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Pricing Framework and Methodology for Electricity Purchases and Sales Related to Non-Utility Power Transactions

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PRICING FRAMEWORK AND METHODOLOGY FOR ELECTRICITY PURCHASES AND SALES RELATED TO NON-UTILITY POWER TRANSACTIONS

Final Report

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EXECUTIVE SUMMARY

S.1 INTRODUCTION

On November 30, 1985 the Government of Indonesia (GOI) enacted a "Law on Power Sector" (Law No. 15). In Article 7 of the law, the GOI set forth its policy to encourage the granting of Power Enterprise Permits (PEPs) to enterprises other than the national electric utility, Perusahaan Umum Listrik Negara (PLN),

In essence, Law 15 reaffirms the GOI's desire to see private sector participation in the power market. The law formally recognizes the potentially important role of non-utility (i.e., non-PLN) power supplies alongside PLN generation in helping to ensure an adequate and economical supply of electricity to sustain the rapidly growing development needs of the nation.

This legislative initiative, if properly implemented, can have far-reaching and beneficial implications for the sector by creating the necessary environment for mobilizing additional resources from the private sector -- capital, technical, managerial, and entrepreneurial. In addition, the injection of competitive elements in the present market, which can essentially be characterized as monopsony (i.e., many buyers and one seller), should provide a benchmark for technical performance, cost and efficiency. This benchmark can serve as a comparative yardstick for all power producers -- PLN as well as non-PLN -- and help establish a market-based self-discipline, leading to more efficient sector performance than can be achieved by regulatory oversight alone. Among other expectations of the GOI is the speedier implementation of new power projects.

The successful integration of non-PLN generated power supplies with PLN generation in meeting national electricity demand in a least-cost mode requires among other things, the formulation and implementation of a framework and methodology for the pricing of power purchase and sale transactions that are likely to take place. This report presents such a framework for rationalizing the pricing of potential transactions within the context of an emerging power market in Indonesia where some entry restrictions to private power suppliers have been lifted.

S.2 PRIVATE SECTOR ROLE

Non-utility generation already plays an important role in the industrial sector and in some rural areas. However, Law 15 recognizes a key point that significant efficiency gains -- including capital additionality -- can potentially be achieved by creating a power market and industry structure that induce a market-type discipline on its participants more by market pressure and less by a central command and control regulatory approach. Such a market would be accessed by larger numbers of sellers of power who are allowed to operate within a transactional environment -- pricing, regulatory, legal -- that is transparent economically rational and fair.

More specifically, the power sector efficiency and capital additionality objectives can be enhanced by facilitating the contributions of private sector enterprises in the following manner:

- Coordinated and integrated use of existing captive generation with PLN. It is estimated that at present there is about 7,000 MW of installed captive generation capacity. This situation presents substantial opportunities for developing a load/demand-side management (DSM) program that provides the necessary incentives and framework for utilization of captive capacity to enhance PLN's grid system reliability at times of system emergency and to reduce the load on the grid for the purposes of peak load management.

- Promote additional investment in non-utility generation plant in situations where that is the least-cost supply option, i.e., where generation costs of non-PLN supply are competitive to supply the load. This condition may prevail in cases involving cogeneration plants.

  Elsewhere, the private supplier can tap certain unique and site-specific advantages, e.g., privately owned hydro sites, use of on-site waste (such as bagasse, rice husks, saw mill waste), large industrial facilities in remote locations that have captive generation or can develop a local resource for power generation (such as hydro, peat, geothermal, coal) to meet their own needs and supply the excess to PLN or directly to meet the local load.

- Introduce competitive market-type discipline and pressure for efficient performance by creating a "contestable power generation market": a market environment where non-utility owned and operated power plants (IPPs) can compete with public utility generation on an "equal and fair" basis," e.g., on a competitive bid basis, with those selected to participate under a build-own-operate (BOO) or some other scheme.

