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Original Article

Least cost energy planning in Thailand: A case of biogas upgrading in palm oil industry

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Abstract

Thailand is currently the world's fourth largest producer of crude palm oil. The palm oil mill effluent is proposed to be used for biogas production. A value added option is then proposed by increasing thermal efficiency of the biogas by removing CO_2 content and increasing the percentage of methane, consequently turning the biogas in to green gas. In this study, the biogas and upgrading process for electricity generation with the subsidy or adder in the long term planning is presented. This analysis uses the MARKAL-based least-cost energy system as an analytical tool. The objective of this study is to investigate upgrading biogas with a selected water scrubbing technique featuring least-cost energy planning. The co-benefit aspect of biogas and biogas upgrading project is analyzed by given an adder of 0.3 Baht/kWh. The target of total electricity generation from biogas is 60 MW in 2012. The result shows that green gas will account for approximately 44.91 million m^3 in 2012 and increase to 238.89 million m^3 in 2030. The cumulative CO_2 emission during 2012-2030 is 2,354.92 thousand tonnes of CO_2. Results show that under the given adders the upgrading project is competitive with the conventional technologies in electricity generation planning.

Keywords: crude palm oil, least-cost energy planning, MARKAL, CO_2 mitigation, co-benefits.

1. Introduction

Thailand has proposed a renewable energy development plan (REDP) intended to promote renewable energy at a share of 20.4% of the total primary energy supply in 2022 (DEDE, 2010). Consequently, the carbon dioxide (CO_2) emission will also be reduced. Thailand also promotes and supports utilization of renewable energy and improvement of energy efficiency in the power sector because of the role of this sector as a major CO_2 emitter. To meet the REDP target, Thailand could take advantage of being an agricultural-based country by focusing on development of the palm oil industry as a renewable energy source. By the end of 2009, Thailand had a maximum of 2.52 million tonnes of potential of crude palm oil (CPO) capacity, 0.135 million tonnes of crude seed palm oil, 5.072 million m^3 of biogas from palm oil mill effluent (POME), 24,676 tonnes of fertilizer, 444,010.24 tonnes of seed palm, 50,577,063 kWh of electricity from biogas, 56,727.20 tonnes of fiber, and of 3 million liters of biodiesel with 64 palm oil mills (POMs), of which 37 POMs were wet extraction process plants and 27 POMs were dry extraction process plants. All of these plants had a total capacity of fresh fruit branch (FFB) of 1,715 tonnes/hr. Most of the POMs are located in two provinces, Surat Thani (13 plants) and Krabi Province (12 plants) (DIW, 2009). The world CPO production increases at a rate of 7% per year. This is an indicator that the CPO is still in high demand. However, the POME containing oil loss from the extraction process causes problems for wastewater treatment. The Department of Industrial Works (DIW) started a biogas pilot plant project in the palm oil industry in 2005. In addition to POME, biogas can also be produced from organic wastes of industry and crops. The

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inputs for biogas production are highly different in cost, revenues, and yields. The biogas yields influence the biogas production and therefore the revenues. The examples of the biogas yield from different dry substrates are as follow 200-400 m^3/tonne of cattle manure and dung, 250-450 m^3/tonne of pig and chicken dung, 350-700 m^3/tonne of energy crops, and 700-900 m^3/tonne of POME (FNR, 2007 and 2009). The POME is a favorable choice for use as input for biogas production because the oil content in POME can be converted to useful energy. However, POME also contains other substances, which are not usable for biogas production. Therefore, a special technique is required for biogas production from POME. The best technique is the anaerobic decomposition of organic matter, known as fermentation. To increase thermal efficiency, biogas retrieved from POME can also be further upgraded to a green gas. Biogas that has been upgraded to natural gas quality is called "green gas" (see Appendix 1). Compared to the biogas, the green gas and natural gas contain 29% more methane. Conceptually, upgrading biogas to natural gas is simply done by removing other gaseous components (H_2S, CO_2, and H_2O). Practically, however, there are many techniques for upgrading biogas; for instance, water scrubbing (WS), pressure swing adsorption (PSA), membrane separation (MS), and others. Each technique requires different electric energy inputs resulting in different methane losses. Electricity is used in the upgrading process in all techniques. For absorption with chemical reaction, the demand for electricity is about 0.15 kWh/m^3 upgraded biogas, while it is 0.3-0.6 kWh/ m^3 upgraded biogas for other techniques (Persson, 2003; Pertl *et al*., 2010). The WS technique is an upgrading process with minimum methane loss, only 1.5%, compared to 4% and 6% losses with PSA and MS, respectively (RENAC, 2009). The WS technique also leads to lower CO_2 emission when compared to other techniques (Pertl *et al*., 2010). The WS technique is also a good choice when the electric energy input is considered, 0.27 kWh/m^3 for WS, 0.2 kWh/m^3 for PSA, and 1.8 kWh/m^3 for MS. Generally, the cost of biogas upgrading to green gas depends greatly on the size of the plant. The upgrading cost for plants utilizing less than 100 m^3/hr of raw biogas is 34.2-45.6 US$/MWh, while it only costs 11.4-17.1 US$/MWh for plants that utilize 200-300 m^3/hr of raw biogas. The electricity demand for upgrading gas corresponds to 3 to 6 % of the energy content in the green gas (Persson *et al*., 2007). The natural gas currently used in Thailand contains methane (74.28%), ethane (5.71%), propane (1.45%), butane, pentane and hexane (0.92%), and CO_2 (15.38%) (PTT, 2006). However, the standards for natural gas quality in developed countries suggest an average methane content of 96% by volume. Compared to these standards, the methane content in the natural gas in Thailand is still quite low. More methane content means better combustion, and hence, less total emission. Therefore, the biogas upgrading process is an essential process that has co-benefits in CO_2 reduction and an improved environment.

