Paper

Supply- and Demand- Side Effects of Power Sector Planning with Independent Power Producers: A Case of Indonesia

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This paper examines the implications of changing of operating mode or duration of contract of independent power producers in power sector planning in Indonesia. In particular, an approach is developed to assess the contributions of supply- and demand-side effects to the changes in CO_2, SO_2 and NO_x emissions from the power sector due to changing of operating mode or duration of contract of independent power producers. The results show that the supply side effect would increase the CO_2, SO_2 and NO_x mitigations, however, the demand side effect would act in the opposite direction. The results also show that the CO_2, SO_2 and NO_x emission mitigations would increase if the operating mode or duration of contract is increased from 60 to 80% or from 5 to 15 years respectively.

Keywords: Power sector planning, demand side management, independent power producer, supply side effect, demand side effect.

1. Introduction

Recently, power sector restructuring has received substantial impetus in the Asian developing countries. One of major components of power sector restructuring is the participation of independent power producers (IPPs). Though the participation of IPPs is increasingly considered desirable by Asian developing countries, the environmental implications of participating IPPs in power sector planning with demand side management (DSM) options are not yet known in the case of most Asian Countries.

Changes in pollutant emissions with the inclusion of IPPs in electricity planning with DSM options can take place through both supply- and demand-side responses. The supply side response takes place in the form of changes in the fuel- and technology-mixes (hereafter called as "supply side effect"). The demand side response occurs in the form of the change in electricity demand due to the adoption of DSM options (hereafter called as "demand side effect").

There are a number of studies examining the implications of considering IPPs in the power sector (see e.g., Ref. (1)~(3)). However, all of them are related to industrialized countries. Furthermore, none of the existing studies separate the individual contributions of supply- and demand-side options to total changes in pollutant emissions.

This study analyzes the implications of changing of operating mode or duration of contract of IPPs for power sector planning in Indonesia – a developing country – during 2003-2017 in terms of capacity-mix, generation-mix, DSM mix, overall thermal generation efficiency, and reliability of the power system from a long term power sector planning with DSM options perspective. It also examines the supply- and demand-side contributions to total changes in CO_2, SO_2 and NO_x emissions due to changing of operating mode or duration of contract of IPPs in the power sector. Furthermore, it computes electricity prices due to changing of operating mode or duration of contract of IPPs.

This chapter is organized as follows. A brief description of the power sector in Indonesia is presented in Section 2, followed by a description of the methodology in Section 3. Section 4 discusses input data and assumptions used. Utility supply side- and demand side-implications, the roles of supply- and demand-side effects on CO_2, SO_2 and NO_x emissions as well as the economic implications of changing of operating mode or duration of contract of IPPs are discussed in Section 5. Finally, major findings are presented in Section 6.

2. Power Sector in Indonesia

Power demand in Indonesia recorded an annual average growth rate of over 13% during 1993–1999 (4) (5). The Java-Bali Islands account for approximately 80% of the total electricity generation and 70% of the total generation capacity in the country. The total installed capacity in the Java-Bali Islands in 1999 was 15,512 MW which comprised of 86.4% thermal power plants and 13.6% hydropower plants. Of the total thermal generation capacity, coal based power plants had the largest share (46.0%), followed by oil-, gas- and geothermal-based power plants with shares of 29%, 21% and 4% respectively (4).

Candidate power plants for the Java-Bali Islands are mainly those based on gas and coal. Oil-based power plants would not be considered as a matter of national

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policy while hydropower plant potential is limited. Nuclear power is likely to be fiercely opposed by environmentalists and is not yet considered as an option [4].

The Government of Indonesia is now restructuring its power sector [6]. One of the restructuring forms is to purchase electricity from IPPs. The government views IPPs as a new source of generation capacity to meet the increasing demand for electricity. This view is based on the Government Regulation No. PP10/1989 Article 8, private is allowed to provide electricity supply. The detail explanation of the regulation is issue in the President decree No. 37/1992 and then renewed with the president decree No. 38/1998. Since the regulation, many privates have invested in providing electricity supply. At present, there are 3,185 MW of IPP plants connected to the system, while 1,320 MW would be committed in year 2004. There is no candidate IPP plant in the present case. The plant types of the existing and committed IPPs are hydro-, geothermal-, gas turbine-, and steam coal-power plants. The IPPs sell power to the existing utility, i.e. P.T. PLN (Persero).

In 1999, the residential and industrial sectors accounted for about 36% and 52% of total electricity demand respectively in the Java-Bali Islands, with the commercial sector accounting for the rest [4]. In 1996, approximately 58% of electricity consumption in the residential sector was for lighting. Approximately 59% of lamps used were incandescent while the rest used fluorescent tubes. In the industrial sector, about 70% of total electricity consumption was used by standard motors [7]. Clearly, this indicates significant potential for electricity savings from the residential and industrial sectors through energy efficiency improvement programs.

3. Methodology

Changes in pollutant emissions from the power sector due to changing of operating mode or duration of contract of IPPs in the power sector could take place due to either supply-side changes (i.e., changes in fuel- and technology-mixes) or changes in electricity demand if adoption of efficient options becomes cost-effective with the changing of operating mode or duration of contract of IPPs. Hereafter, changes in emissions purely due to the supply-side changes is called the "supply-side effect", while the changes solely due to changes in electricity demand due to adoption of DSM options is called the "demand-side effect".

