HARVARD Kennedy School
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Squaring the Circle:

Politics and Energy Supply in Indonesia

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Same Risk, Different Models

Ensuring affordable, stable, and accessible energy supply remains one of the most critical functions of government, particularly in the developing world. The creation and expansion of a national energy system presents governments with inherent risks that must be managed if an economy is to be supplied with the energy it requires to grow. Some risks are structural, and inherent to the sector itself. Energy systems are characterized by high levels of capital intensity (e.g. oil refining), long-cycle investments with extended pay-back periods (e.g. oil exploration and production), natural monopolies (e.g. electric grid and gas transmission), and high levels of risk that result from the combination of these attributes. Energy flows may also carry the added complexity of perceived national security externalities, such as supply risk in the form of oil import dependency on one partner. These structural aspects of the sector create certain functional needs of large-scale capital agglomeration, long-term management of short-term demand cycles and longer-term investment supply cycles, the creation and enforcement of safety standards, the oversight of transmission and dispatch, and other others. The role of the state in such an industry is therefore of critical concern, both in theoretical and empirical terms, and the range of possible policies available is shaped by these functional needs.[1]

While all states must mitigate such complex sources of risk, their approaches for managing this risk differ markedly. On one side of the spectrum, the US federal government has shifted much of the capital risk and investment cycle risk to private firms, long prominent in the energy sector, while much of the regulatory risk (environmental, labor, etc.) has been ceded to state-level governments.[2] These private firms have increasingly become involved in informing the local and federal regulatory process, at times leading to questions of market power and corporate malfeasance. Other variants of this "neo-liberal" organization of the sector include England and Wales, in which strong labor unions and state monopolies in upstream energy supply industries were dismantled by the British state to strengthen competition, yet in comparison with the US, regulatory risk is concentrated more at the level of the central state, resulting in a more active regulatory presence ensuring competition.[3]

Towards the other end of the spectrum, France has attempted to inject aspects of competitive pressure and incentives through private ownership in some industries of its national energy system while maintaining much of the investment cycle, capital and regulatory risk in the hands of the central state in other industries.[4] The French state retains 85 percent ownership of

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[1] For a useful examination of the role of government in energy markets, please see C. D. Foster, *Privatization, public ownership, and the regulation of natural monopoly* (Oxford: Blackwell Publishers, 1992).
[2] See for example Robert Hirsh, *Power loss: the origins of deregulation and restructuring in the American electric utility system* (Cambridge: MIT Press, 1999).
[3] See for example Maarten Arentsen and Rolf Kunneke, "Economic organization and liberalization of the electricity industry: In search of conceptualization", *Energy Policy* 24, no. 6 (1996), pp. 541-552.
[4] See for example: Dominique Finon, "French Energy Policy: The Effectiveness and Limitations of

the firm Electricite de France (EdF), the nation's effective monopoly electricity supplier, yet only 5 percent of Total, S.A., France's "supermajor" oil firm. Industry and state interests relate through corporatist representation on firm governance boards. In sum, common risks inherent in energy provision are constantly faced by all states and require functional responses to serve clear needs, yet their responses of how best to organize industry and policy to manage such risks are diverse. Much of this variation is the result of varying political institutions, which often shape the policy choices available to policymakers.

In Indonesia, the central government finds itself struggling to choose among such energy governance models, defaulting to a mode of governing that borrows some of the least attractive aspects of the state-led model and of the market-led model. In electricity, the Indonesian system clings to a state ownership model in power generation that lacks the competitive elements of even the state-centric Chinese electricity system has introduced. In coal markets, ownership has been liberalized to allow private and competing companies, and exports have grown rapidly. However, artificially depressed domestic coal prices for power generation have starved the nation of adequate supply. This shortage has resulted in draconian measures such as the Domestic Market Obligation (DMO) policy, which holds such coal suppliers hostage to a monopsonist PLN unwilling and unable to pay market rates. Subsidized pricing continues to support the import of expensive diesel fuel and fuel oil, leading to spiraling subsidies. In terms of natural gas, Indonesia remains a major LNG exporter, but low domestic prices make it difficult for domestic consumers to compete with Asian LNG importers such as Japan, who are willing to pay much higher prices.

Indonesia is therefore managing two simultaneous transitions: a transition from a planned to a market economy, and a transition from a centralized to a decentralized governance structure. As a result, vertical modes of control exercised by the old authoritarian regime have been dismantled, while institutional mechanisms governing the horizontal competitive relationships between companies and between central and local governments have yet to mature. The case of Indonesia's electricity industry powerfully illustrates this dual transition, the highly politicized nature of the challenge to meet the energy needs of Indonesian citizens, and the ways in which some groups within government have been attempting to promulgate major reforms. Recent legislation enabled Independent Power Producers (IPPs) to compete with the state-owned electric provider PLN, yet the Indonesian Constitution continues to render such competition illegal, effectively maintaining PLN's monopoly on electricity generation, transmission, and distribution. This unreformed structure encourages state investment in the consumption of electricity, and not the generation of electricity. Without competitive pressures, incentives to invest are largely political, and therefore short term in nature. Unsurprisingly, it is more politically expedient to invest in short term energy consumption rather than energy production,

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Colbertism", in *European Energy Policies in a Changing Environment*, Francis McGowan (ed.) 1996; Pepper Culpepper, "Capitalism, Coordination, and Economic Exchange: The French Political Economy since 1985," in *Changing France: The Politics That Markets Make*, Peter Hall and Bruno Palier (ed.) 2006.

which is a long cycle, multi-year investment. This distortion of investment is significant, as the central government spends enormous sums in the electricity industry – lack of finance is not the obstacle. In fact, were Indonesia to allocate what was spent by the central government on electricity subsidies in 2008 alone to serve as equity investment in coal-fired power plants today, the resulting capacity would more than double the national electricity output.[5]

Indonesian Energy Challenges

Despite democratization, decentralization, and limited liberalization, Indonesia's central state remains active in the national energy market. The electricity industry provides a useful window into the main challenges Indonesia faces in meeting its energy needs, largely because the country is engaging in a national debate over how it should utilize its natural resources to power the growth of its economy. This debate is not confined to esoteric energy concerns, but rather is a debate over the future of Indonesian citizens' relationship to the country's natural resources, of national economic competitiveness, and of the country's political legitimacy. A stable and affordable electricity supply is not only a prerequisite of economic growth in Indonesia, but is also a test case of how policy has prioritized fuel choice, managed subsidies, and sought to or should seek to enable the upgrading of the national economy.

One of the distinctive aspects of Indonesia's energy system, which is often invoked in debates over the right role of the state in energy investment, is the fact that the country is an archipelago consisting of over 18,000 islands. Implicitly, and at times explicitly, the specter of separatism or other forms of secession from the Indonesian Republic frames much of the energy policy debate in the country. This geographical fact fuels a powerful belief that the state is as an important vehicle for reallocating the proceeds of natural wealth as a means to maintain the integrity of the country itself. This belief, first articulated in Article 33 of the 1945 Constitution, and consequently supported by various Constitutional Court decisions through to the present day, binds state ownership to many aspects of Indonesia's natural resource management as a means through which the interests of the people will be ensured in the exploitation and utilization of natural resources.