In this study, the biogas upgrading in the palm oil industry is assessed for long term energy planning. The reference energy system, which includes primary energy supply, energy process and transformation, useful energy and demand technologies, is analyzed in the MARKAL model. Results of co-benefits, total discounted system cost, and effectiveness of CO_2 mitigation are compared to the BAU scenario. Results from the MARKAL model show that biogas power generation is competitive with other electricity generation technologies.

2. Potential of Palm Oil Industry and Renewable Energy in Thailand

Palm oil is an economically important plant in the southern provinces of Krabi, Surat Thani, Chumphon, Satun, and others. FFB output is approximately 4.5 million tonnes/annum and there is also an increasing trend of new growing areas by 5% per annum following the palm oil city policy (KPIO, 2009). There are two types of palm oil extraction technologies, dry and standard (wet) extraction methods. For one tonne of FFB, the following residues are generated, 0.87 m^3 of POME (can be turned into biogas at a heating value of 434.3 MJ/m^3 POME), 0.28 tonne of empty fruit bunch, 0.12 tonne of pressed fiber, and 0.08 tonne of kernel shell (Prasertsan and Sajjakulnukit, 2006). The milling process of one

Appendix 1. Compositions of biogas, green gas and natural gas.

Substance	Biogas	Green gas	Natural gas
Methane	45-70%	94-99%	93-98%
CO_2	25-40%	0.1-4%	1%
Nitrogen	<3%	<3%	1%
O_2	<2%	<1%	-
H_2	Traces	Traces	-
H_2S	< 10,000 ppm	< 10 ppm	-
Ammonia	Traces	Traces	-
Ethane	-	-	<3%
Propane	-	-	<2%

sources; PTT, 2006; FRN, 2009.

tonne of FFB requires 20-25 kWh of electricity and 0.73 tonne of steam (KPIO, 2009). Each extraction process and oil losses are shown in Figure 1. Thailand is the first country in South-east Asia having a policy to encourage electricity generation from renewable energy, the REDP policy under small power producer (SPP) and very small power producer (VSPP) policies. The financial incentive is remarkable in both the promotion of bio-fuels and electricity generation from renewable energy. The targets of renewable energy in total electricity generation are 0.76%, 1.84% and 2.26% in 2008, 2011, and 2016, respectively, and increase to 2.4% of the total energy consumption in 2022 as shown in Figure 2 (DEDE, 2010). To achieve the targets, feed in tariff for the electricity production from renewable energy is required. Feed-in tariff is a policy mechanism designed to encourage the adoption of renewable energy sources.

3. Methodology

3.1 Modeling approach

This study uses the MARKAL (MARKet ALlocation) model, a long term least-cost energy system, as an analytical tool. MARKAL depicts both the energy supply and demand sides of the energy system. It provides policy makers and planners in the public and private sectors with extensive details on energy producing and consuming technologies, and it can provide an understanding of the interplay between the macro-economies and energy use. As a result, this modeling framework has contributed to national and local energy planning, and to the development of carbon mitigation strategies. MARKAL can be used to determine the impact on total

