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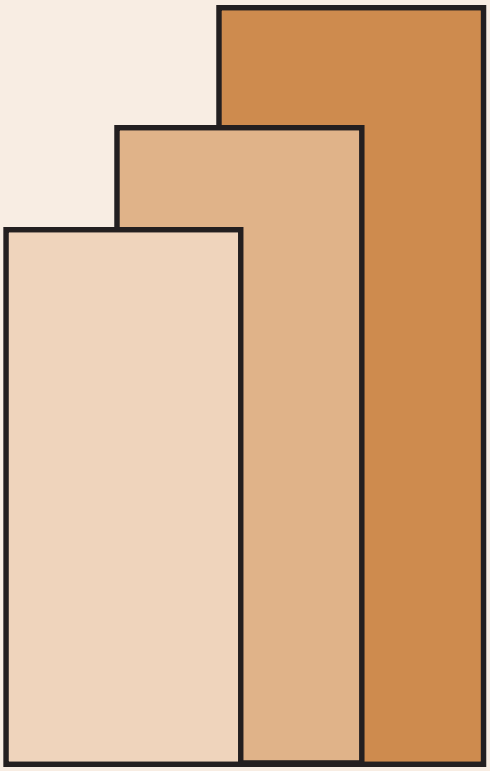

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Adoracion M. Navarro, Keith C. Detros and Kirsten J. dela Cruz[*]

Abstract

This study evaluates the achievement of the desired outcomes of the competition policies contained in the Electric Power Industry Restructuring Act of 2001 (EPIRA). We set the context by tracing the evolution of the electric power industry before EPIRA and post-EPIRA. We look at impacts on the consumers in terms of price affordability and supply reliability and impact on production efficiency in terms of system loss reduction. Pre-EPIRA, electricity price in the Philippines was already high relative to other countries. Trends show that, in real terms, there was a price uptrend during the transition (2001-2005) toward the start of competition in the generation sector. There was a slight downtrend in the real price of electricity after the introduction of spot electricity trading but the price of electricity remains high and it has not declined to pre-EPIRA levels. Supply reliability is still an ongoing concern but the recent past record shows that shortages were managed and did not reach nationwide crisis levels reminiscent of the 1990s. Nevertheless, production efficiency gains were achieved through the reduction of system losses.

There is a danger that the findings on price trends could provide ammunition to those advocating the repeal of the EPIRA and re-nationalization of the industry. It must be emphasized, however, that the country has a long history of private sector-led electric power industry: more than eight decades of private sector-led generation capacity development (1890-1972), less than one and a half decades of government monopoly in generation (1972-1987), less than a decade of mixed private and public sector generation (1987-2006), and an evolving competition with many stakeholder participants, including end-users (2006-present). Moreover, the nationalization years were marked by inefficiencies and fiscal problems that were not borne by electricity consumers alone but by the whole country. Thus, calls to repeal EPIRA are ill-advised. What needs to be done is to find ways of improving its implementation. We must recognize that the evolution in the governance structure of the industry is still unfinished. The electricity spot market has to be governed by an independent market operator; regulatory capacity has to be strengthened; and the energy department needs to beef up its planning function.

Key words: EPIRA, electric power industry, competition, restructuring, electricity price

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1. Introduction

Through the General Appropriations Act (GAA) of 2014, the Philippine Institute for Development Studies (PIDS) was given a mandate and the resources to conduct impact evaluation studies for selected projects and programs of the government (e.g., reforestation program, irrigation projects, and social service projects). As impact evaluation should also apply to policies, the PIDS also pursued the evaluation of outcomes of specific laws such as Republic Act No. 9136 or the Electric Power Industry Restructuring Act of 2001 (hereafter, EPIRA) and RA 8794 or the Motor Vehicle Users' Charge Law. This study focuses on impact evaluation related to EPIRA and narrows down the scope of the evaluation to the desired outcomes of the competition policies contained in the EPIRA.

This study therefore aims to assess the impacts of competition policies in the restructured electric power industry that is brought about by the implementation of the EPIRA. The study clarifies what these competition policies are and attempts to find evidence of their impacts. In pursuing the study, we conducted a series of focus group and key informant interviews with market players and the regulator, mined through the data of energy sector agencies, and reviewed the experiences of other electricity markets.

As the EPIRA restructured one whole industry and affected the whole population, there is no counterfactual in the usual sense of impact evaluation counterfactual concept which utilizes a control group that can be compared with a treatment group.[1] The second best approach then is to compare the situation of the population pre-EPIRA and post-EPIRA. The foremost indicators we look at on the consumption side are electricity price affordability and electricity supply reliability. On the production side, we assess systems losses as an indicator of production efficiency.

The desired outcomes related to electricity price and supply that were set by the EPIRA (enacted on June 8, 2001) can be gleaned from the declaration of policy in Section 2. In particular, Section 2 of the law states, among others,

> "It is hereby declared the policy of the State…
>
> (b) To ensure the quality, reliability, security and affordability of the supply of electric power
>
> (c) To ensure transparent and reasonable prices of electricity in a regime of free and fair competition and full public accountability to achieve greater operational economic efficiency and enhance the competitiveness of Philippine products in the global market…
>
> (j) To establish a strong and purely independent regulatory body and system to ensure consumer protection and enhance the competitive operation of the electricity market…"

It is to be noted that the EPIRA does not exactly promise reducing electricity prices relative to pre-EPIRA levels but ensuring that such are affordable. To sum up, the desired outcomes are:

[1] In project or program impact evaluation parlance, a control group is used as a baseline measure in the sense that it is composed of population (households or individuals) with similar characteristics as the population in the treatment group except that it does not receive the treatment or intervention. The treatment group is the population which received the intervention, such as social services through a project or program.

- reliable, secure and affordable electric power
- transparent and reasonable electricity price
- free and fair competition
- independent regulation
- consumer protection

The major competition-related policies enacted through the EPIRA are:

- Unbundling a vertically integrated industry and introducing competition in the generation sector
- Creating a retail supply sector and introducing competition in the end-user sector

To enable competition, other requisite policies were also introduced, as follows:

- Privatization of the government generation assets and power grid operation and maintenance
- Creation of a spot market for wholesale electricity trading
- Enabling open access to wires
- Establishment of a quasi-judicial regulator
- Setting market share limits
- Prohibiting cross-ownership between transmission and generation/distribution and setting cross-ownership limit between generation and distribution
- Entry regulation through licensing and registration and price regulation in specific areas

Nevertheless, to immediately demonstrate a price impact of the legislation, Section 72 of the EPIRA mandated a rate reduction, as follows: "Upon the effectivity of this Act, residential end-users shall be granted a rate reduction from NPC rates of thirty centavos per kilowatt-hour (P0.30/kWh). Such reduction shall be reflected as a separate item in the consumer billing statement."

2. The evolution of the electric power industry

2.1 The industry pre-EPIRA

The electric power industry started in the Philippines as a private sector-led industry in 1890 and remained so until the late 1960s; the government pursued rural electrification through the cooperative business model starting in 1969; the monopoly of generation by the National Power Corporation (NPC) started in 1973; and then the re-entry of private sector in the generation sector through independent power producers (IPPs) started in 1987. Prior to the 2001 restructuring under the EPIRA, the electric power industry had a vertically integrated generation and transmission sector through the NPC and wholesale power purchases from the IPPs were predominantly through the NPC. Distribution utilities were local monopolies in their respective service areas.

2.1.1 A historically private sector-led electric power industry

According to the NEA's narrative of the historical background of the industry, from 1890 to the late 1960s, power generation and distribution were largely controlled by private entities. Although Commonwealth Act 120 created the NPC in 1936, the law tasked it to develop the country's hydropower potential, thus making it one among the then existing developers of generation capacity (NEA n.d.). World Bank (1994) explains that government intervention through NPC was justified on the grounds that (i) decisions with regard to the development of particular hydro sites required inputs from and had an impact on a number of other sectors of the economy; and (ii) the construction of hydro facilities involved capital investments so large that only the govermment was thought to have the needed resource mobilization capacity.

The Manila Electric Company (Meralco) remained the largest privately-owned utility which also had the highest contribution to the country's total generation capacity. Moreover, back then, there were small generating systems that were installed and owned by private operators and local government units (NEA n.d.). Private interests developed virtually all electric power facilities and vertically integrated investor owned businesses supplied most load centers in Luzon, Visayas and Mindanao. It was only in hydropower generation and through the NPC where the government had a significant generation ownership and participation (World Bank 1994). Such was the situation for more than eight decades, that is, until 1972.

2.1.2 A period of public sector-led development

On August 14, 1969, Republic Act 6038 created the National Electrification Administration (NEA) and laid the groundwork for accelerated electrification in the countryside. The law provided a framework for rural electrification through not-for-profit cooperatives as a business model and loans and technical assistance from the NEA. In 1972, then President Ferdinand Marcos imposed Martial Law and shortly thereafter, the Marcos administration seized the assets of Meralco.

Marcos issued Presidential Decree No. 40 which granted monopoly powers to the NPC as it concentrated all generation and transmission ownership and development rights to the entity. This also entailed the government implementing artificially suppressed pricing policies to keep electricity prices low for residential consumers and other small consumers.

2.1.3 The re-entry of private sector generation through the IPPs

After almost one and a half decades of government dominance in the electric power industry, in 1986, the administration of then president Corazon Aquino reverted Meralco to private ownership. The administration then decided not to operate the Bataan Nuclear Power Plant "for reasons of safety and economy" (EO 55 s. 1986).[2] Dolan (1991) also reported that the Aquino government decided not to use the facility because it was located on a seismic fault.[3] In 1987, Aquino issued Executive Order (EO) 215 reversing the policy of granting generation monopoly to NPC and entertained proposals from independent power producers (IPPs) for build-operate-transfer (BOT) and build-own-operate (BOO) arrangements for new generating capacity. EO 215 s. 1987 amended PD 40 to specifically allow the private sector to generate electricity and categorically state that "the generation of electricity, unlike the transmission and distribution of electricity, is not a natural monopoly and can be undertaken by more

[2] In addition, to relieve the NPC of the foreign debt service burden related to the plant as it will not be able to earn revenues for such, the national government assumed the corresponding foreign and peso obligations incurred by the NPC in constructing the plant (EO 55 s. 1986).

[3] The debate on whether the BNPP is worth reviving resurfaced in 2009 when then Congressman Mark Cojuangco authored a bill mandating the immediate rehabilitation, commissioning and commercial operation of the plant. But scientists debunked the scientific soundness of the assumptions of the bill; for instance, a professor emeritus of the University of Illinois at Chicago said that BNPP commissioning proponents are selective of facts and ignore inconvenient scientific truths that are easily available and verifiable and then laid down the such verifiable evidences in his paper "Geological Hazards of the Bataan Nuclear Plant: Propaganda and Scientific Fact" (Rodolfo 2009). A 2012 scientific journal article also shed more light on the BNPP safety issue: Lagmay et al (2012) reports the result of detailed geological fieldwork in Mt. Natib, the site of the BNPP, and concluded, among other things, that the nearest eruptive center of the volcano is 5.5 km away from the plant, pyroclastic flows can affect the BNPP site, and an associated thrust fault at the nuclear site cuts through lahars up to the ground surface.

than one entity." The first BOT contract for a power plant was then signed in 1989 by the NPC and Hopewell Energy Management, Ltd.[4]

As reported by Woodhouse (2005), the Philippines' move toward independent power generationthis move is consistent with the experience in many other developing countries. The move was also meant to avert power shortages that were expected to arise due the removal of what would have been a large chunk of new capacity from the BNPP. A power crisis did occur during the last year of the Aquino administration and during the early years of the presidency of Fidel Ramos, who successfully ended the power crisis in 1994. However, it was not only the BNPP non-operation that led to the crisis; it was compounded by the slow approval of NPC projects and the El Nino-caused droughts, which in turn reduced the capacity of hydropower plants. Woodhouse (2005) described that at the peak of the shortage, the blackouts averaged 12-14 hours per day, 300 days per year and the World Bank (1994) estimated that the gross economic cost of the outages was US$0.50/kWh.

The vast majority of IPP contracts were with the NPC because until 1991, the NPC interpreted EO 215 s. 1987 as not entailing direct supplies to electricity distributors and that it should be the single buyer of generated electricity. But as the power shortage worsened, the government allowed the direct supply of IPPs to Meralco (World Bank 1994). In the late 1990s, the depreciation of the peso due to the Asian financial crisis caused the NPC's contracted IPP payments to balloon and, at a time when indicators point toward an impending fiscal crisis during the Estrada presidency, social awareness and criticism of the IPPs grew exponentially (Woodhouse 2005).

2.1.4 The bankruptcy of the NPC: a GOCC problem that became a national problem

The deteriorating NPC financial position and eventual bankruptcy in the 1990s is well known. Woodhouse (2005) partly attributes this to the impact of the Asian financial crisis. According to him, the financial crisis did not affect the Philippines as suddenly or severely as its South-East Asian neighbors. During 1997 to 1999, major macroeconomic indicators declined severely, but not as steeply as in Indonesia, Malaysia or Thailand. Although the Philippine market was not impacted as severely as those in Indonesia, Malaysia, or Thailand, neither has it rebounded as those markets have. Rather, the Philippines continued to move along with growth rates of between 3-5% annually. Similarly, where the currencies of Malaysia and Thailand had rebounded somewhat from there mid-crisis lows, the Philippine peso had continued its progressive decline in relation to the dollar. In the IPP sector, this resulted in a continued increase in the peso cost of power from dollar-denominated IPP contracts. Thus, where the impact of the crisis on other South-East Asian countries was sudden and acute, in the Philippines, the crisis introduced a new period of sustained decline.