The strong link between exploitation of natural resources and the financial condition of the state is reflected in the evolution of the state's revenue growth, and continues to be reflected in current energy policy. Historically, Indonesia's energy system was dominated by petroleum (with a more limited contribution by natural gas), and the state was in turn dependent on oil and gas extraction for the majority of its revenue. By the late 1970s and into the early 1980s,

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[5] Additional coal-fired power generation capacity would equal over 27,000MW. Indonesian electricity subsidies in 2008 equaled 84 million rupiah. Capacity increase figure assumes two-thirds of investment would be in the form of debt, approximate total coal-fired power plant construction costs of $1,000/kW, and an exchange rate as of 2/20/2008: 1 million rupiah = $108.72 (http://www.exchange-rates.org/Rate/IDR/USD/2-20-2008).

Indonesia was producing over 80 million tons of oil annually. By 1982, 50 percent of the state's budget derived from petroleum (and limited gas) revenue. An economic state-owned corporate ecosystem shuttled such revenue from oilfield to state coffers. State energy firms such as Pertamina served as regulator and market player upstream and downstream in the oil and gas sector, while state firms such as PLN transformed seemingly low cost inputs into much-needed electricity.

Yet by 2010, oil production and its contribution to the state budget had both been approximately halved, and in the meantime Indonesia has become one of Asia's top buyers of sweet crude. As a result, that same year, nearly half of oil and gas revenue was lost to fuel subsidies, and another 20 percent was lost to electricity subsidies. Despite this, approximately 45 percent of Indonesia's primary energy consumption continues to rely on petroleum. The government's 2025 Energy Blueprint calls for the diversification of energy supply and the increased use of coal, renewable energy, and natural gas. In contrast, current government investments in major oil storage expansion reflect increasing appreciation that the import trend will continue for some time, and that dependence on oil-based solutions without adequate domestic refining capacity will therefore also continue. Pertamina in 2011 is completing three storage tanks, each with a capacity of 400,000 barrels to store imported sweet crude.

Electricity Woes

The current state of Indonesia's electricity industry reflects similar challenges. Historically, Indonesia maintained electricity output growth at over 10 percent a year, or more than twice GDP growth. This was the case in the period 1990-2000. Since 2000, electricity output has grown at approximately 6 percent a year – much less than electricity demand growth. Average electricity prices, while rising, are still only about eight cents per kilowatt-hour (kWh), while the cost of producing new electricity is in the range of nine to eleven cents.[6] Large subsidies (roughly three cents per kWh) to state-owned electricity provider PLN help make up the difference in operating costs, but not enough to allow adequate investment. The result is that in 2009 supply fell about 40 percent short of demand. If real GDP grows at 6.5 percent over the next few years, electricity demand growth will likely be about twice that level. Generating capacity, given current plans, will not grow nearly as fast.[7] While there is a "fast track" program to add 10,000 megawatts (MW) of capacity, this will not shrink the gap. In fact, since the program was announced in 2004, only 9.4 percent of the 10,000 MW goal has been installed. This results in frequent blackouts and depressed output and investment.

Many firms are therefore forced to buy diesel generators to maintain their electricity supply when PLN cannot provide power. At current prices, diesel power costs thirty cents or Rp

[6] This figure does not include the extra costs for transmission and distribution.
[7] One commercial consulting group, Research and Markets, predicted in 2011 that electricity would grow by 67 percent in Indonesia from 2010 to 2020. This is less than 5.5 percent a year and less than likely GDP growth.

2500 per kWh, well above the average PLN price of less than Rp 800 per kWh.[8] The diesel solution is expensive, polluting, noisy and a bother for firms that would rather not have to manage their own generation. In addition, there are 80 million Indonesians that do not even have access to electricity – with an electrification rate of 66 percent, Indonesia has one of the lowest rates of connection of any large Asian economy. While difficult geography plays a role, so does the lack of investment in generation and transmission/distribution.

The obvious solution is to charge enough to cover costs of new power, allowing capital to be attracted to the sector. This is not likely to happen. Consumers have become used to subsidies and any attempt to raise electricity prices elicits attacks that price increases will hurt "the poor" and boost inflation[9]. While selective price increases for wealthier consumers and businesses have been implemented, they are partial and unpopular. In addition, PLN labor unions fight against any attempt to undermine PLN's monopoly power or change its status as a state enterprise. Indeed, the Indonesian Constitution clearly states that PLN should be the major supplier, though others are allowed to supply power if PLN cannot. While law 20/2002 supported liberalization of the electricity supply industry, the Indonesian Constitutional Court annulled the law, citing Article 33 of the Constitution and the importance of state ownership.

The result is a form of stalemate. Plans by PLN to increase production fall well short of probable demand growth. Reliability of supply has improved around Jakarta but is likely to worsen as GDP growth boosts demand. Many households in the Outer Islands have no or unreliable power. This shortage holds back the growth of industry and reduces the attractiveness of Indonesia – and particularly East Indonesia – as a place to invest. It also raises the cost of electricity to those using diesel and adds to the subsidy burden of the government, taking badly needed resources away from improving infrastructure. Between 2005 and 2008, the Indonesian government spent more on energy subsidies than on national defense, education, health, and social security combined. In 2006, Indonesia's electricity subsidy more than tripled from $1 billion to more than $3 billion as a result of higher international crude prices and high levels of diesel use for power generation. By 2008, the electricity subsidy had risen to over $8 billion – nine times defense expenditures, six times health expenditures, 1.5 times education expenditures, and well over the entire amount spent on capital investment that year. The question is if, within realistic political constraints, a better policy is possible.

Demand Side Solutions

Most proposals to solve the electricity shortage involve raising the price of electricity to its actual cost, except perhaps for very poor households. Such proposals are motivated by the

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[8] Electricity prices for industry were recently raised and are now about Rp 900 per kWh.

[9] Neither objection is valid. If electricity prices were raised by $6 billion – the amount of subsidies – that would be less than 1 percent of GDP, which will be $850 billion in 2011. Such an increase could be phased in over 2-3 years, with little impact on inflation. Low prices for the first 50-60 kWh a month (the maximum amount used by those poor lucky enough to have access) would cost perhaps $50 a year for twenty million poor families, a maximum of $1 billion a year. Recent subsidies have been four to six times higher.

assumption that higher prices would reduce the demand for electricity. It is true that historically in Indonesia (and in neighboring Vietnam), the demand for electricity has grown at about double the real GDP growth rate. However, most studies do not find a high responsiveness of electricity demand to price with the ranges likely for Indonesia. Typical price responsiveness suggests that a 10 percent price hike will result in a short-term response of a 2-3 percent reduction in demand, and a 5-6 percent reduction in demand over several years. The response is lower if other prices also rise.