The total change of a pollutant emission with the changing of operating mode or duration of contract of IPPs is equal to the summation of emission changes due to the supply- and demand-side effects. The total change of emission (in tons) of pollutant j in year t with the changing of operating mode or duration of contract of IPPs ($\Delta \in_t^j$) is defined as:

$$\Delta \in_t^j = E_{0,t}^j - E_{IPP,t}^j \quad \cdots\cdots (1)$$

where $E_{IPP,t}^j$ and $E_{0,t}^j$ are total emissions (in tons) in year t of pollutant j from the power sector with and without changing of operating mode or duration of contract of IPPs respectively.

The total emission change $\Delta \in_t^j$ can be decomposed into supply side-, demand side- and joint-effects, i.e.:

$$\Delta \in_t^j = \Delta E_{SS,t}^j + \Delta E_{DS,t}^j + \delta_t^j \quad \cdots\cdots (2)$$

where $\Delta E_{SS,t}^j$ and $\Delta E_{DS,t}^j$ represent changes in the emission (in tons) of pollutant j due to supply- and demand-side effects in year t, respectively, while δ_t^j represents the joint effect of supply- and demand-side factors of pollutant j in year t (in tons). In some studies, the joint effect was also called the interaction of effects [18] or the residual [19].

The change in emission of pollutant j due to the supply-side effect $\Delta E_{ss,t}^j$ (i.e., the change in emission due to changes in generation mix and generation efficiency) can be expressed as:

$$\Delta E_{SS,t}^j \triangleq \left(E_{0,t}^j - G_{0,t} \sum_{i=1}^{n} \varepsilon_{ij} \left(G_{IPP,i,t} \Big/ \sum_{i=1}^{n} G_{IPP,i,t} \right) \right) \quad \cdots\cdots (3)$$

where, $E_{0,t}^j$ = total pollutant j emission (in tons) without changing of operating mode or duration of contract of IPPs in year t, $G_{0,t}$= total electricity generation (in MWh) without changing of operating mode or duration of contract of IPPs in year t, $G_{IPP,i,t}$= electricity generation (in MWh) of plant type i with changing of operating mode or duration of contract of IPPs in year t, and ε_{ij}= emission factor (in tons/MWh) for pollutant j of plant type i.

The demand-side effect in total emission mitigation ($\Delta E_{DS,t}^j$) can be expressed as:

$$\Delta E_{DS,t}^j \triangleq (G_{0,t} - G_{IPP,t}) \sum_{i=1}^{n} \varepsilon_{ij} \left(G_{0,i,t} \Big/ \sum_{i=1}^{n} G_{0,i,t} \right) \quad \cdots\cdots (4)$$

where, $G_{IPP,t}$ = total electricity generation (in MWh) with changing of operating mode or duration of contract of IPPs in year t, and $G_{0,i,t}$= electricity generation (in MWh) of plant type i without changing of operating mode or duration of contract of IPPs in year t.

The joint effect (δ_t^j) can be derived as:

$$\delta_t^j = \Delta \in_t^j - (\Delta E_{SS,t}^j + E_{DS,t}^j) \quad \cdots\cdots (5)$$

The framework for analyzing the implications of changing operating mode and duration of contract of IPP plants in generation expansion planning considering DSM options is presented in Figure 1. The model determines the least cost mix of supply- and demand-side options during a planning horizon. The proposed generating units are represented by integer variables while their end-use electricity using devices are represented by continuous variables.