[4] EO 215 s. 1987 preceded the formal policy using public-private partnerships in financing and building infrastructure which used to be undertaken by the government: RA 6957. In 1990, RA 6957 legislated the framework for the use of the BOT mode and its variants in the financing, construction, operation and maintenance not only of power plants but of all other infrastructure projects.

In the assessment of Woodhouse, this decline affected the IPP sector in two ways. First, because of a shortfall in electricity demand precisely when significant new capacity came on line, the electricity sector entered a period of excessive oversupply in the late 1990s. Constrained by the take-or-pay provisions of the IPP contracts, Napocor began paying higher unit prices for electricity as dispatch of plants sank to as low as 30-40%. Second, while recovering its IPP payments from a dwindling number of kilowatt hours sold, Napocor also saw its IPP payments increase substantially due to the pesos' loss of value.

The overoptimistic power demand projections complicated the problem. Woodhouse described that in the early- and mid-1990s, the government forecast demand growth as ranging from 9.5-12% per year, although these projections were abruptly derailed by the Asian financial crisis. However, in 1994, the World Bank already warned implicitly against the risk of over-commitment through the uncoordinated signing of power purchase agreements with IPPs, which essentially passed demand risk to the consumer through take-or-pay provisions.

The assessment in the 2004-2010 Medium Term Philippine Development Plan (MTPDP) also described the deterioration of the NPC's financial position. The operations and financial conditions of NPC until end of 1997 were viable and satisfactory. However, due to the significant devaluation of the Philippine peso brought about by the Asian financial crisis, NPC has incurred significant losses amounting to PhP3.2 billion in 1998 (NEDA 2004).

SEPO (2006) also explained that contributing to NPC's net income loss was the faster growth of operating expenses compared to operating revenues. The poor revenue growth was attributed largely to NPC's inability to charge rates that could at least recover its cost. The financial statements of NPC showed that it consistently registered a net income loss from 1999 to 2004, the largest of which was the P117.0 billion loss in 2003. It has also failed to register a positive net income since 1997.

Another factor is the significant increase in coal and oil prices. Given the significant levels of fuel purchases, the NPC is very sensitive to price volatilities and availability of fuel in the market, thus, the need to cover for such volatilities and fuel availability uncertainties. The NPC debt portfolio had three major currencies, namely, US dollar, Japanese yen and the euro. Historical averages and forward rates indicated depreciation of the peso against these currencies. Furthermore, there was a mismatch between the revenues received in pesos and the debts paid in foreign currencies (NEDA 2004). This provided the boost to the then growing sentiment toward privatizing NPC assets, and restructuring the electricity industry.

Immediately prior to EPIRA enactment, the industry structure can be summarized as follows: The generation, transmission and supply activities were vertically integrated and the state-owned NPC acted as the transmission grid operator, dominant generator, and dominant supplier of wholesale electricity to distribution utilities (i.e., private distribution utilities, local government-owned distribution utilities, and electric cooperatives). Other generators, that is, the independent power producers, sell the bulk of their generated power to NPC and some to Meralco.

2.2 The industry post-EPIRA

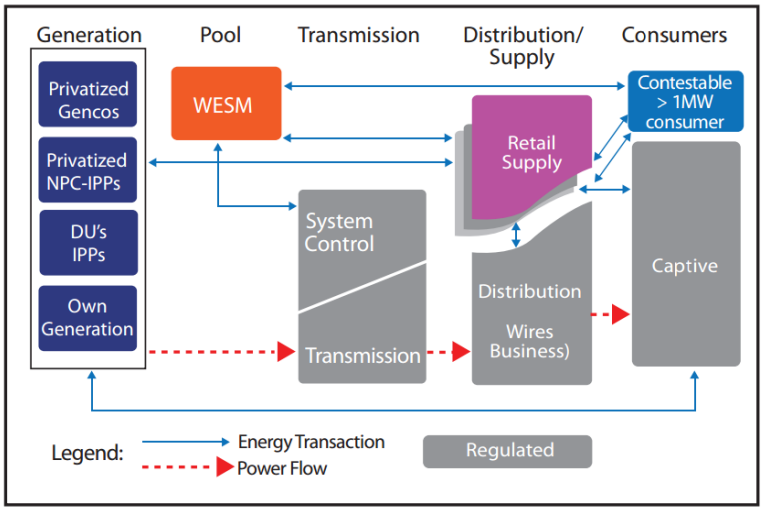
The government then took several steps through the EPIRA to restructure the electric power industry. The law abolished the Energy Regulatory Board and created the Energy Regulatory Commission (ERC) to enforce regulations for a new and restructured industry. The law also created the Power Sector Assets and Liabilities Management Corporation (PSALM) to take over the assets and liabilities of NPC, privatize generation assets (i.e., generating plants and IPP administration contracts), and use the proceeds to pay down the outstanding debt of NPC.

The EPIRA also created the National Transmission Corporation (Transco) to assume the ownership of the transmission assets, initially take over the power grid operation function, and gradually divest the sub-transmission assets. Eventually, the concession for grid operation was offered to the private sector through a competitive bidding. The private National Grid Corporation of the Philippines (NGCP) won the bid and now operates the Luzon, Visayas and Mindanao power grids.

The distribution sector is still a regulated sector with local monopolies held by the distribution utilities in their respective franchise areas. Open access to distribution wires and retail competition is now allowed. Under retail competition, consumers with at least one megawatt of electricity consumption can freely choose their suppliers. The transition to retail competition officially began on June 26, 2013 and 239 consumers in the contestable market are now being supplied by their chosen suppliers. A new sector was thus created, the retail electricity supply sector. Under the law, the contestable market shall be extended to end-users consuming 750 kilowatts of electricity after two years of implementing retail competition.

The Philippines' electric power industry now has four distinct sectors: generation, transmission, distribution, and retail electricity supply. Ownership is also mixed as both the government and the private sector owns electricity generation assets, the government owns the power grid, and cooperatives and private utilities own distribution assets (Figure 1). With the emergence of a more complex market structure in the electric power industry, a huge challenge to spot and curb market power exercise also emerged.

Figure 1. Post-EPIRA Market Structure



Source: KPMG Global Energy Institute, 2013

2.2.1 Electric power generation

To facilitate the privatization process, the EPIRA provided for the creation of the Power Sector Assets and Liabilities Management Corporation (PSALM) to take over all existing generation assets and liabilities of the NPC. PSALM was also tasked to use the revenue generated to pay the outstanding debt of the NPC. Furthermore, Executive Order No. 215 series of 1987, which allows private sector to generate electricity, classifies four types of generating plants: (1) co-generation units or the simultaneous generation of both electricity and heat from the same fuel, (2) electric generating plants intending to sell their production to the grids, (3) electric generating plants intended primarily for the internal use of the owner, and (4) electric generating plants outside the NPC grids.

The latest EPIRA status report released by the Department of Energy (DOE), which covers November 2014 to April 2015 period, highlights the privatization of the remaining generation assets, particularly the Power Barges (PBs) 101-104 as well as the transfer of contract to an Independent Power Producer Administrator (IPPA) of Unified Leyte Geothermal Power Plant (ULGPP) for the Bulk Energy. As of June 2015 4, the privatization level of NPC generating facilities has reached 89.7%, following the successful bid of Naga Power Plant Complex in March 2014. Meanwhile, the proposed closing and turn-over schedule of Angat Hydro-electric Power Plant to Korean Water Resources, Inc. was officially done in October of the same year.

Another entity established by the EPIRA is the Energy Regulatory Commission (ERC). Its main task is to promote competition, encourage market development, and enforce regulations in the newly restructured market. This is because, contrary to PD 40, power generation under the EPIRA was not considered a public utility operation, as stated in Section 6 of RA 9136 otherwise known as EPIRA Act of

2001. This made the generation sector of the industry competitive and opens to other players in the market. Under the EPIRA, any person or entity engaged in generation and supply shall not be required to apply for a national franchise; provided that it secures a certificate of compliance from the ERC.

Based on the 26th EPIRA Status Report, the generation sector is still dominated by the San Miguel Energy Corporation (SMEC) with 25% in the Luzon Grid or 18 % of the National Grid. This is followed by the Aboitiz Power Corporation with 18% and 16% of the Luzon Grid and National Grid, respectively, while First Gen Corporation has 17% and 15%. Meanwhile, Global Business Power Corporation (GBPC) lead the Visayas region with 29.64% share for the Visayas Grid, while in Mindanao, the state continues to control the generation sector, with NPC and PSALM holding 47% and 18% of the generation capacity, respectively.

Meanwhile, with the privatization of assets and the advent of opportunities for new industry players, the EPIRA also provided for a mechanism for competition under the Wholesale Electricity Spot Market (WESM).

Thus, under the present market, generated power is traded though 1) bilateral contracting between generating firms and DUs and big end-users, and 2) through the wholesale electricity spot market (WESM). With bilateral contracts, generation firms can have agreements with various distribution companies. To address the concern on weak competition for DUs' power purchases, the DOE issued in June 2015 a circular which mandates all DUs to undergo Competitive Selection Process (CSP) in Securing Power Supply Agreements (PSA). The general principles behind said circular are to (a) increase transparency in the procurement process, (b) promote and instill competition in the procurement and supply of electric power to end-users, (c) ascertain least-cost outcomes, and (d) protect public interest. Entities that will be covered are the different players in the distribution sector (see discussion under distribution section). Small players and IPPs, which have little or no cross-ownership and control with ECs and DUs, will also have a fairer level playing field in obtaining supply contracts.

Meanwhile, in accordance with the WESM rules, generation firms with facilities connected to a grid shall make information available to the market operator to enable the latter to implement appropriate dispatch scheduling. Based on the DOE's 26th EPIRA report, some of the regulatory measures presented include revisiting the recommendations on establishing and implementing a market floor price under the WESM Design Study and PEMC's Market Studies on WESM Price Cap and Floor Price as well as on Mitigating Measures. In addition, DOE issued another circular which aims to promulgate the protocol for the central scheduling and dispatch of energy and contracted reserves in preparation for the commercial operations of the WESM reserve market. With the said protocol, the DOE can be able to monitor all available generation capacity in both energy and reserve. Similarly, it would provide more preparations to the participants for the eventual commercial operation of the WESM Reserve Market.

On the other hand, for remote areas not connected to the grid (also known as missionary areas), the generation of power is the responsibility of Small Power Utilities Group (SPUG). Upon the enactment of EPIRA into law, the role of SPUG was strengthened. SPUG is authorized to undertake missionary electrification or electrification of areas not connected to the main transmission network. As provided by law, SPUG will implement the Missionary Electrification Development Plan and is to be funded by SPUG revenues and from the "universal charge" collected from all end-users.

2.2.2 Wholesale electricity market

With the privatization of NPC generation assets, many players in the generation sector emerged and competition was introduced through the establishment of the wholesale electricity spot market (WESM) in Luzon in 2006 and in Visayas in 2010.

WESM provides for a centralized platform where the electricity is treated as a commodity and prices are determined via bids based on actual use (demand) of buyers and availability of electricity (supply) traded sellers. The Philippine Electric Market Corporation (PEMC) and the National Grip Corporation (NGCP) of the Philippines work together in the operation of the WESM, with the former as the market operator, while the latter is the designated system operator of the spot market. WESM started its operation in Luzon in 2006 and in Visayas in 2010. As of April 2015, the integrated WESM (Luzon and Visayas) has a total of 237 registered participants, including 67 generating companies and 170 customers, which in turn are comprised of 14 Private Distribution Utilities (DUs), 71 Electric Cooperatives (ECs), 78 Bulk users, and 7 Wholesale Aggregators.

The wholesale electricity market now consists of the bilateral market, where contracting between a DU and a genco occurs and each medium to long-term power supply agreement is subject to review and approval by the regulator, and the spot market, where hourly trading of electricity happens. As shown in Table 1 (data beginning from July 2006 up to January 2015), majority of the metered electricity quantity is derived from bilateral contracts between DUs and gencos.

