Developing a Green Path Power Expansion Plan in Indonesia by Applying a Multiobjective Optimization Modeling Technique

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Abstract: This paper aims to apply a multiobjective optimization modeling technique to a power expansion problem evaluating two objectives functions: minimizing the power generating cost and minimizing CO_2 emissions, between which there is a tradeoff. A convex curve is obtained representing the relationship between the generating cost (Rp/kWh) and CO_2 emissions (ton). This represents a bad-luck curve where there is an increasing marginal cost to reduce 1 t of CO_2 emissions. This is because most of the less-carbon-intensive power plants consume oil, which has the highest fuel cost. Instead of simply minimizing CO_2 emissions, this paper argues that Indonesia needs to pursue technology to switch from steam coal subcritical technology to supercritical and ultra-supercritical technology to reduce CO_2 emissions. It is further found that the generating cost will increase by less than 1.6% and yearly CO_2 emissions can be reduced by about 6.9% by adopting supercritical technology. This implies that adopting ultra-supercritical technology can cut CO_2 emissions by more than half. A squeezing effect is also found by adopting more-advanced steam coal technology. Thus, promoting renewable energy and gas utilization also should be enhanced. The green path power system allows both CO_2 emissions and the generating cost to increase gradually, but with lower CO_2 emissions than by minimizing the generating cost alone. It is thereby proposed that the current feed-in tariff for renewable energy also needs to be supported with an emissions reduction target. **DOI: 10.1061/(ASCE)EY.1943-7897.0000392.**

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Introduction

An electric power supply is one of the most important and fundamental elements for sustaining national economic growth and competitiveness. In 2009, electricity consumption per capita reached 590 kWh, but the Indonesian government has a target of increasing electricity consumption per capita to about 2,500 kWh in 2025 and 7,000 kWh in 2050 (Soerawidjaja 2011). The Indonesian government has attempted to increase the national installed capacity by implementing its first fast-track program. The program aims to promote energy diversity from oil to coal, gas, and renewable energy. The fast-track program also aims at reducing the burden of electricity subsidies as the power system will be designed to consume less oil.

Based on the work plan of the fast-track program in 2014, the share of steam power plants (coal based) in the total installed capacity would rise from about 48.8% in 2006 to about 63% in 2014 (Sambodo and Oyama 2010). This also indicates that coal will become the backbone of the primary energy supply for the national electricity system. Currently, electricity and heat contribute the most to CO_2 emissions from the energy sector and the share will increase in the future if planned systems depend on carbon-intensive sources (Sambodo and Oyama 2012). Thus, the power system will be trapped in a carbon lock-in situation if there is no well-designed green power system in the future.

Although Indonesia does not have a binding CO_2 emissions target, it has shown strong commitment to ease CO_2 emissions. Following the Copenhagen 15th Conference of the Parties (COP15) on January 30, 2010, Indonesia has planned to voluntarily reduce CO_2 emissions by 26% with domestic efforts and 41% with international support by 2020. According to the Ministry of Finance, this means reductions of around 6 and 24%, respectively, below the 2005 total national emissions levels (Ministry of Finance and Australia Indonesia Partnership 2009). This reduction covers seven major areas, namely peat-land, forestry, agriculture, energy, industry, transportation, and waste. Further, the government also followed up on the emissions target by issuing Presidential Regulation 61, Year 2011 on the National Action Plan for Greenhouse Gas Emissions Reduction (Republic of Indonesia 2011b). However, evidence from the energy sector indicates that although in the short-term, a 1% increase in the total primary energy supply (TPES) will increase CO_2 emissions by 0.82%, while in the long run, it will increase to around 1.0% (Sambodo and Oyama 2012). This implies that Indonesia needs more-robust strategies to ease the growth of CO_2 emissions in the future. However, it is still unclear what the consequences from pursuing a green power system are and what Indonesia needs to prepare in order to ease the transition to a low-carbon power system.

This paper aims to evaluate the tradeoff between minimizing both generating costs and CO_2 emissions. Furthermore, the possibility of implementing a constraint on CO_2 emissions into the

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power system is evaluated. A mathematical programming model is built to obtain an optimal power expansion plan, and then an attempt is made to narrow down the analysis of the power-generating sector in the Java-Bali system. The Java-Bali region was picked as the area of focus for four reasons. First, following the fast-track program, the Java-Bali system obtained the highest share of additional capacity (Sambodo and Oyama 2010). Second, currently the share of installed capacity in the Java-Bali region is about 71% of the national power capacity, and the share of electricity production relative to national production is about 76.5% (PT.PLN 2011). Third, the Java-Bali system is coincident, while outside of Java-Bali, it is noncoincident. Finally, about 50% of CO_2 emissions from the energy sector are driven by the power sector (Sambodo and Oyama 2012). Thus, pursuing a green path for the power system in the Java-Bali system can contribute significantly to reducing CO_2 emissions at the national level.

Data and Scenarios

Electricity Demand

Electricity demand is usually expressed by the load duration curve (LDC). Basically, LDC represents the demand for electricity that corresponds with a specific time period (Rowse 1978) and generation capacity must be sufficient to meet this demand (Meier 1984). The area under the LDC represents the electricity-production requirements in megawatt-hours. Although the LDC can usually be expressed by a nonlinear function, the LDC is here linearized by a step function in order to deal with the electricity demand for using a linear programming optimization model. There are several methods for forecasting the LDC such as applying an artificial neural network (ANN) to forecast the long-term peak-load forecasting (Tanoto et al. 2010) and the Elman-Recurrent Neural Network (RNN) (Suhartono and Endharta 2009). Previous studies only provide information on the peak load; however, the present study assumes that the yearly electricity consumption pattern between 2007 and 2020 follows the pattern in 2006. This study uses the daily load duration curve from November 21, 2006, in the Java-Bali system when the load was at a maximum for the annual demand. However, it is important to monitor daily movement to check how robust the assumptions are as, for example, an increase in gross domestic product (GDP) per capita or income can affect the pattern of the LDC.

Fig. 1 shows the daily curve of Perusahaan Listrik Negara (PT.PLN)/State Electricity Company at the Java-Bali system. PT.PLN is a state-owned company in the power sector in Indonesia, being responsible for improving the electrification ratio at the national level. Currently, PT.PLN does not hold single authority to conduct business. The peak time appears between 7:00 and 8:00 p.m., reaching about 15,000 MW. After 8:00 p.m., electricity consumption tends to decrease gradually. The yearly LDC is divided into five blocks: (1) Block 1 represents peak hours; (2) Block 2 represents Intermediate 1; (3) Block 3 represents Intermediate 2; (4) Block 4 represents Intermediate 3; and (5) Block 5 represents the base load (Fig. 1).

Capacity Planning

Between 2011 and 2020, the additional capacity in the Java-Bali system will increase by about 32,147 MW, and PT.PLN will add about 18.462 MW, while the independent power producer (IPP) will add about 13,685 MW (PT.PLN 2011). Steam power plants will have the highest contribution in terms of the additional capacity. About 70% of the additional capacity will come from steam-coal power plants (PT.PLN 2011). Additional capacity from geothermal and combined-cycle plants will increase at a similar level of about 2.8 GW (PT.PLN 2011). Additional capacity from solar panels will increase significantly, because the government has special programs to promote solar panels, such as the 100% Solar Panel for 100 Islands program.

The share of IPP to total installed capacity will increase to about 32% in 2020 while it was about 17% in 2010. Furthermore, the share of renewable energy is expected to slightly increase to about 16.7% in 2020 while it was about 15.4% in 2010 (PT.PLN 2011). The shares of hydropower and geothermal plants are expected to decrease from about 15.4% in 2010 to about 12.3% in 2020 (PT.PLN 2011). Thus an increase in the share of renewable energy is mainly driven by the additional capacity from the solar panels. In fact, PT.PLN does not count electricity production from the solar panels in its business plan. This may be because electricity production from solar panels will not be connected to the national grid system. The share of the electricity production from hydropower and geothermal power between 2010 and 2020 will increase from about 10.6% to about 14.3% (PT.PLN 2011). This is because the share of electricity production of geothermal power tends to increase rapidly while the share of hydropower tends to decrease. The share of installed capacity from renewable energy tends to decrease while the share of its production tends to increase as geothermal power has a relatively higher level-of-availability factor compared to the other types.