With the exception of largest users who pay eight cents per kWh, heavy residential users now pay over ten cents per kWh and most industrial users pay nine cents. As a result, most rates do not need more than a 10 percent to 30 percent increase to reach current costs. This would suggest that if prices were fully adjusted to costs, the result would be an approximate 10 percent reduction in demand from what it would otherwise be. Since demand is growing at more than 10 percent a year when GDP growth is 6-7 percent, this price effect would "buy" Indonesia less than one year of electricity demand growth. Additional gains in energy efficiency are possible with improved standards or subsidies for more efficient appliances, light bulbs, machinery and so on. But if Thailand's 2200 kWh per capita production is taken as a likely future for Indonesia, it will be necessary to boost electricity output by 150 percent to 180 percent by the time income per capita doubles in PPP terms over the next 12-15 years. In other words, Indonesia will need a lot more supply to meet demand even if electricity is fully priced.

Supply Side Solutions - Basic Information About Electricity Costs

With short- and medium-term demand side solutions to power shortages fairly dim, the importance of supply side solutions becomes even more apparent. Much of the debate over supply side solutions relates to analyses of cost. The cost of producing power depends on the cost of fuel and the cost of the generating unit. The annual cost of the generating unit depends on its initial cost, the interest rate or overall cost of capital, the hours per year the unit is operated, and the number of years it will operate.[10] The cost of fuel is a major determinant of total costs and can fluctuate considerably if the electricity producer does not have a long term supply contract with stable prices or fuel price hedging clauses.

The three most likely sources of affordable power in this decade are from natural gas, coal, and geothermal resources. The price of geothermal electricity to PLN (achieved through a feed-in tariff) has recently been set at just under ten cents per kWh. This is likely to be sufficient to attract new investment in many locations, but only if PLN is willing to sign a take-or-pay contract and the participating local government approves relevant land use, forestry, and environmental permits. Indeed, if the cost of capital were 8 percent, the cost of geothermal in larger scale units could probably be as low as seven cents per kWh, assuming nearly full-time production. (Private investors may target higher rates of return.)

[10] There are also overhead and maintenance costs, which are rather small. See Appendix I for a detailed discussion of costs for various types of generating units.

The cost of natural gas to customers in Indonesia is set to reflect the limited supplies available from local sources delivered through pipeline. This price is set by the government at $7-$9 per thousand cubic feet (about 1 million BTU) and in an efficient combined cycle generating plant, the cost of electricity is about seven to eight cents per kWh. However, there is a shortage of gas for domestic use in Indonesia and if LNG were bought from local producers or imported, the cost would be $12 to $15 per million BTU for gas delivered to the user, thus raising the cost of electricity to 10-12 cents per kWh.

The export price of high quality coal is currently $120 per ton[11] and a ton of 25 million BTU/ton coal will produce 2800 kWh in a modern coal-fired power plant. Under such circumstances, a fuel cost of just over four cents per kWh combines with other capital and operating costs that add five cents per kWh. The resulting kWh of coal-fired power costs nine to ten cents in an efficient plant.

In summary, an approximate price for generating additional power from any of the three sources can be estimated at about eight to ten cents per kWh on Java and Sumatra. Other islands, with smaller units and fewer economies of scale, will have higher costs. This is not the historical cost of power, which is much lower, but the cost of power in the future, as new supplies of electricity are brought on stream, and assuming fuel prices stay in their current range. The cost of transmitting and delivering power is additional, and depends on the geography, density, amount of power per user and other variables. Typically, one to three cents per kWh should be added for moving power from the generator through the grid to the user. This means the final cost of power will be eleven to thirteen cents to the user, less any applicable subsidies. At Rp 8600 = $1, this is about Rp 1000 per kWh for a retail price. If the exchange rate were to depreciate, the cost in rupiah would be higher; if the exchange rate appreciated, the rupiah cost of power would fall. (See the appendix for a detailed description of generator costs, heat rates, and other assumptions.)

Actual prices charged to larger volume residential users and to business and industry now approach these levels of actual costs, so in principle, it should be possible to spend a modest amount to keep down rates for small users[12] and to price in full costs to others with only limited further rate increases. This is a rough calculation that applies to Java and major consuming areas that need larger coal, gas or geothermal plants. On smaller islands, it may be necessary to use more expensive sources of electricity and have higher per kWh subsidies (if that is deemed "fair") or higher electricity prices for small groups of customers. The people served in these remote areas would be a small fraction of total population. Nearly 90 percent of Indonesians live on Java, Sumatra, Sulawesi, and Kalimantan. The decision to lower electricity prices where it

[11] http://leeuniversal.blogspot.com/2011/06/booming-indonesian-coal-exports.html
[12] Indonesia had 40 million PLN customers (mostly residential) in 2010. If half of them were "poor" and eligible for subsidies, and if the first sixty kWh per month were subsidized at 600 Rp per kWh, then annual subsidy costs would be $1 billion. This compares favorably to the subsidy levels of $4 to $6 billion in recent years.

costs more to provide electricity is a social and political decision that should be directed mainly at poorer consumers.

Supply Side Solutions - Natural Gas

Natural gas is sold through a government regulated monopoly, PGN. The price is set at a level which recovers costs for buying, transporting and distributing the gas. PGN gets its gas, 290 billion cubic feet (bcf) in 2009, through pipelines that transport the gas from producing fields to consumers. The amount of gas available from these sources is limited. Indeed, PGN representatives indicated in recent interviews that they could not even buy as much gas as Pertamina and Chevron had contracted to supply them. Gas was used for the Duri steam flooding oil extraction, which had a higher priority than other domestic uses. PGN had contracts to buy 636 million cubic feet a day but could receive only 520 million cubic feet a day. The retail price of gas depends on the type of user and location, but is generally $6.50 to $10 per thousand cubic feet (tcf).

It is possible to import LNG and heat it into natural gas, but this is significantly more expensive than pipeline gas. Current fob prices for LNG (export at point of production) are about $12/tcf, either from Indonesia or from other exporters such as Qatar. Unloading and heating the gas and bringing it to the final consumer would bring the total cost to $14-$15/tcf. Selling large amounts of LNG would require charging a much higher gas price than is currently allowed. Moreover, the nuclear accident in Japan has tightened the market for LNG, as it is being used to substitute for domestic nuclear power in many cases.

In 2009, one estimate was that electricity output in Indonesia was 120 billion kWh short of demand. If this shortfall were to be provided by gas-fired electricity, it would require supplying 750 bcf of gas (more than twice current use, excluding the gas used for oil production) to meet the balance of 2009 electricity demand, even if efficient combined cycle gas generating units were used. Given that electricity demand is doubling every six or seven years, it would clearly require a major expansion of gas supplies to provide a meaningful portion of incremental electricity from gas. While incremental gas imports are planned of 182 bcf annually in Java in 2012 and 91 billion cubic feet in Medan in 2013, this would only take care of existing customers who wish to be served. It would do little or nothing to keep up with demand growth nor eliminate the national backlog of demand for electricity.