Table 1.Spot Quantity vs Bilateral Quantity Load (MWh), July 2006 – Jan 2015

Month	Metered Quantity (Load), MWh	Spot Quantity (Load), MWh	%	Bilateral Contract Quantity (Load), MWh	%
Jul-06	3,094,164.95	1,355,434.37	44%	1,738,730.58	56%
Aug-06	3,147,800.36	1,159,428.23	37%	1,988,372.13	63%
Sep-06	3,314,855.13	1,291,334.84	39%	2,023,520.30	61%
Oct-06	2,873,285.25	1,224,467.60	43%	1,648,817.65	57%
Nov-06	3,234,958.03	1,069,288.10	33%	2,165,669.93	67%
Dec-06	2,972,091.65	519,152.06	17%	2,452,939.59	83%
Jan-07	3,035,805.04	589,925.05	19%	2,445,879.99	81%
Feb-07	3,102,610.89	510,281.30	16%	2,592,329.59	84%
Mar-07	2,980,658.77	536,155.65	18%	2,444,503.12	82%
Apr-07	3,407,504.68	698,602.96	21%	2,708,901.72	79%
May-07	3,460,944.49	503,878.03	15%	2,957,066.46	85%
Jun-07	3,561,655.99	805,535.91	23%	2,756,120.08	77%
Jul-07	3,408,973.90	531,237.60	16%	2,877,736.29	84%
Aug-07	3,286,050.22	460,225.65	14%	2,825,824.57	86%

Month	Metered Quantity (Load), MWh	Spot Quantity (Load), MWh	%	Bilateral Contract Quantity (Load), MWh	%
Sep-07	3,362,494.13	358,578.07	11%	3,003,916.06	89%
Oct-07	3,229,031.96	247,585.19	8%	2,981,446.77	92%
Nov-07	3,204,655.78	346,596.90	11%	2,858,058.88	89%
Dec-07	3,083,441.24	371,343.26	12%	2,712,097.98	88%
Jan-08	3,131,009.80	411,372.54	13%	2,719,637.26	87%
Feb-08	3,212,635.82	454,532.74	14%	2,758,103.08	86%
Mar-08	3,041,008.30	354,398.37	12%	2,686,609.93	88%
Apr-08	3,634,855.57	634,329.07	17%	3,000,526.50	83%
May-08	3,323,367.13	356,234.23	11%	2,967,132.90	89%
Jun-08	3,538,106.32	400,132.11	11%	3,137,974.21	89%
Jul-08	3,435,104.78	408,863.87	12%	3,026,240.91	88%
Aug-08	3,399,912.16	372,803.00	11%	3,027,109.16	89%
Sep-08	3,530,050.75	511,447.58	14%	3,018,603.17	86%
Oct-08	3,421,671.57	466,154.42	13.60%	2,955,517.15	86%
Nov-08	3,447,266.38	535,759.02	15.50%	2,911,507.37	84%
Dec-08	3,151,245.74	545,175.13	17.30%	2,606,070.61	83%
Jan-09	2,906,720.56	604,622.65	20.80%	2,302,097.92	79%
Feb-09	3,358,810.66	766,465.14	22.80%	2,592,345.53	77%
Mar-09	3,222,969.29	537,701.69	16.70%	2,685,267.60	83%
Apr-09	3,503,547.55	414,910.72	11.80%	3,088,636.83	88%
May-09	3,463,438.29	516,030.34	14.90%	2,947,407.95	85%
Jun-09	3,608,313.89	475,456.08	13.20%	3,132,857.82	87%
Jul-09	3,538,571.31	357,675.26	10.10%	3,180,896.05	90%
Aug-09	3,671,459.51	586,189.83	16.00%	3,085,269.69	84%
Sep-09	3,652,903.81	486,078.85	13.30%	3,166,824.96	87%
Oct-09	3,347,101.84	512,979.44	15.30%	2,834,122.40	85%
Nov-09	3,575,986.76	474,059.82	13.30%	3,101,926.94	87%
Dec-09	3,381,576.00	447,970.83	13.20%	2,933,605.16	87%
Jan-10	3,391,691.08	464,968.76	13.70%	2,926,722.32	86%
Feb-10	3,709,258.54	678,908.20	18.30%	3,030,350.34	82%
Mar-10	3,496,870.27	479,469.01	13.70%	3,017,401.26	86%
Apr-10	3,785,877.48	587,784.31	15.50%	3,198,093.17	84%
May-10	4,025,236.25	632,741.76	15.70%	3,392,494.49	84%
Jun-10	4,120,067.20	711,151.61	17.30%	3,408,915.59	83%
Jul-10	3,705,460.47	594,644.27	16.00%	3,110,816.20	84%
Aug-10	3,900,844.43	462,747.56	11.90%	3,438,096.86	88%
Sep-10	3,893,171.32	321,815.88	8.30%	3,571,355.44	92%
Oct-10	3,721,843.57	363,704.17	9.80%	3,358,139.40	90%

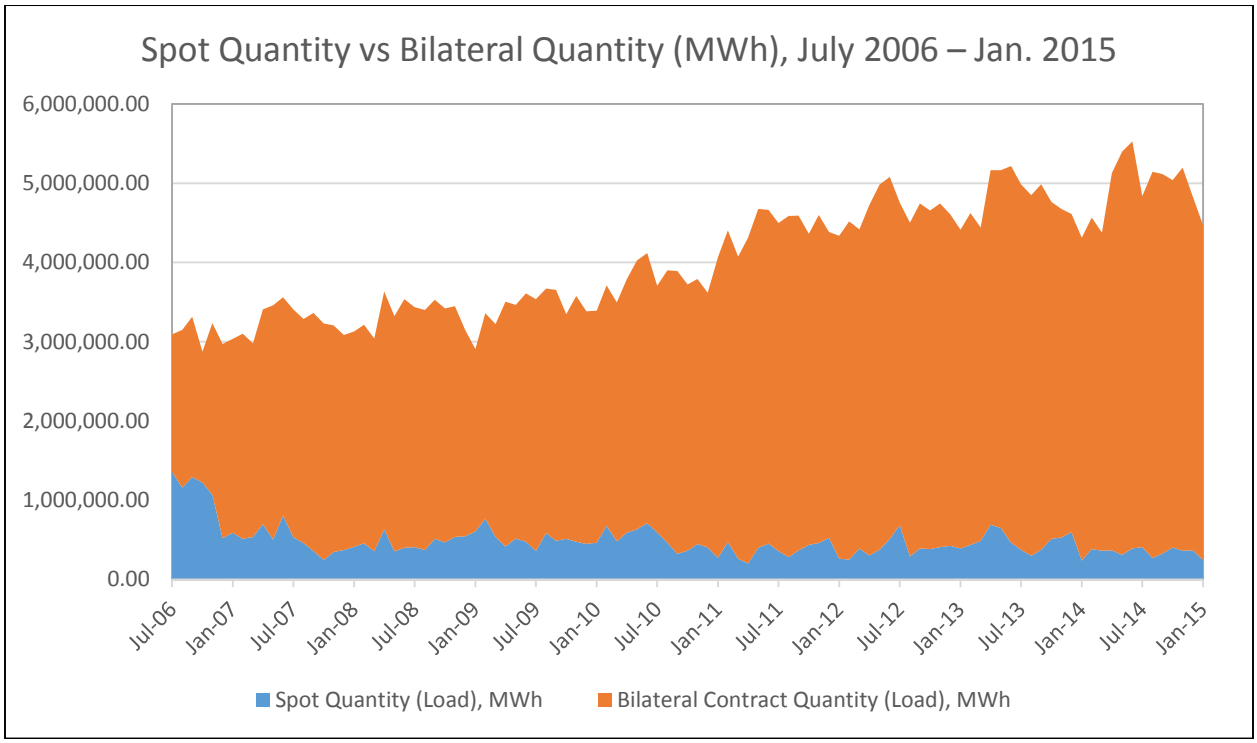
Month	Metered Quantity (Load), MWh	Spot Quantity (Load), MWh	%	Bilateral Contract Quantity (Load), MWh	%
Nov-10	3,791,123.99	448,742.73	11.80%	3,342,381.26	88%
Dec-10	3,618,918.64	403,623.82	11.20%	3,215,294.82	89%
Jan-11	4,065,400.56	272,481.78	6.70%	3,792,918.77	93%
Feb-11	4,405,384.21	470,203.49	10.70%	3,935,180.72	89%
Mar-11	4,072,738.35	263,789.55	6.50%	3,808,948.79	94%
Apr-11	4,313,514.71	202,777.98	5%	4,110,736.73	95%
May-11	4,675,217.40	399,466.39	9%	4,275,751.00	91%
Jun-11	4,665,692.14	453,082.12	10%	4,212,610.01	90%
Jul-11	4,496,424.04	358,118.31	8%	4,138,305.73	92%
Aug-11	4,588,527.67	280,049.63	6%	4,308,478.03	94%
Sep-11	4,591,257.49	364,979.67	8%	4,226,277.81	92%
Oct-11	4,359,048.50	435,802.47	10%	3,923,246.03	90%
Nov-11	4,597,790.37	460,942.12	10%	4,136,848.25	90%
Dec-11	4,386,874.52	524,084.49	12%	3,862,790.03	88%
Jan-12	4,335,207.47	261,447.91	6%	4,073,759.57	94%
Feb-12	4,519,990.57	251,555.63	6%	4,268,434.94	94%
Mar-12	4,416,326.59	389,036.20	9%	4,027,290.40	91%
Apr-12	4,724,661.49	303,929.41	6%	4,420,732.08	94%
May-12	4,980,881.89	373,513.98	7%	4,607,367.91	93%
Jun-12	5,080,154.44	513,897.32	10%	4,566,257.12	90%
Jul-12	4,756,271.85	686,471.55	14%	4,069,800.30	86%
Aug-12	4,502,480.50	288,702.16	6%	4,213,766.33	94%
Sep-12	4,745,836.69	391,723.48	8%	4,354,113.21	92%
Oct-12	4,656,469.61	382,553.20	8%	4,273,916.41	92%
Nov-12	4,744,798.66	405,825.13	9%	4,338,973.53	91%
Dec-12	4,607,806.64	425,066.37	9%	4,182,740.26	91%
Jan-13	4,414,305.72	389,527.57	9%	4,024,778.15	91%
Feb-13	4,621,906.41	436,075.11	9%	4,185,831.30	91%
Mar-13	4,440,321.96	489,406.63	11%	3,950,915.33	89%
Apr-13	5,165,108.01	690,301.91	13%	4,474,806.09	87%
May-13	5,164,987.79	649,414.99	13%	4,515,572.80	87%
Jun-13	5,216,803.55	462,431.41	9%	4,754,372.14	91%
Jul-13	4,987,292.11	372,992.40	7%	4,614,299.70	93%
Aug-13	4,849,001.48	298,890.93	6%	4,550,110.55	94%
Sep-13	4,987,626.49	376,226.02	8%	4,611,400.47	92%
Oct-13	4,766,261.63	512,972.96	11%	4,253,288.67	89%
Nov-13	4,677,500.80	528,864.25	11%	4,148,636.54	89%
Dec-13	4,609,734.84	596,725.33	13%	4,013,009.51	87%

Month	Metered Quantity (Load), MWh	Spot Quantity (Load), MWh	%	Bilateral Contract Quantity (Load), MWh	%
Jan-14	4,312,799.83	237,572.21	6%	4,075,227.62	94%
Feb-14	4,567,631.21	381,847.63	8%	4,185,783.58	92%
Mar-14	4,377,185.09	363,153.84	8%	4,014,031.24	92%
Apr-14	5,127,579.02	365,717.19	7%	4,761,861.83	93%
May-14	5,398,330.57	311,115.95	6%	5,087,214.61	94%
Jun-14	5,529,234.27	392,073.55	7%	5,137,160.72	93%
Jul-14	4,838,209.25	405,791.36	8%	4,432,417.88	92%
Aug-14	5,142,299.09	269,169.24	5%	4,873,129.84	95%
Sep-14	5,114,897.88	327,069.32	6%	4,787,828.56	94%
Oct-14	5,038,319.29	402,860.62	8%	4,635,458.47	92%
Nov-14	5,198,478.23	362,334.42	7%	4,836,143.75	93%
Dec-14	4,829,185.14	367,714.59	8%	4,461,470.55	92%
Jan-15	4,469,259.37	246,913.22	6%	4,222,346.15	94%

Source: PEMC.

As shown in Figure 2, bilateral contract transactions have been generally increasing (or spot transactions have been generally declining) since the WESM opened in 2006, peaking at 94% of the total metered quantity load in May 2014.

Figure 2.Spot Quantity vs Bilateral Quantity Load



Source: PEMC

2.2.3 Transmission

In the restructured electric power industry, the transmission function of NPC was initially transferred to a new government entity and then eventually to a private firm via a concession contract. Section 8 of the EPIRA law created the National Transmission Commission, or Transco. Transco is mandated by law to assume NPC's authority and responsibility for the planning, construction, operation and maintenance of transmission facilities, including grid interconnections and ancillary services. In March 1, 2003, the transfer of transmission function was completed and Transco started operating and managing the power transmission system.[5]

The EPIRA also provided for the privatization of the operation and further development of the transmission network. In Section 21, the law directed the PSALM to award the operation and development of the transmission facilities to a qualified party via an outright sale or concession agreement. On December 12, 2007, the consortium of Monte Oro Grid Resources Corporation, Calaca High Power Corporation, and State Grid Corporation of China won in a bidding conducted by PSALM for the operation and maintenance of the nationwide transmission network. The winning bid amounted to P3.95 billion. The consortium later reorganized to become the National Grid Corporation of the Philippines (NGCP).

Finalizing the privatization process of the transmission network, Republic Act No. 9511 (also known as the Franchise Law) was signed into law on December 1, 2008. The Franchise law granted a 25-year concession to NGCP, which is renewable for another 25 years. Although the Franchise Law authorizes the National Grip Corporation of the Philippines (NGCP) to operate and manage the transmission netwrok, the ownership of all transmission assets remain with the Philippine government through the TRANSCO.

Technically, the transmission network is a natural monopoly, with NGCP as the sole operator in the country. Given this, the Franchise Law has included guidelines in the preventing anti-competitive behavior, and unfair trade practices. Specifically, Section 7 of the EPIRA law prohibits cross-ownership between NGCP and other electric power industry players in the generation, distribution, and retail supply. In particular, any stockholders, directors, and officers of the NGCP or any of their relatives up to the fourth level degree of consanguinity and their respective spouses are not allowed to hold shares of stock in other power industry stakeholders. Further, losing bidders for the concession agreement shall not be allowed to share in the ownership or share of stocks of NGCP within 10 years of the effectivity of the Franchise law.

