	15	25	28	0	60	11	2
2040	21	0	36	18	25	25	0	59	14	2
Mindanao										
2016	16	0	49	2	33	20	0	74	1	6
2022	13	0	49	8	30	16	0	77	2	5
2028	12	0	46	16	26	15	0	78	3	5
2034	10	0	45	21	24	12	0	78	5	4
2040	8	0	46	24	22	10	0	79	7	4

*Sum not equal to 100 due to rounding.

Note: The numbers shown in this tables sums up the shares for all loads.

Box 4d: Assumptions on Fuel Mix by Grid
(%)

Policy 4: Increased utilization of Variable Renewables (solar, wind, run-off river hydro) and biomass										
	Installed Capacity Mix (β_{FG})					Power Consumption Mix (μ_{FG})				
	Coal	Natural Gas	Conventional RE	Variable RE	Others	Coal	Natural Gas	Conventional RE	Variable RE	Others
Luzon										
2016	39	21	25	4	12	50	27	20	1	3
2022	35	20	29	6	10	43	26	25	3	2
2028	33	21	30	9	7	41	23	27	7	1
2034	30	21	32	13	4	38	21	28	12	1
2040	28	20	33	15	3	36	18	29	16	1
Visayas										
2016	29	0	36	10	25	34	0	62	1	3
2022	24	0	39	12	25	28	0	66	5	2
2028	24	0	37	14	25	28	0	61	9	2
2034	24	0	35	16	25	28	0	55	15	2
2040	21	0	34	20	25	25	0	53	20	2
Mindanao										
2016	16	0	49	2	33	20	0	74	1	6
2022	13	0	46	11	30	16	0	77	2	5
2028	12	0	45	17	26	15	0	76	5	5
2034	10	0	45	21	24	12	0	75	8	4
2040	8	0	43	27	22	10	0	74	12	4

*Sum not equal to 100 due to rounding.
Note: The numbers shown in this tables sums up the shares for all loads.

Box 5: Assumption on the Share Allocation for Power Consumption by Load (δ_{LG})
(%)

	Base	Midmerit-peak-ancillary
Luzon	92%	8%
Visayas	97%	3%
Mindanao	93%	7%

*Sum not equal to 100 due to rounding.

In order to obtain the aggregate fuel mix for the country (Table 9), we first compute for the level of gross installed capacity and power consumption for each type of fuel for each grid, i.e., $GIC_{FG} = GIC_G \times \beta_{FG}$ and $G_{FG} = EC_G \times \mu_{FG}$, respectively. Summing up the required gross installed capacity across all grids for each fuel and dividing by the aggregate gross installed capacity, we arrived at the aggregate fuel mix for the country, i.e., $\beta = {\sum_G GIC_{FG}}/{GIC}$. Same method is applied for the aggregate consumption mix, i.e., $\mu = {\sum_G EC_{FG}}/{EC}$. This is done for

each of the policy regimes. The aggregate installed capacity mix and consumption mix is presented in Table 9.

For illustration purposes, we still apply the fuel mix assumption provided in Table 9 for all cases even if policy regime 2 follows the increased utilization of a lower-cost resource.

Table 9: Assumptions on Fuel Mix Share for Policy Regimes 1, 2, 3, and 4 (%)

	Installed Capacity Mix (β)					Power Consumption Mix (μ)				
	Coal	Natural Gas	Conventional RE	Variable RE	Others	Coal	Natural Gas	Conventional RE	Variable RE	Others
Policy 1: 30-30-30-10										
2016	35	15	29	4	16	44	20	32	1	3
2022	30	24	27	4	15	37	30	29	1	2
2028	29	28	27	4	12	36	34	25	3	2
2034	30	29	26	4	11	37	35	22	4	2
2040	30	30	26	4	10	38	35	20	5	2
Policy 2: Utilization of the lower-cost resource										
2016	35	15	29	4	16	44	20	32	1	3
2022	38	14	29	3	16	47	21	28	1	3
2028	40	15	29	3	13	50	20	27	1	2
2034	44	15	28	2	10	55	17	25	1	2
2040	49	14	27	2	8	63	11	24	1	1
Policy 3: Increased utilization of conventional renewables (hydro and geothermal)										
2016	35	15	29	4	16	44	20	32	1	3
2022	31	15	34	5	15	38	21	37	2	2
2028	29	15	34	10	12	36	17	40	4	2
2034	27	15	35	14	9	33	15	43	7	1
2040	24	15	36	16	8	31	15	43	10	1
Policy 4: Increased utilization of Variable Renewables (solar, wind, run-off river hydro) and biomass										
2016	35	15	29	4	16	44	20	32	1	3
2022	31	15	33	7	15	38	20	37	3	2
2028	29	15	33	11	12	36	17	38	7	2
2034	27	15	34	15	9	33	15	38	12	1
2040	24	15	35	18	8	31	13	38	16	1

Note: 2016 data are a carryover of the fuel mix as of June 2015. Conventional renewables include hydro (19%) and geothermal (10%). Variable renewables include wind (2%) and solar (1%); biomass (1%) is also added here. *Sum not equal to 100 due to rounding.

The power generation by type of fuel and grid (G_{FG}) is converted to kWh (Table 8, Line 26). Generation price by fuel source by grid (GP_{FG}) is given in Tables 6-8. Generation cost by fuel source for each grid (GC_{FG}) is then obtained by multiplying the generation by the price ($G_{FG} \times GP_{FG}$), (Table 8, Line 28). While we assumed that generation price is constant until 2040 in the baseline case, the blended generation charge (BGC_G) varies depending on the policies, which differ according to the fuel mix. Summing up the cost of generation over all fuel types and dividing by the total power generation $\left(\frac{\sum_F GC_{FG}}{\sum_{FG} G_{FG}}\right)$, we obtain the blended generation charge per kWh for each grid (BGC_G), (Table 8, Line 29).

The result of the numerical exercise is presented in Table 10. Gross installed capacities and gross generation are summed across grid (Box 6) to obtain the values for the country corresponding to the four policy regimes under the strong-growth scenario and policy regime 1 under the weak-growth scenario.