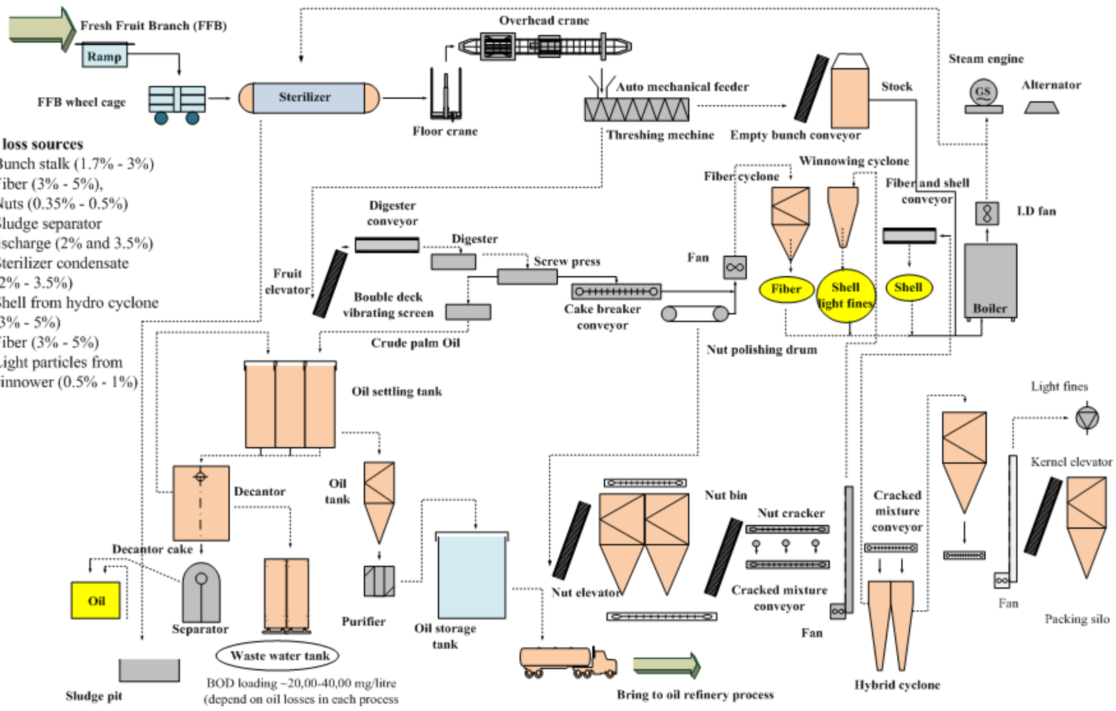

Figure 1. Selected large POM technology with wet exaction process.

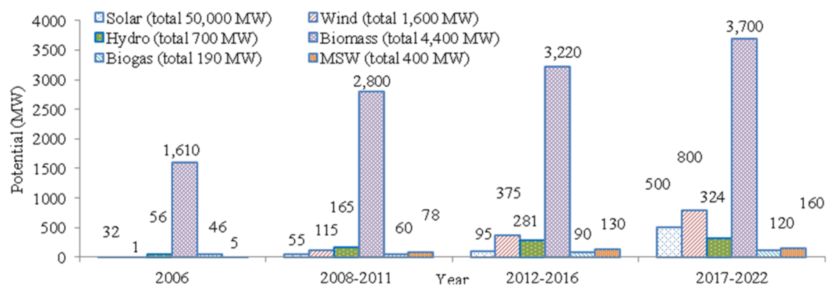

Figure 2. Renewable energy potentials in Thailand (DEDE, 2010).

energy system costs, changes in economy-wide energy intensity, and in the case of electrical systems, changes in emissions levels, price of electricity and meeting demands, and changes in other characteristics of the energy system resulting from the implementation of renewable technologies. It is well suited for different assessments. Least cost energy planning is an approach to resource planning that considers demand management solutions equally with strategies to increase capacity by considering all significant impacts (costs and benefits), including non-market impacts, and involves the public in developing and evaluating alternatives. The goal of least cost energy planning is to minimize the cost to society of meeting the demand for energy service. The planning period begins in 2007 and ends in 2030. The original MARKAL model was developed by Energy Technology Systems Analysis Programme (ETSAP) (Noble, 2007). As a part of the biogas upgrading process from POME, the economic sectors based on MARKAL were formulated, hereafter called "MARKAL-Thailand model" (Pattanapongchai and Limmeechokchai, 2009). The MARKAL-Thailand model portrays the entire energy system from imports, exports, and domestic production of fuel resources, through fuel processing and supply, explicit representation of infrastructures, conversion to secondary energy carriers, end-use technologies and energy service demands in the agricultural, residential, commercial, transport, and industrial sectors. A schematic diagram of MARKAL-Thailand building blocks is shown in Figure 3.

3.2 Cost and utility of biogas upgrading

Biogas forms wherever organic material accrues under exclusion of oxygen or anaerobic digestion. The end product of fermentation is biogas that is mainly composed of methane. The energy content of the biogas is directly dependent on the methane content. The higher the fats and starch content, which are easy to break down during fermentation, the greater the gas yields. One cubic meter of methane has energy content equivalent to ten kilowatt hours (~9.97 kWh) (FRN, 2009). Biogas belongs to the same gas-family as natural gas. After upgrading, calorific values and densities are similar to natural gas. The burning characteristics have to be the same as natural gas, such as the primary air requirement in the burner, the speed of the flame and the ignition temperature. The most efficient way of using biogas is in a heat-power combination where 88% efficiency can be reached. But this is only valid for larger installations and under the condition that the exhaust heat is used profitably (Lundeberg, 2009). Upgrading and feeding biogas to substitute the natural gas offers the possibility to use the upgraded biogas at the location of demand for electricity and fuel for vehicles. Raw biogas contains impurities comprising about 30-45% CO_2 which hinders the compression process, and traces of H_2S and water vapor which facilitate corrosions in the generator and other storage devices. WS is the absorption of CO_2 and H_2S in biogas using water at high pressure (see Figure 4). The cogeneration unit is the compact unit within a biogas plant in which the gas is converted to electricity and heat. The overall efficiency of a cogeneration unit is between 80-90% of the energy from the biogas. The electric efficiency is 30-43%, depending on the size and type of construction. The investment costs of different sizes for biogas upgrading plant are presented in Table 1.