One aspect that presents a potential to abuse market power, given that the NGCP is the sole player in the transmission business, is the setting of the transmission rates. However, safeguards have been in place by virtue of Section 7 of the EPIRA. The law states that the transmission of electricity shall be a 'regulated' common carrier business, with ERC having supervision in the ratemaking aspects. Pursuant to Section 43(f) of the same law and Rule 15, Section 5(a) of the corresponding Implementing Rules and Regulations, the ERC was given authority to develop and implement a methodology that shall be used to set the transmission wheeling rates. In May 29, 2003, the ERC released Case No. 2003-34 and

[5] See www.transco.gov.ph.

promulgated Guidelines on the Methodology for Setting Transmission Wheeling Rates. The said guidelines has been revised and re-issued in July 20, 2009 by virtue of ERC Case No. 2009-008RM.

Each regulatory period for NGCP is set to five (5) calendar years.[6] Currently, the concessionaire is implementing the third regulatory period until December 2015. Steps to for the 4th Regulatory Period are being pursued by both the ERC and the NGCP which is set to commence by 2016. Issues being discussed for the implementation of the 4th round of rate setting include alternative building blocks of transmission rates and the extension of the regulatory period from five (5) years to ten (10) years.[7]

2.2.4 Electricity distribution

As for the distribution sector, it is still a regulated common carrier business run by local monopolies with defined franchise areas. The distribution sector is composed of electric cooperatives (ECs), private distribution utilities (DUs), local government unit (LGU)-owned utilities, and other duly authorized entities regulated by the ERC. Based in the Distribution Development Plan 2010-2019, there are currently 121 ECs, 17 private DUs, and 8 LGUs in the distribution sector.

The EPIRA has also brought about the unbundling of rates. Currently, end-users are able to see the various components of their electric bills: generation charge, transmission wheeling rate, system loss, distribution charge, consumer subsidies, universal charge, and government taxes. The current "lifeline rate" or socialized pricing mechanism and the universal charge for "missionary electrification" were also schemes introduced by the EPIRA.

2.2.5 Retail electricity supply

The EPIRA also laid down the framework for the formation of the retail supply sector. Under the retail competition and open access (RCOA) of distribution wires, eligible consumers have the liberty to contract their supply of electricity among authorized suppliers, rather than through the franchised distribution utility. For the initial implementation, Section 31 of the EPIRA provides that end-users that consume a monthly average of at least 1 megawatt for the preceding 12 months of the effectivity of the law shall be part of the contestable market. Two years after the implementation, the threshold level shall be lowered to 750 kilowatts as stated in the EPIRA-IRR. EPIRA stipulates that the ERC shall conduct evaluations every year after that with the aim of lowering the threshold until it reaches the household demand level.

To fully comprehend the RCOA regime, an introduction of the terms and the industry platers is in order.[8] The *'contestable market'* refers to the end-users who are given the choice to select their supplier, as determined by the ERC. The *'contestable customer'* is an entity that is part of the contestable market.

[6] Section 2.5.1 of the Revised Transmission Wheeling Rates Guidelines.

[7] NGCP Issues Paper for the 4th Regulatory Period.

[8] See DOE Department Circular No. 2012-05-005 and Department Circular No. 2012-11-0010.

On the other hand, there are also *'directly connected customers'* which refer to industrial or bulk electricity customers which are directly supplied by a generation company. The *'supplier'* or a '*retail electricity supplier'* herein is the any person or entity authorized by ERC to sell, broker, market or aggregate electricity. This is different from a *'local retail electricity supplier'* is the DU, but refers to the non-regulated business segment catering to the contestable market in its respective franchise area. Local retail electricity suppliers are not required by the ERC to obtain a license for its provision of supply services. Should a contestable customer fail to secure a supplier, the 'supplier of last resort' is designated to serve the demand of the contestable customer based on the rules set by ERC. Technically, the DUs are considered as the supplier of last resort. Should the DU is not able to accommodate the demand, the ERC shall designate a neighboring DU to serve as the supplier of last resort. There are also '*retail metering services provider'* in the market which provides metering services to the contestable customers. Finally, 'aggregators' refer to any person or entity engaged in consolidating demand for the purpose of purchasing or reselling on a group basis. The aggregators become active in the retail market in 2016 when aggregators can compete with suppliers for contestable customer with an average monthly demand of 750 kW to 999 kW.

On June 6, 2011, by virtue Resolution No. 10, Series of 2011, the ERC has certified that all the preconditions necessary for RCOA are already in place[9]. Further, DOE Department Circular No. 2012-02-0002 has designated the PEMC as the Central Registration Body. The CRB is tasked to oversee the development and management of RCOA as a market. Included in the tasks of the CRB: i) review of WESM rules and manuals; ii) development of market infrastructure, systems and processes; iii) conduct of training for market participants; iv) comply with DOE directives; and v) coordinate with stakeholders and government agencies. The CRB remains under the supervision of the DOE. Since then, the ERC, DOE and industry stakeholders (inputs gathered through public consultations) have been working on hammering out the framework for the implementation of RCOA. Relevant policy issuances which provided for the rules and framework under which RCOA operates are summarized below. The commercial operation of RCOA, starting with those with a monthly average consumption of at least 1 megawatt, officially commenced on June 26, 2013.

Table 2. Summary of Relevant Policy Issuances for the Implementation of RCOA

Date	Policy Issuance	Title
24-Feb-12	DOE Department Circular No. 2012-02-0002	Designating the Philippine Electricity Market Corporation (PEMC) as the Central Registration Body (CRB)
9-May-12	DOE Department Circular No. DC 2012-05-005	Prescribing the General Policies for the Implementation of the Retail Competition and Open Access

[9] Section 31 of the EPIRA laid out five (5) preconditions that should be met before RCOA implementation:

a) Establishment of the wholesale electricity spot market;
b) Approval of unbundled transmission and distribution wheeling charges;
c) Initial implementation of the cross subsidy removal scheme;
d) Privatization of at least seventy (70%) percent of the total capacity of generating assets of NPC in Luzon and Visayas; and
e) Transfer of the management and control of at least seventy percent (70%) of the total energy output of power plants under contract with NPC to the IPP Administrators.

Date	Policy Issuance	Title
29-Nov-12	DOE Department Circular No. DC 2012-11-0010	Providing for Additional Guidelines and Implementing Policies for Retail Competition and Open Access and Amending Department Circular No. (DC) 2012-05-0005
17-Dec-12	ERC Resolution No. 16, series of 2012	Resolution Adopting the Transitory Rules for the Implementation of RCOA
9-Jan-13	DOE Department Circular No. 2013-01-0002	Promulgating the Retail Rules for the integration of Retail Competition and Open Access in the Wholesale Electricity Spot Market
28-May-13	Joint Statement on the Implementation of RCOA	DOE and ERC On the Implementation of Retail Competition and Open Access
9-Jul-13	DOE Department Circular No. 2013-07-0014	Promulgating the Retail Market Manuals for the Implementation of RCOA and Providing for Transitory Arrangements
19-Jun-15	DOE Department Circular No. 2013-06-0010	Providing Policies for the Full Implementation of RCOA in the Electric Power Industry

Source: DOE and ERC

On June 19, 2015, the DOE has provided for the full implementation of RCOA by virtue of Department Circular No. 2015-06-0010. In its initial implementation, the DOE has allowed eligible contestable customers to remain with their respective DUs as the transition to RCOA continues. However, full implementation of RCOA means that this interim period is only until June 25, 2016. By June 26, 2016, mandatory contestability shall be enforced on all eligible members of the contestable market. This means contestable customers are mandated to secure a retail supply contract with a supplier, a generator, or a prospective generation company. As per PEMC's data, only 40% of the projected contestable customers have registered with the PEMC.

Another relevant provision in the same circular is the expansion of contestability. Starting June 26, 2016, users with an average monthly demand of 750 kW to 999 kW for the preceding 12-month period are now part of the contestable market and should secure their respective retail supply contracts. In this segment of the contestable market, retail aggregators are allowed to compete with suppliers, generation companies or prospective generators. Contestable customers sharing a contiguous area may contact an ERC-licensed aggregator as long as the pooled demand shall not be lower than 750 kW. Section 2 (d) of the same circular stated that the ERC shall promulgate guidelines for retail aggregation before its implementation. The department circular also provides that, subject to ERC's evaluation of the retail market's performance, those with an average demand of 501 kW to 749 kW shall be allowed to choose their suppliers effective June 26, 2018.

In terms of the players in the market, the CRB has registered 435 total participants or equivalent to 40% of the prospective players as identified by the ERC. In 2014, the RCOA regime only had 275 participants[10]. Currently, there are 377 contestable customers, 12 local retail suppliers, 16 retail

[10] Philippine News Agency. (2015). 'Number of WESM retail participants surges from a year ago'. Accessed November 12, 2015 from http://goo.gl/k57xlv.

electricity supplier, 24 retail metering service provider and 6 registered suppliers of last resort. This number continues to grow as the CRB continues processing applications for entry into the market. Table 3 details the market structure, in comparison to the projected number of players; while Table 4 shows the number of pending applications.

Table 3. Summary of RCOA Registration

Participants	Prospective based on ERC Data[a]	Registered[b]	Percentage
Contestable Customer	970	377	39%
Local Retail Electricity Supplier	23	12	52%
Retail Electricity Supplier	18	16	89%
Retail Metering Service Provider	39	24	62%
Supplier of Last Resort	27	6	22%
Grand Total	**1,077**	**435**	**40%**

Notes: [a] Data from the 26th EPIRA Status Report

[b] Number of participants are from the PEMC Participant List, last updated October 2015

Source: PEMC

Table 4. Summary of RCOA Applications

Participants	Applications
Contestable Customer	15
Local Retail Electricity Supplier	2
Retail Electricity Supplier	4
Retail Metering Service Provider	5
Supplier of Last Resort	3
Grand Total	**29**

Source: PEMC

3. Post-EPIRA impacts

Fourteen years after the EPIRA and nine years after the introduction of a competitive electricity spot market, we analyze what happened to the indicators of price affordability, supply reliability and system loss reduction (as a measure of production efficiency). Data for this analysis are not readily available in the public domain but the PIDS research team exhausted every means possible in getting such data from energy sector stakeholders and other entities.

3.1 Price affordability

Trends on the system rate

We tried to construct a time series of price data and found it very challenging for various reasons. The NEA averaging of system rates uses simple average of the rates of ECs and DUs, not weighted by MW sold by EC or DU. There is also no information on MW sold and therefore we cannot reconstruct a more correct way of getting the average price per kWh. Not all years have complete data set—for instance, of the 12 private DUs in Luzon in 2007, only three DUs have price data. Monthly volatility calculations using the system rates cannot be done because the monthly price data of NEA began only in 2011 and the data from 1990 to 2010 are annual price data. There was no 2014 data for private DUs except the December average rate; we therefore used the December 2014 price data as proxy for the whole year.

Table 5. Average System Rates (PHP/kWh), 1990-2014

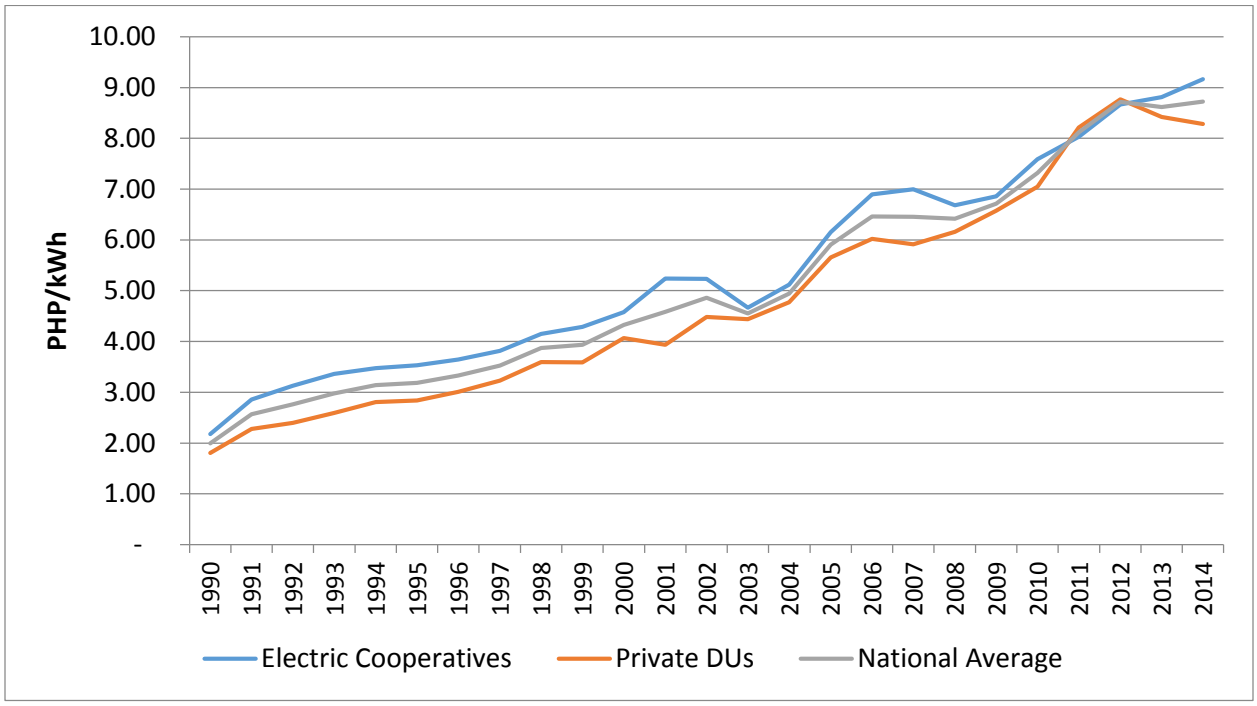
	Electric Cooperatives	Private Distribution Utilities	National Average
1990	2.18	1.81	1.99
1991	2.86	2.28	2.57
1992	3.13	2.40	2.76
1993	3.36	2.59	2.98
1994	3.48	2.81	3.14
1995	3.53	2.84	3.19
1996	3.65	3.01	3.33
1997	3.82	3.23	3.52
1998	4.15	3.59	3.87
1999	4.29	3.59	3.94
2000	4.58	4.07	4.32
2001	5.24	3.94	4.59
2002	5.23	4.49	4.86
2003	4.67	4.44	4.55
2004	5.12	4.77	4.95
2005	6.16	5.65	5.90

	Electric Cooperatives	Private Distribution Utilities	National Average
2006	6.90	6.02	6.46
2007	6.99	5.91	6.45
2008	6.68	6.16	6.42
2009	6.86	6.57	6.72
2010	7.59	7.05	7.32
2011	8.03	8.21	8.12
2012	8.67	8.77	8.72
2013	8.81	8.42	8.62
2014*	9.16	8.28	8.72

Note: *For year 2014, the available figure for private distribution utilities is the average rate for December only and this is used as proxy for the annual private DU rate. Electric cooperatives have complete data for 2014.