Table 10: Generation Capacity in Strong and Weak Growth Scenarios, 2015-2040

Indicator	2015	2016	2022	2028	2034	2040
Strong Growth Scenario						
Population Growth Rate (%)	…	1.46	1.21	1.05	0.84	0.61
GDP per Capita (PhP)	74,453	79,299	110,216	154,741	219,707	316,173
GDP per Capita Growth Rate (%)	…	6.51	5.72	5.89	6.11	6.35
Electricity Consumption = Gross Generation (MWh)	81,896,000	85,434,660	111,382,600	143,576,000	184,496,300	236,865,100
Installed Capacity (MW)	18,279	18,983	24,143	30,545	38,682	49,096
Blended Generation Charge (PhP/kWh)						
Policy 1: 30-30-30-10 Fuel Mix	…	4.35	4.38	4.42	4.46	4.47
Policy 2: Least-cost Resource	…	4.38	4.37	4.34	4.32	4.29
Policy 3: Increased Conventional RE	…	4.38	4.43	4.50	4.58	4.65
Policy 4: Increased Variable RE	…	4.38	4.47	4.57	4.70	4.82
Weak Growth Scenario with Policy 1						
Population Growth Rate (%)	…	1.68	1.57	1.40	1.21	1.04
GDP per Capita (PhP)	74,453	76,155	87,550	101,441	118,873	140,791
GDP per Capita Growth Rate (%)	…	2.29	2.39	2.56	2.76	2.93
Electricity Consumption = Gross Generation (MWh)	81,896,000	83,204,540	95,137,580	109,676,600	126,681,700	146,383,200
Installed Capacity (MW)	18,279	18,539	20,912	23,803	27,185	31,103
Blended Generation Charge (PhP/kWh)	…	4.35	4.38	4.42	4.46	4.47

Notes:
1. Strong growth scenario has an annual 7% GDP growth rate and low variant population growth rate.
2. Weak growth scenario has an annual 4% GDP growth rate and medium variant population growth rate.
3. Policy 1: 30-30-30-10 mix; Policy 2: increased utilization of the lower-cost resource; Policy 3: increased use of conventional renewables; and Policy 4: increased use of variable renewables. Policies 2, 3 and 4 take account of the emission charge.

Box 6: Generation Capacity in Strong- and Weak-Growth Scenarios by Grid, 2015-2040

Indicator	2016	2022	2028	2034	2040
Luzon					
Strong Growth Scenario					
Electricity Consumption = Gross Generation (MWh)	63,221,648	82,423,124	106,246,240	136,527,262	175,280,174
Peak Demand (MW)	9,886	12,889	16,614	21,350	27,410
Installed Capacity (MW)	13,969	17,753	22,446	28,412	36,047
Case 1 (Base): Blended Generation Charge (P/kWh)					
Policy 1: 30-30-30-10 Fuel Mix	4.33	4.36	4.38	4.41	4.40
Policy 2: Least-cost Resource	4.37	4.36	4.31	4.26	4.18
Policy 3: Increased Conventional RE	4.37	4.41	4.45	4.52	4.60
Policy 4: Increased Variable RE	4.37	4.45	4.53	4.65	4.76
Weak Growth Scenario with Policy 1					
Electricity Consumption = Gross Generation (MWh)	61,571,360	70,401,809	81,160,684	93,744,458	108,323,568
Peak Demand (MW)	9,628	11,009	12,692	14,659	16,939
Installed Capacity (MW)	13,644	15,384	17,504	19,983	22,855
Blended Generation Charge (P/kWh)	4.33	4.36	4.38	4.41	4.40
Visayas					
Strong Growth Scenario					
Electricity Consumption = Gross Generation (MWh)	11,106,506	14,479,738	18,664,880	23,984,519	30,792,463
Peak Demand (MW)	1,837	2,396	3,088	3,968	5,094
Installed Capacity (MW)	2,549	3,252	4,124	5,233	6,652
Case 1 (Base): Blended Generation Charge (P/kWh)					
Policy 1: 30-30-30-10 Fuel Mix	4.96	5.00	5.05	5.09	5.13
Policy 2: Least-cost Resource	4.98	4.96	4.93	4.92	4.91
Policy 3: Increased Conventional RE	4.98	5.02	5.12	5.17	5.26
Policy 4: Increased Variable RE	4.98	5.04	5.14	5.27	5.39
Weak Growth Scenario with Policy 1					
Electricity Consumption = Gross Generation (MWh)	10,816,590	12,367,885	14,257,958	16,468,621	19,029,816
Peak Demand (MW)	1,790	2,046	2,359	2,725	3,148
Installed Capacity (MW)	2,489	2,812	3,206	3,667	4,201
Blended Generation Charge (P/kWh)	4.96	5.00	5.05	5.09	5.13
Mindanao					
Strong Growth Scenario					
Electricity Consumption = Gross Generation (MWh)	11,106,506	14,479,738	18,664,880	23,984,519	30,792,463
Peak Demand (MW)	1,761	2,296	2,959	3,803	4,882
Installed Capacity (MW)	2,464	3,138	3,974	5,037	6,397
Case 1 (Base): Blended Generation Charge (P/kWh)					
Policy 1: 30-30-30-10 Fuel Mix	3.82	3.88	4.03	4.12	4.18
Policy 2: Least-cost Resource	3.83	3.88	3.94	4.09	4.27
Policy 3: Increased Conventional RE	3.83	3.95	4.15	4.31	4.36
Policy 4: Increased Variable RE	3.83	4.02	4.23	4.37	4.56
Weak Growth Scenario with Policy 1					
Electricity Consumption = Gross Generation (MWh)	10,816,590	12,367,885	14,257,958	16,468,621	19,029,816
Peak Demand (MW)	1,715	1,961	2,261	2,611	3,017
Installed Capacity (MW)	2,406	2,716	3,094	3,535	4,047
Blended Generation Charge (P/kWh)	3.82	3.88	4.03	4.12	4.18

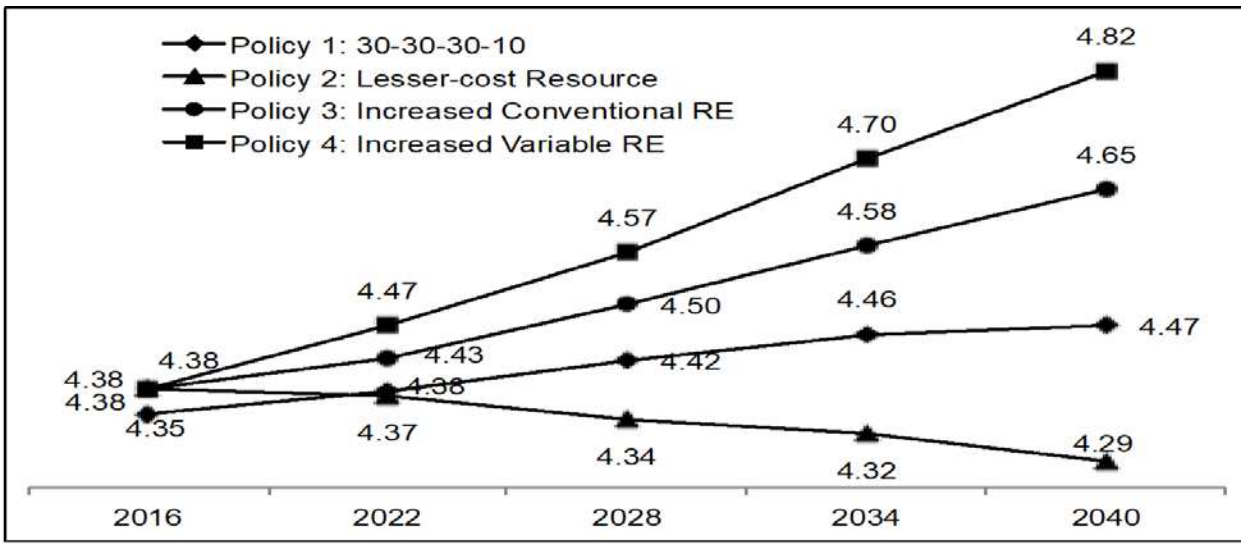
Under the strong-growth scenario, regardless of policy regime, the result shows that the country needs to increase its installed capacity from 18.2 GW in 2015 to about 49 GW in 2040, a 169% increase, to support the 7% annual growth from 2016-2040. This required installed capacity in 2040 is close to the 2012 installed capacity of Thailand and Indonesia, which are at about 53 GW and 48 GW, respectively. Gross generation would increase from 81,896 GWh in 2015 to 236,865 GWh in 2040, a 189% increase. Under the weak-growth scenario, the result shows that the country needs to increase its installed capacity from 18.2 GW in 2015 to about 31 GW in 2040; a 70% increase. Gross generation would increase from 81,896 GWh in 2015 to 146,383 GWh in 2040, a 78% increase.