- Facilitate the formation of new and more effective participation of existing rural distribution companies, as well as small project entrepreneurs who can meet certain

minimum operational performance standards, thereby contributing not only to rural development but also in containing costs for such development.

Market Definition

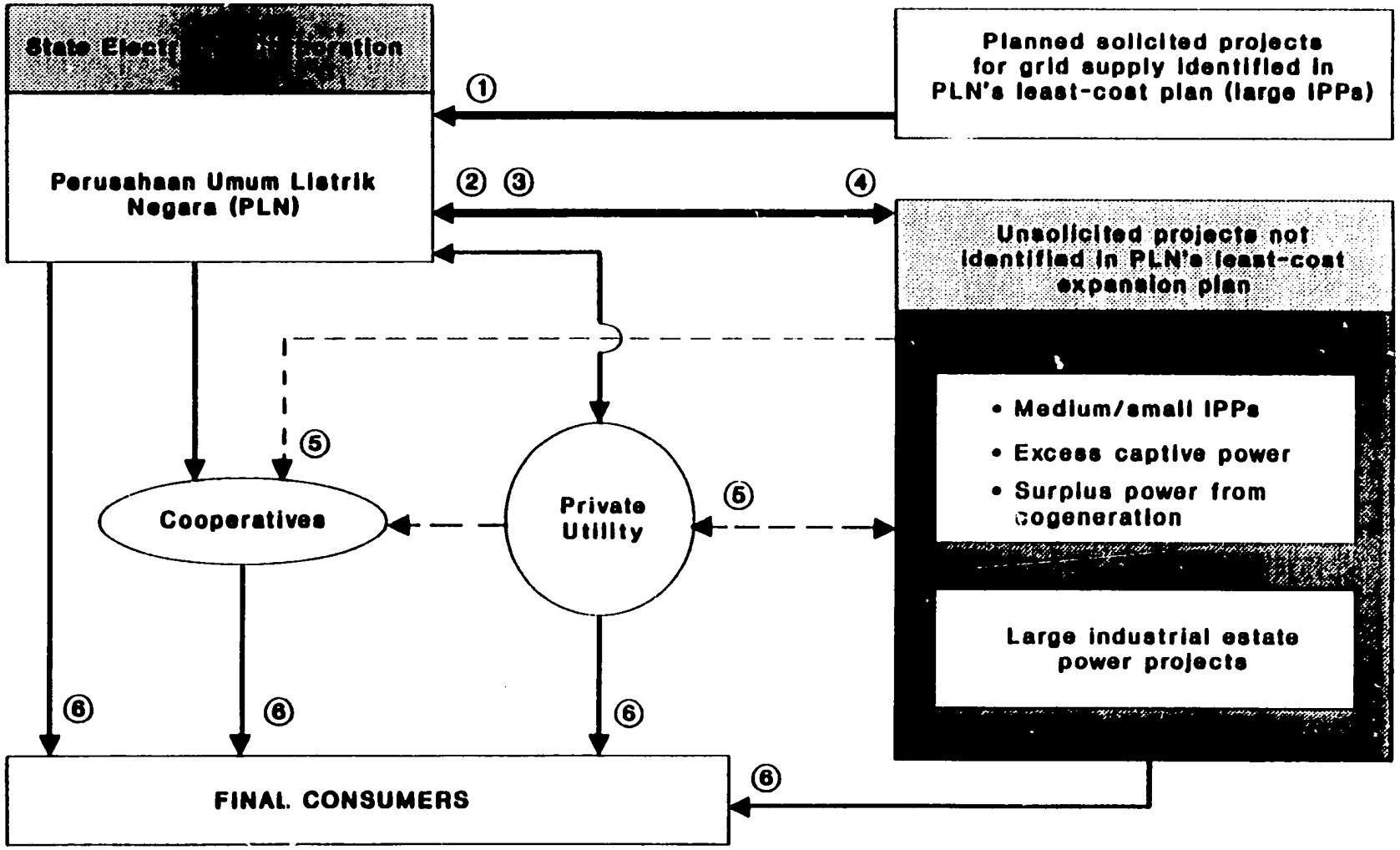
Broadly speaking, a "power market" can be defined by the collection of economic agents (buyers and sellers) and the institutions and regulatory rules in place that collectively define one or more mechanisms for effecting a variety of power purchase and sale transactions in a relatively open manner as regards information on the terms of such transactions, including pricing and risk sharing.