Source: NEA for ECs; DOE for the others

Figure 3. Average system rates per type of utility, in nominal terms



We compute below the system rate in real terms. The consumer price index (CPI) used in converting nominal figures to real figures has 2006 as base year. Since the rebased CPI time series of the Philippine Statistics Authority starts at 1994, the 1990-1993 real prices cannot be computed.

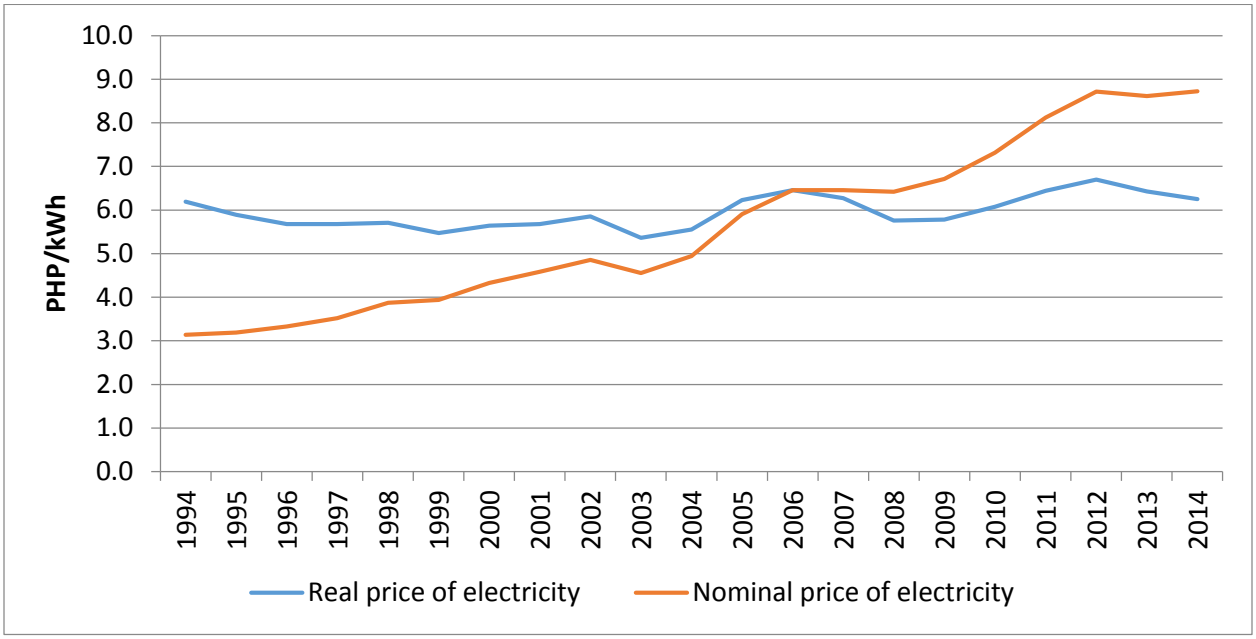
Table 6. National average system rate in nominal and real terms, 1994-2014

	System rate in nominal terms	System rate in real terms	CPI (2006=100)
1994	3.14	6.19	50.7
1995	3.19	5.89	54.1
1996	3.33	5.68	58.6
1997	3.52	5.68	62.0
1998	3.87	5.71	67.8
1999	3.94	5.48	71.9
2000	4.32	5.64	76.7
2001	4.59	5.68	80.8
2002	4.86	5.85	83.0
2003	4.55	5.36	84.9
2004	4.95	5.56	89.0
2005	5.90	6.23	94.8
2006	6.46	6.46	100.0
2007	6.45	6.27	102.9
2008	6.42	5.76	111.4
2009	6.72	5.78	116.1
2010	7.32	6.07	120.5
2011	8.12	6.44	126.1
2012	8.72	6.70	130.1
2013	8.62	6.43	134.0
2014*	8.72	6.25	139.5

Note: *For year 2014, the available figure for private distribution utilities is the average rate for December only and this is used as proxy for the annual private DU rate. Electric cooperatives have complete data for 2014.

Source: NEA for ECs; DOE for the others

Figure 4. Nominal and real prices of electricity



It is also worth recalling that pre-EPIRA, electricity price in the Philippines was high relative to other countries (Table 7).

Table 7. Retail Electricity Tariffs across Selected Asian Countries (June 1998)

Utility	Residential Tariffs	Industrial Tariff
Perusahan Listrik Negara, *Indonesia*	0.63	0.66
Korea Electric Power Corp., *Korea*	4.83	1.95
Metropolitan Electricity Authority, *Thailand*	5.54	2.24
Tenaga Nasional Berhad, *Malaysia*	5.92	2.39
Taiwan Power, *Taiwan*	6.46	2.41
Singapore Power, *Singapore*	6.96	2.84
Manila Electric Company, *The Philippines*	9.51	3.84
China Light & Power, *Hong Kong*	11.46	4.63
Kansai Electric, *Japan*	12.18	4.92
The peso exchange rate against the dollar in June 1998 was P49.39 to $1		

Source: Velasco, M. (2005) as cited in Woodhouse (2005).

The national average system rate in nominal terms is essentially the nominal price of electricity in the country on the average, and the national average system rate in real terms is essentially the real price of electricity in the country on the average. The nominal price of electricity is the value of electricity in terms of money whereas the real price of electricity is its value in terms of the bundle of goods and services in the CPI basket. If we see an increasing trend in the real price of electricity, then it is rising more quickly than the general price level. If we see a downtrend, then it is rising more slowly. Unfortunately, the time series is too short to yield a meaningful regression result for pre-EPIRA and post-EPIRA years. Thus, we rely on calculation of averages.

Figure 4 above shows that:

- the electricity price rose more slowly than the general price level during the pre-EPIRA years (1994-2000)
- the electricity price rose relatively more quickly during the transition toward the establishment of a competitive wholesale market for electricity (2001-2005), and
- an ambiguous pattern from the time the WESM was introduced up to 2014.

Calculating the average annual growth of the real prices clears up the ambiguity:

1994-2000	-1.55% average annual growth rate (AAGR)	a downtrend during the pre-EPIRA years
2001-2005	2.34% AAGR	an uptrend during the transition
2006-2014	-0.40% AAGR	a downtrend after the establishment of the WESM

If we are to exclude the 2014 data (given that the 2014 private DU component of the system rate is incomplete), we also get a downtrend albeit at a slower rate.

2006-2013	-0.06% AAGR	a downtrend after the establishment of the WESM

Why was the real price of electricity on a downtrend in 1994-2000? It will be hard to argue that such is due to NPC's productivity because it was during this time that the financial problems and eventual bankruptcy of the NPC was eating up what little fiscal space the national government then had. Note, however, that the 1994-2000 period covers the Asian financial crisis period and the average annual inflation then was 7.14 percent. Thus, the more correct way of viewing the pattern is that the general price level, that is, the representative price of all goods, was rising more quickly than that of electricity in 1994-2000. Moreover, Woodhouse (2005) explained that once the power crisis abated[11] and the government had learned from its early IPP experiences, prices fell again—the average postpower crisis IPP was 12% less expensive in terms of cost/kWh than its predecessors, a result of both a more competitive bidding environment and a shift away from expensive fuel.

[11] It was generally agreed that the power crisis has been resolved by 1994.

What could explain the uptrend during the transition toward the establishment of the WESM or the start of competition in the generation sector? With the benefit of hindsight, we can surmise that one of the reasons is the oil price crises of the 2000s. It could also be partly due to generation rate adjustments after the large-scale privatization of NPC's generating assets, resulting in electricity price increases that were faster than the general price inflation. What is clear is that the 2001-2005 period involved transition pains.

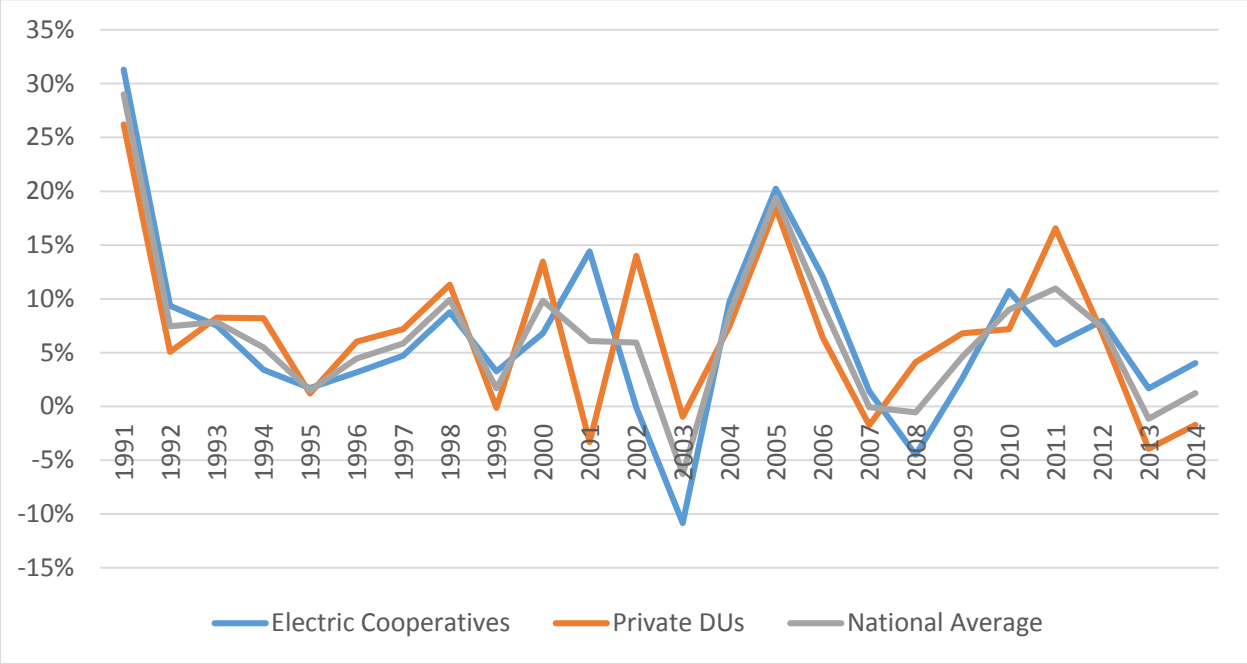
What could explain the downtrend after the establishment of the WESM? Given the problem of attribution, one should not be easily tempted to attribute this alone to EPIRA gains and conclude that competition is indeed working. We must nevertheless grant that it could be one among many possible reasons. Another possible reason is the drastic fall in the price of oil from 2008 onwards, which could have lowered the real cost of power generation in the country. Moreover, although the CPI average inflation is already low during the period (4.25% annual average inflation from 2006-2014), the rate of increase of the prices of other commodities in the CPI basket could have been higher than that of the price of electricity.

Overall, although we have observed a slight downtrend in the real price of electricity after the introduction of competition in the spot market, we conclude that the price of electricity remains high and it has not declined to pre-EPIRA levels. However, we reiterate that the desired outcome expressed in the declaration of principles of the EPIRA is not necessarily price declines but price affordability.

Changes in price volatility

Price variation over the long term is shown in Figure 5 below. The trend on annual inflation of nominal system rates shows the high-inflation environment of the early 1990s, when no new capacity was built to replace the mothballed nuclear power plant. Rolling brownouts in many parts of the country were experienced at the time. The post-EPIRA years show both inflation and deflation (negative inflation).

