Modeling Power Plant Expansion in Java-Bali System: Evaluating Minimizing Cost and Minimizing CO_2 Emissions[1]

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1. Introduction

Since the economic crisis in 1997/98, the new installed capacity of *PT Perusahaan Listrik Negara* / the State Owned Electricity Company (PT.PLN) has showed decreasing rate of growth from about 10.4% before the crisis to about 2.1 % after the crisis (Sambodo and Oyama, 2010). Because of economic downturn, Indonesia had excess in electricity supply for more than 7,700 MW (EGAT, 1998 as cited in Soontornrangson et al., 2003). However, excess supply remained shortly due to gradual increase in electricity consumption as the economy has been recovered. On July 2008, power shortage could not be avoided and to minimize unnecessary black out on the power system, five ministries released a join regulation on shifting working hour for the industrial sector in Java-Bali area[2].

Following the Presidential Instruction No 1/2010 on the acceleration in implementation of national priority development (*Percepatan Pelaksanaan Prioritas Pembangunan Nasional Tahun 2010*), the energy sector is one of the top priority of the government programs. There are three out of four actions for the energy security program that are directly related to the electricity sector such as: (i) improving electricity supply; (ii) developing geothermal; (iii) promoting alternative energy other than geothermal such as photovoltaic, microhydro, conducting feasibility study on ocean, and socialization on nuclear power plant. Further, on June 2010, PT.PLN up dated the electricity business plan of power supply (*Rencana Usaha Penyediaan Tenaga Listrik*) between 2010 and 2019. This plan replaced the old one that was issued on December 2008. There are four reasons why PT.PLN needs to construct the new business plant (PT.PLN, 2010): (i) to fulfill growth of load; (ii) to minimize supply shortage; (iii) to increase reserve margin; and (iv) to introduce hydro and geothermal power into the power system. The business plan covers three major activities in electricity sector such as generating, transmission, and distribution. In developing generating system, PT. PLN aims to obtain the least cost principle, but PT. PLN also attempts to operate renewable energy such as geothermal and hydropower, even it has relatively high cost compare to other fossil fuel power plants.

Although, carbon pricing is widely seen as the most efficient economic instrument to control CO_2 emissions (Resosudarmo et al., 2011), PT.PLN has not internalized cost of CO_2 emissions into the power plant expansion model. Shrestha and Marpaung (1999) suggested a very high carbon tax that is about US$100-US$200/ ton-carbon in their model. They found that a high carbon tax can improve the performance of the power system. Shrestha and Marpaung (1999) also pointed out that carbon tax can reduce emissions by 67.2% and 86% respectively comparing without carbon tax. On the other hand, Rachmatullah et al. (2007) proposed US$ 4/ton-carbon to reduce the CO_2 emissions by 15%. However, we argue that carbon tax policy politically is very difficult to implement because the Indonesian government still provides electricity subsidy and the amount has increased from about US$ 796.7 billion in 2005, to about US$ 5,976 billion in 2011[3]. Similarly with Resosudarmo et.al (2011) argued that distributional and political considerations make reforming energy price difficult to achieve.

[1] This paper is prepared for the 3rd International Association for Energy Economics (IAEE) Asian Conference, 20-22 February 2012, Kyoto, Japan, under the theme: Growing Energy Demand, Energy Security and the Environment in Asia.
[2] Due to operation of 3 new power plants, on September 2010 government cancelled this regulation.
[3] We assumed 1US$=Rp 9,000

Further, Shrestha and Marpaung (1999) said that a high carbon tax not only reduce the economic welfare, but also have adverse effects on tax revenue. Considering the recycling of revenue generating by carbon tax may also difficult problems. It is important to note that Indonesia does not have a mandatory obligation to reduce CO_2 emissions. However, following the President Regulation No 61/2011 on National Agenda to reduce GHGs emissions, CO_2 emissions reduction from energy and transportation sector is expected about 5% from the total emissions reduction's target[4].

Following concern on low carbon economy paradigm, Indonesia needs to promote green investment in power generating sector because this can avoid risks on 'carbon lock-in' in the future. According to IEA (2009), there are three pillars to curb CO_2 emissions from the electricity sector: (i) significant improvements in energy efficiency of electricity end use; (ii) providing policy incentives such as through a price on CO_2 emissions or subsidies for promoting low carbon technology; (iii) enhancing research and development in low carbon generation technologies. Similarly Ang et al. (2011) discussed the important of fuel switching and generation efficiency improvement for reducing the emissions.

This paper aims to construct the model of power expansion plant by considering two objective functions: (i) minimizing generating cost (objective 1); and (ii) minimizing CO_2 emissions (objective 2). In the analysis, we evaluate the two objectives in terms of total CO_2 emissions, CO_2 emissions intensity (ton CO_2/MWh), output diversification index, and average generating cost (Rp/kWh). We also evaluate *ex-post* reserve margin, share of independent power producer (IPP) to the total electricity production, and share of renewable to non renewable power plant. There are two contributions of this paper. First, in terms of academic exercise, this paper can be a new literature that attempts to reduce CO_2 emissions especially in Indonesia with minimization CO_2 emissions strategy base on the existing technology. Second, this paper can provide alternative strategies for Indonesia in dealing with reduction of CO_2 emissions growth in the future.