There exists a wide range of power transactions that buyers and sellers can potentially engage in within a power market, once there is more than supplier. The schematic in Exhibit 1 highlights the major power transactions that are consistent within the private power market model in Indonesia. The most significant transactions -- in terms of potential numbers and megawatts involved -- are potentially those shown by the bold lines in Exhibit 1, i.e., transactions labelled as categories 1, 2, and 3.

Transactions in category 1 represent potential power purchases from large private power projects, typically under a BOO contractual arrangement, and with the additional but important qualifier that such projects are identified in PLN's least-cost expansion plan. By contrast, categories 3 and 4 represent the potentially large number of medium (category 3) and small size (category 4) power purchase transactions from IPPs that have access to an economic resource on-site (such as hydro, peat, agricultural residue, by-product waste, and wind), excess power purchases from industry with captive generation, and excess power output of cogeneration plant installed by industry.

Also included in categories 2 and 3 are potential power purchases from power plants that are being proposed for development to serve large industrial estates. Some of the proposed projects in this category are large projects and would have surplus capacity during off-peak hours as well as possibly during the evening hours of the system peak. Such large sized plants should achieve conversion efficiencies typically realized by baseload utility plants and since they would be located in proximity to the loads, network losses would be avoided as well. Therefore, it should be a matter of high priority from the national efficiency perspective to provide the right price signals in order to foster optimal development of this private power supply potential.

Exhibit 1
MAJOR POWER TRANSACTION CATEGORIES WITHIN A PRIVATE POWER MARKET IN INDONESIA



S.3 FRAMEWORK FOR PRICING

The proposed framework draws upon the economic theory of efficiency pricing as the primary guiding philosophy. In the ideal paradigm of a perfectly competitive power market, an equilibrium linkage between supply and demand is achieved via the market-determined (efficiency) prices that reflect the real resource cost of supply. Economic theory suggests that under such conditions the relevant opportunity cost of a good -- such as electricity -- is its marginal cost, i.e., the cost of producing one more unit at a given point in time, or equivalently, the opportunity cost of resource savings ("avoided cost"), because of the power purchase from a private supplier.

Marginal cost pricing assures that society's resources and needs are balanced in the most efficient manner. Efficiency prices provide both the incentive and financial means for suppliers to build and operate the optimal amount and mix of capacity and to meet consumer demand most efficiently, i.e., in the least-cost manner.

By contrast, in the case of the emerging power market in Indonesia, an administered transfer pricing is recommended and indeed necessary. The term *administered pricing* denotes the setting of prices for permissible power transactions between the various participating economic entities involved -- some of whom wield market power whereas others may not -- by extra-market forces such as regulators. Administered pricing is distinguishable from market pricing, wherein actually observed efficiency prices are the outcome of the dynamic interplay between supply and demand in the marketplace, and there is little need for regulatory oversight.

The need for administered pricing arises in the context of markets that lack strong competitive elements, as is the case with the way most power markets are organized today. Even with the market opening to IPPs and NUGs, for the foreseeable future, market power and concentration in the generation power market will continue to be heavily skewed, a situation that is fundamentally different from a purely competitive market paradigm.

The proposed adaptation of competitive market-type features to the power market context at hand is an administered price regime with the following goals:

1. Efficiency and Accountability

   - help maintain an efficient national market (i.e., satisfy consumer demand and growth, and at least cost)
   - efficient utilization of existing productive assets

2. Transparency

   - price validity
   - rules of the game are well defined and known to all
   - fair and equitable
   - easy to implement.