Figure 5. Annual inflation of nominal system rates

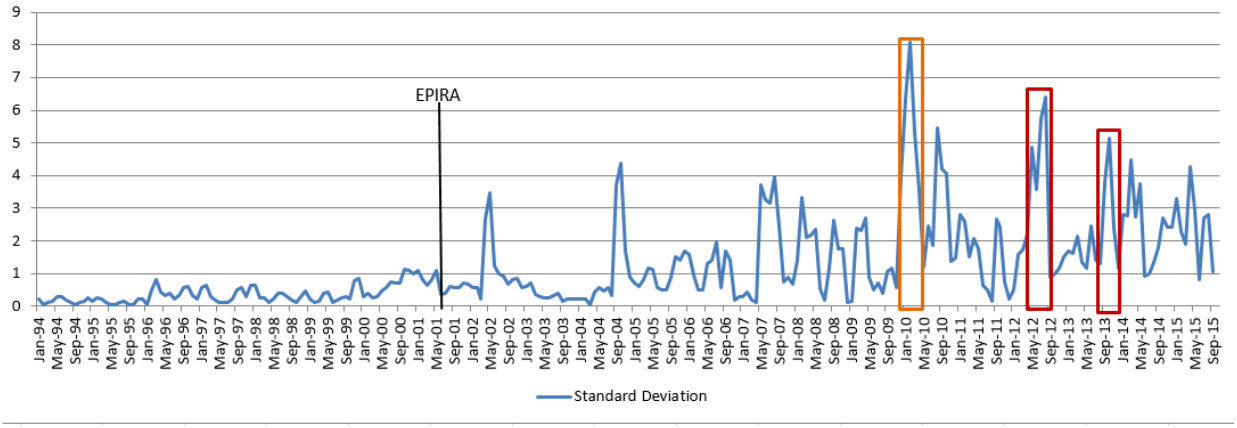


The volatility of prices is its variation over a period of time, and a volatility indicator tells us how turbulent the price is during a given time period. Calculating standard deviation is one way of estimating volatility and we apply it here. We use the time-series data on the price index of the representative electricity price in the component "Housing, Water, Electricity, Gas, and Other Fuels" of the Philippine CPI. [12] The time series does not indicate which of the 146 distribution utilities around the country are considered representative. But it is likely that the representative utility or utilities in the price index are large utilities and representing large segments of end-users; therefore, it can be surmised that they are significant buyers of electricity in the WESM and are affected by spot volatility.

We derive the standard deviation of the representative price index per rolling 3-month period and, as expected, the result shows that the price of electricity became more volatile post-EPIRA (Figure 6). Note that trading at the spot market is conducted every hour and there were trading hours where the price cleared at the previous cap of PHP62/kWh. The highlighted spikes show periods of high volatility.

[12] The Philippine Statistics Authority (PSA) gave PIDS access to unpublished time series of the representative CPI for electricity in the "Housing, Water, Electricity, Gas, and Other Fuels" component of the CPI with the proviso that the raw data be used for this study only.

Figure 6. Volatility of Representative Electricity Price, January 1994 - October 2015



What attracts attention by the public and policymakers is not what happened in the long term but what is occurring in the short term. For instance, the late 2013 price spikes in the WESM which led to a sudden upsurge in Meralco rates affected more than 70% of the Luzon consumers and the spikes became very controversial.

Consumers and businesses naturally desire price stability as large swings in prices could, at the least, complicate their planning for expenditures and, at worst, result in financial losses. The EPIRA, however, did not categorically promise price stability and the debates then on the proposed EPIRA recognized that there will be price volatility in the spot market for electricity. Nevertheless, policymakers must look at ways to curb sudden price spikes. One current measure that is being looked at is to permanently reduce the PHP62/kWh bid cap in the WESM. Another measure is to re-design the market in such a way that incentives to exercise market power are minimized.

Trends in the components of electricity price

Among the price components, universal charges (23.5%) and government taxes (19.25) account for the highest rate of increase since 2004. This is followed by generation charge which increases annually at a rate of 4.6% over the past decade. Another data worth noting is the decrease in system loss charges billed to the consumers. This improved efficiency by Meralco has resulted to the -0.3% decrease in the system loss price. In total, the Meralco rates have an average increase of 4.7% over the same period.

Table 8. Growth Rates of MERALCO Rate Components (All Customer Groups), 2004-2014

	2004	2014*	Average Annual Growth Rate
Generation	3.458	5.425	4.6%
Transmission	0.863	0.942	0.9%
System Loss	0.467	0.451	-0.3%
Distribution	1.111	1.628	3.9%
Subsidies	-0.025	0.001	-
Universal Charge	0.040	0.328	23.5%
Gov't Taxes	0.138	0.794	19.2%
TOTAL	6.050	9.568	4.7%

Note: Annual average rates for all customer group.
*2014 is Year-to-Date annual average, as of October 2014.

Source: Meralco

Table 9. Growth Rate of ECs' Rate Components (Residential only), 2008-2013

	2008	**2013**	**AAGR**
Generation	2.92	4.88	11%
Transmission	1.12	1.18	1%
System Loss	0.62	0.86	7%
Distribution*	1.73	1.73	0%
RSFC	-	0.37	-
Subsidies and other charges**	0.02	-0.09	-240%
Government Charges***	0.53	0.96	12%
Total	6.94	9.89	7%

Notes: * includes Distribution, Metering and Supply
** includes Lifeline and Inter-class cross subsidies
*** includes Universal Charges, VAT, and other taxes

The large negative figure for subsidies and other charges may have been due to the EPIRA-mandated removal of cross-subsidies.
Although universal charges are not a tax, the NEA lump these together with government taxes. No separate EC figures distinguishing universal charges from government taxes are found from the NEA data.
RSFC stands for Reinvestment Fund for Sustainable Capital Expenditure

Source: National Electrification Administration

For the electric cooperatives, data available is only for the residential customers. As with the Meralco-franchise area, regions served by electric cooperative experienced an average annual increase of 12% in government charges for the period of end-year 2008 to end-year 2013. Government charges include universal charges, VAT, and other taxes. This is followed by the generation charge which has the average annual growth rate of 11%. However, unlike Meralco, the electric cooperatives have an increase in system loss charge. This is pegged at 7% over the same period of time.

3.2 Supply reliability

One of the objectives of the EPIRA is to have a secure and reliable power supply in the country. This means that the supply of electricity must always meet the demand of the consumers to ensure continuous access to electricity. However, electricity is a good that have some unique characteristics. For one, it cannot be stored like other produced goods, thus the need to balance the supply and the demand at all times is critical. Otherwise, when supply shortage occurs, rotating brownouts and outages are experienced by the end-users.

To fully comprehend the intricacies of the supply and demand dynamics of the electricity sector, the supply aspect (in terms of capacities in the grid) and the demand aspect (in terms of peak demand and reserve margin) must be introduced.

The *installed capacity* refers to the maximum capacity of the generating plants which are connected to the grid. It is important to distinguish what is installed from what is dependable in terms of power supply. The *dependable capacity* refers to the capacity that is left when taking into account ambient limitations for a time period such as a month or a season. This includes factors such as efficiency ratios and the temperature. Essentially, dependable capacity is lower than the installed capacity to take into account these adjustments that the power plants need to continuously run. Finally, the *available capacity* refers to what is actually injected or dispatched into the grid. Available capacities may be lower than the dependable capacity due to equipment limitations such as unforced outages, or scheduled maintenance of the generation facilities.

As earlier stated, the capacity in the grid needs to be able to meet the demand to ensure that electricity is served to end-users in a reliable manner. In this case, it is not only the peak demand that needs to be met, but also the required reserve margin. The required reserve margin refers to the allowance over the

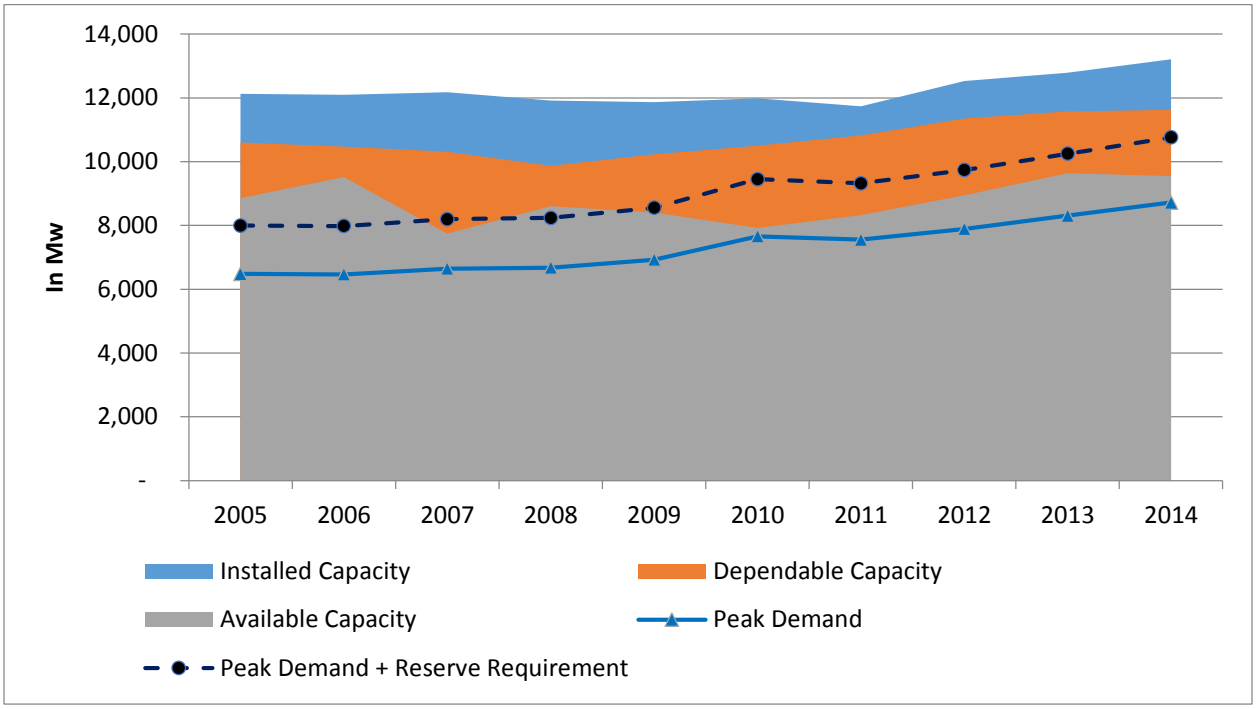
peak demand to ensure the integrity of the grin and avoid power interruptions[13]. To examine the trends of supply reliability in the post-EPIRA market structure, we discuss below the supply demand situation in the past ten years.

For Luzon, the demand has been increasing at a faster rate than the supply over the past ten years. The average annual growth rate of the peak demand is at 3.35%; while available capacity has been increasing by only 0.84%. In terms of installed and dependable capacity, the average annual growth over the last ten years has been 0.96% and 1.03% respectively. Given that the peak demand and the corresponding reserve margin needed is rising at a greater rate, there is a need to ensure that new power plants are constructed to help ensure supply in the coming years.

Outages, forced and unforced, must also be constantly monitored to avoid load curtailment in the grid. In 2013 for example, there were a multitude of breakdowns in the generation facilities. In May that year, a cascading outage involving five power plants resulting in approximately 3,700 MW of electricity to come offline. The outages included Calaca Units 1 and 2 (2 x 300 MW), Ilijan Block 1 (3 x 204 MW), San Lorenzo module 50 and 60 (2 x 265 MW), Sta Rita module 10 to 40 (4 x 265 MW), Sual Unit 1 (647 MW). Further, GNPower Units 1 and 2 (2 x 325 MW) has several unforced outages since its operation in May 2013 due to high vibrations of tube leaks. The Pagbilao Unit 2 was also offline from 31 August to 13 November 2013; while San Lorenzo Unit 2 (265 MW) had transformer trouble and was offline from May 2013 to May 2014. Figure 7 below shows the demand supply situation in the Luzon grid from 2005-2014.

[13] For Luzon and Visayas, the ERC-approved required reserve margin above peak demand is 23.4% – composed of 2.8% Load Following and Frequency Regulation, 10.3% Spinning Reserve, 10.3% Back-Up. As for Mindanao, the ERC-approved required reserve margin above peak demand is 21% -- composed of (2.8% Load Following and Frequency Regulation, 9.1% Spinning Reserve, 9.1% Back-Up.