2. Methodology

2.1 Model

We divide the modeling analysis into two periods: 2006-2009 and 2010-2019. The energy planning covered periods between 2006 and 2019 for three reasons. *First* on 5 July 2006 government launched the fast track program on power supply. With this program the total additional national electricity capacity in 2009, will increase between 7,900 MW and 11,422 MW. This program was continued in 2010 with the second fast track program and additional of national capacity will increase to about 10,098 MW in 2014. *Second*, following the recent PT.PLN's business plant 2010 – 2019, we utilize information on additional installed capacity. *Finally*, because between 2006 and 2009 we have the actual data, this can help us to estimate parameter of availability factor[5]. We focus our analysis for power plant in Java-Bali system because currently share of installed capacity is about 72.3% in Java-Bali system and about 77% of national rated capacity and electricity production is based in Java-Bali system (PT.PLN, 2009). We developed the basic model that has been prepared by Sarker and Newton

[4] There are two justifications for issuing this regulation. First, due to geographic condition, Indonesia is very vulnerable to the impact of climate change. Thus it is important to take mitigation actions. Second, Indonesia has commitment to reduce green house gases emissions at least by 26% in 2020. In the energy sector, more than 60% of emissions reduction from energy sector will be driven by two major activities such as mandatory energy management for 200 enterprises and energy efficiency from home appliances, For example, in 2014 the implementation of energy saving technology will reach 7.90 million kWh and in 2020, it can reach 13.53 million kWh. From the power generating sector, the action plans are devoted for constructing small scale power plant from renewable energy such as hydro power, wind, solar and biomass with total additional capacity is about 1,225 MW.

[5] In this section, we attempt to evaluate robustness of model estimate. The power plant expansion model needs to fulfill two conditions: (1) total output is as close as possible to actual output and (2) output for each type of power plant is as close as possible to actual output for each type of power plant.

To obtain the two conditions we simulate the model by conducting two fine tuning actions:

1. Adjusting availability factor (AF). We define availability factor as follows:
   $$AF = \frac{available\,time}{calender\,period} = \frac{operating\,time + standby}{calender\,period}$$
2. Conducting demand side management

We do not have information on the AF, but we can estimate it by trial and error. Thus, obtaining the suitable of availability factor is one of the most challenging tasks.

(2008) and we are interested not only to obtain the optimal output combination of the least-cost but also the least CO_2 emissions[6]. The parameters and decisions variables are defined as follows:

Parameters:
TD_p = duration of load block p in hours
PD_p = maximum power demand in MWh in a load block p
VCF_i = generating cost (Rp/MW-h) for old fossil fuel power plant type i – PT.PLN
$VCNF_j$ = generating cost (Rp/MW-h) for old non-fossil fuel power plant type j - PT.PLN
CEF_i = capacity (MW) of existing old fossil fuel power plant type i – PT.PLN
$CENF_j$ = capacity (MW) of existing old non-fossil fuel power plant type j – PT.PLN
AFF_i = availability factor for old fossil fuel power plant type i – PT.PLN
$AFNF_j$ = availability factor for old non-fossil fuel power plant type j – PT.PLN
$AFFP_i$ = availability factor for old fossil fuel power plant type i – Private
$AFNFP_j$ = availability factor for old non-fossil fuel power plant type j – Private
AFF_k = availability factor for new fossil fuel power plant type k – PT.PLN
$AFNF_l$ = availability factor for old non-fossil fuel power plant type l – PT.PLN
$AFFP_k$ = availability factor for old fossil fuel power plant type k – Private
$AFNFP_l$ = availability factor for old non-fossil fuel power plant type l – Private
$EI1_i$ = emissions intensity (ton CO_2/MWh) for fossil power plants that have been operated since 2006 type i
$EI2_k$ = emissions intensity (ton CO_2/MWh) for fossil power plants that have been operated since 2010 type $_k$
$CEFP_i$ = capacity (MW) of existing old fossil fuel power plant type i – Private
$CENFP_j$ = capacity (MW) of existing old non-fossil fuel power plant type j – Private
$VCFP_i$ = generating cost (Rp/MW-h) for old fossil fuel power plant type i – Private
$VCNFP_j$ = generating cost (Rp/MW-h) for old non-fossil fuel power plant type j - Private
$ADDF_i$ = capacity for new fossil fuel power plant type i – PT.PLN
$ADDNF_j$ = capacity for new non-fossil power plant type j – PT.PLN
$ADDFP_i$ = capacity for new fossil fuel power plant type i – Private
$ADDNFP_j$ = capacity for new non-fossil power plant type j – Private
$VCFN_k$ = new generating cost (Rp/MW-h) for fossil fuel power plant type k – PT.PLN
$VCNFN_l$ = new generating cost (Rp/MW-h) for non-fossil fuel power plant type l - PT.PLN
$VCFNP_k$ = new generating cost (Rp/MW-h) for fossil fuel power plant type k – Private
$VCNFNP_l$ = new generating cost (Rp/MW-h) for non-fossil fuel power plant type l - Private
Index:
i, j, k and l = plant type,

fossil fuel for capacity that already exist between 2006 and 2009 consists of i = 1 (steam), i = 2 (combine cycle), i = 3 (gas turbine), i = 4 (diesel)

non-fossil fuel for capacity that already exist between 2006 and 2009 consist of j = 1 (geothermal),and j = 2 (hydro)

new fossil fuel for capacity between 2010 and 2019 consists of k = 1 (steam), k = 2 (combine cycle), k = 3 (gas turbine)

new non-fossil fuel for capacity between 2010 and 2019 consist of l = 1 (geothermal),and l = 2 (hydro)

p = load duration block, p = 1, …, P (in given period); where p = 1 indicates peak hour and p = 5 shows base load

Variables:
$OutF_{ip}$ = electricity production (MWh) from fossil fuel power plant of type i in block p – PT.PLN, for capacity between 2006-2009

[6] *As applied to the power sector, Integrated Resource Planning/IRP can be described as an approach through which the estimated requirement for electricity services during the planning period is met with a least cost combination of supply and end-use efficiency measures, while incorporating concerns such as equity, environmental protection, reliability and other country-specific goals* (D'Sa, 2005).