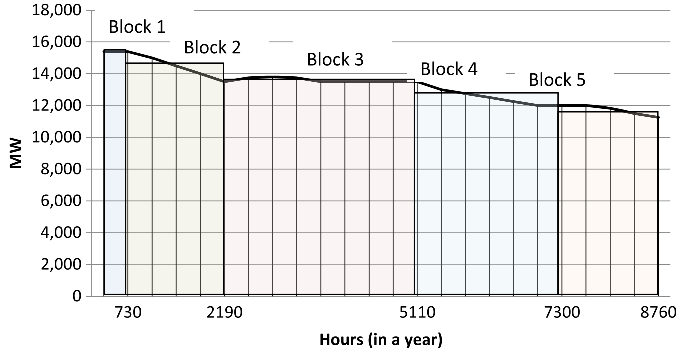


Fig. 1. Yearly load duration curve (LDC) in the Java-Bali region in 2006

Generating Costs

Two types of power plants are defined in this study: old and new. Old power plants are those operated before 2010, while new power plants will operate between 2011 and 2020. An autoregressive moving average model (ARMA) is applied to estimate the generating cost for each type of old plant between 2010 and 2020. The ARMA model is adopted for the old power plants to use a series of detailed generating cost data for each type of power plant during the period from 2011 to 2020. The ARMA model also allows the upper and lower bounds for generating cost to be obtained, which helps in applying sensitivity analysis. In estimating the generating cost for the new plants, the levelized busbar cost formula is applied. New power plants are not supposed to consume oil while the oil cost is embedded in ARMA. It is also assumed that old power plants still consume oil. Regarding the generating cost for new geothermal plants, the Ministry of Energy and Mineral Resources (MEMR) Regulation 2/2011 (Republic of Indonesia 2011a) is adopted, which states, "PT.PLN has to buy electricity from geothermal power plants at a cost of 9.70 cent US$/kWh" or about Rp 873/kWh. On August 16, 2012, MEMR issued new Regulation

22/2012, superseding Regulation 2/2012. PT.PLN needs to purchase electricity from geothermal plants at US\$11.00/kWh (US\$12.50/kWh), assuming US\$1.00 = Rp 9,000, if it is connected with high (medium) voltage. Furthermore, according to the MEMR Regulation 04/2012 on the purchasing price from medium-scale and small-scale producers of renewable energy, the purchasing price depends on interconnection. For example, connection to the medium voltage is Rp 656/kWh multiplied by F, where F represents an incentive factor, e.g., in Java-Bali $F = 1.0$; in Sumatera and Sulawesi, $F = 1.2$; in Kalimantan, West Nusa Tenggara, and East Nusa Tenggara, $F = 1.3$; in Maluku and Papua $F = 1.5$; and interconnection to the low voltage is also Rp 1,004/kWh multiplied by F. An average value of about Rp 917/kWh is used in this study. In addition, because there is no regulation for generating costs from small-scale coal and gas plants, it is treated as excess power. According to MEMR Regulation 04/2012, PT.PLN has to buy excess power at a rate of Rp 656/kWh multiplied by F if it is interconnected with medium voltage and Rp 1,004/kWh multiplied by F if it is connected with low voltage. For simplicity, an average value of about Rp 917/kWh is assumed.

CO_2 Emissions

CO_2 emissions intensity is calculated for each type of power plant by applying the following formula (Graus and Worrell 2011):

$$CO_2 - \text{INTENSITY}_j = \sum_1^n (C_i I_i)/P_j \tag{1}$$

where i = fuel source $1, \ldots, n$; $C_i = CO_2$ emission factor per fuel source (IPCC 2006) (t CO_2/TJ); I_i = fuel input per fuel source (TJ); and P_j = power production per fuel source (GWh) for plant j. Thermal efficiency is also important to determine the level of CO_2 emissions (IEA 2009). With proper maintenance, power plants can operate at the design level. This study assumes that power plants are properly maintained and the level of CO_2 emissions is determined by fuel consumption.

Scenarios

The baseline scenario, or the business-as-usual (BAU) scenario, assumes that the new steam-coal power plants use subcritical technology, there is no demand-side management (DSM) policy, and fuel costs remain constant. Then the proposed definition of the policy scenarios is based upon the following assumptions. First, there is a possibility of implementing the DSM policy, assuming that electricity consumption can be reduced by 5 and 10% for each demand block [PT.PLN (Persero) does not include energy efficiency and DSM in their business plant]. Second, for new power plants, possible steam-coal power technologies are also applied: subcritical, supercritical, and ultra-supercritical. Detailed data on these technologies are given in Table 1, which provides detailed information on subcritical, supercritical, and ultra-supercritical power plants.

Following PT.PLN's business plan, fluctuations in oil prices will not significantly affect the generating cost as the share of electricity production from oil is small. Thus, using the lower bound in the ARMA model is preferred. Although in its business plan, PT. PLN has shown strong commitment to reducing oil consumption, in reality, there are three major constraints that lead PT.PLN to use oil (PT.PLN 2012): (1) the supply of gas is lower than the demand; (2) there are delays and cancellations in the development of the gas infrastructure; and (3) there are delays in the first fast-track program. While assessing two scenarios, a sensitivity analysis was also conducted when the price of coal and gas increased by 100%.

Optimization Model For Determining Future Electric Power Expansion

In developing the mathematical programming model, previous studies are referred to, including Anderson (1972), Shrestha and Marpaung (1999, 2006), Rachmatullah et al. (2007), and Sarker and Newton (2008). The proposed model is characterized in the following areas: (1) including the fast-track program; (2) promoting technology and a fuel-switching approach and carbon constraint

Table 1. Generating Cost for a New Power Plant

Description	Unit	Steam subcritical	Steam supercritical	Steam ultra-supercritical
Life	Year	30	30	30
Discount rate	%	12	12	12
Recovery factor	—	0.124	0.124	0.124
Investment cost	million USD	1,200	1,400	1,600
Capital cost/year	million USD/year	148.97	173.80	198.63
Capital cost	USD/kW	1,200	1,400	1,600
Capacity	MW	1,000	1,000	1,000
Capacity factor	%	80	80	80
Production	GWh	7,008	7,008	7,008
Fuel type (pure)	—	Coal lignite	Coal lignite	Coal lignite
SFC gas (SFC coal)	Mscf/kWh(kg/kWh)	(0.5388)	(0.4875)	(0.427)
Heat content	kcal/Mscf(kcal/kg)	(4,200)	(4,200)	(4,200)
Efficiency (net, LHV)	%	38	42	48
Heat rate	kcal/kWh	2,263	2,048	1,792
Fuel consumption	Mscf (t)	(3,776,241)	(3,416,599)	(2,989,524)
Fuel cost	million USD/year	188.81	170.83	149.5
Capacity charge	Cent/kWh	2.13	2.48	2.83
O&M fix	Cent/kWh	0.34	0.40	0.46
Fuel cost	Cent/kWh	2.69	2.44	2.13
O&M var	Cent/kWh	0.08	0.07	0.06
Total cost	Cent/kWh	5.24	5.39	5.49
Total cost	Rp/MWh	471,600	485,100	494,100
Carbon intensity	tonCO_2/MWh	0.98	0.88	0.77

Note: LHV = lower heating value; Mscf = million standard cubic feet for gas; O&M = operation and maintenance cost.