Meeting the required installed capacity is a necessary but not a sufficient condition for the improvement of the well-being of Filipinos, which is the main objective of this study. The price consumers pay to access and consume electricity matters. This is reflected in the blended generation charge (BGC), which constitutes 47% of the total bill of residential consumers (Meralco 2015). Therefore, a significant reduction in the blended generation charges will improve the economic well-being of the Filipino consumers.

Focusing on the strong-growth scenario, Figures 14–18 show the projected trends for the blended generation charge under the five cases of possible evolution of fuel prices. For each of these cases, we compare the performance of the four policy regimes on fuel mix: *Policy 1*: 30-30-30-10 mix (the current policy stance of the government), *Policy 2*: increased utilization of the lower-cost resource, *Policy 3*: increased use of conventional renewables, and *Policy 4*: increased use of must-dispatch renewables. Policy regimes 2, 3 and 4 take account of the emission charge. It should be noted that in all the five cases of possible evolution of fuel prices, the fuel mix assumptions under the four policy regimes remain the same as given in Table 5.

Holding fuel technology and prices constant at 2015 levels (Case 1), Figure 14 shows that Policy regime 2 performs best, where the blended generation charge will decrease by 2.21%, from PhP4.38 per kWh in 2016 to PhP4.29 per kWh in 2040. On the other hand, maintaining the 30-30-30-10, the “balanced aspiration” would be costly. Following Policy regime 1, the blended generation charge is projected to increase from PhP4.35 per kWh in 2016 to PhP4.47 per kWh in 2040, an increase of 2.77%. Policy regime 3, which increases the fuel share of conventional renewables such as hydro and geothermal, performs better than Policy regime 4, but this may not be a realistic assumption given the hard constraints of natural reserves. Increasing the share of must-dispatch renewables, Policy regime 4, at current generation prices can lead to an increase of 9.87% in the blended generation charge by 2040.

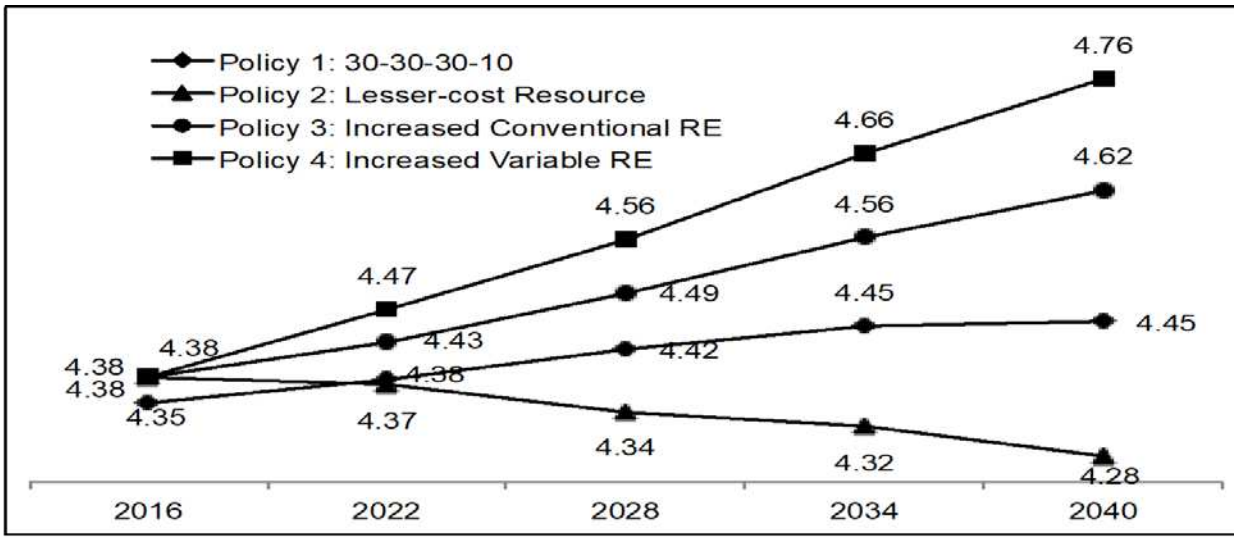
Figure 14: Case 1 (Baseline constant fuel price) - Generation Price Projections



Source: Authors' calculations.
Note: Policy regimes on fuel mix: 1) 30-30-30-10 mix, 2) increased utilization of the lower-cost resource, 3) increased use of conventional renewables, and 4) increased use of variable renewables. Policy regimes 2, 3 and 4 take account of the emissions charge.

Holding fuel prices constant from 2015-2040, this exercise shows that there is a better alternative to the balanced aspiration on fuel mix, which mandates the maintenance of 30% share of renewables. Policy regime 2 could potentially help in bringing the cost of power down by lowering the cost of the blended generation charge. While fixed fuel prices are assumed under Case 1 the problem is dynamic in nature. Policy regime 2 is the utilization of the lower-cost resource where coal is favored since it is presently the cheapest. Depending on how technology evolves, policy regime 2 favors whichever has the lower cost, not necessarily coal. Figure 15 shows the projected generation price trends under Case 2 when FIT degression rates are incorporated in the prices of must-dispatch renewables. Case 2 lowers the prices of must-dispatch renewables, while prices of other fuel sources remain the same as in Case 1. The analysis shows that the performance rank of the four policy regimes is the same as in Case 1. As expected the generation charges under policy regimes 3 and 4 go down in 2040 relative to our benchmark provided in Case 1 in Figure 14.