There are major supplies of coal bed methane in South Sumatra that could be profitably exploited at current prices (ex wellhead) of $5-$7/tcf. Estimates of recoverable gas will certainly run into many trillions of cubic feet, but it is premature to know how much gas can be recovered and how soon this gas could become available. There are also important environmental questions since production of coal bed methane involves pumping water and solvents into the coal and fracturing it. This may result in polluting surface water or releasing undesirable chemicals. However, if this gas source is safely available, it would supply much of Sumatra and Java with natural gas in much higher amounts than current supplies. It would also, if transported by pipeline, prove to be cheaper than LNG.

In the past, many power plants signed long-term contracts for coal or gas to minimize supply risk. PGN could sign similar contracts with both the natural gas producers and with PLN or other electricity generating companies. The cost of transporting gas for PGN from South Sumatra to West Java is about $1.50/tcf, so new supplies could be brought in at current prices as they became available.

There have been criticisms concerning the $1.50 cost of transporting gas in pipelines from South Sumatra to West Java. One existing pipeline was recently completed and partly funded with ADB loans. It consisted of a 36 inch segment of pipeline that ran 176 km from Gressik to Pagardewa, a 32 inch segment of pipeline that ran 270 km from Pagardewa to the coast over difficult and swampy terrain, a 161 km undersea pipeline segment from the coast of South Sumatra to Muara Bekasi in West Java, and a 34 km connector to the existing grid. The amount invested was estimated to be $652 million for a total distance of 661 km. The capacity of the pipe was up to 460 million cubic feet a day. However, actual deliveries have been lower than this due to inadequate gas production for sale to PGN, so the fixed costs of the pipeline per unit of gas sold are higher.[13]

In 2006, a BAPPENAS report[14] analyzed either using an existing LNG train in Kalimantan and "importing" LNG to Java, or building a pipeline from East Kalimantan to Semarang. They concluded that the pipeline with a capacity of 419 billion cubic feet a year (1.15 bcf/day) would cost only $0.72 per million BTU to deliver the gas – even though this pipeline had to stretch 619 km on land and 600 km under the Java Sea. It is reasonable to ask why a longer pipeline is projected to cost half as much to transport gas as a shorter one. If the existing pipelines can transport the full design capacity of gas, the costs of moving gas from Sumatra to Java should fall sharply to perhaps fifty or sixty cents/tcf.

In short, now that many electricity prices have been allowed to rise towards their realistic costs levels, it makes little sense to maintain the price of gas used for electricity generation below its supply cost. Residential and industrial users will want to continue using gas at close to the current price, even though gas use is effectively curtailed due to scarce supplies. If the apparent large South Sumatra gas reserves can be produced, the present prices can apply to much larger quantities of gas for all users. But if the only realistic way to match supply and demand is to use LNG imports, then *at least* gas sold to PLN should reflect the actual cost, not the average cost of blended supplies. PLN – or private providers – will want secure fuel supplies for an

[13] If the line were fully used, a $.60 per thousand ft3 charge would yield $100 million a year, enough to repay costs.
[14] "Transporting natural gas from East Kalimantan to Java: Why did we choose a pipeline option?" by Hanan Nugroho and Eddy Satriya. The paper was presented to the 2nd Asian Pipeline Conference & Exhibition in November 2006. It mentions that the potential non-power demand in Java is 1.28 bcf/day and the cost of the proposed pipeline would be about $1.6 billion. Operating costs would be $32 million a year.

expensive investment in a combined cycle generator. These can only be secured at a market price. Since the higher fuel cost could be passed on to customers charged market prices for electricity, the system could shift from a cheap but unavailable supply to one that is more costly but unconstrained – if the pipeline supplies remain limited. If production and pipeline imports to Java can be boosted significantly, then something close to the present price could be maintained. If not, the LNG supplies would still enable electricity production that cost only one-third of diesel-fired power.

One way or another, increased use of natural gas is part of the solution to increased electricity production. Gas is clean, can produce electricity in moderately sized generators and is relatively low in carbon intensity. If gas can be provided cheaply in adequate quantities by pipeline, it should be used. If it has to be shipped as LNG, it will be more expensive but still worth using, albeit in lower amounts. However, if LNG becomes a source of gas supply, PLN should be able to contract for long-term supplies for their generators at market prices. This can be implemented without changing LNG gas prices for other users. However, PNG should charge "fair" prices for transporting gas by pipeline – an issue for regulators.

Supply Side Solutions - Geothermal

Indonesia lies on the "ring of fire" and enjoys up to 28,000 megawatts of potential geothermal energy, mainly on Sumatra and Java. Only about 4 percent of this potential has been developed, even though geothermal electric power emits almost no carbon, is reliable as a base load source of power, and is reasonably competitive in terms of cost. A recent decision by the Ministry of Energy directed PLN to buy power at up to 9.7 cents per kWh. This should be enough incentive to spur more investment, but creates obvious problems for PLN unless it can charge more for its power sales or get more subsidies. (Larger geothermal units normally have lower costs and would be paid less.) A target of 4,000 MW by 2014 has been announced, though this was recently raised to 10,000 MW. The new target is very ambitious given procedural delays in developing new geothermal production.

Geothermal field development involves drilling test and production wells down to a depth of several thousand feet to find reliable reservoirs of steam and/or hot water to use as a heat source to drive turbines. Costs are determined by the cost of drilling (which in turn depends on the depth and type of soil), the number of wells, and how well the wells and reservoirs maintain production. Average costs in Indonesia range from approximately $3000 to $4000 per kilowatt of capacity, but once production is set up it can operate nearly full-time. As a recent ADB report has highlighted, the exploration and well drilling phase of geothermal projects constitute, on average, 42 percent of a geothermal plant's total capital cost, second only to plant construction (at 46.6 percent).[15] Production from the geothermal field has to be connected to the grid, though this is normally not a long distance in Java. The size of a geothermal field can vary from a few dozen megawatts to several hundred. Geothermal energy is especially well-suited to the needs in Sumatra or other "outer islands", where the local size of electricity demand is relatively modest

[15] ADB, "Developing Contingent Liability Control System of Geothermal Projects", May 2011.

and there is not an island-wide grid.