Table 2. Indices for Old and New Power Plants

Indices	Definitions	Correspondences
i	Old plant: fossil fuel	$i = 1$ (steam); $i = 2$ (combined cycle); $i = 3$ (gas turbine); $i = 4$ (diesel)
j	Old plant: nonfossil fuel	$j = 1$ (geothermal); $j = 2$ (hydro)
k	New plant: fossil fuel	$k = 1$ (steam); $k = 2$ (combined cycle); $k = 3$ (gas turbine)
l	New plant: nonfossil fuel	$l = 1$ (geothermal); $l = 2$ (hydro); $l = 3$ (solar panel); $l = 4$ (micro hydro)
p	For the LDC block	$p = 1$ peak hours; $p = 2$ intermediate 1; $p = 3$ intermediate 2; $p = 4$ intermediate 3; $p = 5$ base load

instead of a carbon tax; (3) separating the player PT.PLN from IPP; (4) introducing a renewable energy preference; and (5) dealing with two objective functions, i.e., minimizing the generating cost and minimizing CO_2 emissions.

Indices and Parameters

Indices and parameters are denoted as indicated in Tables 2 and 3.

Decision Variables

Decision variables for determining electricity production are defined corresponding to the respective type of power plant for each block in the approximate LDC (Table 4). There are two main sources, old and new, for electricity production. As the present study is more interested in promoting renewable energy, electricity production is split into renewable and nonrenewable energy. Thus, eight decision variables are obtained as given in Table 3.

Constraints

Capacity Constraints

The 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. According to the Glossary of Nuclear terms (Koelzer 2012), availability factor is a measure of the ability of power plants, unit, or plant section to perform its operational function. For old power plants, the following capacity conditions are defined:

$$\begin{aligned}
\mathrm{OutF}_{ip} &\leq \mathrm{AFF}_i \times \mathrm{CEF}_i \times \mathrm{TD}_p \forall i, p \\
\mathrm{OutFP}_{ip} &\leq \mathrm{AFFP}_i \times \mathrm{CEFP}_i \times \mathrm{TD}_p \forall i, p \\
\mathrm{OutNF}_{jp} &\leq \mathrm{AFNF}_j \times \mathrm{CENF}_j \times \mathrm{TD}_p \forall j, p \\
\mathrm{OutNFP}_{jp} &\leq \mathrm{AFNFP}_j \times \mathrm{CENFP}_j \times \mathrm{TD}_p \forall j, p
\end{aligned} \tag{2}$$

For new power plants, the following capacity constraints need to be met:

$$\begin{aligned}
&\mathrm{OutNEWFP}_{kp} \leq \mathrm{AFFPN}_k \times \mathrm{ADDFP}_k \times \mathrm{TD}_p \forall k, p \\
&\mathrm{OutNEWNF}_{lp} \leq \mathrm{AFNFN}_l \times \mathrm{ADDNF}_l \times \mathrm{TD}_p \forall l, p \\
&\mathrm{OutNEWNFP}_{lp} \leq \mathrm{AFNFP}_l \times \mathrm{ADDNFP}_l \times \mathrm{TD}_p \forall l, p \\
&\mathrm{OutNEWF}_{kp} \leq \mathrm{AFFN}_k \times \mathrm{ADDF}_k \times \mathrm{TD}_p \forall k, p
\end{aligned} \tag{3}$$

Primary Energy Supply Constraint for Fossil Fuel

The total output from a fossil-fuel power plant cannot exceed the fuel consumption (*fuelcons*) after controlling for the possibility of the energy requirement (*req.fos*) during the process of energy transformation

Table 3. Parameters

Category	Symbol	Definition
Electricity demand	TD_p	Duration of load block p in hours
	PD_p	Maximum power demand in MWh in a load block p
Generating cost (Rp/MWh)	VCF_i	Old fossil fuel power plant type i—PT.PLN
	VCNF_j	Old nonfossil fuel power plant type j—PT.PLN
	VCFP_i	Old fossil fuel power plant type i—IPP
	VCNFP_j	Old nonfossil fuel power plant type j—IPP
	VCFN_k	New fossil fuel power plant type k—PT.PLN
	VCFNP_k	New fossil fuel power plant type k—IPP
	VCNFNP_l	New nonfossil fuel power plant type l—IPP
Capacity (MWh)	CEF_i	Existing old fossil fuel power plant type i—PT.PLN
	CENF_j	Existing old nonfossil fuel power plant type j—PT.PLN
	CEFP_i	Existing old fossil fuel power plant type i—IPP
	CENFP_j	Existing old nonfossil fuel power plant type j—IPP
	ADDF_k	New capacity for fossil fuel power plant type k—PT.PLN
	ADDNF_l	New capacity for nonfossil power plant type l—PT.PLN
	ADDFP_k	New capacity for fossil fuel power plant type k—IPP
	ADDNFP_l	New capacity for nonfossil power plant type l—IPP
Availability factor	AFF_i	Old fossil fuel power plant type i—PT.PLN
	AFNF_j	Old nonfossil fuel power plant type j—PT.PLN
	AFFP_i	Old fossil fuel power plant type i—IPP
	AFNFP_j	Old nonfossil fuel power plant type j—IPP
	AFFN_k	New fossil fuel power plant type k—PT.PLN
	AFNFN_l	New nonfossil fuel power plant type —PT.PLN
	AFFPN_k	New fossil fuel power plant type k—IPP
	AFNFP_l	New nonfossil fuel power plant type l—IPP
CO_2 emissions intensity ($\mathrm{t\,CO_2/MWh}$)	$EI1_i$	Old fossil power plants type i
	$EI2_k$	New fossil power plants type k

Table 4. Decision Variables

Electricity production (MWh)	Symbol	Definition
Old plant	OutF_{ip}	Fossil fuel power plant of type i in block p—PT.PLN
	OutNF_{jp}	Nonfossil fuel power plant of type j in block p—PT.PLN
	OutFP_{ip}	Fossil fuel power plant of type i in block p—IPP
	OutNFP_{jp}	Nonfossil fuel power plant of type j in block p—IPP
New plant	$\mathrm{OutNEWF}_{kp}$	Fossil fuel power plant of type k in block p—PT.PLN
	$\mathrm{OutNEWNF}_{lp}$	Nonfossil fuel power plant of type l in block p—PT.PLN
	$\mathrm{OutNEWFP}_{kp}$	Fossil fuel power plant of type k in block p—IPP
	$\mathrm{OutNEWNFP}_{lp}$	Nonfossil fuel power plant of type l in block p—IPP

$$\sum_{i=1}^{I}\sum_{p=1}^{P}(\mathrm{OutF}_{ip}+\mathrm{OutFP}_{ip})+\sum_{k=1}^{K}\sum_{p=1}^{P}(\mathrm{OutNEWF}_{kp}+\mathrm{OutNEWFP}_{kp})\leq \mathrm{req.fos}\times \mathrm{fuelcons} \tag{4}$$

Primary Energy Supply Constraint for Nonfossil Fuel

The total output from a nonfossil power plant cannot exceed the primary energy supply (*primaryenergy*) that is devoted to produce electricity for each type of power plant after adjusting the possibility of the energy requirement (*req.nonfos*) during the transformation

$$\sum_{j=1}^{J}\sum_{p=1}^{P}(\mathrm{OutNF}_{jp}+\mathrm{OutNFP}_{jp})+\sum_{l=1}^{L}\sum_{p=1}^{P}(\mathrm{OutNEWNF}_{lp}+\mathrm{OutNEWNFP}_{lp})\leq \mathrm{req.nonfos}\times \mathrm{primaryenergy} \tag{5}$$