$OutNF_{jp}$	= electricity production (MWh) from non-fossil fuel power plant of type j in block p – PT.PLN, for capacity between 2006-2009
$OutNEWF_{kp}$	= electricity production (MWh) from new fossil fuel power plant of type k in block p – PT.PLN, for capacity between 2010-2019
$OutNEWNF_{lp}$	= electricity production (MWh) from new non-fossil fuel power plant of type l in block p – PT.PLN, for capacity 2010-2019
$OutFP_{ip}$	= electricity production (MWh) from fossil fuel power plant of type i in block p – Private, for capacity 2006-2009
$OutNFP_{jp}$	= electricity production (MWh) from non-fossil fuel power plant of type j in block p – Private, for capacity 2006-2009
$OutNEWFP_{kp}$	= electricity production (MWh) from new fossil fuel power plant of type k in block p – Private, for capacity 2010-2019
$OutNEWNFP_{lp}$	= electricity production (MWh) from new non-fossil fuel power plant of type l in block p – Private, for capacity 2010-2019

Objective Functions

Objective 1 Minimizing Cost

$$\begin{aligned} Minimize Z_1 = & \sum_{i=1}^{I}\sum_{p=1}^{P} VCF_i \times OutF_{ip} + \sum_{j=1}^{J}\sum_{p=1}^{P} VCNF_j \times OutNF_{jp} + \sum_{i=1}^{I}\sum_{p=1}^{P} VCFP_i \times OutFP_{ip} + \\ & \sum_{j=1}^{J}\sum_{p=1}^{P} VCNFP_j \times OutNFP_{jp} + \sum_{k=1}^{K}\sum_{p=1}^{P} VCFN_k \times OutNEWF_{kp} + \sum_{l=1}^{L}\sum_{p=1}^{P} VCNFN_l \times OutNEWNF_{lp} + \\ & \sum_{k=1}^{K}\sum_{p=1}^{P} VCFNP_k \times OutNEWFP_{kp} + \sum_{l=1}^{L}\sum_{p=1}^{P} VCNFNP_l \times OutNEWNFP_{lp} \end{aligned} \tag{1}$$

Objective 2 Minimizing total amount of CO_2 emissions

$$Minimize Z_2 = \sum_{i=1}^{I}\sum_{p=1}^{P} EI1_i \times (OutF_{ip} + OutFP_{ip}) + \sum_{k=1}^{K}\sum_{p=1}^{P} EI2_k \times (OutNEWF_{kp} + OutNEWFP_{kp}) \tag{2}$$

Constraints:

1. ***Capacity constraint***. Output for each type of power generation unit cannot exceed the total capacity of the existing or planned units of this type, multiplied by the corresponding availability factor:

$$\begin{aligned} & OutF_{ip} \le AFF_i \times CEF_i \times TD_p \text{ for all } i, \text{ and } p \\ & OutNEWF_{kp} \le AFF_k \times ADDF_k \times TD_p \text{ for all } k, \text{ and } p \\ & OutFP_{ip} \le AFFP_i \times CEFP_i \times TD_p \text{ for all } i, \text{ and } p \\ & OutNEWFP_{kp} \le AFFP_k \times ADDFP_k \times TD_p \text{ for all } k, \text{ and } p \\ & OutNF_{jp} \le AFNF_j \times CENF_j \times TD_p \text{ for all } j, \text{ and } p \\ & OutNEWNF_{lp} \le AFNF_l \times ADDNF_l \times TD_p \text{ for all } l, \text{ and } p \\ & OutNFP_{jp} \le AFNFP_j \times CENFP_j \times TD_p \text{ for all } j, \text{ and } p \\ & OutNEWNFP_{lp} \le AFNFP_l \times ADDNFP_l \times TD_p \text{ for all } l, \text{ and } p \end{aligned} \tag{3}$$

2. ***Primary energy supply constraint***. Total output from fossil power plant cannot exceed fuel consumption (*fuelcons*) after we control for possibility of energy requirement (*req.fos*) during the process of energy transformation.

$$\sum_{i=1}^{I}\sum_{p=1}^{P}(OutF_{ip}+OutFP_{ip})+\sum_{k=1}^{K}\sum_{p=1}^{P}(OutNEWF_{kp}+OutNEWFP_{kp})\leq req.fos\times fuelcons \qquad 4)$$

3. ***Primary energy supply constraint for non fossil fuel***. Total output from non fossil power plant cannot excess the primary energy supply (*primary*) that is devoted to produce electricity for each type of power plant after we adjust for the possibility of energy requirement (*req.nonfos*) during the transformation.

$$\begin{aligned}&\sum_{j=1}^{J}\sum_{p=1}^{P}(OutNF_{jp}+OutNFP_{jp})+\\&\sum_{l=1}^{L}\sum_{p=1}^{P}(OutNEWNF_{lp}+OutNEWNFP_{lp})\leq req.nonfos\times primaryenergy\end{aligned} \qquad 5)$$

4. ***Demand satisfaction***: Electricity production at each load block must to satisfy the demand. We introduce *dsm* parameter that represent for demand side management. We implement demand side management (DSM) policy with reducing the each load block area *(PD)* by 5% and 10% respectively[7].