The objective function of the model used is total cost

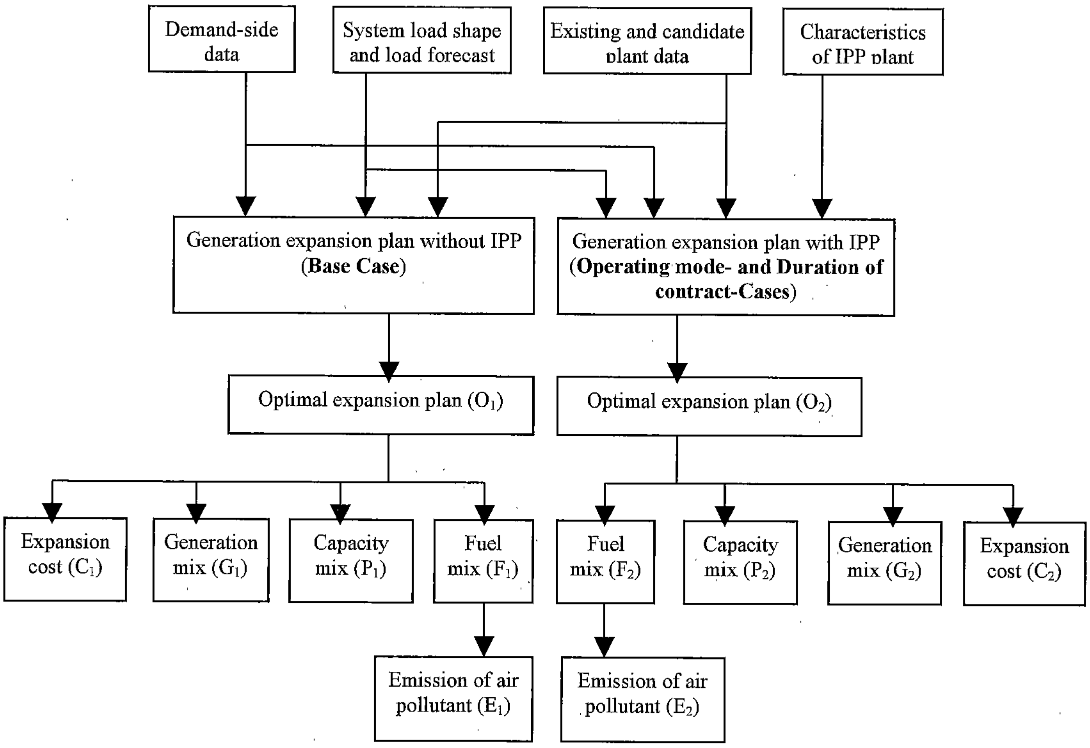

Fig. 1. Flow chart for assessing the implications of changing of operating mode and duration of contract of IPPs in power system planning with DSM options [8]

which is the sum of supply- and demand-side costs. The supply-side cost consists of capacity costs of candidate power plants, as well as fuel-cost and operation and maintenance-costs of existing, committed and candidate power plants of the existing utility and IPPs. The demand-side cost represents the cost of energy efficient end-use appliances/equipments net of the cost of the end-use appliances/equipments that would be replaced. The model includes the following constraints:

a. Power demand constraints: Total power generation from all existing and candidate power plants, and power generation avoided by energy efficient end-use appliances/equipments cannot be less than the sum of total power demand and transmission and distribution losses in all periods ("blocks"), seasons and years of the planning horizon considered.
b. Plant availability constraints: Power generation from each power plant at any daily period, season and year cannot exceed its available capacity.
c. Reliability constraints: The sum of installed power generation capacity of all plants and generation capacity avoided by energy efficient end-use options in any year can not be less than peak power demand plus a reserve margin in that year.
d. Hydro energy constraints: Total energy generation from a hydropower plant cannot exceed the level of hydro energy available to the plant in each season and year of the planning horizon.
e. Annual thermal energy generation constraints: Electrical energy generation from each thermal plant cannot exceed an upper limit that corresponds to the installed capacity and availability of the plant.
f. Efficient end-use device constraints: The level of energy efficient device selected in a year cannot exceed the maximum feasible level of such device in the year.
g. Maximum capacity constraints: Total number of generating units of each type in the planning horizon cannot exceed the maximum permissible (i.e., feasible) number of units. That is, total installed capacity of a type of power plant cannot exceed the maximum allowable capacity of that type of plant.
h. Fuel availability constraint: Electricity generation by a thermal power plant cannot exceed the level corresponding to the maximum available quantity of the fuel used by the plant.

The optimal (i.e., the least cost) outcomes of the generation expansion planning model are obtained by using CPLEX – a mathematical programming software [9].

In this study, a 15 year planning horizon (i.e., 2003-2017) has been considered. Each year is divided into 2 seasons and the daily chronological load curves are divided into 12 blocks in order to capture variations in electrical power demand and usage patterns of end use devices over different periods of a day.

4. Input Data and Assumptions

The data on existing hydro and thermal power plants are presented in Tables 1 and 2 respectively, while the data on technical characteristics and costs of candidate power plants are presented in Table 3. The data of the IPP plants (existing and committed) are presented in Table 4. There is no candidate IPP plant in the present

Table 1. Technical characteristics data of existing hydro power plants

Plant name	Pant Type	Fuel type	Total capacity (MW)	Emission factor (g/kWh)		
				CO_2	SO_2	NO_x
Cirata	Hydro	-	1,000	-	-	-
Saguling	Hydro	-	700	-	-	-
Mrica	Hydro	-	180	-	-	-
Sutami	Hydro	-	105	-	-	-
Plengan	Hydro	-	2	-	-	-
Cikalong	Hydro	-	19.2	-	-	-
Prakan	Hydro	-	10	-	-	-
Jelok	Hydro	-	5.1	-	-	-
Timo	Hydro	-	12	-	-	-
Garung	Hydro	-	26.4	-	-	-
Wonogiri	Hydro	-	12.4	-	-	-
Sempor	Hydro	-	1	-	-	-
W. Lintang	Hydro	-	18.4	-	-	-
K. Ombo	Hydro	-	26.5	-	-	-
W. Lingi	Hydro	-	54	-	-	-
Lodoyo	Hydro	-	4.5	-	-	-
Mendalan	Hydro	-	17.4	-	-	-
Siman	Hydro	-	7.2	-	-	-
Selorejo	Hydro	-	4.5	-	-	-
Madiun	Hydro	-	8.1	-	-	-
Sengguruh	Hydro	-	29	-	-	-
Tulung Agung	Hydro	-	36	-	-	-

Source: Ref. (4)