Demand Satisfaction Constraint

Electricity production at each load block must satisfy the demand. The DSM policy is implemented, reducing each load block area (PD) by 5 and 10%, respectively. The DSM policy will shift down the load curve due to energy efficiency and energy conservation. Energy efficiency refers to the adoption of a specific technology that reduce overall energy consumption without changing the relevant behavior while energy conservation implies merely a change in the consumer's behavior (Oikonumou et al. 2009). There is a possibility of replacing inefficient appliances in the residential sector such as replacing incandescent lamps with fluorescent lamps (CFL) and replacing standard motors with energy-efficient motors (Shrestha and Marpaung 2006). Worldwide experiences "have proved that DSM is useful for energy efficiency on the consumer side and could be the first priority in face of climate challenge" (Hu et al. 2011). In Indonesia, the relationship between electricity consumption and economic growth shows that the electricity conservation policy will have no significant impact on economic growth (Sambodo and Oyama 2011). The DSM also contributes to energy efficiency, which has several benefits: reduced exposure to rising international energy prices, energy cost saving for end-users, lower need for expensive energy infrastructure, lower local pollution, and lower CO_2 emissions (IEA 2009). Some of the DSM might involve load shifting, i.e., intertemporal substitution between blocks when prices are high in peaking periods

$$\sum_{i=1}^{I}(\mathrm{OutF}_{ip}+\mathrm{OutFP}_{ip})+\sum_{k=1}^{K}(\mathrm{OutNEWF}_{kp}+\mathrm{OutNEWFP}_{kp})+\sum_{j=1}^{J}(\mathrm{OutNF}_{jp}+\mathrm{OutNFP}_{jp})+\sum_{l=1}^{L}(\mathrm{OutNEWNF}_{lp}+\mathrm{OutNEWNFP}_{lp})\geq \mathrm{PD}_p\,\forall p \tag{6}$$

Constraint on Contract Agreement for Fossil Fuel

PT.PLN needs to purchase a certain amount of power supply from IPP. A purchase parameter (*purchase*) is therefore introduced that shows the minimum share that can be purchased by PT.PLN from an IPP (the parameter is estimated using actual data from between 2006 and 2009)

$$\sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{OutFP}_{ip}+\sum_{k=1}^{K}\sum_{p=1}^{P}\mathrm{OutNEWFP}_{kp}\geq \mathrm{purchase}\times\left(\sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{OutF}_{ip}+\sum_{k=1}^{K}\sum_{p=1}^{P}\mathrm{OutNEWF}_{kp}+\sum_{j=1}^{J}\sum_{p=1}^{P}\mathrm{OutNF}_{jp}+\sum_{l=1}^{L}\sum_{p=1}^{P}\mathrm{OutNEWNF}_{lp}\right) \tag{7}$$

Constraint on Contract Agreement for Nonfossil Fuel

As PT.PLN needs to buy electricity from renewable resources, a new parameter on the renewable contract agreement (*purchaserew*) needs to be set. The simulation attempts to obtain the highest possible parameter value for *purchaserew* by gradually increasing it

$$\sum_{j=1}^{J}\sum_{p=1}^{P}\mathrm{OutNFP}_{jp}+\sum_{l=1}^{L}\sum_{p=1}^{P}\mathrm{OutNEWNFP}_{lp}\geq \mathrm{purchasere}\,w\times\left(\sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{OutF}_{ip}+\sum_{k=1}^{K}\sum_{p=1}^{P}\mathrm{OutNEWF}_{kp}+\sum_{j=1}^{J}\sum_{p=1}^{P}\mathrm{OutNF}_{jp}+\sum_{l=1}^{L}\sum_{p=1}^{P}\mathrm{OutNEWNF}_{jp}\right) \tag{8}$$

Constraint on Promoting Renewable Energy

Every simulation attempts to obtain the highest preferences of the renewable energy parameter. It is assumed that there are flexibilities to set the share of renewable energy in the power system. The parameter preference for renewable energy is *pref*

$$\sum_{j=1}^{J}(\mathrm{OutNF}_{jp}+\mathrm{OutNFP}_{jp})+\sum_{l=1}^{L}(\mathrm{OutNEWNF}_{lp}+\mathrm{OutNEWNFP}_{lp})\geq \mathrm{pref}\times\left[\sum_{i=1}^{I}(\mathrm{OutF}_{ip}+\mathrm{OutFP}_{ip})+\sum_{k=1}^{K}(\mathrm{OutNEWF}_{kp}+\mathrm{OutNEWNFP}_{kp})\right]\forall p \tag{9}$$

Objective Function

Two types of criteria are considered, represented by minimizing the generating cost (Objective 1) and minimizing CO_2 emissions

(Objective 2), respectively. First, the generating cost for both old and new plants (Y_1) is minimized. As the Indonesian government still provides electricity subsidies, minimizing the generating cost will lead to minimizing them. PT.PLN's business plan also aims at minimizing the generating cost, which can be expressed as follows:

$$\begin{aligned}\text{Minimize } Y_1 = &\sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{VCF}_i \times \mathrm{OutF}_{ip} + \sum_{j=1}^{J}\sum_{p=1}^{P}\mathrm{VCNF}_j \\ &\times \mathrm{OutNF}_{jp} + \sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{VCFP}_i \times \mathrm{OutFP}_{ip} \\ &+ \sum_{j=1}^{J}\sum_{p=1}^{P}\mathrm{VCNFP}_j \times \mathrm{OutNFP}_{jp} + \sum_{k=1}^{K}\sum_{p=1}^{P}\mathrm{VCFN}_k \\ &\times \mathrm{OutNEWF}_{kp} + \sum_{l=1}^{L}\sum_{p=1}^{P}\mathrm{VCNFN}_j \times \mathrm{OutNEWNF}_{lp} \\ &+ \sum_{k=1}^{K}\sum_{p=1}^{P}\mathrm{VCFNP}_k \times \mathrm{OutNEWFP}_{kp} \\ &+ \sum_{l=1}^{L}\sum_{p=1}^{P}\mathrm{VCNFNP}_j \times \mathrm{OutNEWNFP}_{lp} \qquad (10)\end{aligned}$$

Similarly, the total CO_2 emissions minimization criteria can be expressed by the following objective function (Y_2), which aims at minimizing the amount of CO_2 emissions both from old and new power plants for each block of power demand:

$$\begin{aligned}\text{Minimize } Y_2 = &\sum_{i=1}^{I}\sum_{p=1}^{P} EI1_i \times (\mathrm{OutF}_{ip} + \mathrm{OutFP}_{ip}) + \sum_{k=1}^{K}\sum_{p=1}^{P} EI2_k \\ &\times (\mathrm{OutNEWF}_{kp} + \mathrm{OutNEWFP}_{kp}) \qquad (11)\end{aligned}$$

Minimizing the generating cost is combined with minimizing CO_2 emissions in order to develop the green path power system. The computational procedure consists of three steps:

1. Calculate total CO_2 emissions from the optimal solution obtained from minimizing the generating cost, where the upper bound (UB) is assumed;
2. Similarly, calculate total CO_2 emissions from minimizing CO_2 emissions, where the lower bound (LB) is assumed; and
3. Solve the generating-cost-minimization problem by adding the bounding constraint for CO_2 emissions. Start with the lower bound (LB), then increase the bound of CO_2 emissions gradually. Here, total CO_2 emissions are increased by 1 million units until reaching the upper bound (UB). Thus, the relationship between generating-cost minimization and CO_2 emissions minimization can be found

$$\begin{aligned}&\sum_{i=1}^{I}\sum_{p=1}^{P}\mathrm{EI}_i \times (\mathrm{OutF}_{ip} + \mathrm{OutFP}_{ip}) + \sum_{k=1}^{K}\sum_{p=1}^{P} EI_k \\ &\times (\mathrm{OutNEWF}_{kp} + \mathrm{OutNEWFP}_{kp}) \le UB \qquad (12)\end{aligned}$$

Numerical Results

Business-as-Usual Scenario

Fig. 2 shows the optimal solution for minimizing the generating cost. More than 70% of electricity production, reaching about 85% in 2012, is supplied by steam power plants. New additional