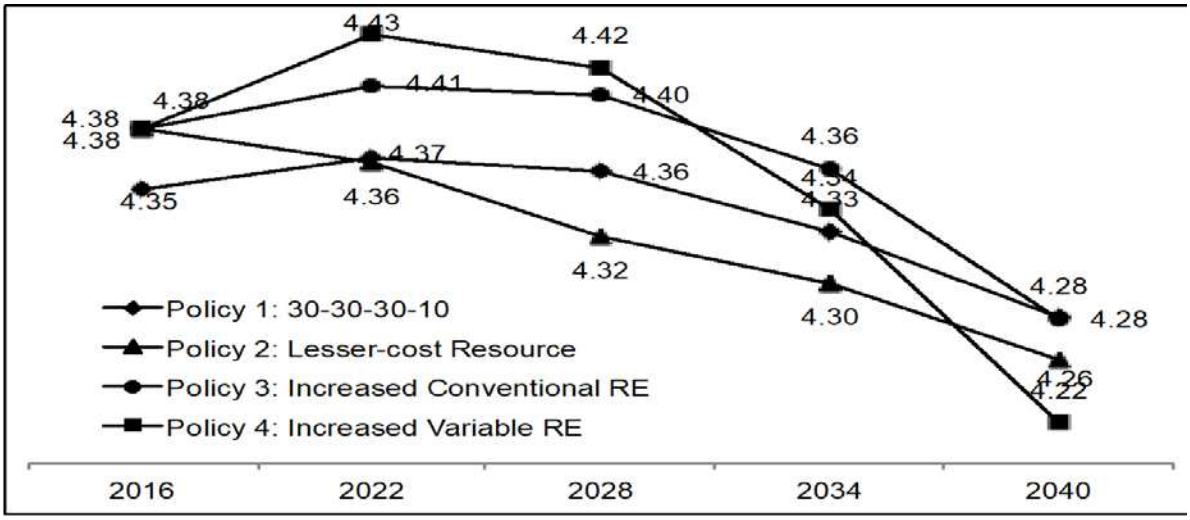
Figure 15: Case 2 - Generation price projection when prices of RE incorporate FIT degression rates (PhP/kwh)



Authors' Calculations

Figure 16 presents the results for Case 3 when we allow for a 3% annual decrease in the average prices of must-dispatch renewables. It must be noted that Case 3 is a bottom-up exercise because we ask the question to what extent the price of renewables must go down for policy regime 4 to perform better. Figure 16 expectedly shows that Policy regime 4 gives the lowest blended generation charge by 2040. If the technologies for solar, wind, run-off river hydro, and biomass evolve accordingly, then policy regime 2 transforms into policy regime 4, i.e., the increased utilization of the lower-cost resource, which in this case point to these must-dispatch renewables.

Figure 16: Case 3 - Generation price projection with annual decrease in average RE prices by 3% (PhP/kwh)

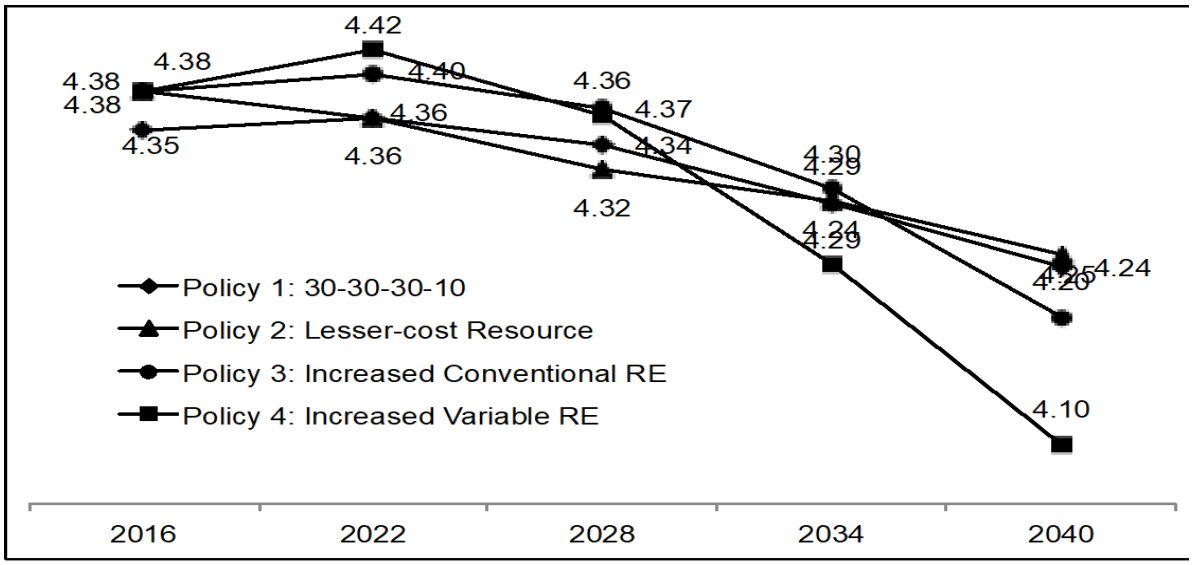


Authors' Calculations

Figure 17 shows the results for Case 4, which is a variant of Case 3. Solar price is projected to decrease by 8% annually and average prices of must-dispatch renewables are decreased by 3%. As expected, the result shows that Policy regime 4 gives the lowest blended generation charge by 2040 at PhP4.10 per Kwh. Similarly, if solar technology changes rapidly, then policy

regime 2 transforms into policy regime 4, leading to the increased utilization of the lower-cost solar resource.

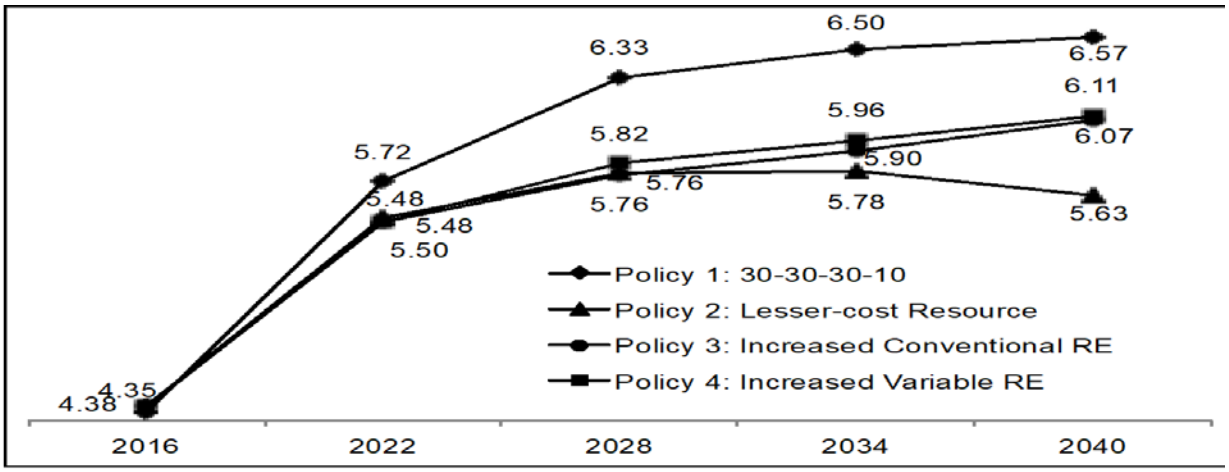
Figure 17: Case 4 – Generation price projection with annual decrease by 8% in the price of solar and 3% in RE (PhP/kWh)