Figure 7. Supply Reliability in the Luzon Grid, 2005-2014

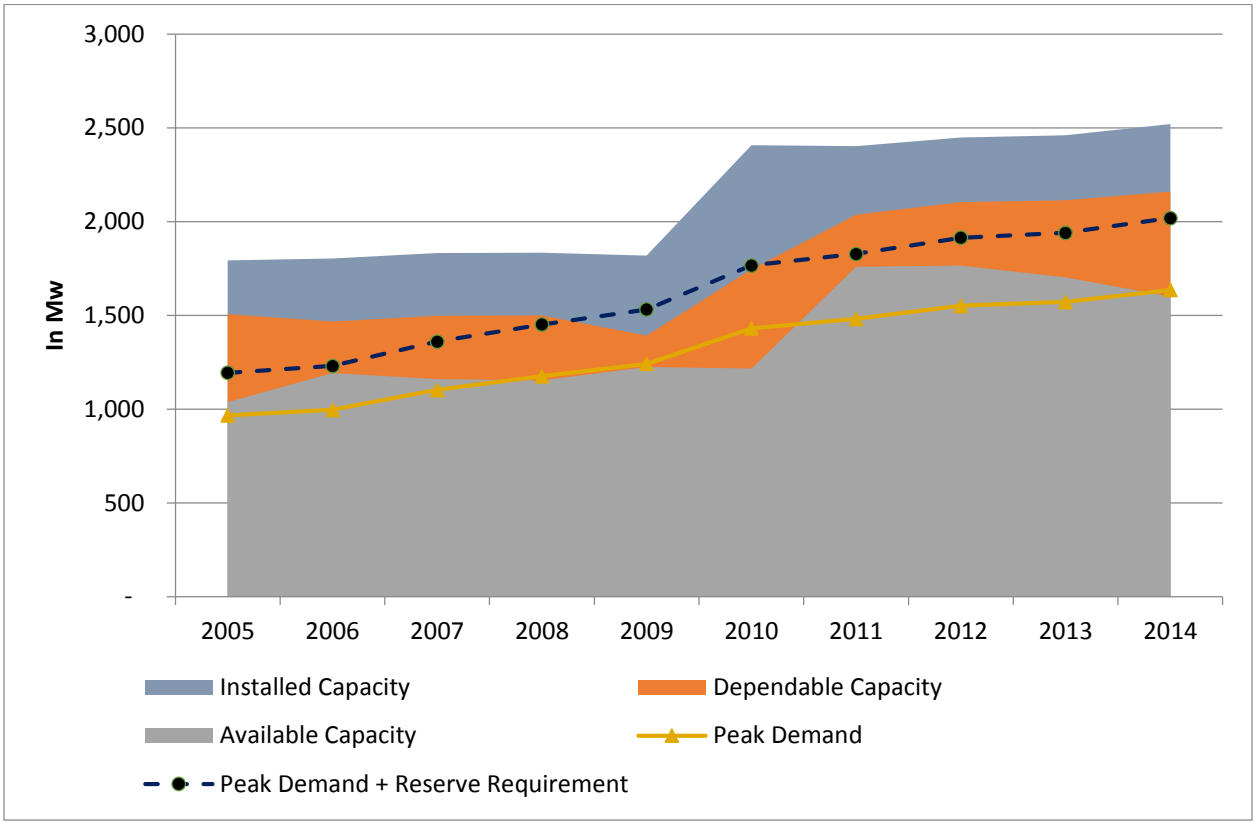


Source: Department of Energy and National Grid Corporation of the Philippines
Note: The ERC-approved reserve margin for Luzon and Visayas is 23.4%.

For the Visayas grid, the same trend can be observed in terms of the peak demand outgrowing the available capacity. For the previous ten years, peak demand was increasing at an average of 6.02% annually. On the other hand, the available capacity was increasing at rate of 5.24%. The installed capacity was increasing at a rate of 3.85% annually, while the dependable capacity had an average annual increase of 4.08% in the last decade.

In 2009, the required reserve margin was more than the dependable capacity which led to rotating brownouts in Cebu and other areas in the region. However, this was addressed in 2010 with approximately 590 MW of power plants coming online. Coal fire plants by Cebu Energy Development Corporation (3 x 82 MW), Panay Energy Development Corporation (2 x 72 MW) and KEPCO-Salcon (2 x 100) were commissioned. Despite this development however, brownouts were still experienced in 2010 as the available capacity were below the peak demand. This was due to maintenance works to the Panay Diesel Plant and power barges 102 and 103. Figure 8 below shows the demand supply situation in the Visayas grid from 2005-2014.

Figure 8. Supply Reliability in the Visayas Grid, 2005-2014

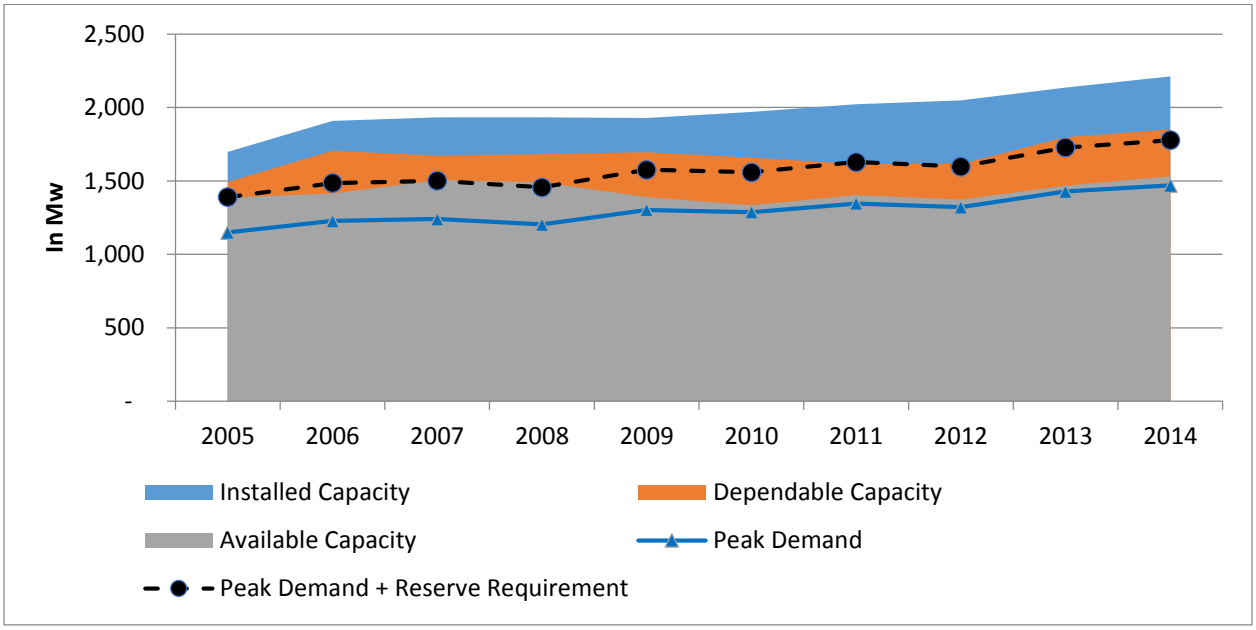


Note: The ERC-approved reserve margin for Luzon and Visayas is 23.4%.
Source: Department of Energy and National Grid Corporation of the Philippines

As for the Mindanao grid, the supply has been tight since 2009 where the required margin is over available capacity by 195 MW. Rotating brownouts has been experienced especially during summer times and dry season where water levels in hydropower plants such as the Agus and Pulangi hydropower compelxes are affected. These fluctuations in capacity have not been able to meet the steady growth of demand in Mindanao. For the last decade, the peak demand is increasing at average annual rate of 2.77%. Meanwhile, the available capacity only has an average growth rate of 1.12%. Although installed capacity is growing at an average of 2.97% annually, dependable capacity average annual growth (2.42%) is still lower than the peak demand average annual growth.

Since 2009, the required reserve margin the Mindanao has not been met by the available capacity. What is more alarming is that since 2010, the available capacity has been almost equal with the peak demand, not to mention the required reserves. Thus, the Department of Energy has implemented initiatives such as the Interruptible Load Program to curtail such crisis. Figure 9 below shows the demand supply situation in the Mindanao grid from 2005-2014.

Figure 9. Supply Reliability in the Mindanao Grid, 2005-2014



Note: The ERC-approved reserve margin for Mindanao is 21%.

Source: Department of Energy and National Grid Corporation of the Philippines

3.2 System loss reduction

System losses happen in both the transmission system and the distribution system. System losses refer to amount of electricity that have been injected to the grid but are not paid for by the users.[14] According to the Philippine Distribution Code, system losses can be classified into three: technical loss, non-technical loss, and administrative loss[15]. The technical loss involves the conductor loss when electricity travels, the core loss in transformers, and any losses due to technical metering error. On the other hand, the non-technical loss refers to the energy lost due to pilferage, meter-reading errors and meter tampering. Finally, the administrative loss refers to the energy required for the proper operation of distribution system and any unbilled energy for community-related activities. With regards to the administrative losses, the Philippine Distribution Code states that DUs should submit to the ERC their required allowance. The ERC then approves this, after due notice and hearing, based on the connected essential load. In practice, the administrative load is considered as part of the operation and maintenance expense of the distribution utility.

Historically, there are observable improvements in efficiently transmitting electricity in the country. As an initiative to lower system losses in the country, Republic Act 7832 or the Anti-electricity and Electric Transmission Lines/Materials Pilferage Act was passed into law in 1994. RA 7832 declared acts such as

[14] Antmann, P. (2009). Reducing Technical and Non-Technical Losses in the Power Sector. Energy Unit, World Bank.
[15] Section 3.4. Philippine Distribution Code.

tapping, tampering, stealing and damaging transmission lines as unlawful and imposed penalties for electricity pilferage. Data shows that the combined transmission and distribution loss has been decreasing over the past two decades. This is from a high of 17.1% in 1995, it is down to 11.4% in 2012[16].

Table 10. System Loss: Average Annual Growth Rates, Pre- and Post-EPIRA

Grids	Average Annual Growth Rates	
	Pre-EPIRA (1991-2000)	Post-EPIRA (2001-2015)
Luzon	-0.26%	-2.47%
Visayas	0.53%	-1.92%
Mindanao	0.63%	-6.92%

Source: NGCP
Note: *2015 data is January to August

For the transmission systems alone, the same trend of improvement in terms of efficiency of the country's transmission network can be observed over the last 25 years. Much improvement can be seen during the post-EPIRA period (2001-2015). Data from the pre-EPIRA years (1991-2000) shows that the Luzon grid has been decreasing its system loss by an average of 0.26% annually. But when EPIRA was implemented, the Luzon grid was decreasing by an annual average of 2.47%. For the Visayas grid, pre-EPIRA system loss has an annual average increase of 0.53%. In the post-EPIRA years, the Visayas grid recorded an average decrease of 1.92% yearly. Finally, the Mindanao grid has an average annual increase in system losses of 0.63%, but has vastly improved post-EPIRA with an average annual decrease of 6.9 %. Table 10 above summarizes the comparison of average annual growth rates pre- and post-EPIRA.

In addition, there are also ERC-approved loss factors (caps) per grid in the post-EPIRA years. According to TransCo, the ERC-approved loss factor for Luzon is 2.98%, for Visayas is 3.67% and 4.35% for Mindanao. The figures were the actual system losses of year 2000, and were adopted as caps. This has not been changed ever since.[17] Figure 10 shows the transmission system losses per grid in the country vis-à-vis the caps as set by ERC.

[16] World Bank Database. (2015). Electric power transmission and distribution losses (% of output). Accessed from
[17] Data given by TransCo during the 6th Task Force Meeting, November 26, 2014, Philippine Institute for Development Studies, Makati City.

Figure 10. Transmission System Loss vs. ERC caps, per Grid, 2001-2015

Source: NGCP
*Note: * 2015 data cover January to August*

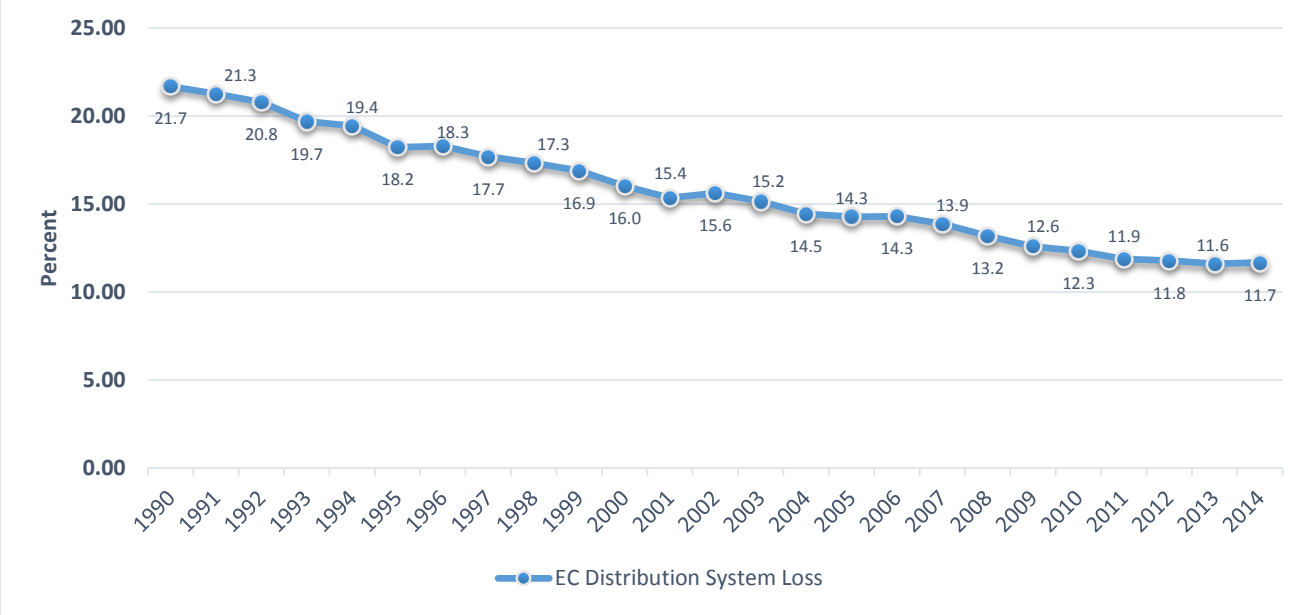
As the figures would show, over the last five years, there is a considerable improvement in minimizing the system loss across the grids. The losses are below the ERC-approved loss factors. As for the performance of NGCP as the transmission concessionaire, the system losses has also shown a decreasing trend since 2009. Luzon grid has an average annual decrease of 4.09%, while Visayas grid has an average annual decrease of 1.99%. Mindanao has seen the greatest improvement since 2009 as it has been able to decrease system losses by an average or 6.92% yearly. According to NGCP, this can be attributed to the investments they have made over the years, and better metering systems they have installed to better capture the input and outputs of the grid.