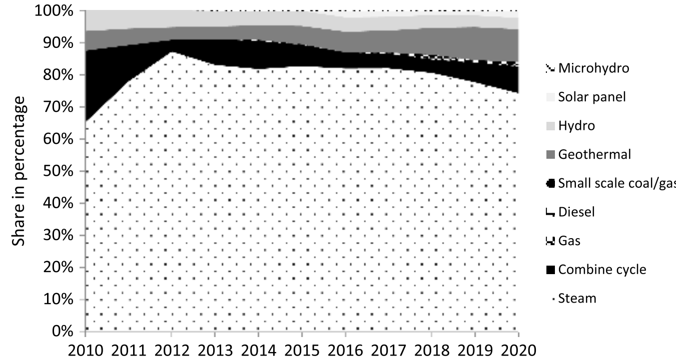


Fig. 2. Share of electricity production from minimizing generating costs (subcritical scenario)

capacity from geothermal plants also tends to increase while the share of electricity production from combined-cycle plants in 2020 will be lower than that in 2010. Furthermore, there is no electricity production from diesel power plants as they are the most expensive. Thus PT.PLN does not plan to construct any new diesel power plants. However, in 2014, PLN rented diesel power plants to produce 1,946 GWh while in 2010, rented diesel plants produced about 3.2 GWh. Therefore, it is expected that there will be more rented diesel power plants utilized outside Java-Bali.

The composition of electricity production will change rapidly if decision makers prefer to prioritize minimizing CO_2 emissions (Fig. 3). The share of steam production would increase from about 40% in 2010 to about 45% in 2020 even though the share itself is much lower than the cost-minimization case given in Fig. 2. On the other hand, others types of power plants will take the offer of the rapid growth if the government pursues minimizing CO_2 emissions. Combined-cycle and gas plants will become important to support the system, while the shares of geothermal power, hydropower, and solar panels will also tend to increase. However, the availability of gas is the key factor in boosting electricity production from combined-cycle and gas power plants. The proposed model does not separate the primary energy supply by source (coal, oil, and gas); instead all three elements are totaled.

As seen from Fig. 4 based on the subcritical scenario, CO_2 emissions will increase from about 104 million t in 2010 to about 222 million t in 2020, an increase of about 113.5% within 10 years. In 2010, more than 76% of CO_2 emissions was contributed by PT. PLN's power plants, but in 2020, it will decrease to about 50.5%. However, as seen from Fig. 5, the yearly CO_2 emissions under a

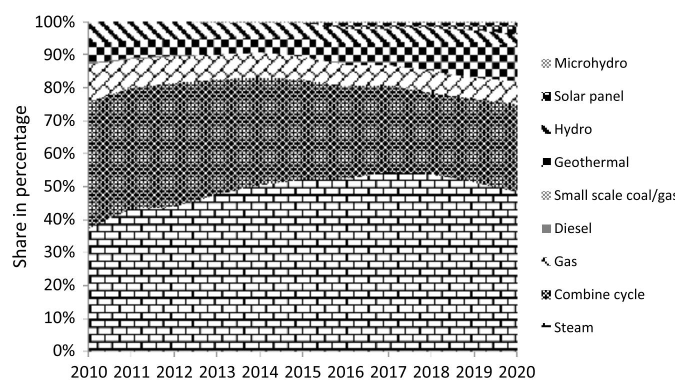


Fig. 3. Share of electricity production from minimizing CO_2 emissions (subcritical scenario)

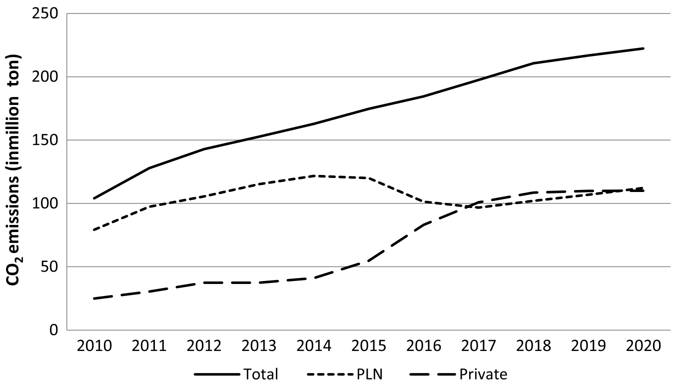


Fig. 4. CO_2 emissions from minimizing generating costs (subcritical scenario)

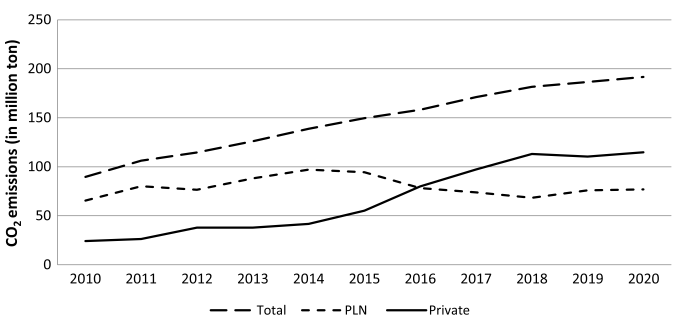


Fig. 5. CO_2 emissions from minimizing CO_2 emissions (subcritical scenario)

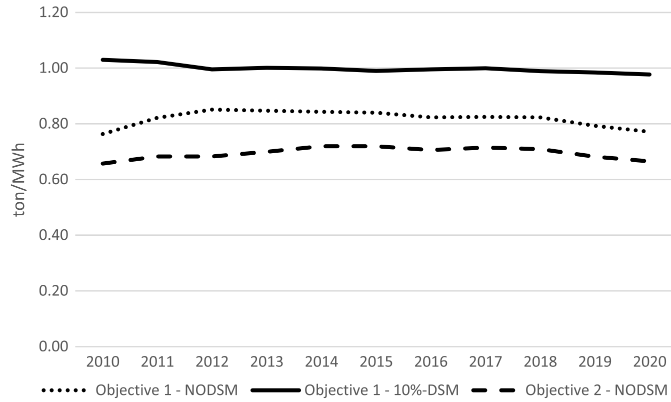


Fig. 6. Emissions intensity (t/MWh) subcritical scenario, minimizing generating costs

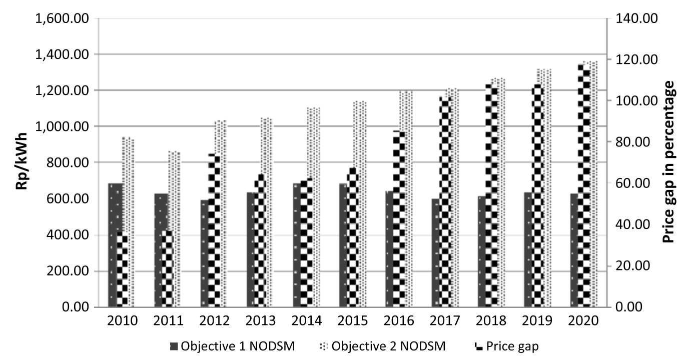


Fig. 7. Generating costs and percentage of price gap

strategy of minimizing CO_2 emissions is about 15% lower than that of minimizing the generating cost. Further, as seen from Fig. 5, only PT.PLN has more capacity to reduce CO_2 emissions. This is because PT.PLN has more capacity in combined-cycle and gas power plants than IPP. Thus, under the CO_2 minimization strategy, about 60% of CO_2 emissions will be driven by IPP.

More than 95% of CO_2 emissions are driven by steam power plants. Thus, upgrading steam technology from subcritical to supercritical and ultra-supercritical is necessary to reduce CO_2 emissions. Emissions intensity tends to decrease especially after 2015 for two reasons (Fig. 6). First, new power plants with lower emissions intensity, such as combined-cycle and gas, will start to operate. Second, more than 2.8 GW of new geothermal power plants will start to work, and more than 2.4 GW of solar panels will also support the system.