$$\begin{aligned}&\sum_{i=1}^{I}(OutF_{ip}+OutFP_{ip})+\sum_{k=1}^{K}(OutNEWF_{kp}+OutNEWFP_{kp})\\&\sum_{j=1}^{J}(OutNF_{jp}+OutNFP_{jp})+\sum_{l=1}^{L}(OutNEWNF_{lp}+OutNEWNFP_{lj})\geq PD_{p}\end{aligned} \qquad 6)$$

for all p

5. ***Contract agreement***. PT.PLN needs to purchase certain amount of power supply from independent power producers. We introduce purchase's parameter (*purchase*) that shows the minimum share of electricity that can be purchased by PT.PLN from PT.PJB[8].

$$\begin{aligned}&\sum_{i=1}^{I}\sum_{p=1}^{P}OutFP_{ip}+\sum_{k=1}^{K}\sum_{p}^{P}OutNEWFP_{kp}+\sum_{j=1}^{J}\sum_{p=1}^{P}OutNFP_{jp}+\\&\sum_{l=1}^{L}\sum_{p}^{P}OutNEWNFP_{kp}\geq purchase\times(\sum_{i=1}^{I}\sum_{p=1}^{P}OutF_{ip}+\sum_{k=1}^{K}\sum_{p=1}^{P}OutNEWF_{kp}+\\&\sum_{j=1}^{J}\sum_{p=1}^{P}OutNF_{jp}+\sum_{l=1}^{L}\sum_{p}^{P}OutNEWNF_{jp})\end{aligned} \qquad 7)$$

6. ***Promoting renewable energy***. We assume that there are flexibilities to set the share of renewable energy in the power system. *pref* indicates parameter preference on renewable energy.

$$\begin{aligned}&\sum_{j=1}^{J}(OutNF_{jp}+OutNFP_{jp})+\sum_{l=1}^{L}(OutNEWNF_{lp}+OutNEWNFP_{lp})\geq\\&pref\times(\sum_{i=1}^{I}(OutF_{ip}+OutFP_{ip})+\sum_{k=1}^{K}(OutNEWF_{kp}+OutNEWNFP_{kp}))\end{aligned} \qquad 8)$$

for all p

Further, the diversification index (DI) is expressed as follows (Costello, 2007)*:*

$$DI=\sum -S_i\ln(S_i) \qquad 9)$$

[7] The demand side management (DSM) policy will shift down load curve and this is due to energy efficiency and energy conservation. A clear distinction between energy efficiency and energy conservation is that the former refers to adoption of a specific technology that reduce overall energy consumption without changing the relevant behavior, while the latter implies merely a change in consumer's behavior (Oikonumou, et al. 2009). Shrestha and Marpaung (2006) used replacing inefficient appliances in residential such as incandescent lamps with fluorescent lamps (CFL) and replacing standard motors with energy efficient motors. Similarly Hu at al. (2011) also said that 'worldwide experiences have proved that DSM is useful on energy efficiency on the consumer side and could be the first priority in face of climate challenge'. Further, Sambodo and Oyama (2011) found that in Indonesia there is a neutral relationship between electricity consumption and economic growth or the electricity conservation policy will have no impact on economic growth.

[8] In Java-Bali area, PT.PLN purchases electricity mostly from PT. PJB (*Pembangkit Jawa Bali*) that is one of subsidiaries of PT.PLN. There are two of big private companies / independent power producer (IPP) that sell electricity to PT. PLN namely PT.Paiton Energy and PT. Jawa Power with capacity in 2010 about 1.23 GW and 1.22 GW respectively.

where the diversity index directly relates to the share of generation by the *i*-th type of generation (i.e. S_i). This index measure changes in installed capacity composition among all power plan energy sources. The higher the index, the more desirable it is, because it shows more types of generation technologies and fuel sources in the system, and also shows more balance and diversity in input use. In this study, we replace installed capacity with electricity production.

2.2 Input data and scenarios

2.2.1 Load duration curve (LDC)

There are several methods to forecast LDC. Tanoto at al. (2010) applied artificial neural network (ANN) to forecast long-term peak load forecasting between 2010 and 2018. Suhartono and Endharta (2009) studied Elman-Recurrent Neural Network (RNN) which can explain AR and MA order effects simultaneously for double seasonal time series data forecast and compare the forecast accuracy with double seasonal ARMA model. Further, PT.PLN's business plan (2010-2019) also provides information on peak load. Thus, we optimize information from previous studies in developing the LDC. Because, we only have information on peak load, we assume that pattern of hourly consumption remain unchanged during the period of analysis or we assume that pattern of electricity consumption between 2007 and 2019, follow the pattern in 2006[9].

2.2.2 Generating cost

Average generating cost for each type of power plant consists of five components such as fuel, maintenance, depreciation, other and personnel. Between 2006 and 2009 we used actual generating cost and we estimated generating cost for additional new capacity between 2010 and 2019, by applying the levelized busbar cost formula[10]. For old power plant we estimated the generating cost by applying ARMA forecasting. Regarding generating cost for geothermal we adopted the Ministry of Energy and Mineral Resources Regulation No. 2/2011, that is stated PT.PLN has to buy electricity from geothermal power plant at cost 9.70 cent US$/kWh.