3. Maintain Financial Viability of Efficient Producers

Of the three goals noted above, the third is unique to the power market. Financial viability is not guaranteed in competitive markets, which favor survival of the economically fittest. Indeed, it is this feature that provides the built-in incentive for efficiency and accountability in a competitive market. In contrast, at least in an initial deregulation scenario, which is the case in Indonesia, guarantees of financial viability for *efficient* IPPs will be expected to be provided. Under these conditions the power project developer would be granted annual recovery of all fixed costs (including a fair return) as well as any variable costs. In essence, the market risk associated with demand fluctuations and fuel price fluctuations and possibly labor cost changes would be transferred and shouldered by ratepayers.

One effect of the lack of market risk in power markets is that absent effective regulation it cannot be ensured that a least-cost expansion path for sector expansion is achieved. Therefore, regulators will need to oversee the calculation and setting of administered prices and to ensure that such prices, as well as the development of private and PLN power supplies, conform to a least-cost expansion plan, thereby helping ensure the efficiency and accountability goals.

The objective of the short-run efficient utilization of existing productive assets refers to the use of power supplies from all sources in accordance with the principle of merit order dispatch. To ensure this, energy price payments to NUGs and IPPs should reflect PLN's *short-run marginal energy costs*.

The transparency principle is extremely important in the power market context as well. Transparency in a competitive market price system means that prices are publicly known to

all economic agents, they are direct in that they represent the actual cost of resources expended (price validity), and whereas prices may vary by market segments, such differential pricing is not discriminatory, but is justified by the different market characteristics. Furthermore, if differences arise between various economic agents, fair and speedy recourse is available through a legal system. In the power market, transparency is interpreted more or less analogously.

The importance of transparency cannot be overstated. Transparency facilitates more rational and long-term oriented decision making. With less guesswork, transaction costs can be lowered because less time needs to be devoted to figure out the market and more importantly, the perceived risk is reduced. Ultimately, this will also translate into more IPPs and NUGs willing to "come to the table," and result in increased additionality of power, financial resources, and in the case of IPPs, in a lower cost of capital, as well as requiring fewer guarantees.

S.4 ADMINISTERED PRICING BASIS FOR SELECTED POWER TRANSACTIONS

This section provides a brief summary of the basis for setting administered efficiency prices for transactions within each category identified in Exhibit 1.

Category 1: Large Independent Power Producers

The first type of transaction represents a power purchase by PLN from a dedicated power project identified in PLN's unconstrained least-cost expansion plan (LCEP) and sponsored by an independent power producer (IPP). Such projects potentially include the coal-fired Paiton projects (Units 7 and 8), and the baseload coal projects in Central Java (2 x 600 MW) and in West Java (1 x 400 MW).

The recommended methodology for transfer pricing related to such power purchases is a blend of two concepts:

- "avoided cost pricing" and
- bidding.

Put simply, avoided cost represents the incremental resource savings -- fuel, labor, capital, etc. -- that would occur as a consequence of the contemplated power purchase. Equivalently, it

represents the incremental cost that would otherwise be incurred absent the power purchase in question.[1]

Whereas specific aspects vary, a bidding process works as follows. Periodically, (e.g., annually) the utility (in the present context, PLN) would update the load forecast and determine the need for additional resources based upon a least-cost planning study.

Next, the capital expenditure requirements for the least-cost plan would be estimated. These requirements would be assessed against clearly articulated guidelines on the amount of financing PLN can count on from the GOI and the amount of additional debt PLN is permitted to incur within a time frame encompassing a minimum of the next five years of the planning horizon. Within such a framework, PLN would determine the amount of capacity it can finance and therefore build. The remaining resource requirements would be offered to the private sector by issuance of "requests for proposals" for additional resources specified by variables such as plant capacity, unit size, fuel type, timing, dispatchability, availability, and other performance and design characteristics.[2]

The implementation of such a framework would require the GOI to implement and adhere to a multi-year capital expenditure program agreement that provides a more predictable and longer-term financial basis for PLN management to make long-term investment decisions. In particular, because of the long lead times involved in power plant construction (typically from four to five+ years for major baseload units), PLN needs clear and stable policy guidance as to the likely sources and magnitude of investment funds that will be made available by the GOI and the amounts it will be authorized to raise in local and foreign capital markets for at least a five-year forward horizon.