The average emissions intensity between 2010 and 2020 for minimizing the generating cost with 10% demand-side management is about 0.82 t/MWh, while the case without demand side management is about 1 t/MWh, and that for minimizing CO_2 emissions is about 0.69 t/MWh. (Fig. 6). Emissions intensity from minimizing CO_2 emissions is 15% lower than that of minimizing the generating cost. The Energy United Kingdom (U.K.) White Paper (DECC 2011) suggest that the emissions performance standard (EPS) for new power stations at about 450 g CO_2/kWh (Newbery 2012). In the case of Japan, as part of Keidanren Voluntary Action to cope with global warming from fiscal year 2008 to 2012, the government attempted to reduce emissions approximately 20% from fiscal year (FY) 1990 to about 0.34 kg CO_2 per kWh, and the current level is 0.410 kg CO_2 per kWh (IEA 2008).

It is important to set up emissions-intensity targeting because the emissions intensity in the Java-Bali system is relatively higher than in developed countries. Under minimizing the generating cost, although the DSM can reduce the total CO_2 emissions, the emissions intensity with the DSM is 22.5% higher than without the DSM. This is because by implementing the DSM, there will be more opportunities to reduce the cost, and steam power plants with the lowest cost will increase while electricity production decreases.

As seen from Fig. 7, the strategy of minimizing the generating cost will decrease the cost from about Rp 687/kWh in 2010 to about Rp 625/kWh in 2020. This is because newer steam power plants have lower generating costs than old power plants. Furthermore, as seen in Fig. 7 minimizing CO_2 emissions will lead to much higher generating costs. The price gap between the two objectives will also tend to increase from about 36% in 2010 to about 117% in 2020. This indicates that pursuing a minimization of CO_2 emissions will become much more expensive than minimizing the generating cost. Thus, it becomes difficult to pursue low CO_2 emissions, and power systems will be locked in to high CO_2 emissions in the future. This result supports the tendency for climate objectives to be pushed down in priority compared to delivering energy security and affordability (Bazilian et al. 2010).

As seen from Fig. 8, the model gives a higher share of renewable energy than PT.PLN's estimate. This is due to the fact that the model assumes electricity production from solar panels and microhydro plants. Furthermore, two green constraints were added into the model obtained from contract agreements for nonfossil and renewable energy preferences. Also, the share of electricity production from IPP tends to increase from around 20% in 2010 to around

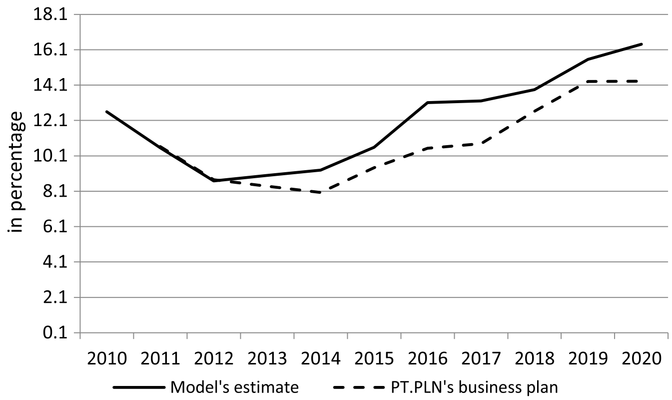


Fig. 8. Share of renewable energy production and PT.PLN's business plan

50% in 2020 under both Objectives 1 and 2. This is mainly due to new investment in steam and geothermal power plants. In the future, the authors believe there will be more players in the power-generating sector.

Policy Scenarios

The DSM policy can help Indonesia to reduce CO_2 emissions. As seen from Fig. 9, if the Java-Bali system can effectively implement the 5 or 10% DSM policies, CO_2 emissions in 2020 will increase to about 209.7 million or 195.4 million t, respectively. Thus, by implementing the 10% DSM policy, the CO_2 emissions are slightly above the minimized CO_2 emissions, that is, about 191.6 million t. This analysis does not consider a rebound effect or a backfire effect. A rebound occurs where potential energy savings from greater energy efficiency are reduced (e.g., 20% rebound means only 80% of the expected saving actually occurs) while backfire occurs if energy consumption rises with efficiency (Fouquet and Pearson 2012).

As seen from Fig. 10, if the additional steam power plant capacity is based on supercritical technology, yearly CO_2 emissions will be about 6.9% lower than with subcritical technology on average. If new ultra-supercritical power plants start to operate in 2017, the space to reduce CO_2 emissions becomes wider than before. In 2017, the first ultra-supercritical technology is expected to operate (with a capacity of $2 \times 1{,}000$ MW) in central Java. Ultra-supercritical technology has the lowest CO_2 emissions intensity (Sambodo 2012). This would be the first public-private partnership (PPP) with

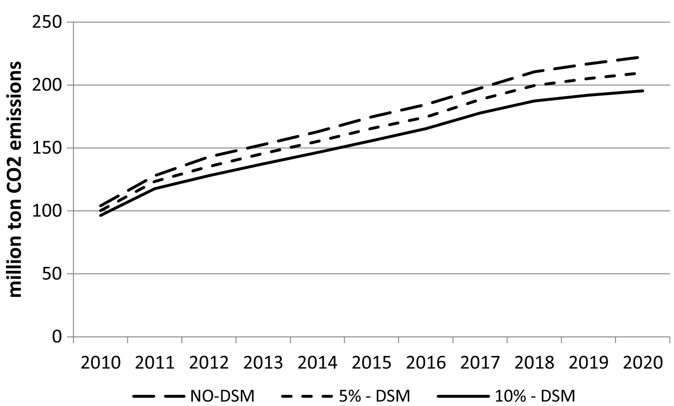


Fig. 9. CO_2 emissions from minimizing generating costs: Subcritical scenario with demand-side management

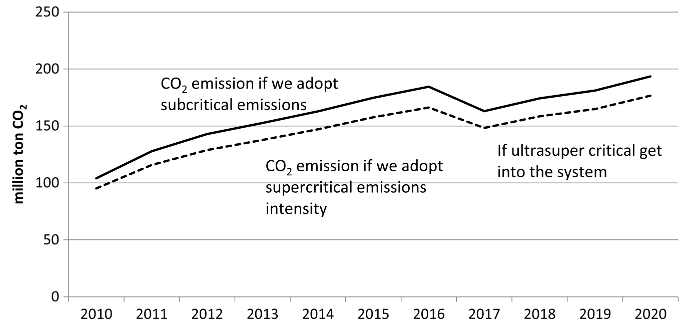


Fig. 10. CO_2 emissions from minimizing the generating cost with several scenarios

a project value of about US$3.2 billion and the winning consortium includes Japan-based Electric Power Development, (J-Power), Adaro Energy local coal mining, and the Japan-based Itochu Corporation. The government has provided support in facilitating and supporting the investment process; these actions include expediting measures for items such as the power purchase agreements, guarantee agreements, and recourse agreements. However, the project has not shown a substantial progress. Since the project was approved in 2011, land-ownership issues and environmental problems have become major obstacles.

By locking additional steam capacity with supercritical technology, and if ultra-supercritical power plants start to operate in 2017, CO_2 emissions under the strategy of minimizing the generating cost will be lower than minimizing CO_2 emissions under a subcritical scenario. This indicates that technology matters in reducing CO_2 emissions under the generating-cost-minimizing strategy.

If the prices of coal and gas increase by 100% under the subcritical technology, the average generating cost will tend to increase from about 12.4% in 2011 to about 51% in 2020 (Table 5). If the Java-Bali system utilizes supercritical technology before the price increases, the generating cost from the supercritical technology will increase less than 1% between 2010 and 2015 and below 1.6% between 2016 and 2020. This indicates that adopting new technology will cause the generating cost to increase marginally. The generating cost of steam-subcritical only increases by 53%. Although the generating cost from gas power plants will increase by about 88%, the generating costs from small coal/gas, geothermal, large-hydro, and microhydro plants are much lower than those of gas power plants. Thus, those power plants will be fully optimized after fuel cost increases of 100%. Finally, as Table 5 indicates, by adopting new technology earlier, fuel cost rises can be lower than without adopting new technology (Table 5, Column 7).