4. Scenario Descriptions

In this study two scenarios are analyzed in the long term planning: the business-as-usual (BAU) scenario and the green gas or upgrading biogas (UPD) scenario. To compare the UPD scenario with the BAU scenario, this study assumes that has BAU is a case that has not yet implemented any policy except normal adder following REDP. Details of the BAU and UPD scenarios are shown in Table 2. Appendix 2 contains the details of power plants in each scenario.

(i) BAU Scenario

This scenario investigates Thailand's energy system in the context of the current trend and future projection. The load forecast used was prepared by Thailand's Load Forecast Committee (EGAT, 2009). The Thailand-MARKAL model is used as an analysis tool in with PDP2007 for development of an optimum plan in the next 24 years. In the BAU scenario, the GDP growth rate is provided by the National Economic Social Development Board (NESDB). The average GDP growth rate during 2007-2011 is 5.0%. The average GDP growth rate during 2012-2020 is 5.6%. Thereafter, it is assumed that the GDP will increase at rates of

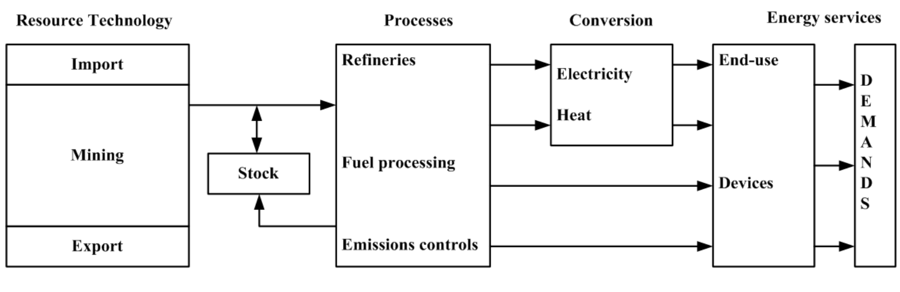

Figure 3. Schematic diagram of MARKAL-Thailand building blocks.

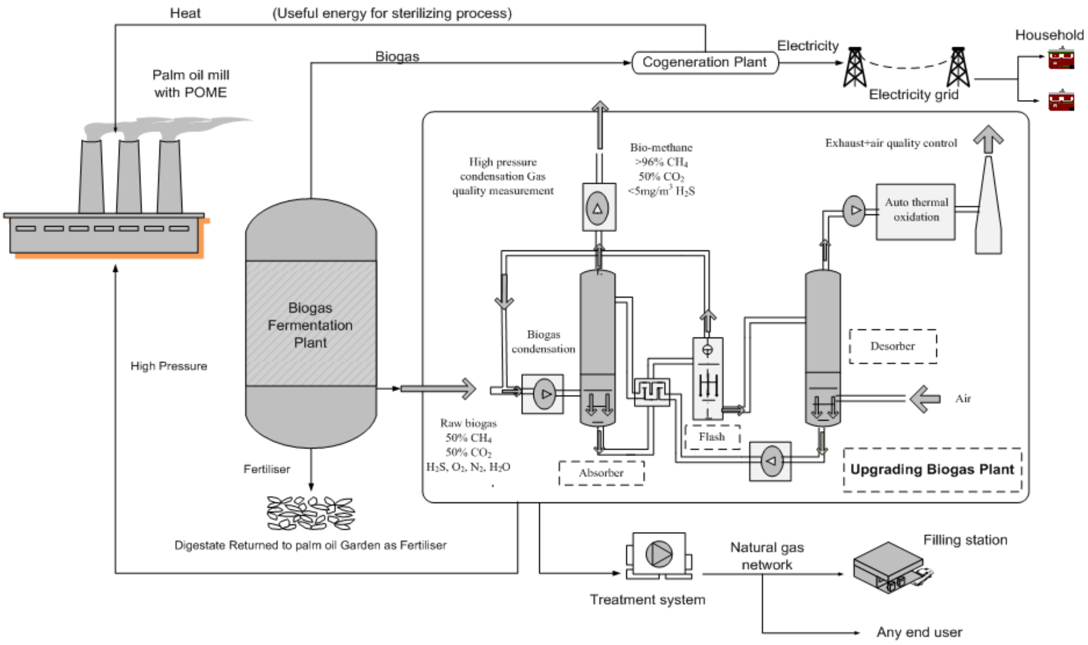

Figure 4. Green gas production in POM and benefits of municipalities (This system was developed by authors).

Table 1. Costs of upgrading biogas plant (from RENAC, 2009).

Cost	Biogas plant capacity (m^3/hr)		
	50	250	500
Investment (US$)	545,851	670,617	733,000
Capital fixed cost (US$/annum)	56,924	70,180	75,639
Operation cost (US$/annum)	24,953	31,191	34,310
Consumption cost (US$/annum)	19,494	51,466	103,711

Note: Exchange rate, US$ 1 = 35 Baht.