2.2.3 Emissions Intensity

We calculated CO_2 emissions intensity for each type of power plant by applying power generation formula as follows (Graus and Worrell, 2011)[11]:

$$CO_2 - INTENSITY_j = \sum_{1}^{n} (C_i I_i) / P_j \qquad 10)$$

where i is the fuel source $1, \ldots, n$, C_i is CO_2 emission factor per fuel source (we used IPCC default emissions factors) (tone CO_2/TJ), I_i the fuel input per fuel source (TJ), P_j the power production per fuel source (GWh) for plant j. We calculate emissions intensity for each type of power plant base on the following steps: (1) indentify fuel consumption and electricity production (note for period 2006 – 2009 data obtained from Statistik PLN various year; and for period 2010 – 2019 obtained from PT.PLN Business Plan); (2) calculate emissions intensity for each type of fossil fuel; (3) calculate share of fuel consumption for each type of power plant after we convert fuel consumption into BOE; (4) identify oil consumption for each type of power plant (we assume the share remain constant); (5) identify gas consumption for each type of power plant (we assume the share remain constant); (6) finally we calculate emissions intensity for each type of power plant.

2.2.4 Scenarios

We developed power plant expansion model into four scenarios (**Table 1**). Each scenario is different in terms of fuel and technology combination. In developing scenario we only focus on coal-steam power plant because coal steam power plant will be the backbone of power supply in the future and coal-steam power plant has the highest

[9] We used daily load duration curve on 21 November 2006 in Java-Bali system as a basis because at that date the load was maximum for the one year demand.

[10] We assume the discount rate is 12% for all plants. Basic information on generating cost we obtained from: http://www.worldenergyoutlook.org/docs/weo2008/WEO_2008_Power_Generation_Cost_Assumptions.pdf. Further, base on steam generating cost between 2006 and 2009, on average price of independent power producer (IPP) was about 14.4% above the PT.PLN's price and we keep this percentage unchanged between 2010 and 2019.

[11] By applying 5 different methods of estimation (power and heat generation, power generation, power loss factor, substitution principle, and energy method), in the case of Indonesia all the method showed similar result that CO_2 intensity was about 696 g/kWh in 2007 (Graus and Worrell, 2011).

CO_2 emissions. For objective 1, we have four scenarios and each scenario consist of 3 types of the DSM policy and it is similarly with objective 2. In total, we have 24 combinations of possible scenario.

Table 1 **Developing scenario for new power plant**

		Type of fuel for steam power plant	
		Lignite ✓ 4,200 kcal/kg ✓ Price: USD 50/ton	**Sub-bituminous** ✓ 5,100 kcal/kg ✓ Price: USD 70/ton
Type of coal-fired power technology	**Subcritical** ✓ Construction cost: 1,200 USD per kw ✓ Efficiency (net, LHV) 38%	***Scenario 1*** ▪ Generating cost 5.24 cent/kwh ▪ Emissions intensity: 0.98 tonCO_2/MWh	***Scenario 2*** ▪ Generating cost 5.67 cent/kwh ▪ Emissions intensity: 0.81 tonCO_2/MWh
	Supercritical ✓ Construction cost: 1,400 USD per kw ✓ Efficiency (net, LHV) 42%	***Scenario 3*** ▪ Generating cost 5.39 cent/kwh ▪ Emissions intensity: 0.88 tonCO_2/MWh	***Scenario 4*** ▪ Generating cost 5.77 cent/kwh ▪ Emissions intensity: 0.73 tonCO_2/MWh

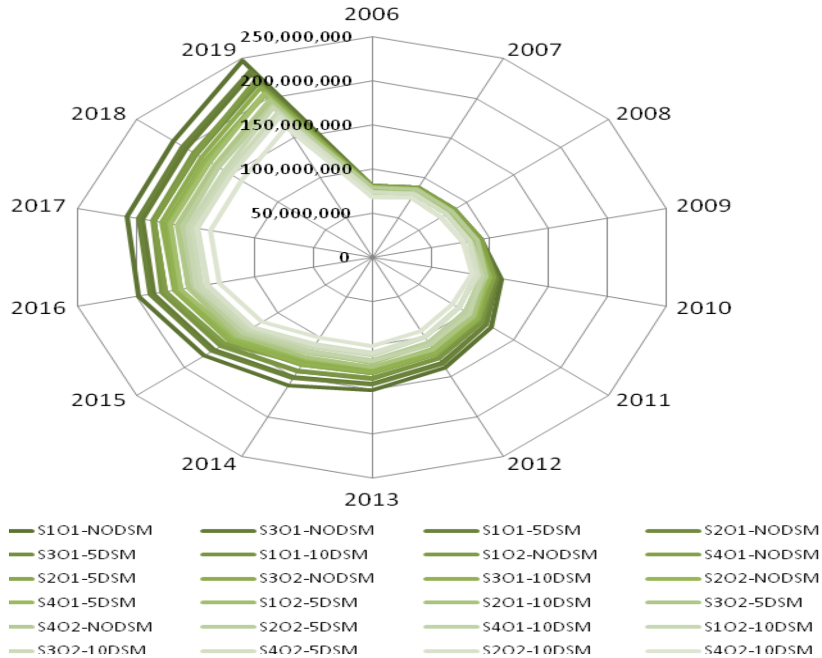
3. Results and discussions

In general, minimizing CO_2 emissions from the power sector is a matter of selecting output combination among the fossil fuel (steam, combine cycle, gas and diesel), because geothermal and hydro power have similar output both under objective 1 and objective 2. However, the major obstacle is how to maximize availability factor from renewable energy especially from hydro power plant[12]. We observe by pursuing objective 2, electricity production from PT.PLN's steam power plant will decrease by 36.5% compare to objective 1. Most of deceasing output from steam power plant will be offset by combine cycle and gas power plant. Further, growing electricity consumption leads to more demand on primary energy supply in the future. Thus, government needs to secure primary energy supply for the power sector such as for coal and gas. Currently to secure primary energy supply, the Ministry of Energy and Mineral Resources issues the ministerial declare on the minimum percentage of coal that need to be provided for domestic uses. Similarly the similar regulation also issued for gas. Thus primary energy supply is managed based on command and control policy.