Authors' Calculations

Figure 18 shows the results for Case 5, where all fuel prices are assumed to change simultaneously. Projections of the EIA (2016) were applied to the 2015 fuel prices for the Philippines in the conduct of this exercise. The EIA annual average growth projection for coal up to 2040 is at 0.50%, which is relatively lower than that for other fuel sources, i.e., at 2.50% for natural gas, 4% for oil and -0.64% for must-dispatch renewables . Policy regime 2, the utilization of the lesser-cost resource, performs best, posting a blended generation charge of PhP5.63 per Kwh by 2040.

Figure 18: Case 5 - Generation price projection when all fuel price changes simultaneously (PhP/kWh)

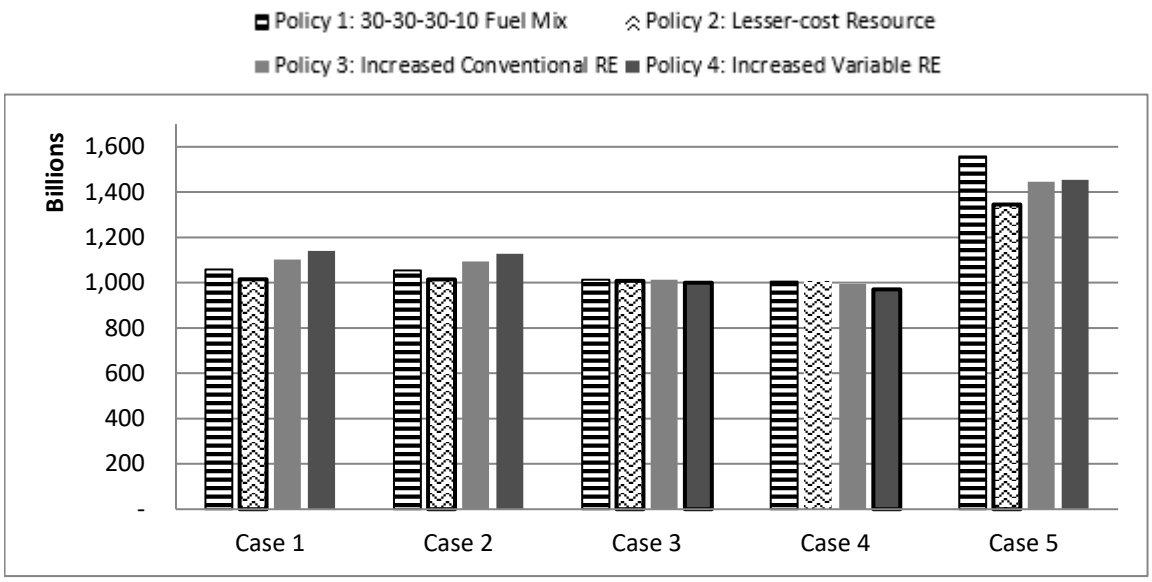


Authors' Calculations

Since the objective is to improve the well-being of the Filipinos, it is not enough to meet the required generating capacity under strong-growth scenario. We also consider the cost. Given

the projection on prices under the five cases, we then compute how much it would cost to generate the electricity that would support the consumption of 236,865 GWh under the Strong-growth scenario. Figure 19 compares the total generation cost of the four policy regimes under the five possible cases of the evolution of fuel prices. Policy regime 2 costs the least specifically under cases 1(PhP1,015 billion), 2 (PhP1,014 billion), and 5 (PhP1,345 billion). With case 3, policy regime 4 is the least cost at PhP1,000 billion. Note that policy regime 2 stipulates increased utilization of the lesser-cost resource. Thus, under case 3, policy regime 2 effectively transforms into policy regime 4.

Figure 19: Total Generation Cost in 2040
(PhP Billions)



To reiterate, our overriding objective is to improve the well-being of Filipinos by lowering the price of electricity in an economically efficient manner. The numerical exercise illustrates that the optimal fuel mix is not constant over time but should exploit the opportunities opened up by less costly resources while taking environmental and health costs[8] into account.

An important caveat is that the fuel mix in the four policy regimes is based on current and projected prices and the current situation. This does not account for the intermittency cost of renewable generation capacity and the cost of integrating renewables into the grid, which may require additional investment. For example, 16 GW of wind turbines in the pipeline of Scotland requires a grid investment of c £4 billion (House of Lords 2008, II p. 252). In Britain, a 34% share of renewables in their generation and transmission imposes a likely cost of £6.8 billion a year, or an extra 38% increase (House of Lords 2008, I 252). The intermittent nature of renewable generation, such as in wind and solar, requires additional investment in new capacity from reliable conventional sources (or even in nuclear energy) to serve as back-up sources (Van Kooten 2010). In the United Kingdom, the pursuit of a 15% renewables target requires roughly doubling the requirement for new capacity.

[8] Our numerical exercise did not include health costs. A study for the Philippines is wanting.

III. PROPOSED TARGETS FROM 2016 TO 2040

We have translated the government's '2040 vision' in terms of per capita income growing to PhP316,173 ($6,873) in 2040 at constant 2000 prices from the 2015 level of PhP74,453 ($1,618). This meant that per capita income had to grow at 6% per year. In section I, we built strong- and weak-growth scenarios. The vision for 2040 was realized in the strong-growth scenario whereas a business-as-usual case was illustrated in the weak-growth scenario. We then asked what was required from the energy sector to attain the vision by focusing on the fuel mix policy and how it could influence the electricity price.

Here, we then outline measurable indicators and proposed indicative targets constituting energy security through to 2040 (Table 11). We take energy security to have three dimensions: accessibility, affordability, and reliability. Accessibility is defined as the percentage of the population that has access to electricity. In 2012, 87.5% of Filipinos had access to electricity. The target for the current administration (2016-2022) can be 90%. The indicator for affordability is the price that consumers pay. Our analysis in Section I focused on the generation costs that make up 47% of the electricity bill. Since the EPIRA, the generation sector has already been privatized. The government can facilitate a more competitive environment not by restricting/prohibiting a fuel mix but, rather, by letting the market work. Following market signals, the generation sector will rationally adhere to the utilization of least cost-resource. The targets under affordability correspond to the results presented in Figure 14.