5.80%, 5.75%, 5.65%, 5.55% and 5.50% per annum during 2020-2022, 2022-2024, 2024-2026, 2026-2028, and 2028-2030, respectively. In 2006, existing biogas digesters from municipal solid waste (MSW) had a total capacity of 29 MW. In 2010, the target of REDP is set to 60 MW, and is considered as a candidate power plant in the BAU scenario. In the BAU scenario, the economies of each sector are projected to undergo a moderate economic development and market-oriented transformation during 2006-2030. The technologies considered in the transport sector include gasoline, diesel, liquefied petroleum gas (LPG), jet fuel, and kerosene technologies. The maximum available stocks of non-renewable energy resources, e.g., coal, lignite, oil and natural gas, were estimated by taking the sum of three quantities; proven reserve of the resource, 50% of its probable reserve and 25% of its possible reserve. The international prices of imported oil, gas and coal are estimated to increase during 2006-2030. A discount rate of 10% per year is used in this study. All cost figures discussed in this paper are expressed in 2006 constant prices. Basic assumptions driving the energy systems, such as future energy demands, domestic resources availabilities, conversion technologies and their appliances stocks in the starting year and energy prices, are collected from several sources, whereas emission factors used to quantify the pollutants and emissions are based on the previous data from EGAT's Environment Division (EGAT, 2009) from the year 1970 to 2008. EGAT has developed the emission factor for Thailand by measurement from EGAT's power plant. The planning horizon of the study is 2006-2030 given the present adder cost to renewable energy during 2008-2015 except solar and wind (2008-2018) (DEDE, 2010). Adder is an additional bonus of electricity production.

(ii) UPD Scenario

In the UPD scenario, the maximum level of upgrading biogas in the palm oil industry was limited to 60 MW as required in the REDP from total renewable energy of 3,276 MW in 2012 (DEDE, 2010). The investment costs for a biogas plant can be estimated at 300-500 US$/m^3 of the bioreactor;

Table 2. All scenarios and selected technologies

Power plant technologies/fuels	Scenarios	
	BAU	Biogas upgrading (UPD)
Conventional fossils (42 units) and renewable energy (8 units) - Total installed capacity 28,954.8 MW (biogas capacity 29 MW) - Starting year 2006	√	√
New biomass (Domestic biomass: paddy husk, bagasse and fuel wood) - Installed capacity 111 MW - Starting year 2010	√	√
New gas-fired CCGT (Imported LNG) - Total installed capacity 4,200 MW - Starting year 2014 (1,400 MW) and 2020 (2,800 MW)	√	√
New coal-fired IGCC (Imported and domestic coal and lignite) - Installed capacity 2,100 MW - Starting year 2020 (2,100 MW)	√	√
Supercritical (Imported and domestic coal and lignite) - Installed capacity 700 MW - Starting year 2020 (2,100 MW)	√	√
Upgrading biogas (POME biogas digester) - Installed capacity 60 MW - Starting year 2012	×	√

the lower number is for large plants and the higher number is for small plants. A simple UPD plant for power generation has an additional cost of 650 US$/kW according to German experience. To be added are the costs for the combined heat and power (CHP) plant at about 72,000 US$. This study assumed that subsidy is given to adder for biogas upgrading plants at the level of adder in 2012. The average efficiency of a power generator set is 31% for the biogas in the palm oil industry. The Germany technology is low loss and high efficiency as a case in Rathenow city (RENAC, 2009). In this study the efficiency of CHP in an upgrading plant increases to 40%.

5. Optimization Results

5.1 BAU scenario

5.1.1 Primary energy supply

The results indicate that the total primary energy supply use in the BAU increases from 6,350.5 PJ in 2006 to 39,229.1 PJ in 2030, which is equivalent to an average annual growth rate (AAGR) of 7.59% (see Figure 5). Total useful energy is increased from 2,660.6 PJ to 8,524 PJ by 2030, which is equivalent to a 4.85% AAGR. The percentage of total imported fossil fuel increases from 638.1 PJ to 4,026.0 PJ or 7.67% of AAGR. In the all economic sectors, i.e. the commercial, industrial, residential, transport, and agricultural sectors, the total fuel consumption increases with AAGR of 8.08%, 5.66%, 1.73%, 3.14%, and 3.72%, respectively. In the non-energy sector, the total fuel consumption has an AAGR of 5.28%. In the future, imported coal and lignite will increase at an AAGR of 9.83 %, from 220.7 PJ in 2006 to 2,338.0 PJ in 2030. This growth rate reflects the least cost energy demand and supply for Thailand during the period of 2006-2030. Least cost energy demand and supply are optimization techniques to compute a least cost path for the energy system, both supply and demand.