In interviews with Chevron, numerous administrative and procedural obstacles were mentioned that did not prevent, but did slow down, the development of geothermal. Even in the well-established Salak plant, they estimated that expanding from 377 MW to 500 MW would take several years, due to negotiations with the Ministry of Forestry (most potential wells are on protected forest land), local bupatis, and others.[16] Though they did not say so, it appeared that obstacles might be placed in their way as a negotiating tactic to extract better terms. If this is so, the question is whether the priority of developing geothermal is high enough that ways could be found to streamline the administrative procedures. For example, if a "geothermal ombudsman" were set up as a required arbitrator to coordinate across ministries (energy and forestry) or administrative levels (national and kabupaten), then the prospect of a fair and fast decision might prompt the forestry and local negotiators to reach agreement more quickly. This would also apply to land disputes for transmission lines. Since most geothermal sites are near mountains and most demand is in flat areas, some level of transmission lines are normally required.

Geothermal power will remain a relatively modest part of the total electrical supply. However, it would be desirable to make it easier and faster to develop this source. Since most geothermal reserves are in forest areas, the small earthquakes (usually magnitude 3.5 or less) that sometimes accompany geothermal production tend not to be very worrisome. This source could be especially useful where local demand is not high and a widespread integrated grid transmission capacity is not available. In that case, the modest scale (a few dozen MW) would be appropriate and much cheaper than diesel production and much more reliable than solar or wind energy.

Supply Side Solutions - Coal

Coal is Indonesia's most abundant fossil resource. The country is home to 4.3 billion tons of proved coal reserves, or 0.5 percent of the global total. Because of the rapid increase in coal exploitation, Indonesia's 2009 reserves-to-production ration (R/P) equaled 17 years. This ratio has dropped by more than 50 percent in only five years, as the 2005 R/P figure was over 38 years. While many policymakers find such a rapid drop alarming, others point to the lack of systematic exploration. As indicated in the figures below, Indonesia's coal resources are substantial, recently estimated to be over 120 billion tons. This figure has risen considerably from approximately 60 billion tons as recently as 2007. As a result, Indonesia's resource and reserve estimates need to be treated with caution, and will undoubtedly change as exploration expands. In contrast to neighboring Australia's supply of bituminous coal with calorfic values

[16] Switching the legal definition of geothermal from "mining" (which is heavily regulated in forest areas) to "energy services" would help to reduce some of these issues.

as high as 7500 kcal/kg, nearly 90 percent of Indonesia's reserves are sub-bituminous (4500-5800 kcal/kg) and lignite.[17]

Classification of Indonesia's Coal Reserves by Coal Rank (2007)

Coal Rank	Calorific value (kcal/kg) GAD	GAR	Reserves (in million tonnes) (gad) Probable	Proven	Total	% of Total
Lignite	<5100	<4500	4,292	1,105	5,397	29%
Sub-bituminous	5100– 6100	4500 -5800	8,214	2,971	11,185	60%
Bituminous	>6100	<5800	744	1,385	2,129	11%
Total	**n/a**	**n/a**	**13,250**	**5,461**	**18,711**	**100%**

Source: Indonesian Coal Book, 2008/2009, ICMA, 2008.

Classification of Indonesia's Coal Resources by Coal Rank (2007)

Coal Rank	Calorific value (Kcal/kg, gar)	Resources (million tonnes) (gad) Hypothetical	Inferred	Indicated	Measured	Total	% of Total
Lignite	<4500	5,058	6,579	3,652	5,750	21,039	23%
Sub-bituminous	4500 – 5800	16,925	22,104	9,042	10,867	58,938	63%
Bituminous	>5800	1,650	6,515	968	4,293	13,426	14%
Total	n/a	23,633	35,198	13,662	20,910	93,403	100%

Source: Indonesian Coal Book, 2008/2009, ICMA, 2008.

At first glance, Indonesia's coal industry structure is seemingly fragmented, with over 80 producers. However, the industry is experiencing a consolidation as the Coal Contracts of Work (CCOW) licenses that were granted beginning in the 1980s contained clauses that require foreign investors to engage in staged equity divestments. As a result, ten years after start of production, 50 percent of a mining project must be held by an Indonesian company. Such a requirement has allowed companies such as Bumi Resources, Indonesia's largest coal producer, to grow rapidly, now producing over 27 percent of the nation's coal. Three coal mining companies now control over 60 percent of national production. Bukit Asam, Indonesia's state-owned coal producer, produces under ten percent of Indonesia's coal. While coal consumption has grown significantly in the last decade, most of incremental production has fueled exports. Indonesia is the world's largest thermal coal exporter, and second largest coal exporter overall.

As a result of such growth in exports, and significant disparities between prices for coal in the domestic and foreign markets, the GOI has established a Domestic Market Obligation (DMO) in an effort to guarantee sufficient domestic supply. Regulation No. 34 (2009) issued by the Ministry of Energy and Mineral Resources ("MoEMR"), entitled "Domestic Market Obligation for Minerals and Coal" obliges producers of mineral products, including coal, to set

[17] Sometimes coal is described in terms of BTU (British Thermal Units) per ton. Multiplying the kilocalorie per kilogram number by four gives the approximate BTU per kg. and multiplying that number by 1000 gives BTU per metric ton of coal.

aside a percentage of their annual production for sales to domestic users. The quota is set annually, depending on the domestic market needs of Indonesia (particularly PLN). In reality, the DMO serves an implicit export tax, as it requires that 20 percent of coal production be sold at prices that are nearly half the market price.

To date, only low-rank coal has been assigned a DMO quota. Fearing that royalties would be based on artificially low selling prices charged to an offshore affiliate, the GOI instituted a monthly minimum reference benchmark price for thermal coal and for coking coal. The thermal coal price is based on a formula that averages four international coal indices. With the benchmark price as a reference, coal categories are established based on ranges of coal characteristics such as moisture and sulfur content, with reference prices that are more specific. While recent regulations have been promulgated to specify trading mechanisms, it is clear that fulfilling the DMO has caused significant concern among major coal producers. PLN, already enjoying considerable leverage as a monopsonist of domestic coal for electricity production, now is emboldened by the DMO to place even more pressure on coal producers to provide coal at subsidized rates. This subsidy comes in many forms, not least of which is the late or partial payment of coal received, various forms of graft, and prices that are well below export prices. The export tax of 2005, repealed in 2006, served as a similar blunt mechanism to force coal producers to sell into a highly subsidized domestic market.