Category 2: Medium Size NUGs, IPPs, and Cogenerators (>5 MW)

The second class of power transactions identified in Exhibit 1 deals with power sales by NUGs in the mid-size range (typically in the 5 to 50 MW range). Individual projects in this category are unlikely to be identified in PLNs' least-cost expansion plan. However, had PLN known about these site-specific projects, they would be incorporated in the least-cost plan.

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[1] The *avoided cost pricing* approach first achieved prominence in the context of the 1978 "PURPA" legislation in the U.S., which required utilities to purchase excess power from cogenerators under "avoided cost principles." *Bidding* procedures have also be instituted in several states in the U.S. in recent years.

[2] By contrast, in some jurisdictions in the U.S., the bidding framework for resource acquisition is structured such that the utility is essentially the provider of last resort, i.e., all incremental resource requirements are offered for bidding. Bids above the utility's avoided cost are not accepted. Any unmet resource needs are then built by the utility.

The model in the main text above is better suited in Indonesia, at least for the foreseeable future.

For non-firm sales, a "standard offer" is proposed. A standard offer simply refers to a tariff that is publicly posted by PLN, as are all other tariffs for retail power sales. PLN's power purchase price for this type of transaction would be a posted tariff based on the "short-run marginal energy cost"; this being the system avoided cost.

For firm power purchases, it is recommended that the seller be given the choice of a standard offer under which PLN posts a two-part tariff; energy prices are set at short-run incremental fuel costs, and a capacity payment is pegged to long-run marginal capacity costs (LRMC).

Category 3: Small NUGs and IPPs (< 5 MW)

Two standard offers are recommended for this category of transactions: non-firm and firm. For sellers in this category, negotiated tariffs are not recommended. These offers should be developed with the pricing basis already identified above for Category 2 transactions. In this manner, small power producers and cogenerators can avoid protracted and potentially costly negotiations that would otherwise require utilizing legal and technical experts in dealing with PLN.

Category 4: Sales by PLN to Industry with Captive Generation

Industrial customers with self-generation may require supplemental power supplies to augment their generation, maintenance power (when their generators are down for maintenance), or standby/backup power service (when their generator is down on forced outage). Tariffs must be developed for these transactions because they are an essential part of a power market wherein there are non-utility power producers. These tariffs should not be discriminatory for otherwise, they will restrict the optimal development of private supplies and their interconnections and synchronization with the grid.

Category 5: Third-Party Sales between Non-PLN Producers, Cooperatives, and Private Utilities

Transactions in this category will mirror some or all of the transaction categories 1 through 4 identified above, except that the buyer is not PLN. The pricing principles applicable for such third-party transactions are the same for the corresponding transactions 1 through 4 described above.[3]

[3] As a practical matter, category 1-type transactions within the third-party sales category are unlikely for the foreseeable future. Rather, any third-party transactions will mirror those in categories 2, 3, and 4.

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Category 6: Final Consumer Sales

As can be seen from Exhibit 1, category 6 transactions refer to sales made to final consumers by PLN and non-PLN producers.

The first option is the traditional accounting cost-of-service based approach, under which the tariff yield/average price is set to recover these costs. However, the tariff structure should reflect the marginal cost structure. This method will typically lead to price differentiation across islands and possibly even within an island. Another major underlying principle in this context is to establish a direct link between costs and tariffs, thereby obviating the need for subsidies.

S.5 CONTRACT PRICING STRUCTURE FOR DEDICATED IPPs AND OTHER LARGE NEGOTIATED POWER PURCHASES

This section discusses the pricing determination approach for large power purchases from IPP projects such as Paiton and "Paiton-like" projects.