Figure 1 shows the 24 combinations of CO_2 emission from objective 1 and objective 2 with demand side policy options. As we seen from the figure the grading of color decrease gradually when the emissions decrease. Thus, scenario S1O1-NODSM has the highest emissions, while S4O2-10DSM has the lowest emissions[13]. In 2019, the amount of CO_2 emissions will be between 178.6 and 246.9 million ton or it will increase about 178.6% and 246% respectively compare to the level in 2006. We observe that due to fuel switching strategy, the growth of average emission is lower than the technology switching. However, Indonesia needs to do fuel switching and technology switching simultaneously to reduce rapidly the emissions CO_2 emissions in the future. Next, Indonesia still can reduce CO_2 emissions by implementing the DSM policy. Further, Indonesia still can reduce CO_2 emissions by pursuing CO_2 minimization strategy. As seen from **Figure 1**, under the S1O2-NODSM, emissions will increase from 79 million ton in 2006 to about 223 million ton in 2019 or it increases about 183%. However, under the S4O2-10DSM, the emissions increase from 69 million ton about 163 million ton or it raises about 137%.

[12] Rainfall is very important for hydro power electricity production. Further, land use change over the capture areas and overexploitation of dam also affect water availability.

[13] S1, S2… = scenario 1, 2…; O1 = objective 1, O2 = objective 2; NODSM = no demand side management, 5DSM = 5% demand side management; 10DSM = 10% demand side management. Thus, S1O1-NODSM means scenario 1, objective 1, no demand side management.



Note: we sorted the data base on the average emission between 2006 and 2019

Figure 1 **CO_2 Emissions in ton**

Although CO_2 emissions tend to increase, we observed that the emissions intensity tends to decrease for all the scenarios (**Figure 2**). This is driven by two major factors. First, while oil consumption tends to decrease, natural gas consumption tends to rise. Second, the new power generating will be more efficient in energy consumption or coal consumption to produce one unit MWh can be reduce from about 0.886 ton in 2006 to about 0.838 ton in 2019[14]. Next, as seen from **Figure 3,** we sort emissions intensity from the highest to the lowest. In general, we observe that objective 2 has lower emissions intensity than objective 1 for all the scenarios (except for S4O1-5DSM and S4O1-10DSM that are lower than S1O2-NODSM). This indicates that by conducting fuel switching, technology upgrading, and DSM policy, we expect emission intensity will be lower than minimizing CO_2 without conducting the DSM policy. However we observed that implementation of DSM policy under cost minimization strategy will give more space for steam power plant to increase production due to low generating cost. Thus emissions intensity tends to increase. It is also possible that the DSM policy can have lower emissions intensity than no DSM policy. This is because when output decrease in order to minimize the cost, steam production will increase. Steam production will come from two sources old plant and new plant. Old plants not only have higher emission intensity but also have higher generating cost than the new steam power plant. Thus the DSM policy will give more chance for new plants to operate and we can expect that CO_2 emissions intensity tend to decrease.

[14] In the case of China, coal consumption for coal-fired power plant to generate a unit MWh decreased from 0.370 ton in 2005 to about 0.339 in 2009 (Hu et al, 2011). Similarly with Kahrl at al (2011) that said the Chinese central government agencies have led an effort to shut down small (≤ 50MW) and old (>20 years, ≤200 MW) units, retiring 60.6 GW of these unit between 2006 and 2009. Further, they Kahrl (2011) also said that the average thermal efficiency of coal-fired power plants in China has been able to sustain a linearly increasing trend since the 1960s, and now reportedly surpasses the average efficiency of US coal plants by a significant margin.