5.1.2 Final energy consumption and power generation mix

The total final energy consumption (TFC) of Thailand would grow at an AAGR of 4.19% or from 4,355.5 PJ in 2006 to 11,896.4 in 2030 during the planning horizon (see Figure 6). For electricity generation, natural gas is currently the major energy resource of supply, and is expected to decrease from 227.9 TWh (79.24% share of TFC) in 2006 to 365.89 TWh (53.11% share of TFC) in 2030. On the other hand, the share of renewable energy in the TFC would be increased from 2.072 TWh (0.721% of the TFC) to 103.156 TWh in 2030 (14.97% of the TFC).

Appendix 2. Details of power generation technologies.

	Technologies & owner	Installed capacity (MW)	Fix O&M ($/kWyr)	Variable O&M ($/GJ)	Investment ($/kW)	(%)	Lifetime (years)	AF (%)
	Available technologies							
1	[a]Coal thermal (IPP)	673	28	1.3	1,080	32	20	80
2	Biomass (SPP&VSPP)[c]	555	35.64	1.139	1,415	30	20	70
3	[e]Biogas (SPP&VSPP)	29	115.77	2.778	2,554	31	15	70
4	[d]Lignite thermal (EGAT)	2,400	24	1.81	1,125	32	30	80
5	Oil thermal (EGAT)	578	27.72	1.139	991	32	30	80
6	Diesel gas Turbine (EGAT)	1,091	12	7.97	350	25	15	70
7	Gas CHP (SPP)	1,572	36	0.28	530	32	20	85
8	[i]Hydro large (EGAT)	3,421	10	0.97	1,745	45	50	33
9	Geothermal (EGAT)	10	70.7	103.3	3,152	45	20	77
10	Coal CHP (SPP)	750	30.1	1.39	1,150	32	20	80
11	[h]Solar PV (VSPP)	32	22	19.44	4,084	45	15	20
12	[a]CCGT (IPP)	6,357	7.92	0.28	570	41	25	80
13	CCGT (EGAT)	2,383	7.92	0.28	570	41	25	80
14	[f]Oil CHP (SPP)	900	27.72	0.83	1,150	30	20	80
15	[g]Wind turbine (EGAT)	2	19.60	-	1,600	40	10	15
16	[i]Small hydro	55	58.61	0.14	2,800	30	30	20.5
17	Interconnect (Lao PDR)	340	-	-	-	-	15	80
18	Interconnect (Malaysia)	300	-	-	-	-	10	80
19	Diesel engine (EGAT&PEA)	76	12	7.97	800	25	15	70
20	Gas thermal (EGAT)	3,630	23	0.28	430	41	20	80
21	Gas thermal (IPP)	1,580	23	0.28	430	41	20	80
22	MSW (SPP)	21	35.4	-	5,736	30	20	50
23	CCGT (EGAT)	2,764	7.92	0.28	570	41	25	80
	New technologies							
24	LNG CCGT (EGAT)	4,200	23	3.93	750	56	30	80
25	Coal IGCC (EGAT)	2,100	38.3	1.96	1,900	48	30	80
26	Supercritical (EGAT)	700	23.8	1.96	1,400	42	30	80
27	[d]Biomass (SPP&VSPP)	111	71.4	12.6	600	56	20	70

Note: = thermal efficiency; AF = availability factor. *Sources:* [a] Thermal power plants (IPP) and CCGT(IPP) with coal-fired and natural gas are characterized as base load plant (EGAT, 2008, 2010). [b] Thermal power plants(EGAT) and CCGT(EGAT) with coal-fired, fuel oil and natural gas are characterized as base load plant (EGAT, 2008, 2010). [c] Biomass power plant (SPP& VSPP) is enabled through mixing of biomass (bagasse, paddy husk, wood chip and palm oil residual) to a level of between 25.49%, 50.36% 12.23% and 11.92% respectively (Srisovanna, 2001). [d] New biomass plant co-firing (SPP&VSPP)) is enabled through mixing of biomass (bagasse, paddy husk, woody biomass) to a max level of between 5%, 5% and 10% in conventional coal-fired plants.(Santisirisomboon, 2001). [e] Biogas (SPP&VSPP) from the farm and waste water is characterized as non-base load plant (EGAT, 2008). [f] A range of central combined heat and power generation (CHP) technologies is included and characterized as non-base load plant. [g] For wind, a resource potential of wind speed in Thailand is 2.8 m/s. Seasonal availability factors (AF(Z)(Y)) are also included (EGAT, 2008). [h] For solar PV, a seasonal availability factors (AF(Z)(Y)) are also included. [i] For hydro, a seasonal reservoir availability factors (SRAF(Z)) are also included (Nguyen and Ha-Duong, 2009; EGAT, 2008, 2010).