For the distribution system loss, RA 7832 also established a cap on the recoverable rate of system loss. The cap for private distribution utilities was set at 9.5% at the end of the fourth year following the act,

while the cap for electric cooperatives was at 14%. The system loss cap was further lowered by virtue of ERC Resolution No. 17, Series of 2008. Under the revised caps, the actual cost of the technical and non-technical losses shall be passed on by the distribution utilities to the consumers, but shall not exceed 8.5% for private distribution utilities, and 13% for the electric cooperatives. As of 2014, 67.5% of the electric cooperatives are under the set cap of ERC.

For the distribution system of electric cooperatives, there is also a decreasing trend in terms of system losses. For the electric cooperatives, it has a record low system loss of 11.61% in 2013. For 2014, this has slightly increased to 11.67%. In general, the system losses for electric cooperatives has been decreasing by an annual average of 2.55% over the past two decades. Figure 11 details the historical system losses of electric cooperatives.

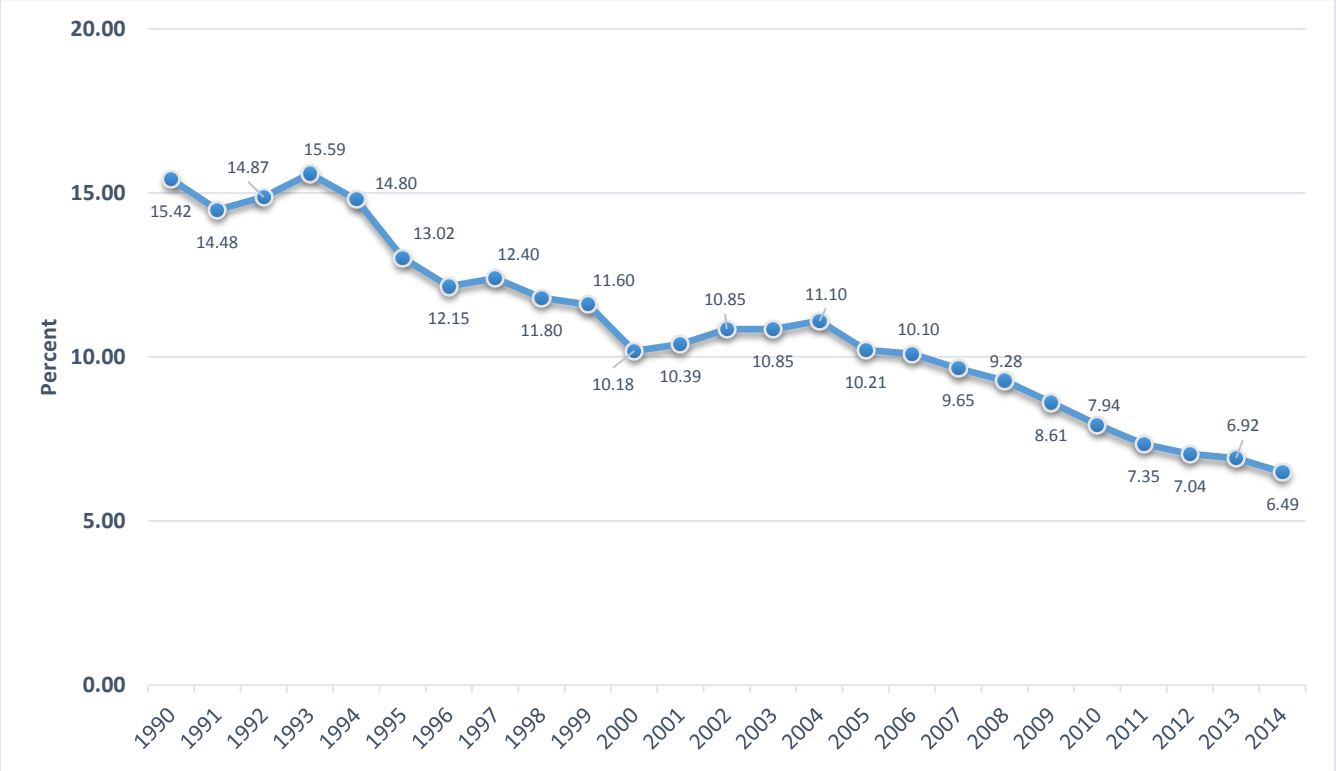
Figure 11. Distribution System Loss of Electric Cooperatives, 1990-2014



Source: NEA

As for the performance of electric cooperatives for 2014, commendable are the electric cooperatives of Misamis Oriental I (2.71%), Leyte II (3.80%) and Dinagat Island (5.23%) which has the lowest system loss within their respective franchise areas. Meanwhile, regulatory agencies can help the electric cooperatives in ARMM improve the distribution of electricity. It is important to highlight that Maguindanao recorded almost half of their electrical transmission as losses (at 42.92% system loss). Basilan (31.72%) and Sulu (31.24%) also needs careful attention.

Figure 12. Distribution System Loss of MERALCO, 1990-2014



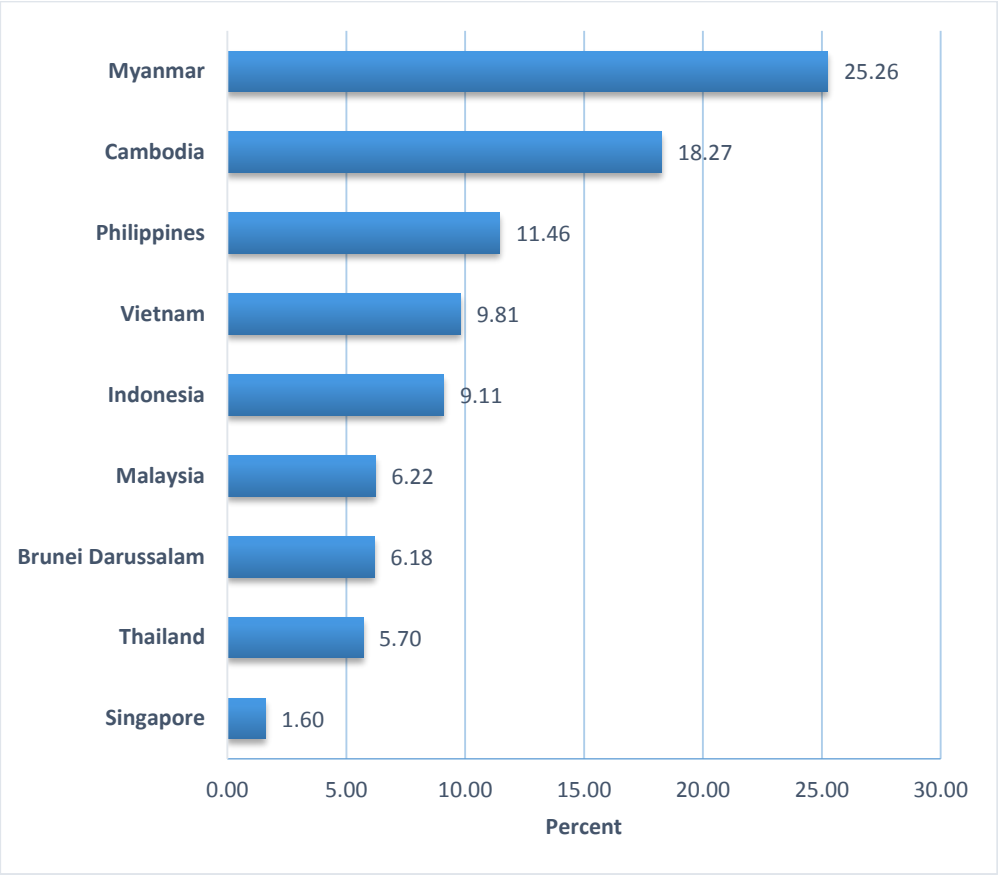
Source: MERALCO

As for MERALCO, the largest private distribution utility in the country, system losses has also shown a decreasing trend. For 2014, the system loss is also a record low for the company at 6.49%. In the post-EPIRA period, the system losses in the MERALCO franchise area peaked in 2004. MERALCO has stated that this can be attributed to the 'difficulty of times' brought about by prevailing economic conditions.[18] MERALCO believes when the cost of electricity is high, pilferage is also high. In general, MERALCO has been able to reduce their system losses by an average of 3.6% decrease annually in the post-EPIRA period. This is an improvement considering in the pre-EPIRA years of 1990, the average annual decrease is at 4.1%.

On the other hand, in comparison to other ASEAN nations, the Philippines has the 3rd largest transmission and distribution losses with 11.46% as of 2012. Cambodia and Myanmar are the countries with the highest losses. On the other hand, Singapore leads the ASEAN countries in efficiency with losses only at 1.60%. This is followed by Thailand and Brunei Darrusalam with 5.70% and 6.18% respectively.

[18] Gatdula, D. 'Meralco reports jump in system losses to 11.1% in 2004'. Accessed November 15, 2015 from http://goo.gl/7CHqcU.

Figure 13. Transmission and Distribution Losses across ASEAN, 2012



Note: No data available for Lao PDR.

Source: World Bank Database

The data suggests that despite the improvement of system losses in the country in the last two decades, the Philippines still lags behind most of its ASEAN counterparts in terms of efficiency. The system losses is also another form of economic loss, especially taking into account the fact that generated power comes from fuel.[19] Investments in improving distribution services of electricity should be pursued. In terms of non-technical losses such as theft and pilferage, stakeholders state that there is a need to forcefully implement the RA 7832. Minimizing the technical losses (through investments) and the non-technical laws (through RA 7832) would certainly help in reducing the cost of electricity in the country.

[19] Ibid. 12

4. Conclusions

The assessment shows that electricity prices post-EPIRA remain high and although there was a slight downtrend after the introduction of the WESM, prices were still high relative to pre-EPIRA levels. Supply reliability is still an ongoing concern but the recent past record shows that shortages were managed and did not reach nationwide crisis levels reminiscent of the 1990s. Moreover, production efficiency gains were achieved through the reduction of system losses.

There is a danger that the findings on price trends could provide ammunition to those advocating the repeal of the EPIRA and re-nationalization of the industry. It must be emphasized, however, that the country has a long history of private sector-led electric power industry: more than eight decades of private sector-led generation capacity development (1890-1972), less than one and a half decades of government monopoly in generation (1972-1987), less than a decade of mixed private and public sector generation through IPPs and the NPC (1987-2006), and evolving competition with many stakeholders participating, including end-users (2006-present). Moreover, the nationalization years were marked by inefficiencies and fiscal problems that were not borne by electricity consumers alone but by the whole country.

Looking at prices alone can also lead to contradictory results. For instance, in the studies of electricity market liberalization in Table 11 below, seven out of 12 studies show an increase in household electricity prices.

Table 11.Cross-country studies on the impact of electricity market liberalization on energy prices

Studies	The steps of electricity market liberalization	Electricity prices	
		Households	Industrial Consumers
Steiner (2000)	Wholesale electricity market, unbundling of electricity production from transmission, allowing TPA access to the grid	↑	↓
	Privatization	↑	↑
Doove *et al.* (2001)	Wholesale electricity market, unbundling of electricity production from transmission, allowing TPA access to the grid	↓	↓
Zhang *et al.* (2002)	Wholesale electricity market, privatization, independent regulatory agency	-	-
Evans, Green (2003)	Wholesale electricity market	↑	↑
Hatori, Tsutsui (2004)	Wholesale electricity market	↓	↓
	Unbundling of electricity production from transmission, TPA access to the grid, privatization	↑	↑
	Retail electricity market	↑	↓
Roques *et al.* (2005)	Liberalization of electricity markets	-	-

Studies	The steps of electricity market liberalization	Electricity prices	
		Households	Industrial Consumers
Joskow (2006)	Wholesale electricity markets, retail electricity market	↓	↓
Hogan, Meade (2007)	Unbundling of electricity production from transmission	↑	↑
Fiorio *et al.* (2008)	Unbundling of electricity production from transmission	↓	↓
Bushnell *et al.* (2008)	Unbundling of electricity production from transmission	↑	↑
Yarrow (2008)	Liberalization of electricity markets	↓	↓
Nagayama (2009)	Liberalization of electricity market in Eastern Europe	↓	↓

Source: Transformation in Business & Economics 12:3(30), 2013

It is also important also to look at how well other energy policy targets are being met. Among such objectives are ensuring reliability of supply and avoiding, or at least minimizing, brownouts, and reducing system losses. It is also important to take a look back at the situation pre-EPIRA and managing the fiscal affairs of the government as one more objective.

Finally, we must recognize that the evolution in the governance structure of the industry is still unfinished. The WESM has to be governed by an independent market operator; the ERC's regulatory capacity needs strengthening; and the DOE needs to beef up its planning function. The government already has its hands full in the developmental role currently reserved for it in the electricity sector: rural electrification. The government should remain committed to this role while exploring ways to engage the private sector as partner in innovative mechanisms for rural electrification. (Right now, it has a framework provided through the mandates of NEA and DOE on rural electrification and it can improve on that framework.) With respect to the EPIRA, what needs to be done is not to repeal it but to find ways of improving its implementation. What needs to be amended in the law is also worth examining in the next Congress.

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