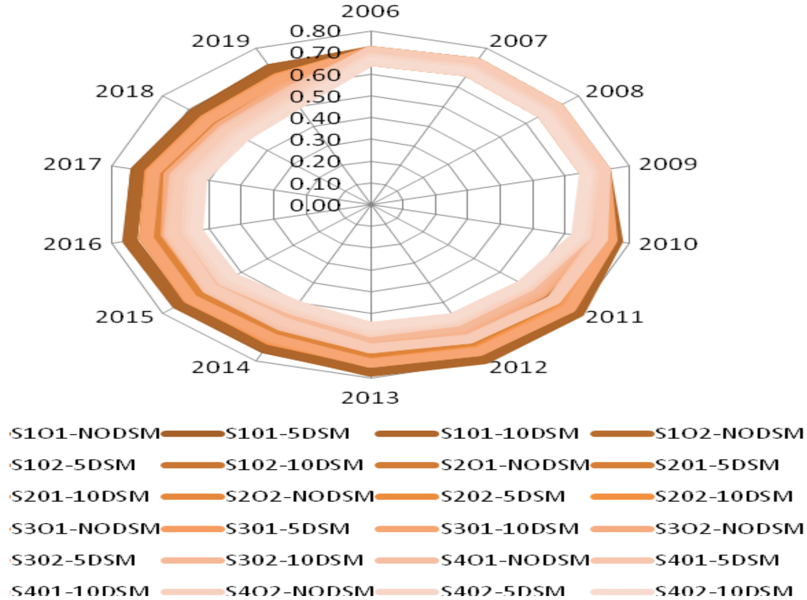


Figure 2 **Emissions intensity (ton CO_2 / MWh)**

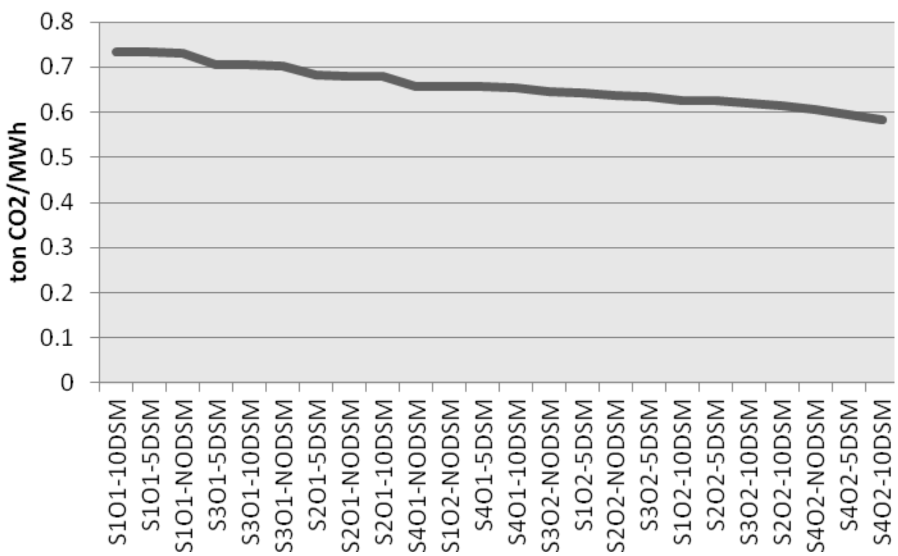


Figure 3 **Average Emissions intensity between 2006 and 2019 (ton CO_2 / MWh)**

As seen from **Figure 4**, pursuing objective 2 can increase diversification index of the system. This is because objective 2 will give more chances for less carbon intensity power plant to operate. In general, we also can argue that under objective 1, implementing the DSM policy can reduce diversification index. This is because the DMS policy will give more chances for high carbon intensity power to operate and this will reduce production from other power plants that have relatively more expensive generating cost. However, in 2014, diversification index with the DSM policy is higher than without the DSM policy. This is because at that year share of production combine cycle, gas and geothermal from PT.PLN PLN tend to increase. This is due to new investment at that period.

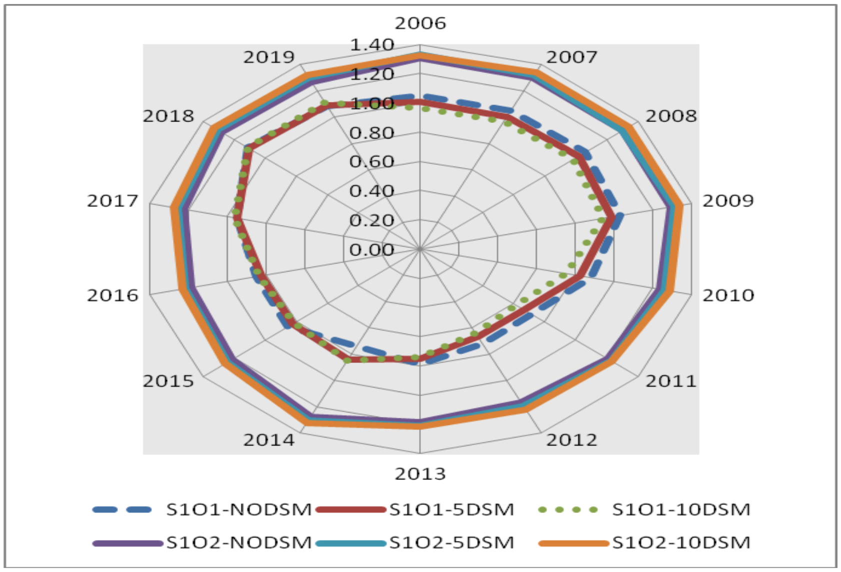


Figure 4 **Diversification index**

In terms of generating cost, objective 2 is more expensive than objective 1, because power plants with less emissions intensity have expensive generating cost (**Figure 5**). Further, we also observe that by implementing the DSM policy, generating cost will be lower than without implementing the DSM policy. We can argue that the price difference between objective 2 and 1 is the premium or extra cost to minimize CO_2 emissions. Comparing objective 1 and 2, the result shows that between 2006 and 2019, the extra cost (average percentage change between objective 2 and 1) increases by 85%.