Table 2. Technical characteristics data of existing thermal power plants

Plant name	Plant type	Fuel type	Total capacity (MW)	Heat rate (kcal/kWh)	Emission factor (g/kWh)		
					CO_2	SO_2	NO_x
Priok	CC	Gas	1,180	1,997	416	0.002	1.192
Priok	Diesel	Diesel	6	2,857	825	2.587	7.081
M. Karang	CC	HSD	509	1,880	543	1.702	4.659
M. Karang	Steam	Gas	300	2,999	624	0.003	1.790
M. Karang	Steam	Gas	400	2,699	562	0.002	1.611
M. Tawar	CC	HSD	620	2.067	597	1.872	5.124
M. Tawar	GT	HSD	290	3,147	908	2.851	7.802
T. Lorok	CC	HSD	1,028	2,034	587	1.842	5.041
T. Lorok	Steam	MFO	300	2,955	966	16.803	3.001
Grati	CC	HSD	488	1,866	539	1.690	4.625
Grati	GT	HSD	342	2,799	808	2.535	6.938
Suralaya	Steam	Coal	1,600	2,532	1,276	4.617	3.723
Suralaya	Steam	Coal	1,800	2,433	1,226	4.436	3.578
Paiton	Steam	Coal	800	2,380	1,171	4.237	3.417
Gresik	CC	Gas	1,580	2,047	426	0.002	1.222
Gresik	Steam	MFO	200	2,661	870	15.134	2.702
Gresik	Steam	MFO	400	2,529	827	14.381	2.568
Gresik	GT	HSD	100	4,230	1,221	3.831	10.486
Bali	Diesel	HSD	25	2,268	654	2.053	5.618
Bali	GT	HSD	43	4,683	1,352	4.241	11.607
Bali	GT	HSD	84	3,423	988	3.101	8.486
Bali	GT	HSD	145	3,448	995	3.123	8.547
Fajar	GT	Gas	100	3,699	792	0.002	6.806
Gilimanuk	GT	HSD	133	2,996	865	2.713	7.426
Salak	Geoth.	-	165	-	-	-	-
Kamojang	Geoth.	-	140	-	-	-	-
Drajat	Geoth.	-	55	-	-	-	-

Source: Ref. (4)

case. The data on peak power demand and electrical demand profile used in this study are based on Ref. (4). The cost and caloric value of fuel used by power plants are presented in Table 5. Emission factors used for the calculation of emissions of CO_2, SO_2 and NO_X from power generation are based on Ref. (10)~(12).

Five DSM options are considered in this study. They involve replacing inefficient appliances in residential and industrial sectors with the efficient ones. Only residential and industrial sectors are considered due to more than 82% of the electricity was consumed by these two sectors. The DSM options considered in residential and industrial sectors are replacing incandescent lamps with compact fluorescent lamps and standard motors with energy efficient motors respectively. This is because in residential and industrial sectors, most electricity was consumed by lamps and motors respectively. The five DSM options considered in this study are:

Table 3. Technical characteristics and cost data of candidate power plants

Plat name	Plant type	Fuel type	No. of units	Unit capacity (MW)	Heat rate (kcal/kWh)	Capacity Cost at 2000 prices (US$/kW)	Emission factor (g/kWh)		
							CO_2	SO_2	NO_x
Rajamandala[a]	Hydro	-	1	55	-	1,482	-	-	-
Kesamben[a]	Hydro	-	1	33	-	2,835	-	-	-
Lesti[a]	Hydro	-	1	11	-	2,296	-	-	-
Jawa PS[a]	Hydro	-	1	1,000	-	539	-	-	-
New location	Geothermal	-	15	55	-	1,196	-	-	-
New location	Steam coal	Coal	UR[b]	400	2,287	1,122	1,152	4.1	3.4
New location	IGCC	Coal	UR[b]	540	1,911	1,400	963	0.004	0.3
New location	PFBC	Coal	UR[b]	400	1,911	1,220	963	0.180	0.6
New location	CCGT	Gas	UR[b]	600	1,699	625	354	0.0	1.0
New location	Gas turbine	Gas	UR[b]	100	2,457	500	511	0.0	1.5

[a] Firm energy availability from Rajamandala, Kesamben, Lesti and Jawa PS hydro plants are 120 GWh, 96 GWh, 28.9 GWh and 1,460 GWh respectively.
[b] UR= Unrestricted

Source: Ref. (4)

Table 4. Existing and committed IPP plants

Name of plant	Plant type	Fuel type	Total capacity (MW)	Heat rate (kcal/kWh)	Status
Jatiluhur	Hydro	-	180	-	Existing
Wayang Windu	Geothermal	-	110	-	Existing
Drajat	Geothermal	-	70	-	Existing
Dieng	Geothermal	-	60	-	Existing
Salak	Geothermal	-	165	-	Existing
Cikarang	Gas turbine	Gas	150	2,047	Existing
Paiton I	Steam	Coal	1,230	2,324	Existing
Paiton II	Steam	Coal	1,220	2,324	Existing
Tanjung Jati B	Steam	Coal	1,320	2,324	Committed in 2004

Source: Ref. (4)

Table 5. Cost and caloric value of fuel used by power plants

Fuel type	Fuel cost (US$/Gcal)	Caloric value (kBTU/kg)
MFO	11.44	39.08
HSD	17.33	43.82
Coal (P.T. PLN)	3.54	20.24
Coal (IPP)	6.60	20.24
Natural Gas	11.85	59.03

Source: Ref. (4)

Table 6. Technical characteristics and cost data of existing and efficient end use equipments