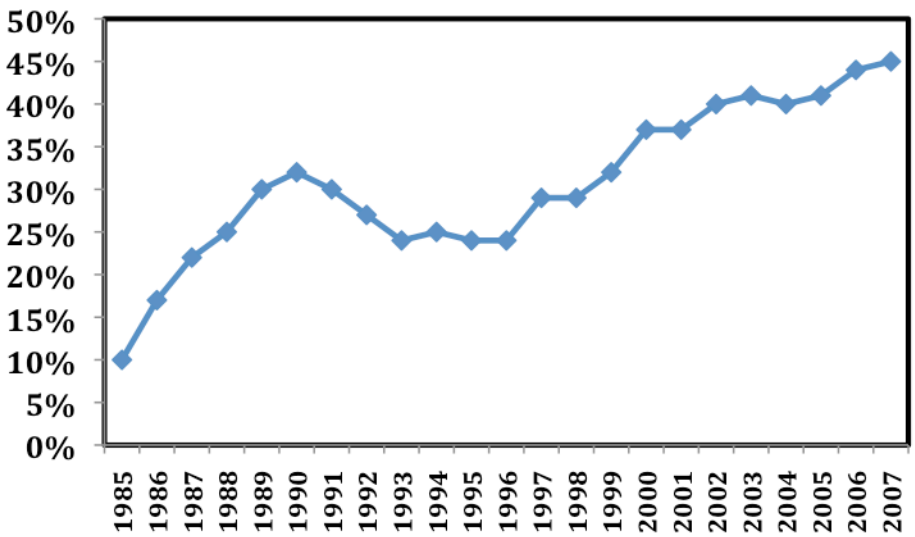
A recent draft regulation effectively accomplishes the same goal as the DMO, but this time in the name of upgrading the value-added capacity of Indonesia's mining industry. In mid-July 2011, the Coordinating Ministry for the Economy circulated an advanced draft of a regulation entitled "Value added Upgrading of Minerals and Coal through Processing and Refining Activities" that will ban the export of low-calorific coal starting in January 2014, thus affecting all coal of 5,100 kcal/kg or below. Some observers estimate that the regulation will prevent up to 130 million metric tons of coal being exported.[18] The ostensible goal of the regulation is to generate "economic, social and cultural benefits", as yet undefined, and coal is further divided into two categories: "coal as commodity" and "coal as an energy raw material or domestic source of energy". As Bill Sullivan writes, the required processing of "coal as a commodity" may be in the form of crushing, washing, blending, upgrading (usually through water content reduction), or the processing of low rank coal into "activated carbon". The latter category may require processing in the forms listed above, as well as briquetting, liquefaction, water mixing, processing into coke coal, or processing or extraction by underground coal gasification (UCG).

Nearly two-thirds of Indonesia's domestic coal demand is for electricity production, with the remainder dedicated to industrial use. Coal-fired electricity production in Indonesia is carbon intensive, averaging 1,047.2 grams of CO_2/kWh in 2008. This figure had increased from 967.3 in 2002. In comparison, oil-burning power plants produce 731.1 grams of CO_2/kWh and average gas-fired plants produce an even lower 507.0 grams.[19] While lower than the corresponding figure in India, Malaysia, and the Philippines, Indonesia's electricity-related

[18] Bill Sullivan, "No low cv coal exports after 2014 – A nationalistic aspiration somewhat at odds with reality", *Coal Asia Magazine*, Aug-Sept 2011.
[19] IEA, OECDiLibrary, 2011.

carbon intensity is higher than that of China (899.9), Vietnam (987.8) and the US (901.4) The national weighted average total for Indonesia is 726.1 grams CO2/kWh, which is 11 percent higher than that of Malaysia, 37 percent higher than that of Thailand, 50 percent higher than the Philippines, and 76 percent higher than Vietnam.

Coal's Contribution to Electricity Production



Measured Carbon Intensity and Calculated Environmental Cost of Fossil Fuel Power Plants in Indonesia

Type of Power Plant	**Carbon Intensity (CO2 kg/kWh)**	**Cost of Environmental Damage (US Cents/kWh)**
Coal-fired Steam	922	2.45
Oil-fired Steam	735	1.96
Natural Gas-fired Steam	503	1.34
Oil Combined Cycle	620	1.65
Natural Gas Combined Cycle	407	1.08
Gas Turbine (Natural Gas)	726	1.93
Gas Turbine (Diesel)	1,230	3.27
Diesel Generator	772	2.05

Source: Widiyanto, A., Kato, S., Maruyama, N. "Environmental impact analysis of Indonesian electric generation systems" Japan Society of Mechanical Engineers International Journal Series B 46/4, pp. 650-9.

Indonesia's average thermal coal unit size is 300MW, and the national fleet's average thermal efficiency has ranged from 34 to 35 percent in recent years.[20] Only 11 of Indonesia's coal-fired units are rated 600MW and above, and an international tender process was completed in April 2011 for the construction of the nation's first ultra super-critical plant. The plant consists of two units, each rated at 1,000MW, and was proposed by an international consortium led by Pt Adaro Energy of Indonesia, in partnership with Electric Power Development Co., Ltd., and ITOCHU Corporation, both of Japan. The consortium received a Letter of Intent from PLN on June 17, 2011, and the plant will be built in Batang, Central Java. Construction is scheduled for August 2012, however a PPA has not yet been signed.

Moving forward, coal clearly dominates the country's planned additional capacity. Over 17,000MW of coal-fired capacity is already under some form of bidding and tender, while natural gas and geothermal units under consideration only equal 8,000MW, and 1,200MW respectively. This is largely because of coal's continued cost advantage. Most coal-fired power plants have overnight costs that range between $1,000 and 1,400/kWh. Construction times also vary, but usually do not exceed four years. If externalities are excluded and if low domestic prices of coal are assumed, coal is the cheapest source of electricity. The appendix describes various estimates of the cost of generating electricity with coal.

One of the obstacles to rapid growth of coal-fired power remains transport and related infrastructure bottlenecks. As a recent IEA report has outlined, Indonesia's coal resources are mostly located in Kalimantan and Sumatra. The majority of demand is in Java-Madura-Bali. Mine-mouth power plants are one way of achieving "coal-by-wire" to overcome such transport challenges, but will only be a partial solution. The barges used by coal suppliers in Kalimantan and Sumatra operate in narrow rivers and are often rendered impassable during the dry season. Moreover, Indonesia's cabotage policy requires transport vessels to fly Indonesian flags, creating periodic supply shortages that delay deliveries.

As a result, the DMO should be replaced with an explicit export tax of equivalent value. Such a tax would raise direct fuel costs for PLN, but the GOI would be receiving higher revenues that could be invested on PLN infrastructure. PLN in turn may invest in coal-fired production at higher levels, but more importantly could divert some of the resources to the building of much-needed gas pipeline infrastructure. Removing DMO would reduce the monopsonist power that PLN exerts on coal prices, reduce the opacity and corruption that plague supplier relations with PLN, encourage fuel switching and the build out of natural gas, and would enable coal producers to export at their discretion. This export freedom would increase coal exploration investment, reduce the problems of coal quality that occur when coal is rationed and underpriced, and

[20] IEA, "Energy Policy Review of Indonesia", 2008, p.174.

enables the Ministry of Finance to spend the increased tax revenue as it sees fit. An explicit export tax will also lead to industry consolidation, as smaller, less efficient coal producers who have been skirting mandatory pricing regimes will be unable to compete.