Table 11. Measurable Indicators and Proposed Targets

	Benchmark year units	2012/ 2015	2016-2022	2022-2028	2028-2034	2034-2040	Remarks
1. Accessibility	2012 (% of pop)	87.5	90	92	94	95	2012 is based on WB
2. Affordability: Price (full cost including health & environmental cost) - Generation Charge	2015 PhP/KWh	4.38	4.37	4.34	4.32	4.29	2015 Blended Generation Charge (BGC) based on MERALCO prices. Projection based on authors' preliminary calculation
3. Reliability: Loss of Load Expectation (LOLE)	2015 day(s)/year	1.2	1.1	1	1	0.9	2015 is based on WB estimates. 1 day optimal LOLE is based on del Mundo 1991.

Sources of basic data: WDI (2014); Meralco (2015); del Mundo (2015).

The third dimension for energy security is reliability, which can be measured using the engineering concept called "Loss of Load Expectation" (LOLE). It is defined as the expected number of times in a year that the available generation capacity, considering scheduled- and forced-outages of power plants, will not meet system daily peak demand, i.e., the number of days in a year that there will be "brownouts" (blackouts) caused by unscheduled power plant outages. In the US and Europe, a standard LOLE is approximately 0.3 to 0.1 day per year. In the Philippines, the LOLE has been previously estimated to be 1.2 days per year (Del Mundo 2014). The target for the current administration is to shorten the LOLE to 1.1 days per year.

IV. KEY REFORMS AND ALTERNATIVE PATHWAYS

A. Investment Coordination in Generation, Transmission, and Distribution

Given the long gestation period to build a power plant, the benefits from planning ahead far exceed the costs. Concomitant with investment in generation are the coordinated investments in the transmission and distribution infrastructure. A well-conceived master plan that accounts for the current assessment of the industry and provides incentive-compatible arrangements will attract investors to bet on the country for the long term. Coordination has never been the Philippines' strong suit, and we have to do much better in this regard in the next 25 years. A master plan coordinating investment in generation, transmission, and distribution infrastructure must be drawn up at the start of the new administration. This is critical if the Philippines wants to sustain economic growth. An equally decisive factor is the coordination between investment in power generation and investment in the upgrade of the grid.

Negros Island (Region 18) will soon become a considerable exporter of renewable power. Due to the expanded FIT program, many new solar projects are coming on-stream and many sugar mills are acquiring co-generation capacity to supply power to the open market through the grid. The latter is especially exciting because the feedstock used is bagasse (biomass), which used to be a throwaway waste product of sugar milling and is thus a cheap RE source.

The first hurdle is getting the power to the grid. These new RE generation capacities require connection to the grid and those connections are not readily forthcoming, so that some plants (e.g. SONEDCO Milling), which can defray the cost, decided to finance the connection themselves rather than run idle. It is the National Grid Corporation of the Philippines' (NGCP) obligation to provide these connections, but any financing the NGCP does for a connection project has to be approved by the Energy Regulatory Commission (ERC) for future reimbursement. The ERC, with its limited personnel and expertise complement, is normally swamped with petitions for approval that take time to process, and hence result in delays.

The second hurdle occurs after connection to the grid. Negros Island will need to sell this new power to power-deficit regions, including even Luzon. The problem is the limited capacity of the power pipeline connecting Negros to Cebu and, thereafter, to Luzon. If the grid capacity is not upgraded, these new projects will become stranded assets like the Bataan nuclear project. Again, the NGCP is supposed to be involved—but this expensive, though very socially worthwhile project, may have to wait. Our suggestion is for the national government to make the grid upgrade between Negros and Cebu (and, thereafter, its extension from Negros to Mindanao) a priority public-private partnership (PPP) project.

Stable and consistent government policies are important to foster and encourage private investment in power generation. Timely implementation is also crucial. The ERC, for example, has to decide on numerous petitions for tariff adjustments. A cumbersome and contentious accounting review process means added costs which the distribution utilities (DU) eventually pass on to captive consumers. The ERC's recent move to outsource the review process to the market through the Competitive Selection Process (CSP) will free the ERC of considerable burden: it is now the DUs' responsibility to convince the ERC of the transparency and competitiveness of their power supply agreements (PSA). If the CSP is found wanting, the ERC simply subjects the PSA to a Swiss challenge. As to who determines the acceptability of the CSP, the ERC can coordinate with the Philippine Electricity Market Corporation (PEMC) or the PPP Center that has developed some capability on market testing. As to the issue of the PSA contract template, we recommend that a portfolio approach be developed in lieu of per-plant approach to auctioning. This means that the bidders may not necessarily be power generation plants but may indeed be power supply aggregators (e.g. various power types such

as base load and peaking) who can handle the numerous financial minutiae (e.g., risk-sharing among the parties).

Uncertainty in the policy environment discourages inflow of private investment in the power sector; the same results draw from gaps and weaknesses in the physical network, such as the grid connection. It is foolhardy to invest in assets that will become stranded. The few investors who may come in are those likely to demand higher returns for higher risks, or those whose comparative advantage is in extracting compensation from the national government and navigating the bureaucratic maze rather than in efficient operations.

B. Government Investment in the Transmission Highway

Section 8 of the EPIRA created the National Transmission Company (TRANSCO), which assumed the electrical transmission function of the National Power Corporation (NPC). The TRANSCO is owned by the Power Sector Assets and Liabilities Management Corporation (PSALM), which is mandated to privatize its assets either through an outright sale or a concession contract. In December 2008, Congress, through Republic Act (RA) 9511, awarded the franchise to the NGCP, a consortium consisting of Monte Oro Grid, Calaca High Power Corp, and State Grid Corporation of China.

The franchise granted the NGCP the authority to engage in the business of conveying or transmitting electricity through a high-voltage backbone system of interconnected transmission lines, substations and related facilities, and for other purposes. The nature and scope of the franchise also granted the NGCP the authority to construct, install, finance, manage, improve, expand, operate, maintain, rehabilitate, repair, and refurbish the present nationwide transmission system.

Prior to the congressional franchise, one of the TRANSCO's responsibilities, as provided in Section 9 of the EPIRA, was to improve and expand its transmission facilities, consistent with the Grid Code and the Transmission Development Plan (TDP). The TRANSCO was also required to submit any plan for expansion or improvement of its facilities for approval of the ERC. One of the TRANSCO's modes of financing the expansion of its transmission facilities was through loans (e.g. from ADB and JICA).[9] With the award of the franchise, these responsibilities now rest solely with the NGCP, along with financing and seeking the approval of ERC for any investment in expanding the transmission facilities. The ERC's approval of any investment would need to consider the cost implication to consumers as the investment recovery is ultimately passed on to consumers. Our suggestion is that financing and investment should be separate from the regulatory structure of the transmission tariff. Since government owns the transmissions assets, the TRANSCO should play the lead role in planning, investment, and expansion of transmission facilities. Financing, for example, could be in the form of PPP or through the government treasury, depending on the efficacy of the investment. Depending on the mode of financing, consumers can partly finance the expansion, similar to Norway and Chile (Oren et al. 2002).