Sector	Existing end-use equipment				DSM option to replace the existing equipment			
	Appliance type[a]	Ratings[b] (Watt)	Cost[b] (US$ at 2000 prices)	Life[b]	Appliance type[a]	Ratings[b] (Watt)	Cost[b] (US$ at 2000 prices)	Life[b]
Residential	IL	40	0.55	1,000 hrs	CFL	9	9.37	8,000 hrs
	IL	60	0.58	1,000 hrs	CFL	18	9.78	8,000 hrs
	IL	100	0.63	1,000 hrs	CFL	25	10.34	8,000 hrs
Industrial	SM	<7.5hp	385.00	15 years	EEM[c]	<7.5hp	516.25	15 years
	SM	>7.5hp	1,125.00	15 years	EEM[c]	>7.5hp	1,696.00	15 years

[a] IL = Incandescent Lamp; SM = Standard Motor; CFL = Compact Fluorescent Lamp; EEM = Energy Efficient Motor.
[b] Source: Ref. (16).
[c] EEM of size below 7.5 hp are considered to require 4.8% less electrical energy than standard motors of the same size, while EEM of size above 7.5 hp are considered to require 3.4% less electrical energy.

- replacing 40 W incandescent lamps with 9 W compact fluorescent lamps (CFL) in the residential sector (hereafter "DSM-1"),
- replacing 60 W incandescent lamps with 18 W CFL in the residential sector ("DSM-2"),
- replacing 100 W incandescent lamps with 25 W CFL in the residential sector ("DSM-3"),
- replacing standard motors of size below 7.5 hp with energy efficient motors (EEMs) in the industrial sector ("DSM-4") and
- replacing standard motors of size 7.5 hp or above in the industrial sector with EEMs ("DSM-5").

Data on DSM options and the existing electrical equipments/ appliances they would replace are presented in Table 6.

The hourly residential end-use patterns were derived from a sample survey of 500 households belonging to four different tariff categories (13). The survey was conducted in four areas of Java-Bali islands i.e., Jakarta, West Java, Central Java and East Java. In the case of the industrial sector, the hourly utilization profiles of electric motors were based on Ref. (14).

A number of cases or scenarios are considered in this study. There are three major cases are considered, i.e., Base case, operating mode cases and duration of contract cases. It should be noted that DSM options are considered under all cases (Base-, operating mode- and duration of contract-cases). Totally, there are seven cases are considered, and each cases are explained as follows.

- *Base case.* In this case, only the existing and candidate plants of the existing utility, i.e., P.T. PLN (Persero), are considered and IPPs are ignored in the planning.
- *Operating mode cases.* Same as the Base case, except the IPPs are considered in the planning. In these cases, the IPPs sell power to the existing utility, i.e., P.T. PLN (Persero), with three scenarios of minimum operating capacity, i.e., 60, 70 and 80%. The characteristics of the IPP plant, such as unit size, minimum load, forced outage rate, and scheduled maintenance are also incorporated in this case. Hence, there are three cases under the operating mode cases.
- *Duration of contract cases.* Same as the Base case, except the IPPs are considered in the planning, and the duration of contract between the existing utility and the IPPs is set to 5, 10 and 15 years. The minimum operating capacity of each duration of contract is maintained to 80%. Same as operating mode cases, the characteristics of the IPP plant, such as unit size, minimum load, forced outage rate, and scheduled maintenance are also incorporated in this case. Hence, there are three cases under the duration of contract cases.

Normally, imposition of higher operating mode or duration of contract would result in a change in electricity generation cost. This would lead to a change in electricity price and consequently a change in electricity demand and the selection of DSM options. However, the effects of a change in electricity price on the electricity demand and the selection of DSM options are ignored in this study.

5. Results and Discussions

5.1 Supply Side Implications Changing of operating mode or duration of contract of IPPs in the power sector planning with DSM options would affect: (a) the level of generation requirements (as it depends upon the level of power demand avoided by the optimal DSM options selected under the generation expansion planning, (b) generation capacity additions, and (c) generation-mix (the share in power generation of different plants). Furthermore, there would also be changes in overall efficiency of thermal generation, reliability of power generation, capacity utilization and load factor with the changing of operating mode or duration of contract of the IPPs.

Changing of operating mode or duration of contract of IPPs in the power sector planning could affect installed generation capacity. Table 7 presents the installed generation capacity at the end of the planning horizon at selected operating modes and duration of contracts. As can be seen in the table, the installed generation capacity would not change significantly due to changes in operating mode or duration of contract.

Table 7. Generation capacity in year 2017 at selected operating modes and duration of contracts, MW

Scenarios		Existing utility's plants					IPP	Total
		Hydro	Coal	Gas	Geoth.	Oil	plants	
Base case		3,459	36,775	9,759	360	4,863	0	55,216
Operating	60%	3,279	30,600	11,609	360	4,863	4,505	55,216
mode	70%	3,279	29,800	12,509	360	4,863	4,505	55,316
	80%	3,279	29,000	13,209	360	4,863	4,505	55,216
Duration	5 yrs	3,279	33,000	13,709	360	4,863	0	55,211
of	10 yrs	3,279	33,000	13,709	360	4,863	0	55,211
contract	15 yrs	3,279	29,000	13,209	360	4,863	4,505	55,216

Table 8. Electricity generation during 2003-2017 at selected operating modes and duration of contracts