5.1.3 Environmental emissions

This study considered five gases and local pollutant emissions: CO_2, CO, NO_x, SO_2 and PM. CO_2 emission of the country would grow at an AAGR of 8.15% during 2006-2030 (see Figure 7). The electricity generation sector is increased from 62,728.63 to 181,691.34 thousand ton of CO_2 in 2030 with an AAGR of 4.43%. Most CO_2 emissions would increase their share over the planning horizon. Increasing use of coal, lignite, diesel and fuel oil in the power plants would signifi-

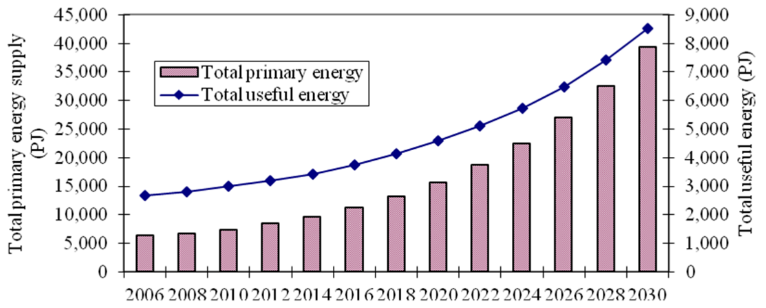

Figure 5. Primary energy supply and useful energy during 2006-2030.

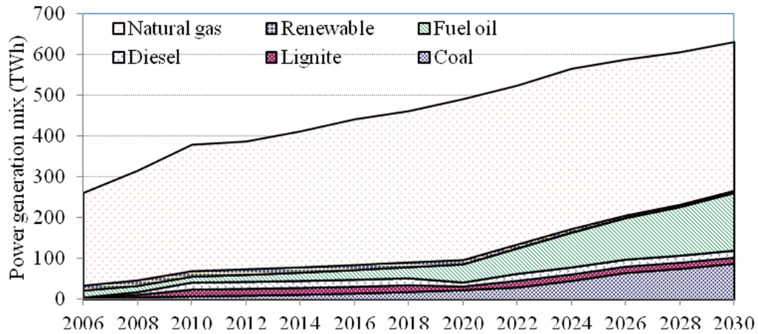

Figure 6. Power generation mix.

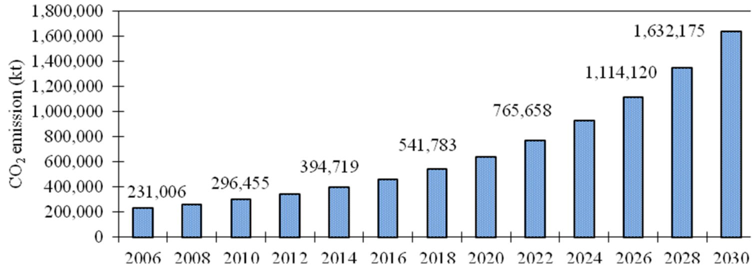

Figure 7. Total CO_2 emission in Thailand during 2006-2030.

cantly increase CO_2 emissions. The SO_2 emission would have AAGR 5.43% corresponding to increasing lignite and coal consumptions in power generation. The NO_x emission would grow at an AAGR of 1.58% during the planning horizon. By 2030, the power sector would share 32.82% of the total CO_2 emission, followed by the industrial (28.41%) and transportation (28.06%) sectors, respectively (see Table 3). The cumulative CO, NO_x, PM, and SO_2 emissions from the power sector during 2006-2030 are 716, 7,205, 149 and 57,053 thousand tonnes, respectively. These emissions come from combine cycle gas turbine (CCGT natural gas) and gas turbine (GT diesel), oil-fired (fuel oil) and coal-fired (coal and lignite) power plants.

5.2 UPD scenario

5.2.1 Subsidy to green gas

If we give the subsidy by adder incentive (during 2012-2020) to the biogas upgrading project, the least cost optimization model will calculate the total incentive, annualized system cost, electricity and green gas output for this project. With installed green gas in 2012 and given adders of all renewable energy technologies, the share of the total renewable electricity generation is increased. Compared with the BAU, the biogas is installed with maximum capacity of 5.07×10^6 m^3 in 2006. To promote the green gas production,

Table 3. CO_2 emissions in the economics sectors in BAU scenario (thousand tonnes of CO_2).

Sectors	2010	2014	2018	2022	2026	2030
Agriculture	10,830.95	12,116.11	13,665.08	15,376.04	18,113.77	26,083.83
Commercial	10,840.77	15,610.7	22,479.41	32,370.35	46,613.31	67,123.17
Power	80,439.74	100,951.1	121,275.9	144,433.4	171,416.4	181,691.34
Industrial	48,694.42	55,278.93	66,140.41	83,198.77	112,589.6	157,271.1
Residential	1,274.72	1,542.42	1,866.32	2,258.25	2,786.07	4,840.98
Transport	54,184.33	60,058.55	67,100.35	74,782.2	83,903.39	94,429.96

Table 4. Relationship between annualized investment cost and green gas output.

Parameters	2012	2016	2020	2024	2026	2028	2030
Annualized cost (million US$)	278.6	545.9	813.2	1080.6	1214.3	1347.9	1481.6
Green gas (million m^3)	44.91	87.91	130.91	174.39	195.89	217.39	238.89

Note: Exchange rate, US$ 1 = 35 Baht.

Table 5. Discounted total system cost and total subsidy (million US$).