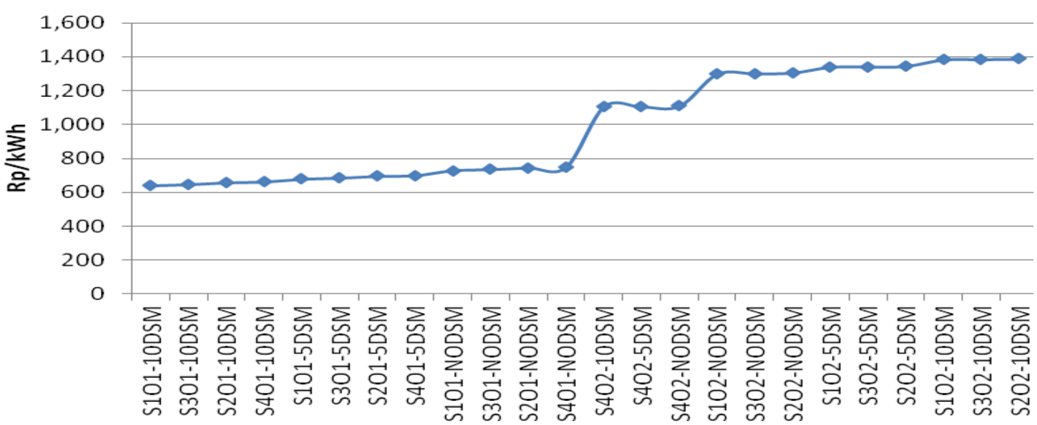


Figure 5 **Average generating costs between 2010 and 2019**

As seen from **Table 2**, between 2010 and 2014 reserve margin tend to decrease. This indicates that new investment cannot cover rapid increase in electricity demand during the peak hour. However, by implementing the DSM policy, reserve margin still can be improved. Further, the reserve margin that is planned by PT.PLN is close to the model estimate when we applied 5% and 10% DSM policy. Finally the model shows that in the future IPP will have greater role to supply electricity for Java-Bali system. This is because following the PT.PLN's business plant scenario, about 36% of additional capacity between 2010 and 2019 will be contributed by private sector and only IPP will develop geothermal power plant in Java-Bali system. Share of renewable energy also tend to increase and in 2014 the share reaches the highest value. This is because in 2014, additional capacity from renewable energy (geothermal and hydro power) obtains the highest value during the planning horizon that is about 2,537 MW and in 2018 it increases about 1,268 MW.

Table 2 **Reserve margin and share of Independent Power Producer (IPP) to total production**

Year	Reserve Margin				Share of IPP to total production	Share of renewable to non renewable		
	NODSM	5%DSM	10%DSM	PLN[1]	S1O1-NODSM	NODSM	5%DSM	10%DSM
2010	37	43	51	34	0.191	0.112	0.117	0.119
2011	29	36	43	41	0.193	0.091	0.095	0.091
2012	26	33	40	40	0.256	0.099	0.100	0.101
2013	22	28	35	35	0.270	0.109	0.116	0.123
2014	26	33	41	43	0.310	0.189	0.201	0.214
2015	34	41	48	35	0.333	0.168	0.179	0.191
2016	33	40	48	35	0.353	0.160	0.170	0.181
2017	27	34	41	34	0.356	0.166	0.176	0.188
2018	35	42	50	35	0.311	0.177	0.188	0.201
2019	22	28	35	35	0.317	0.170	0.181	0.193

Note: NODSM = no demand side management; 5%DSM= 5% demand side management; 10%DSM=10% demand side management; [1]based on PT.PLN's business plan.

4. Recommendations

In general, Indonesia can simultaneously implement fuel switching, technology up grading, conducting the DSM policy and enhancing electricity production from combine cycle and gas power plant to reduce CO_2 emissions. The DSM policy can help Indonesia to reduce CO_2 emissions; even with similar technology and fuel, by implementing 10% DSM, CO_2 emissions from the least cost objective will be lower than minimizing CO_2 without DSM policy. Further, the DSM policy will also reduce generating cost and increase reserve margin. On the other hand, even without implementing the DSM policy, the existing technology still can help Indonesia to reduce emissions, but it can be done at high cost. However, by implementing the DSM policy, there are some risks such as increasing in emissions intensity and decreasing in diversification index. Thus, it is important to complement the DSM policy with emissions intensity and renewable energy targeting.

There are three regulations on the DSM policy: (1) Presidential Instruction No 10/2005, (2) Ministry of Energy and Mineral Resources Regulation (MEMR) No 31/2005, and (3) Government regulation No 70/2009 but there are five main problems on implementation. First, regarding regulation No 1 and 2, energy conservation is base on voluntarily action instead of mandatory action. Second, there are not clearly stated rewards and punishments for take and not to take the actions. Third, due to lack in capacity, personnel and funding, the MEMR could not take proper assessments, monitoring and evaluations[15]. Fourth, there is also lack in program continuation such as electric saving lamp program. Fifth, electricity subsidy can discourage power saving. We suggest that government needs to improve capacity building for monitoring and evaluation. Central and local governments need to set up specific unit or task for evaluating energy saving in electricity sector. This unit needs to collaborate with PT.PLN's units both in central and regional level.

Further, base on the MEMR declare No 1991 K/30/MEM/2011, there is about 82.07 million ton of coal that need to be provided for domestic market in 2012 and share of PT.PLN and IPP is about 57.2% and 10.76% respectively[16]. Further the calorie value for power plant is between 4,000 kcal/kg and 5,200 kcal/kg. Because low rank is cheaper than high rank, due to cost minimization strategy, PT.PLN and IPP will optimize low rank utilization even it has high emissions. Thus, government also needs to encourage high rank utilization for power plant. Alternatively, government can set technology requirement for new coal power plant such as supercritical

[15] The Ministry of Energy and Mineral Resources is helped by four directorate generals, and one of them is Directorate General of New Energy, Renewable and Energy Conservation. Energy conservation is handling by one director.

[16] The regulation said that this amount is about 24.72% from the national coal production.

coal technology by providing more incentives for investment in green technology. Finally, under cost minimization strategy, instead of regulating electricity price from geothermal, government needs to allocate more efforts and incentives in the upstream level to cover exploration risks. Thus, auction on geothermal site will be well informed with a high degree of certainty. This can create more competitive bidding and more space for geothermal utilization in the future without creating price distortion on electricity price.

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