Scenarios		Share in total electricity generation, %						Total
		Existing utility's plants					IPP	(TWh)
		Hydro	Coal	Gas	Geoth.	Oil	plants	
Base case		4.7	84.3	5.4	0.6	5.0	0	2,840.8
Operating	60%	4.5	64.5	6.2	0.9	5.2	18.7	2,841.8
mode	70%	4.5	62.1	7.1	0.9	5.3	20.1	2,844.0
	80%	4.5	58.8	7.5	0.9	5.4	22.9	2,842.0
Duration	5 yrs	4.7	75.1	7.1	1.0	5.0	7.1	2,841.2
of	10 yrs	4.6	65.1	7.4	1.0	5.2	16.7	2,842.7
contract	15 yrs	4.5	58.8	7.5	0.9	5.4	22.9	2,842.0

The structure of electricity generation would also change if changing of operating mode or duration of contract of IPPs are considered in power sector planning. As can be seen from Table 8, the share of electricity generation from coal-fired power plants of the existing utility would decrease from 84.3% in the Base case to 58.8% at the operating mode of 80%. However, the share of electricity generation from gas-, geothermal- and oil-fired power plants would act in the opposite direction. Changes in the duration of contract would also decrease the share of electricity generation from coal fired power plants of the existing utility, i.e., from 75.1% at the duration of contract of 5 years to 58.8% at 15 year duration of contract, but the share of electricity generation from gas-, geothermal- and oil-fired power plants would act in the opposite direction.

The weighted average overall thermal generation efficiency changes due to changes in generation-mix associated with the operating modes and duration of contracts can be seen in Table 9. The weighted average overall thermal generation efficiency during the planning horizon is defined as the sum of annual thermal power generation efficiencies weighted by the corresponding annual shares in total thermal generation during the planning horizon. The table shows that the weighted average thermal generation efficiency would decrease from 43.93% in the Base case to 40.80% at operating mode of 80%. This is because the contribution of electricity generation from the IPPs (which are less efficient

Table 9. Weighted average thermal generation efficiency during 2003-2017 at selected operating modes and duration of contracts (%)

Scenarios		Weighted average thermal generation efficiency (%)
Base case		43.93
Operating mode	60%	40.89
	70%	40.83
	80%	40.80
Duration of contract	5 years	42.14
	10 years	41.34
	15 years	40.80

Table 10. Weighted average capacity factor during 2003-2017 at selected operating modes and duration of contracts (%)

Scenarios		Weighted average capacity factor (%)
Base case		65.08
Operating mode	60%	65.40
	70%	65.38
	80%	65.43
Duration of contract	5 years	65.30
	10 years	65.40
	15 years	65.43

Table 11. Weighted average loss of load probability and expected energy

Scenarios		Weighted average LOLP (%)	Expected energy not served (GWh)
Base case		0.1783	6.19
Operating mode	60%	0.1780	6.07
	70%	0.1785	6.25
	80%	0.1789	6.37
Duration of contract	5 years	0.1696	5.76
	10 years	0.1727	5.98
	15 years	0.1789	6.37

Table 12. Cumulative electricity generation avoided through DSM programs during 2003-2017 at selected operating modes and duration of contracts (GWh)

Scenarios		DSM options					Total
		DSM-1	DSM-2	DSM-3	DSM-4	DSM-5	DSM
Base case		48,540	38,869	21,297	102,885	46,670	258,261
Operating mode	60%	48,540	38,869	21,297	101,885	46,670	257,262
	70%	48,540	38,869	21,297	100,105	46,318	255,128
	80%	48,540	38,869	21,297	101,899	46,437	257,042
Duration of contract	5 years	48,490	38,869	21,297	102,846	46,437	257,939
	10 years	48,540	38,869	21,297	101,283	46,437	256,426
	15 years	48,540	38,869	21,297	101,899	46,437	257,042

power plants in the present case) would increase while the electricity generation from new power plants (which are more efficient power plants) would decrease with the operating modes considered. In the case of changes in the duration of contracts, the longer the duration of contracts, the lower the weighted average thermal generation of efficiency would be (the weighted average thermal generation efficiency would decrease from 42.14% at the duration of contract of 5 years to 40.80% at the 15 year duration of contract). This is because the longer the duration of contracts, the higher the electricity generation from the IPPs (which are less efficient power plants in the presence case), and hence, the lower the electricity generation from the new power plants (which are more efficient power plants).

How would operating modes and duration of contracts affect the utilization of power generation capacity? To answer this, the calculated values of weighted average capacity factors (WACFs) of the power system during the planning horizon at selected operating modes and duration of contracts are presented in Table 10. Capacity factor (CF) is the ratio of total electricity generation during a period to the maximum potential generation during the period with the total installed capacity. The weighted average capacity factor (WACF) is calculated from annual capacity factors with weights being the annual shares in cumulative electricity generation during the entire planning horizon. As can be seen, the WACF under operating mode cases and duration of contract cases would be higher than the Base case. However, changes in the operation modes or duration of contracts would not change the WACF significantly, and the figures are in the range of 65.30 to 65.43%. This is because introducing operation mode or duration of contract to the IPPs would not change the total installed capacity significantly but would shift the electricity generation based on the fuel use. It should, however, be noted that the generation expansion planning model in this study has not considered the cost of decommissioning or abandonment of an existing plant. The results could vary if such costs were also considered.