Scenarios	Total subsidy for adders	Total system cost after subsidy
BAU	6,432	829,549
UPD	12,571	833,790

incentive is needed. The green gas output is estimated to be 0.94 PJ or $44.91 x 10^6$ m^3 with annualized cost at US$ 278.60 million in 2012 and increases to $238.89 x 10^6$ m^3 with annualized cost of US$1,481.59 million in 2030 (see Table 4). Cumulative electricity output from CHP in the UPD scenario (at 0.3 bath/kWh adder) is 55.56 GWh. It means that the subsidy cost for green gas production is effective for the 0.3 Baht/kWh adder. Total electricity output from renewable energy increases after 2012, and then decreases after 2020.

5.2.2 Total supply cost

The total supply cost and subsidy for adders are shown in Table 5. Total supply cost refers to the discounted system cost, including net taxes and subsidies, annualized investment cost of technologies, fixed and variable operation and maintenance (O&M) cost of technologies, costs of domestic resource extraction/mining, and costs of export/import fuel and material delivery.

5.2.3 CO_2 mitigation

The cumulative CO_2 emissions from the power sector during 2006-2030 in BAU and UPD are 1,388,591.08 and 1,386,236.16 thousand tonnes, respectively. The adder incentive for the biogas project in Thailand will exist for 7 years. If we fix CDM (Clean Development Mechanism) cost at 11.34 Euro/tonne of CO_2 the revenue from CDM will get from cumulative CO_2 mitigation multiply with the price in Euro/tonne and total year of subsidy. Under the given adders (adders in 2010) during 2008-2030, the cumulative CO_2 mitigation is 2,354.92 thousand tonne of CO_2 while the incremental cost in this period is US$ 4,240 million. The CO_2 mitigation cost is 1.8 million US$/kt of CO_2.

5.3 Co-benefits of green gas

Co-benefits are the benefits from policy options implemented for various reasons at the same time. The examples of co-benefits of greenhouse gas mitigation or energy efficiency programs are health, emissions, wastes, production, operation and maintenance, working environment and others. This study aims to investigate benefits of emission mitigation, reduced waste disposal cost and time, and an improved public image. The present study shows that the least cost strategy to achieve renewable and CO_2 mitigation targets will also generate benefits in the form of lower cumulative CO, SO_2 NO_x and PM emissions during the planning horizon. As a result of the increasing share of renewable energy, power generation based on renewable energy, i.e., biomass, biogas, small hydro, wind, geothermal solar, and MSW, would also gradually increase during 2008-2030. Moreover co-benefits give the good will to the POM industry in terms of environmental conservation. In addition, nearby communities do not suffer from unpleasant odors of hydrogen sulfide.

5.3.1 Improvement of waste water treatment efficiency

In 2012, the total capacity of wastewater for green gas projects is around 2,245,500 m^3 and up to 11,944,500 m^3 in 2030 (1 m^3 waste water generates 20 m^3 biogas). They have more benefits than an open lagoon waste water system as the anaerobic digester can trap the produced methane and use as fuel for biogas CHP and the upgrading process.

5.3.2 GHG emission mitigation and revenue from CDM

According to the CDM for biogas project, the reduction of CO_2 emissions to the atmosphere is calculated by using the IPCC 2004 guideline (CDM-Meth Panel, 2004). When more mitigation options are added utilizing CDM program for green gas project, the cumulative revenue from CDM in 7 years is US$ 167.12 million (at 0.0168 million US$/kt of CO_2 or 11.34 €/tonne of CO_2). The CO_2 mitigation is estimated to be 1,421.071 tonne of CO_2/annum. When compared with the present carbon credits the revenue from CDM is quite low for supporting green gas project.

6. Discussion and Conclusions

This study developed the MARKAL-Thailand model for least-cost planning with biogas upgrading. The purpose of this model is to investigate CO_2 mitigation, revenue and subsidy for the green gas. In this study, the upgrading biogas plant with CHP technology in palm oil mill was introduced for electricity generation in Thailand from 2012 to 2019. In the UPD scenario, green gas in the electricity production system was introduced for CO_2 mitigation. Results show that adder cost has a very important role in CO_2 mitigation. This study also shows that upgrading biogas is competitive with other electricity generating technologies under a 0.3 baht/kWh adder. The total electricity output from green gas is 55.56 GWh during 2012-2019. In terms of waste management, the biogas and upgrading component has co-benefits more than the other waste water treatment in the terms of zero waste because it is fertilizer for palm oil plantation. From this study, if the revenue from the biogas upgrading project increases by US$ 4,240 million during 2012-2030, the upgrading will have profits. The increasing revenue comes from selling electricity, adders, carbon credits, and fertilizers. Finally, in this study we investigate the effect of adder incentive (0.3 Baht/kWh) to promote the biogas upgrading project to POMs following the REDP plan. The results show that the current adder incentive is competitive for the biogas upgrading project in POMs. For further study, it is recommended that costs of green gas promotion by connecting the gas station and natural gas network for transportation should be studied.

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