It is critical to make investment in transmission expansion incentive-compatible with key stakeholders, consumers, private sector, and government. in the Philippines, the long wait by the NGCP for ERC's approval in consideration of the increase in retail cost is likely to inhibit investment in transmission, which could lead to congestion and, ultimately, higher costs for consumers. Investment in transmission expansion offers great potential benefits for efficiency by increasing access to low-cost generation, improving reliability, and mitigating market

[9] See ADB Project Number: 36018, Loan Number: 1984, dated January 2012 and JICA Report in http://www.jica.go.jp/english/our_work/evaluation/oda_loan/post/2007/pdf/project13_full.pdf

power. Better transmission could potentially reduce the marginal cost of transmission (Joskow 1976), which will eventually lower average wholesale prices.

C. Regulatory Oversight Coordination in Support of a Competitive Market

The recent passage of the Philippine Competition Act, which provides for a National Competition Policy and the creation of the Philippine Competition Commission (PCC), bodes well for a regulatory regime that has more resources and is more transparent. It should be stressed that the PCC and the ERC must work in harmony to ensure that "forum shopping" is avoided and no industry participant exercises significant market power.[10]

Agencies should recognize the limitations of their own capacity as well as the strengths of other agencies. It is a positive development that the ERC has now issued a circular mandating CSP. In the interim, DUs are to prove that their PSA contracts went through transparent and open competitive bidding.

As part of the EPIRA unbundling of the sector, the NGCP, a private for-profit entity, enjoys a monopoly franchise over grid operations. While the NGCP won its franchise through competitive bidding, the PCC and the ERC should ensure that the NGCP, as system operator, does not engage in monopoly pricing. They should also ensure, together with the DOE, that new investments in transmission facilities are on time to meet future demand and that proper maintenance is in place at all times to avoid system failure.

From an economic efficiency and societal welfare viewpoint, the result of regulatory policy should be an industry and an economy where market prices of outputs and inputs faced by consumers and producers reflect their marginal social values and marginal social costs. Moreover, externalities or spillovers should be internalized through corrective tax and subsidy mechanisms to ensure that the market prices faced by consumers and producers more closely reflect their true marginal social values and marginal social costs.

D. Reconciling Two Seemingly Contradicting Instruments: EPIRA and RE Law

The power industry has two major legal instruments: the EPIRA (RA 9136) and the RE Law (RA 9513). An examination of these two laws suggests that they may be working at cross purposes, with the EPIRA apparently being undermined by the RE Law. Reconciling the disparate objectives is needed preparatory to reforming these laws.

The long-term national goals are articulated in the EPIRA. Foremost among them are: to ensure the quality, reliability, security, and affordability of the supply of electric power; to make sure that transparent and reasonable prices of electricity prevail in a regime of free and fair competition, and full public accountability; to promote the utilization of indigenous and new and
RE resources in power generation to reduce dependence on imported energy; and to accelerate the total electrification of the country.

In 2008, the RE Law was passed seeking to (i) reduce dependence on fossil fuels, thus insulating the country's exposure to price fluctuations in the international markets and (ii) increase utilization and development of RE resources as tools in preventing harmful emissions.

[10] As of September 2016, the PCC and ERC were in the final stage of drawing a Memorandum of Understanding (MOU) in coordinating their work.

The main conflict between the two laws lies in how certain provisions of the RE Law seem to run counter to EPIRA's goals of "affordability of the supply of electric power" and "reasonable prices of electricity." In particular, the FIT system under the RE Law raises the price of electricity paid by the consumer.

One way of reconciling the goals of "economic growth and development" with "the promotion of health and safety, and the protection of the environment" (RA 9513) is to address the negative environmental and health effects of carbon emissions from fossil fuel-based power generation through carbon taxes, i.e., directing policy right at the source of the harmful spillovers. The carbon taxes will internalize the negative externality and the revenues generated can be used to finance investments in environmental and health protection.

E. Reform of the Electric Cooperatives

One black hole in the power landscape of the Philippines is the operation of some electric cooperatives (ECs), where financial viability is constantly in question. One reason is the role of local politics in the capture of management. Cooperatives are run on the one-member-one-vote modality—a political and inefficient modality. This results in political capture. Cooperatives must move towards the corporatist lines of one-share-one-vote. This incentivizes greater efficiency and attention to the bottom line. Management should then be passed on to the hands of those with most to lose if the company fails. Wresting cooperatives from the claws of politics is tricky and needs political courage. Denial of power to a population as the ultimate weapon is politically costly for the national government. The effort of the National Electrification Administration (NEA) to provide subsidies for corporatization has resulted in meager harvest. The target is the eventual consolidation of small DUs into only a handful of more financially robust DUs run on corporatist lines and open to private investors. This will also greatly unburden the ERC.

Problems with the ECs and the rural electrification thrust are probably best illustrated in the raging battle for management control over several ECs between those who want registration with the Cooperative Development Authority (CDA) and those who prefer to remain within the ambit of the NEA. Under Section 57 of the EPIRA, "electric cooperatives are . . . given the option to convert into either stock cooperative under the Cooperatives Development Act or stock corporation under the Corporation Code." Those in support of registration with the CDA, like the Association of Philippine Electric Cooperatives, claim that doing so would lower electricity tariffs by P0.25/kWh to P0.40/kWh because the 12% expanded value-added tax and local taxes would be waived. Two prominent examples of ECs where bitter disputes between the pro-CDA and pro-NEA camps prevail are the Batangas II Electric Cooperative in Luzon and the Davao del Norte Electric Cooperative in Mindanao. At present, nevertheless, the vast majority of ECs are still registered with NEA, perhaps because NEA is their major source of finance. What is disturbing about the situation is why this turf war between the two national government agencies is being allowed to continue.

Many ECs have to put their management and finances in order. A growing perception is that the ECs are "essentially political creatures, where local political control and interference is a feature of governance and management" (Castalla 2004, p. 3). This is an issue that needs to be addressed, for ECs are at the forefront of government's efforts to expand access to electricity in the countryside.

To make ECs more efficient, the EPIRA gives them the option of converting to either a stock cooperative or stock corporation. DOE Circular 2004-06-007 urges ECs to "undertake structural and operational reforms… through collaboration with the private investor-operators to gain access to private sector capital and management expertise." This initiative needs to

be monitored more closely, highlighting "best practices" where private sector participation leads to cheaper, and more reliable electricity services.