Exchange Rates and Electricity Prices

The rupiah has fluctuated within a fairly narrow range against the US dollar in the last decade from $1 = 8500 to 10,500 rupiah. This is helpful for PLN because much of the cost of electricity ultimately depends on dollar costs – either because the natural gas or coal is priced in dollars or because the imported capital equipment (which is paid off over time) is imported and priced in foreign currency.

The rupiah is relatively strong right now and so the rupiah price of electricity is 10-20 percent less than if it were just a year or two earlier when the rupiah was weaker – even if the dollar price of electricity had not changed. (In fact, rupiah prices increased in 2009-11, bringing average PLN prices per kWh closer to actual marginal costs.) If the rupiah were to slip towards the weaker end of its range, this would put pressure on PLN if it kept its rupiah prices constant, since rupiah costs would then be higher for the dollar based component of its costs. That is, a weak currency combined with price controls on electricity will cause PLN to have bigger losses, or to require larger subsidies.

One way to deal with this issue is to have a portion of the electric bill be indexed to the actual fuel cost. This will anyway tend to fluctuate even with a strong rupiah and passing the actual fuel cost through to the customer (less any applicable subsidy) would be one way to insulate PLN's accounts from global energy price or exchange rate fluctuations. This would not deal with the part of costs attributable to repaying loans for imported capital goods, but that component tends to be a lot less than fuel.

Another way to deal with this would be to set a notational exchange rate (say Rp. 9500 =$1) and set electricity prices to generate a small profit on new energy production at that rate. If the actual rupiah exchange rate were lower (i.e. stronger), PLN would be allowed to put any surplus into its own stabilization fund and if the Rp were higher (i.e. weaker), it could draw upon that fund. This would insulate PLN from most exchange rate fluctuations that centered around the middle rate, but would not help if the exchange rate continually weakened.

Pricing Policy in Remote Locations

One reason that so many Indonesian families are still not connected is that the geography of Indonesia with its thousands of islands, most of them rather small, makes it difficult and expensive to connect everyone. Diesel generators can work almost anywhere but are very costly. Since capital for even normal capacity expansion is short, expanding connections to remote areas has proceeded slowly. One approach to "equity" is to make the cost of electricity equal, no matter where people live. Another approach is to reduce the cost of basic power in remote locations but not necessarily to equalize it.

It is likely that thin-film solar (roof top) installations will be able to produce electricity, without subsidies, at 15 cents per kWh by 2014.[21] Providing finance for these solar electric systems, with battery backup, would be an alternative way to allow remote households to benefit from basic amounts of power without having to construct costly generating and grid systems. While heavier users would need larger loans, it still should be possible to use decentralized generation as a solution to providing electricity without burdening PLN with a completely uneconomic business model. In India, where a similar proportion of households are not grid-connected, solar electricity is already expanding rapidly.[22]

There are currently 18-20 million households without electricity. If a small (500 watt) solar system cost could be reduced to $1000 and loans extended at 7 percent, the cost of servicing a 20 year loan would be $7.50 a month for perhaps 70 kWh a month or about eleven cents per kWh. Except for the reduction in the interest rate, the cost of the investment would not be subsidized. The assumption is that Indonesia would pass on the government five year bond rate to borrowers, rolling over the debt incurred to extend loans as needed. A higher interest rate covering administrative costs is possible, but the payments would be higher. This would be a fairly low-cost (for the government) way to make power available, though it would be more costly to customers than the current charge which is about nine cents per kWh when any connection is available. The total amount lent would be a few billion dollars per year, assuming 10-20 percent of unconnected households each year would convert to solar electricity.

Industrial Zones and Electricity

Currently, the law is that (with one exception), PLN has the right of first refusal for providing electricity to industrial zones (IZ). It is not legally clear if this means that PLN has to be able to supply power reliably or just sometimes. In any case, it would be desirable to allow all industrial zones to have the option of contracting with "their" factories to supply power if both agreed that it was preferable to buying it from PLN.[23] While current law allows isolated generation to be licensed locally, it is not desirable to have the IZ cut off from the grid for at least two reasons. One is that often the IZ has to invest in a large generating unit and wants to be able to sell surplus power to PLN at a negotiated price until its space is filled up and the factories use all of the IZ electrical capacity. This requires connection to the PLN grid, and of course PLN should have a right to allow this or not. The second reason is that if something happens to the IZ

[21] This is according to Victor Abate, the Director of General Electric solar systems. As quoted in a May 11th, 2011 Bloomberg story, he predicted falling costs and rising efficiency levels. First Solar, another producer of thin film solar units, has manufacturing costs below $750 per kilowatt now, with a steady decline predicted.
[22] See: http://www.nytimes.com/aponline/2011/07/02/world/asia/AP-AS-India-First-Light.html?hp
[23] The 2009 law does allow local governments to license alternative providers but only if they do not connect to PLN's grid. If they connect to the grid, then PLN again is able to veto their proposal, or at least not to connect.

generator, it is desirable to have the PLN grid as a backup. Thus, it is not enough to allow an "island" generator inside of the IZ.

This issue is somewhat academic now because there is a shortage of natural gas supply and without gas, the cost of IZ generation with diesel is very high. Thus, there is little pressure to change the law because it is the gas shortage that constrains more than the law. If gas supplies increased, then the legal question would become important. On the one hand, more gas would allow economic IZ provision of electricity. On the other hand, more gas would allow PLN to quickly increase its own supply and perhaps make the need for IZ generation unnecessary. A smooth mechanism to allow IZ generation with a grid connection would be desirable. It would likely attract private capital to reduce the burden on PLN investment and, with appropriate policies regarding buying and selling power, help both the IZ and PLN improve the reliability of their operations. However, the legal changes would have little impact unless the supply of natural gas improved considerably.

Conclusion

Despite Indonesia's much-vaunted wealth in natural resources, the nation remains acutely unable to transform those resources into the electricity needed to power continued economic growth. Electricity shortages are a critical short-term obstacle to GDP growth, but highlight a more fundamental medium- and long-term concern. To avoid falling into a middle-income trap, Indonesia must be able to upgrade its national economic competitiveness, and enter higher value-added production in the energy supply chain. Indonesian firms must be able to create the fuel processing, services, and transport businesses that will transform unprocessed raw energy materials upstream into more valuable downstream products. The creation of a national energy system engaging in both upstream exploitation and downstream processing requires an efficient electricity supply system.

PLN remains critical to the expansion and reform of such an electricity system. Current under-investment is in many ways rational, and a response to incentives that are misaligned. Should PLN expand the electricity supply to adequate levels and to all customers at currently subsidized prices, the firm would be even further in debt, and would create an even larger fiscal burden on the central government. As a result, there are four primary mechanisms through which expansion of Indonesia's electricity supply can be furthered.

First, as discussed previously, the prices paid by the majority of industrial and residential electricity users should reflect underlying costs. Heavy residential users now pay over ten cents per kWh and most industrial users pay nine cents for their electricity. Most rates therefore do not need more than a 10 percent to 30 percent increase to equal current costs. While large industrial users are currently paying a lower price for their power, a targeted increase in tariffs can be phased incrementally in order to mitigate the impact of this necessary increase.