As total installed generation capacity and plant-mix change with the operating modes and duration of contracts, so would the reliability of electricity generation system. Table 11 presents the values of weighted average loss of load probability (LOLP) and total expected energy not served (EENS) during the planning horizon as alternative measures of the generation reliability at selected operating modes and duration of contracts. Loss of load probability (LOLP) is the proportion of time when the available generation is expected to be unable to meet the system load. Expected energy not served (EENS) is the expected amount of energy not supplied during a period (see, for example, Ref. (17)). Weighted average LOLP is calculated from annual LOLP with weights being the annual shares in cumulative electricity generation during the entire planning horizon. The table shows that the weighted average LOLP and total EENS during the planning horizon do not change significantly associated with the change in operating modes and duration of contracts and almost the same with the Base case.

5.2 Demand Side Implications Table 12 presents figures of electricity generation avoided by different DSM options at selected operation modes and duration of contracts. The table shows that the level of electricity generation avoided by DSM-1, DSM-2 and DSM-3 remain constant in the case of the selected operating mode cases. This is because all the DSM options mentioned above are selected to their maximum level. In the case of 60% operating mode, DSM-5 is also

Table 13. Electricity savings by DSM options as a percentage of potential saving during 2003-2017 at selected operating modes and duration of contracts (%)

Scenarios		Electricity savings (%)					Total
		DSM-1	DSM-2	DSM-3	DSM-4	DSM-5	DSM
Base case		100.0	100.0	100.0	96.6	100.0	98.6
Operating mode	60%	100.0	100.0	100.0	95.6	100.0	98.2
	70%	100.0	100.0	100.0	94.0	99.2	97.4
	80%	100.0	100.0	100.0	95.7	99.5	98.1
Duration of contract	5 years	99.9	100.0	100.0	96.6	99.5	98.5
	10 years	100.0	100.0	100.0	95.1	99.5	97.9
	15 years	100.0	100.0	100.0	95.7	99.5	98.1

Table 14. Weighted average load factor during 2003-2017 at selected operating modes and duration of contracts (%)

Scenarios		Weighted average load factor (%)
Base case		81.73
Operating mode	60%	81.73
	70%	81.74
	80%	81.73
Duration of contract	5 years	81.73
	10 years	81.73
	15 years	81.73

selected to its maximum level. In the case of duration of contract cases, only DSM-2 and DSM-3 are selected to their maximum level. DSM-1 is also selected to its maximum level, however, only for 10 and 15 year duration of contracts.

Table 13 presents the optimal (i.e., cost-effective) level of electricity savings from the selected DSM options during the planning horizon. The table shows that it would be cost effective to use the selected end-use options to their maximum potential level except DSM-4 at the Base case and operating mode cases of 60, 70 and 80%. In the cases of 10 and 15 year duration of contracts, it would be cost effective to use DSM-1, DSM-2 and DSM-3 to their maximum level. However, at 5 year duration of contract, only DSM-2 and DSM-3 would be cost effective to use to their maximum level.

With the change in the mix of DSM options, the system-wide power demand profile could also be affected. The changes in power demand profile at the selected operating modes and duration of contracts are reflected by changes in the weighted average load factor (WALF) of the power system during the planning horizon. Load factor is defined as the ratio of average load during a period to the maximum load during the period. Weighted average load factor (WALF) is calculated from annual load factors with weights being the annual shares in cumulative electricity generation during the entire planning horizon. Note, however, that WALF figures would not change significantly associated with the change of operating modes and duration of contracts (see Table 14). This is because the total DSM options are almost selected to their maximum level under all cases.

Table 15. Shares of supply-side, demand-side- and joint effects in total CO_2, SO_2 and NO_x mitigations during 2003-2017 at selected operating modes and duration of contracts (10^3 tons)

Pollutant	Component	Operating mode (%)			Duration of contract (years)		
		60	70	80	5	10	15
CO_2	SS_Eff	40,710	54,131	71,619	38,701	59,727	71,619
	DS_Eff	-2,311	-3,125	-1,197	-5,353	-6,915	-1,197
	J_Eff	34	60	30	74	146	30
	Tot_Mit	38,433	51,066	70,452	33,422	52,958	70,452
SO_2	SS_Eff	210.1	263.4	341.3	221.3	306.6	341.3
	DS_Eff	-9.8	-12.1	-4.9	-20.5	-25.7	-4.9
	J_Eff	0.2	0.3	0.1	0.4	0.8	0.1
	Tot_Mit	200.5	251.6	336.5	201.2	281.7	336.5
NO_x	SS_Eff	100.9	133.4	176.2	117.8	162.6	176.2
	DS_Eff	-7.1	-9.5	-3.3	-17.4	-21.6	-3.3
	J_Eff	0.1	0.1	0.1	0.2	0.4	0.1
	Tot_Mit	93.9	124.0	173.3	100.6	141.4	173.3

5.3 Environmental Implications Table 15 presents the contributions of the supply-side effect (i.e., change in emissions due to changes in generation-mix and generation efficiency) and the demand-side effect (i.e., change in emissions due to the change in electricity demand resulting from the use of DSM options) to the change in total cumulative emissions of CO_2, SO_2 and NO_X at selected operating modes and duration of contracts during 2003-2017. The table shows that as the minimum operating capacity of the IPP plants is increased, the CO_2, SO_2 and NO_X emission mitigations would increase from the power sector. Furthermore, if the length of contract is increased, the CO_2, SO_2 and NO_X emission mitigations would increase also from the power sector. These two conditions indicate that the existence of the IPP plants considered in this study is quite effective to reduce the CO_2, SO_2 and NO_X emissions. The table also shows that the supply side effect would contribute towards the reduction of CO_2, SO_2 and NO_X emissions, while the demand-side effect would act towards the opposite direction under operating mode and duration of contract cases considered in this study. This is because the total electricity generation under the Base case is lower than that of the duration of contract- or operating mode-cases as a result of the total electricity generation avoided through DSM options under the Base case is higher than that of the duration of contract- or operating mode-cases. This is because less DSM programs are selected under the duration of contract- or operating mode-cases than that of the Base case.