F. Investment in Research and Development

Attention also needs to be directed toward energy research and development (R&D). In fact, the *Philippine Development Plan (PDP) 2011-2016* cites the need for a stronger energy R&D, particularly on RE. Current initiatives are focused on nonfood feedstock development for biodiesel and bioethanol in support of the country's biofuels program. In this regard, partnership among government, academe, and the private sector should be harnessed.

Two government agencies are at the forefront of energy R&D: the DOE and the Department of Science and Technology (DOST). The DOE performs their energy research testing and laboratory services through two divisions: the Geo-scientific Research and Testing Laboratory, and the Appliance Testing and Laboratory. As such, they do not really engage in basic research.

The DOST's Philippine Council for Industry, Energy, and Emerging Technology Research and Development (PCIEERD) is the agency that is more closely associated with basic research. Its governing council is composed of seven members from the government (DOST, Department of Public Works and Highways, Department of Transportation and Communication, DOE, Commission on Higher Education or CHED, Board of Investments–Department of Trade and Industry, and Department of Budget and Management) and three from the private sector. The PCIEERD's Energy, Utilities and Systems Technology Division formulates a science and technology sectoral plan, and "coordinates, evaluates, and monitors R&D programs and projects relating to energy conservation, conventional and non-conventional sources of energy, construction and infrastructure, and transportation sectors". Again, like the DOE, the DOST-PCIEERD coordinates and funds but does not do energy R&D. It gives "Outstanding R&D" cash awards for completed research. Among the recent recipients for energy were "A Portable Power Generating Apparatus for Irrigation System of Small Scale Farming," "Solid Waste to Energy, Fertilizer and Wealth," and "Rapid Electric Vehicle Charging: Charging in Minutes."

Despite the interagency nature of PCIEERD, government resources allocated to energy R&D remain limited, and coordination among government agencies involved in energy R&D is generally lacking. A glaring example of this lack of coordination is in the development of jatropha for biodiesel production in the mid- to late-2000s. While the scientific community was still studying the technical feasibility of using oil from this plant as biodiesel, two competing government-owned and -controlled corporations (i.e., the Philippine Forest Corporation and the Alternative Fuels Corporation) already embarked on a massive jatropha planting program, which eventually went to waste. As academician and former DOST Secretary Emil Javier remarked, the jatropha endeavor was a case where the policy preceded the technology.

One yet untapped RE source of power is ocean thermal energy conversion (OTEC). According to the *PDP 2011-2016:* "to date, the country's potential sites for deep-ocean power consist of 910 blocks equivalent to 73,710 hectares." The DOE has signed several OTEC pre-development contracts, but thus far there has been no operating plant set up. One proponent estimates the need for a FIT of P17.65/kWh for a 10-MW plant to be financially viable.

Meanwhile, nuclear energy remains untapped. The 600–MW Bataan Nuclear Power Plant (BNPP), construction of which started in 1976, was ready to be commissioned by the mid–1980s, but the Cory Aquino administration decided to mothball it for safety and political reasons. Critics cited the Three Mile Island incident in the US in March 1979, where a nuclear reactor suffered a partial meltdown. Even more immediate was the Chernobyl disaster in

Ukraine in April 1986 which happened two months into the Cory Aquino administration. This was considered a level 7 event—the maximum category in the International Nuclear Event Scale. There have been attempts to revive interest in operating the BNPP, but anti-nuclear sentiments have prevailed.

The DOST's Philippine Nuclear Research Institute (PNRI) used to operate a nuclear reactor for research and small commercial operations, but the reactor has been on extended shutdown for quite some time. The PNRI is now looking into the viability of establishing a new accelerator facility. If the project pushes through, PNRI would be in a better position to promote awareness and understanding of the many benefits of nuclear science and technology and, in the process, soften resistance to a nuclear power plant.

A recent development in the energy R&D scene is the Philippine–California Advanced Research Institutes (PCARI) Project of CHED. PCARI is a well-funded project that involves collaborative research among scientists and engineers from Philippine- and California-based universities. Several activities in its first cycle of subprojects deal with experimental testing and validation of new alternative energy technologies and micro-grid systems. One activity, for example, hopes to produce a system that can increase the reliability and resilience of the power distribution network. Another has a self-explanatory title: "Low-cost Electricity for Islands and Rural Areas through RE Microgrids."

V. CONCLUDING REMARKS

To attain the goal of strong economic growth, we estimated electricity consumption to grow at an annual average rate of 4.3%. Focusing on the generation sector, we illustrated how policy reforms on fuel mix could potentially reduce blended generation charges that make up 47% of the total electric bill of households. The results of our simulations showed that a policy that supported the increased utilization of less costly resources could potentially decrease the blended generation charge. On the one hand, with the base-case assumption that technology and, hence, fuel prices would remain constant at 2016 prices from 2016-2040, the emergent policy would imply increased utilization of coal as fuel, since this is still by far the cheapest. With this assumption, blended generation charge could potentially decrease in 2040. On the other hand, if technology for variable renewable energy could evolve rapidly to bring fuel prices down by at least 3% from today's current average prices, then this would point to the increased utilization of variable RE resources.

The paramount objective in our numerical exercises was to improve the well-being of Filipinos by lowering the price of electricity in an economically efficient manner. The results of the five cases with regard to generation price illustrated that the optimal fuel mix would not be constant over time but should exploit the opportunities opened up by less costly resources.

We also assessed the power sector's performance and suggested broad key reforms and alternative pathways. The current *Philippine Energy Plan (PEP) 2012–2030* identifies major policy thrusts as follows: ensure energy security, expand energy access to promote a low-carbon future, climate-proof the energy sector, promote investment in the energy sector, and develop regional energy plans. By 2040, it is hoped that a fully-functioning wholesale electricity market will be in place—one that covers not just spot sales and purchases by generation companies and distribution utilities, but longer-term sales and purchases of different durations as well. The EPIRA itself points out the policy reforms needed to achieve its objectives. For an efficient, competitive electricity market, retail competition and open access (RCOA) should be fully rolled out under a stable policy regime that completes the full implementation of the EPIRA.

The *Filipino 2040* encompasses a set of long-term goals based on the standard of living that Filipinos want to have in 25 years. Verily, a comprehensive plan is essential to realizing this vision. With this as our guidepost, we outlined measurable indicators and proposed indicative targets constituting energy security for the next four administrations prior to year 2040.

Looking forward, we take energy security to have three dimensions: accessibility, affordability, and reliability. The indicator for affordability is the price that consumers pay. Our analysis focused on the generation costs that make up 47% of electricity bill. Since the enactment of the EPIRA, the generation sector has mostly been privatized. The government can facilitate a more competitive environment by not mandating a fuel mix but rather by letting the market work. Following market signals, the generation sector will rationally adhere to the utilization of the least cost-resource.

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