As seen from Fig. 11, when the DSM is implemented, the share of renewable energy (SRE) tends to increase. This is mainly due to the fact that decreasing electricity demand corresponds to a decline in other outputs except for renewable energy. However, as seen from Fig. 11, even after implementing the 10% DSM policy, the share of renewable energy will increase marginally. This means that there is a lack of capacity for renewable energy. Two ways to increase the share of renewable energy are considered. First, the government needs to set a target on the share of renewable energy and the model suggests that 17% of the renewable target in electricity production is achievable in 2020. In 2014, the share of electricity production from renewable energy (hydropower and geothermal power) in Java-Bali was about 5.5% (PT.PLN 2014). Second, the government should provide a feed-in tariff for renewable energy. Thus renewable energy can compete with other fossil

Table 5. Generating Cost (Rp/kWh) and Scenarios

Year	SCB	SCA	GCI	SCCB	SCCI	SCCA	SCCR
2010	686.98	—	0.00	686.98	0.00	—	0.00
2011	628.56	706.54	12.41	631.59	0.48	705.28	11.67
2012	591.32	741.77	25.44	596.68	0.90	739.09	23.87
2013	636.05	805.85	26.70	641.70	0.88	804.50	25.37
2014	681.46	873.68	28.21	687.34	0.86	873.02	27.01
2015	680.51	894.89	31.50	687.22	0.98	893.90	30.08
2016	643.66	886.73	37.76	651.65	1.23	884.90	35.79
2017	599.68	871.76	45.37	608.97	1.53	869.08	42.71
2018	611.10	836.72	36.92	620.32	1.49	821.95	32.50
2019	631.95	895.63	41.73	640.79	1.38	886.19	38.30
2020	623.64	941.80	51.02	632.38	1.38	932.31	47.43

Note: GCI = generating cost increase (%) after fuel costs increase by 100%; SCA = subcritical generating cost after prices increase; SCB = subcritical generating cost before prices increase; SCCA = supercritical after prices increase; SCCB = supercritical generating cost before prices increase; SCCI = supercritical generating cost increases from subcritical (%); SCCR = generating cost increase (%) in case supercritical plants are constructed early and fuel costs increase by 100%.

fuel plants (especially diesel power plants). How much of a feed-in tariff can be provided is discussed in the following section.

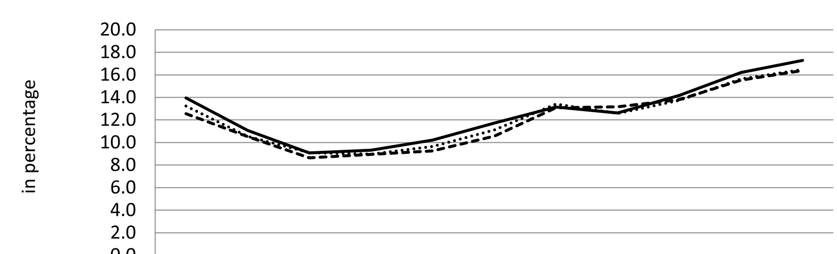
"Green Path" Power Expansion Plan

It is important to identify CO_2 emissions as well as generating costs from two extreme points (upper and lower bounds) because this can provide better information about the relationship between the generating cost (Rp/kWh) and CO_2 emissions. The results between the two extreme points reflect the tradeoff between these two objectives. Columns 1 and 2 in Table 6 provide the total CO_2 emissions and upper bound that indicates the total emissions if decision makers aim to minimize the generating cost, while the lower bound represents total CO_2 emissions. Columns 4 and 5 in Table 6 indicate the total CO_2 emissions when new steam-coal technology is based on supercritical power plants. Because in 2017, Indonesia will have the first ultra-supercritical steam coal technology, the amount of CO_2 emissions is also calculated. Comparing Column 1 and Column 2 under subcritical technology and Columns 4 and 5 under supercritical technology, the range between the upper bound and lower bound with subcritical technology is about 32.5%, which is larger than the range for supercritical technology. Thus, the supercritical technology can help squeeze the range of CO_2 emissions. A similar situation occurs by adopting ultra-supercritical technology. When more-advanced technology is adopted, the opportunity to squeeze emissions output becomes higher than without adopting the new technology.

Fig. 12 depicts an output combination of CO_2 emissions and generating cost between 2010 and 2020. The convex function for each year is obtained. This indicates that generating costs will be higher to obtain the same amount of CO_2 emissions reduction. The black dashes connect the highest CO_2 emissions in 2010 and highest CO_2 emissions in 2020, while the "green path" connect the highest CO_2 emissions in 2010 and lowest CO_2 emissions in 2020. Following the cost-minimization objective that corresponds with the black dashes, in 2020, CO_2 emissions will increase by about 114% (the black dashes do not cut the possible output in years 2014 and 2015. This indicates that the generating cost is too low to obtain the same level of emissions with the black dashes). However, the green dashes show that CO_2 emissions will increase by about 84%. Suppose the government attempts to follow the Copenhagen Accord and implement a 26% reduction of CO_2 emissions from the business-as-usual scenario, or the black path. This means that in 2020, CO_2 emissions are allowed to increase about 88% (that is $114 - 26\% = 88\%$) or a CO_2 emissions reduction of about 27 million t below the BAU scenario. The CO_2 emissions reduction will increase the generating cost to about Rp 1,040/kWh or US11.5 ¢/kWh.

Furthermore, the same analysis is conducted again utilizing supercritical steam technology. Under the black path, CO_2 emissions will increase by about 111%, while the emissions will increase by about 87% along the "green path." If CO_2 emissions are allowed to follow the "green path," the generating cost will be about US11.5–11.7¢/kWh.

If the government allows generating cost increases with low CO_2 emissions, then what type of power plants will benefit from this policy? Output combinations are evaluated from the two objectives in 2020 and the results are given in Table 7. By pursuing CO_2 emission minimization, the share of output from the old power plants will increase to about 41%. This is mainly due to increasing output from combined-cycle and gas, which have low emissions intensity. However, between 2010 and 2020, the generating costs from old combined-cycle and gas power plants will increase by 152 and 193%, respectively. Further output from renewable energy increases slightly. Thus, one can conclude that even by setting up a generating price in the future, the incentives will go toward fossil fuel power plants. This occurs because the capacity of renewable energy grows slowly. Hopefully, by providing a price incentive for



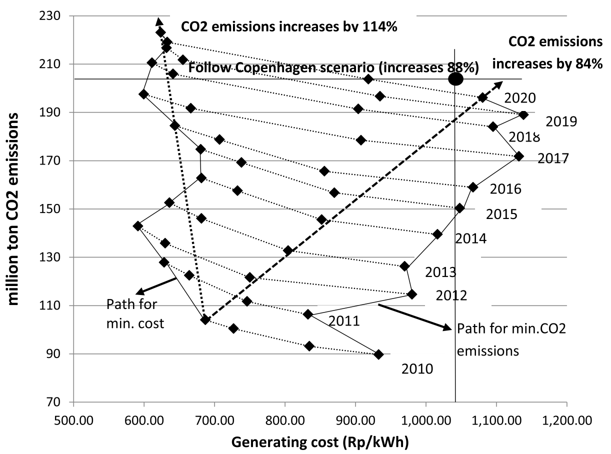
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Model's estimate	12.6	10.5	8.6	9.0	9.3	10.6	13.1	13.2	13.8	15.5	16.4
SRE-5%DSM	13.2	10.5	9.1	9.0	9.7	11.1	13.4	12.6	13.7	15.6	16.5
SRE-10%DSM	14.0	11.1	9.1	9.3	10.2	11.7	13.2	12.6	14.2	16.2	17.3

Fig. 11. Share of renewable energy (SRE with 5 and 10% DSM)