5.4 Economic Implications The operating mode and duration of contract of IPP plants would affect the total cost. The incremental in the total cost would increase with the operating modes. The total cost would increase by 0.45, 0.70 and 0.99% from the Base case if the operating mode is increased to 60, 70 and 80% respectively. Unlike the operating mode cases, the incremental in the total cost would decrease with the duration of contracts. The total cost would increase by 4.37, 2.30 and 0.99% from the Base case if the duration of contract is increased to 5, 10 and 15 years respectively. The increase in the total costs with the operating modes or duration of contracts is due to the increase in electricity generation of IPPs, which in turn would increase the fuel and O&M cost due to the inefficient and the high fuel cost of the IPP plants in the present case. Electricity price would increase from 7.81 USc/kWh in the Base case to 7.83, 7.87 and 8.06 USc/kWh with the operating modes of 60, 70 and 80% respectively (the methodology of electricity price calculation is provided in Appendix). That is, electricity price would increase by about 0.26 to 3.20% when the operating mode is increased from 60 to 80%. Electricity price of the duration of contracts of 5, 10 and 15 years would be 7.86, 7.91 and 8.06 USc/kWh respectively, or, the electricity price would increase from 0.64 to 3.20% if the duration of contract is increased from 5 to 15 years. The increase in the electricity price is due to the fuel cost of IPP plants is higher than the fuel cost of power plants belongs to the existing utility. Furthermore, the thermal generation efficiencies of the IPP plants are lower than that of the existing utility.

6. Conclusions

This paper has assessed the total changes in emissions of key pollutants (CO_2, SO_2 and NO_x) due to changing of operating mode or duration of contract of IPPs in power sector planning with DSM options (as compared to the emissions without IPPs). An approach has been developed to examine the factors that affect the total changes in emissions of pollutants when electricity sector development considered the changing of operating mode or duration of contract of IPPs. There are two major components that affect the total changes in emission, i.e.: supply side effect (i.e., change in emission due to changes in fuel- and technology-mixes) and demand-side effect (i.e., change in emissions associated with changes in electricity demand due to the adoption of DSM options).

This study shows that with the changing of operating mode or duration of contract of IPPs in the power sector of Indonesia, the share of electricity generation from coal based power plants would decrease, while that of gas, geothermal and oil would increase. The weighted average overall thermal generation efficiency is found to decrease if the operating mode or the duration of contract is increased from 60 to 80% or from 5 to 15 years respectively.

The total CO_2, SO_2 and NO_x mitigation would increase if the operating mode or the duration of contract is increased from 60 to 80% or from 5 to 15 years respectively. Decomposition analysis show that, of the total mitigation, the supply side effect would act towards the reduction of the CO_2, SO_2 and NO_x emissions, however, the demand side effect would act in the opposite direction.

Electricity price would increase from 0.25 to 3.19% if the operating mode is increased from 60 to 80% in the case of Indonesia. However, if the duration of contract is increased from 5 to 15 years, electricity price would increase from 0.77 to 3.19%.

It should be noted here that we have not considered the feed-back effects (also called "rebound effect") of changes in electricity price resulting from changes in the operating mode and the duration of contract are not considered in this study. Clearly, the findings of the study could be improved by considering the two cases mentioned above and the effects of electricity price changes. Further research in this area would be interesting.

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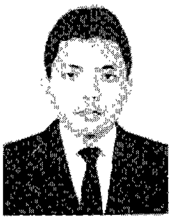
Appendix

1. Electricity price calculation

Electricity price is expressed as the sum of the average incremental cost of generation (AIC_g) and long run marginal cost (LRMC) of the transmission and distribution. The long run marginal cost of transmission and distribution ($LRMC_{T\&D}$) is taken from [15], while AIC_g corresponds to the least cost generation expansion plans derived from the generation expansion planning model. AIC_g is calculated as follows [8]:

$$AIC_g = \left(TC - C_1 - \sum_{i=1}^{T} VC_1 \Big/ (1+r)^i\right) \times 1 \Bigg/ \left(\sum_{i=2}^{T} (E_i - E_1) \Big/ (1+r)^i\right) \qquad \text{(A1)}$$

where TC = present value of total cost of power generation during the planning horizon, C_1 = present value of capital cost in year 1, VC_1 = total fuel, operation and maintenance and DSM costs in year 1, E_i = electricity generation in year i, E_1 = electricity generation in year 1, r = discount rate, and T = planning horizon.



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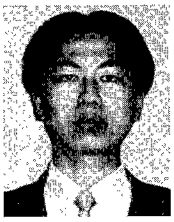

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