Under the administered pricing approach described in the paper, the power supplier should be able to recover all legitimate costs -- including return on investment -- consistent with efficient operations; and consistent with the overall "price cap" that is pegged to a peer plant's economic avoided cost.

A two part pricing structure is recommended with:

- a fixed payment per kilowatt of available capacity
- a unit price per kilowatt hour purchased that is mainly fuel related

The former is somewhat akin to a capacity reservation charge It represents all the agreed-to fixed costs and return of the project company that PLN must pay to maintain the sole right to receive electricity from the plant when called upon. The second component of the purchase is a unit charge per kWh of electricity purchased. This component essentially represents incremental fuel and other variable costs. Indeed, this could be specified in the form of a cost curve (or a family of cost curves) -- as other PLN plants are characterized for dispatch purposes -- that defines the unit price at a loading position, loading level, and specified operating regime.

The two part pricing structure is superior to a take-or-pay pricing structure which is sometime mentioned in this context. To illustrate this consider a 25 year take-or-pay contract for power purchase from a 400 MW baseload coal plant to be operated at an annual load factor of 0.7,

or equivalently supplying 2,453 GWH for each year at a first year price of Rp. 115/kWh, of which Rp.40/kWh represents fuel and other variable costs.

This type of contract, despite its apparent simplicity, has several operational shortcomings that compromise economic efficiency. First, it is not desirable from the national power system's operational standpoint to commit a plant to operate for 25 years at a load factor of 0.70. Over the longer term, new and more efficient plants would be built, pushing this plant up in the merit order economic dispatch and therefore requiring a lower load factor duty, or simply a change in its position in the loading cycle.

Also, because of oil price fluctuations, some oil-fired plants may be cheaper to operate during certain years. Further, new supplies of cogeneration could become available and cheaper to utilize. All these unpredictable situations will call for changing a plant's loading order if an economic dispatch regime is to be followed. This will result in a higher heat rate for the plant. Such efficiency changes can easily result in several millions of dollars of additional fuel costs and represent a substantial risk to the project sponsor. A provision would have to be made in the contract for this type of variance, by anticipating unforseen conditions. The alternative is that PLN has little flexibility in changing the position of the plant in the loading cycle. This would inevitably compromise its ability to closely adhere to a least-cost unit commitment and merit-order dispatch regime.

In summary, a major economic inefficiency embedded in the take-or-pay contract structure stems from the fact that PLN dispatch will treat the given power plant as a "must run unit," i.e., it will be dispatched first even if this results in a higher than least-total cost system operation. By contrast, under the economically efficient two-part pricing structure, the PLN operator "sees" the true marginal price (i.e., the variable energy charge component of price[4]) and therefore can optimally integrate (i.e., dispatch) the power plant into grid operation. In addition, as noted earlier, the actual marginal price will change over time for the given plant and in relation to the marginal price of other plants that are dispatched. Under the two-part pricing structure, grid dispatch and operations will continue to optimally integrate all non-utility power plant operations. This obviously will not happen under the take-or-pay structure since the pressure will be on PLN to dispatch the plant first to take its contracted output regardless of its cost and efficiency vis-a-vis other plants.

The primary advantage of a take-or-pay contract appears to be that on the surface it is simple and therefore perhaps more readily understood by non-utility personnel. However, from an economic efficiency standpoint, a two-part contract pricing structure is far superior. This type of contract pricing structure offers the following benefits:

[4] In the illustration above this would be the fuel related cost, say Rp. 40/kWh

- incentive to maintain high plant availability at all times.
- generation efficiently scheduled accordingly to actual marginal cost (i.e. permits economic dispatch)
- generation unit operation -- commitment, loading levels, dispatch -- in the same manner as all other PLN plants on the grid
- minimization of total cost of system operations.