Table 6. Upper and Lower Bounds of CO_2 Emission (in Tons)

	Subcritical			Supercritical		
Year	Lower bound (LB)	Upper bound (UB)	With supercritical in 2017	Lower bound (LB)	Upper bound (UB)	With supercritical in 2017
2010	89,580,995	104,039,184	—	84,519,829	95,159,616	—
2011	106,291,481	127,884,325	—	99,556,171	115,786,504	—
2012	114,532,331	142,874,950	—	107,171,304	128,796,240	—
2013	126,024,098	152,584,303	—	117,448,106	137,627,453	—
2014	138,818,180	162,810,339	—	129,071,738	147,071,085	—
2015	149,668,708	174,719,136	—	138,819,274	157,607,088	—
2016	158,260,151	184,474,897	—	146,534,039	166,208,940	—
2017	171,088,274	197,534,729	163,001,334	158,053,170	177,904,615	148,271,607
2018	181,501,840	210,542,813	174,248,590	167,753,097	189,934,313	158,520,223
2019	186,502,035	216,704,246	181,002,748	172,460,281	195,480,806	164,775,061
2020	191,618,553	222,284,694	193,547,601	177,678,810	200,970,521	176,487,714

Note: Amount of emission is derived from the first and second steps discussed based on the three steps of the computational procedure; CO_2 emissions with supercritical technology are based on minimizing the generating cost.



Path for minimizing generating cost (path for min.cost) indicates a line connection for the highest CO_2 emissions while the path for minimizing CO_2 emissions (path for min.CO_2 emissions) is a line connection for the lowest CO_2 emissions.

Fig. 12. Paths for minimum cost and minimum CO_2 emissions and "green path" expressed by the diagonally dashed line

renewable energy, the share of renewable energy will increase rapidly and CO_2 emissions can be reduced by more than 26%. It is also necessary to provide more incentives for investment in electric power generation from clean energy resources (Resosudarmo et al. 2011).

Finally, the marginal abatement cost is defined as the one needed to reduce CO_2 emissions by 1 t as given in Table 8. Therefore, power companies need to obtain information on both cost and price for reducing CO_2 emissions. If the cost to remove one unit of pollution is higher than the price of polluting, there is no incentive to reduce pollution. Thus marginal abatement cost can be compared with the carbon tax or carbon price. However, a relatively high marginal abatement cost remains because the emissions reduction can be done by allowing old power plants (combined-cycle and gas) to operate. Because the marginal abatement cost tends to increase, this can be identified as a carbon lock-in situation. In order to reduce CO_2 emissions, utilizing renewable energy and using fossil fuel with lower emissions intensity than steam-coal plants would be necessary. The previous analysis indicates that due to the low capacity of renewable energy, old plants using the combined cycle and gas will obtain this opportunity even if renewable energy has lower generating cost than fossil plants. As the ARMA model considers the price history and in the past both combined-cycle and gas plants used oil, the forecast generating cost will be relatively high. Thus, the oil factor or oil trap makes a major contribution to the relatively high marginal abatement cost. Because, marginal abatement cost is higher than the carbon price, there is a lack of incentive to reduce CO_2 emissions. In fact, the Indonesian government does not have any policies on carbon pricing.

In fact, oil is still important as a primary energy source. For example, based on PT.PLN's business plan for 2010–2019, oil consumption was expected to be about 3.53 million kL in 2010, but the actual oil consumption was about 4.64 million kL, or about 31%

Table 7. Electricity Production in 2020 between Objective 1 and Objective 2 (MWh)

	Objective 1		Objective 2	
Types	Old power plant	New power plant	Old power plant	New power plant
Steam	27,383,952	186,535,970	35,920,570	103,476,860
Combined cycle	0	23,943,720	52,373,450	23,943,720
Gas	0	3,883,600	13,575,890	6,657,600
Diesel	0	0	701	0
Small-scale coal/gas	0	42,048	0	42,048
Geothermal	6,694,835	22,666,510	8,238,785	22,666,510
Hydro	8,886,142	1,157,694	8,886,142	1,310,496
Solar panel	0	6,585,519	0	10,687,200
Microhydro	0	433,620	0	433,620
Total	42,964,929	245,248,681	118,995,538	169,218,054
Share old output to total output	0.149		0.413	

Note: Objective 1 refers to minimizing generating cost and Objective 2 refers to minimizing CO_2 emissions.

Table 8. Average Cost to Reduce CO_2 Emissions by 1 t in the Java-Bali System (USD/ton)

Year	Subcritical before price increase	Subcritical after price increase	Supercritical before price increase	Supercritical after price increase
2010	275	275	379	379
2011	174	134	220	177
2012	291	184	398	230
2013	277	174	363	227
2014	333	207	428	270
2015	378	241	486	305
2016	448	287	580	404
2017	559	366	725	540
2018	479	328	530	409
2019	505	361	557	394
2020	449	351	556	399

above the planned level. In the future oil consumption may be lower than the current consumption and gas consumption will increase rapidly. If this is the case, the marginal abatement cost could decrease in the long run. Furthermore, as seen from Table 8, after fuel costs increase, marginal abatement costs tend to decrease. This occurs because the generating cost from renewable plants becomes cheaper than that for gas turbines. Thus, lower marginal abatement costs can occur if the generating cost from renewable energy is lower than that for fossil fuel. Thus one can conclude that there are three determinant factors that influence the marginal abatement cost: (1) flexibility in utilizing an energy mix toward lower carbon intensity such as gas, (2) availability of renewable energy, and (3) the state of steam technology.

Summary and Policy Recommendations

This research study aims to address the "green path" power system with regard to minimizing both the generating cost and CO_2 emissions. An optimization model was applied to the Java-Bali system in order to find an optimal electric power expansion plan between 2010 and 2020. Even though the proposed model does not consider blackouts, energy shortage, and unstable voltage explicitly, optimal solutions can still be obtained for both criteria of minimizing generating cost and minimizing CO_2 emissions. First, the yearly CO_2 emissions under a strategy of minimizing CO_2 emissions are between 15 and 18%, lower than minimizing generating cost. However, the price difference between these two objectives will also tend to increase from about 36% in 2010 to about 117% in 2020, or on average, an increase of about 78% per year. This indicates that pursuing minimization of CO_2 emissions will become more expensive than minimizing the generating cost. This is mainly because oil prices are included when the generating cost for old power plants is calculated. However, under minimizing the generating cost, if the Java-Bali system utilizes supercritical technology, the generating cost from supercritical technology will increase less than 1% between 2010 and 2015 and below 1.6% between 2016 and 2020. Furthermore, the yearly growth of CO_2 emissions will be about 6.9% lower than with subcritical technology or on average, it is more than half of the CO_2 emission growth under minimization of CO_2 emissions. Indonesia also can reduce CO_2 emissions if electricity production from combined-cycle and gas plants can be increased and to do that, the availability of gas supply need to be secured. Thus investments in gas infrastructure need to be enhanced.

If additional steam capacity with supercritical technology is locked in, and ultra-supercritical power plants start to operate in 2017, then CO_2 emissions under the strategy of minimizing generating cost will be lower than when minimizing CO_2 emissions under a subcritical scenario. This indicates that technology matters in reducing CO_2 emissions under the strategy of minimizing the generating cost. The possibility thus exist to obtain a green path power system if the government allows the generating cost to increase marginally with a target for CO_2 emissions. Furthermore, this study found that US11.5 ¢/kWh and US11.7 ¢/kWh as a price signal for the future green power price in Java-Bali system. By setting this price, the Java-Bali system can reduce CO_2 emissions by 27 million t compared to the BAU scenario. According to MEMR Regulation 22/2012, the average feed-in tariff for geothermal in Java-Bali-Madura is about US$ 11.75/kWh, and it seems that the regulated tariff is very close to the model estimate. However, the authors suggest that the feed-in tariff needs to be supported with an emissions reduction target. This is the missing part of the feed-in tariff policy.

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