Second, Indonesian electricity policy should continue to focus on increasing the nation's electrification rate. Subsidized rates for the poor should be continued, as long as they are targeted to a clear amount of kWh usage for those with modest total connection capacity to ensure that an adequate amount of energy supply is affordable and that the bulk of such subsidies is not enjoyed by the wealthy. In remote areas, low cost solar loans can be extended to residential users.[24] Small and medium sized companies in targeted industries such as energy processing, services, logistics, and transportation could enjoy subsidized electricity rates for the first 2-3 years of their operation in order to spur the creation of innovative energy activities.

Third, the building of ultra super-critical (USC) coal-fired technology should be encouraged through the continued liberalization of coal prices in the electricity industry. Coal price increases place operating cost pressures on power generation companies, which incentivize investments in higher efficiency combustion technology. Chinese coal price increases have had similar effect in catalyzing China's rapid expansion of USC technology. Should power generators continue to enjoy subsidized coal pricing, incentives to invest in USC boilers will remain low.

Fourth, diversification of Indonesia's electricity generation would be greatly enhanced through an increase in investment in the nation's geothermal and gas supplies. Increased tariffs for residential and most industrial users would allow the pass-through of much of the incremental costs these fuels incur. The development of additional gas into Java and the streamlining of geothermal siting approvals between central and local governments through the creation of a geothermal ombudsman would prove important steps forward in the diversification of energy supply. Pertamina Gas' recently announced plan to address gas shortages in West Java through the building of a pipeline connecting Cirebon and Muara Tawar is a step in the right direction. As the gas is to be provided in the form of LNG, the plan will need to include the construction of a receiving terminal, which has proven to be a long elusive goal of Indonesian energy policymakers. Much larger LNG import capacity on Java may be needed if conventional pipeline gas remains limited in supply.

[24] Heavy users in remote areas might need special attention. If natural gas can be piped, that would be one solution. If geothermal is feasible, that would be another. Both solutions allow production of only a few dozen MW at reasonable costs. Large solar installations, though more expensive and area-intensive, are a third possibility.

APPENDIX

Estimates of Capital and Operating Costs for Power Plants

The comparative costs of coal, gas and geothermal and other renewables will largely determine how new supplies of electricity are generated in this decade. Total cost per kWh is determined by the capital cost of the new equipment (partly dependent on the scale of the plant), the interest rate or return to equity charged, the hours of use per year, the costs of fuel and other overhead and maintenance costs. There are also issues of externalities, especially with coal.

One consulting report[25] estimated coal-fired generating costs by island and its mean cost estimates ranged from just above six cents per kWh on Sumatra and Java to eight cents on Sulawesi to ten to fourteen cents in various smaller islands. The higher costs reflect smaller plant size and higher resulting costs. If externalities are included, costs increased by two to three cents per kWh. This kind of fine-grained analysis is needed for specific investment decisions. (The same consulting report suggested geothermal generation costs in the range oft nine cents per kWh for larger fields and thirteen cents for smaller ones – somewhat above other estimates.) The report put the fob price of high quality coal at about $80 a ton while the current export price is closer to $120. If PLN paid the export price of coal, it would add 1.5 cents to the cost of generating electricity. This would bring the cost of coal-fired power close to the eight to ten cent range on Java suggested earlier in this paper.

Another approach is to use foreign capital and operating costs and apply local interest rates and fuel costs. This is done below, using US Department of Energy data for US generating plants. It probably overestimates coal investment costs relative to Indonesia but is likely closer on gas and geothermal costs. The US Department of Energy data for 2010 are given below.[26]

Type of Unit	Overnight cost in $/KW	Fixed O&M per KW	Variable O&M $/MWh	(Size in MW)
Advanced Gas:				
Single Cycle	$665	$6.70	$9.87	210
Combined Cycle	$1003	$14.62	$3.11	400
Coal	$2844	$29.67	$4.25	1300
Nuclear	$5335	$88.75	$2.04	2236
Geothermal	$4141	$84.27	$9.64	50
Wind	$2438	$28.07	$0.00	100
Solar	$4755	$16.70	$0.00	150

Fuel Heat Rate and Efficiency

[25] "Phase 1 Report: Review & Analysis of Prevailing Geothermal Policies, Regulations and Costs," PT Castlerock Consulting, 8 December 2010

[26] http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

Single Gas		Combined Gas		Coal	
9750 Btu/kWh	35%	6430 Btu/kWh	53%	8800 Btu/kWh	39%

Fuel Cost per kWh with Fuel Cost of:

25 million BTU/ton coal @ $120 per ton: 4.2 cents (2.8 cents if $80 per ton)

Single Cycle gas @ $8 per mm BTU: 7.7 cents (1.5 times for LNG price)

Combined Cycle gas @ $8 per mm BTU: 5.1 cents (1.5 times for LNG price)

Nuclear generation fuel cost is usually ½ to 1 cent per kWh

Hypothetical per kWh Capital Charge at 8 percent interest and 6000 hours/year (US cents)

Single Gas	Combined Gas	Coal	Nuclear	Geothermal
1.6	1.7	4.2	7.4	5.8

(Wind and solar units will not operate for 6000 hours per year.) Usually ¼ to ½ as much is realistic. If wind operated for 3000 hours and solar for 2000 hours, the capital costs would be 9.5 cents and 28 cents. A 10 year life is assumed for single gas; 20 year for combined cycle gas; 30 year for coal; and 40 year for nuclear and geothermal. Plant life can be extended through more extensive maintenance.

Hypothetical Costs of Power (US cents)

	Fuel	Capital	O+M	**Total**
Coal	4.2	4.2	0.8	9.2
Single Gas Cycle	7.7	1.6	0.6	9.9 (13.8 cents for LNG)
Combined Gas Cycle	5.1	1.7	0.9	7.7 (10.4 cents for LNG)
Nuclear	0.6	7.4	1.9	9.9 (7.9-8.9 if operating 7-8000 hours per year)
Geothermal	0	5.8	2.4	8.2 (6.7-7.2 if operating 7-8000 hours per year)
Wind	0	9.5	0.9	10.4
Solar	0	28	0.8	28.8

Note: These costs do not reflect the cost of transmission and distribution, which would add several more cents per kWh depending on a number of factors.

These costs are only broadly indicative since, for example, actual fuel costs can be lower (for coal) and capital costs can also vary considerably depending on scale and site. Solar costs can be expected to decline considerably over a five year period although electricity storage costs are another cost to be considered if the system is operating without fossil fuel backup. The number of hours a unit is used per year will vary, especially on smaller islands, with irregular load profiles and small grids. Finally, externalities in terms of pollution, carbon, etc. are not considered. As suggested, these would add two to three cents per kWh for coal but less for other sources.