By contrast, the take-or-pay contract structure only offers the first of these three benefits identified above.

Capacity Payments Under Two-Part Contract Pricing Structure

Under the two part contract pricing structure described above several formulae can be developed to determine actual payments for the first component i.e., capacity payments. The primary considerations in formulating such a formula should be that payments be linked directly to performance and not be made on a cost incurred basis. In other words, the formula should provide a built-in incentive and penalty structure for efficient performance. The following formula typifies this approach:

Capacity payment = A + B + C

where, A = Fixed payment to recover capital costs for the Billing Period, (month).

B = Payment to recover fixed costs of operations and maintenance for the Billing Period, costs that are independent of the amount of kWh generated.

C = Payment to recover other fixed costs for the Billing Period that are agreed to and represent "pass throughs" of actual costs such as insurance costs, taxes, etc. that are not predictable with an acceptable degree of accuracy and that are not already included in components B & C..

Capital costs (component A) can be calculated as follows:

$$A = [CPR * DC * AR] - [(y * 1.1) (CPR) (CC-DC)]$$

where, CPR = Capacity Payment Rate per kW per Billing Period in the elected currency(ies) of Seller. This rate reflects an expected availability rate.

DC = Dependable Capacity (kW) for the Billing Period, is defined as the maximum dependable load carrying capability of the facility, exclusive of capacity required for facility use. Dependable capacity can be determined by tests conducted in accordance

with a mutually agreed test criterion on a periodic basis, and cannot exceed the contract capacity.

CC = Contract capacity (kW), means the net amount of power offered by Seller during the Contract Period as measured at a specified interconnection point.

AR = Availability rate is defined as the net amount of electricity that the Project is capable of generating during the Billing Period in kWh and taking into consideration actual downtime for forced outages, maintenance and any capacity deratings during the billing period, divided by the product of the Dependable Capacity and the number of hours in the Billing Period.

y = A factor that is equal to 0 if $(0.95 * CC) \leq DC \leq CC$, and otherwise equal to 1.0

The capacity payment rate CPR utilized for the calculation defined above will be arrived at on a negotiated basis. Furthermore, the CPR will vary over the contract horizon (e.g., 25 years under a BOO scheme). The possibilities are many in this regard. Under one scheme, CPR payments could mirror the profile of debt service that is embedded in the financing package. Smoother profiles, i.e., with fewer step changes can be developed by levelizing payments over specified periods and by adjusting the time phased manner in which equity holders achieve their target internal rate of return. The CPR payment profile finally chosen will be the outcome of contract negotiations and will be driven by the financing structure, and the temporal profile of return of shareholder equity.[5]

S.6 CONCLUDING OBSERVATIONS

Private sector participation in the Indonesian power sector -- in the form of IPPs, NUGs, cogeneration, captive power -- holds the promise of significant benefits to the nation. However, if this promise is to be realized and sustained to any significant extent, it will be necessary to rationalize and implement a market transactional structure and environment in which the rules of the game -- regulatory, contractual, legal, financial -- are transparent, fair and equitable, and provide efficient, unambiguous, strong signals to all the power producers and potential entrants as regards the financial and risk implications of participating in the market as well as the financial rewards from efficient performance.

[5] A project financial model that can simulate after-tax cash flows given the financing structure is required to address this linkage between project financing and CPR profiles that are not only equivalent but also consistent with the "financial architecture" of the project. An example is presented in Chapter 4.

This report proposes an administered efficiency pricing framework that is grounded in the notion of economic efficiency. In contrast to a highly competitive market where supply-demand interactions automatically determine efficiency prices, in the power market, administered efficiency prices must be derived from a least cost expansion plan for the sector. Furthermore, unlike a highly competitive market which is self-policing and hence self-regulating, in the power market some independent regulatory oversight will be essential to ensure that PLN's least cost plan is indeed such. If properly implemented, this pricing approach will stimulate optimal (least cost) development and efficient utilization of Indonesia's energy resources jointly by IPPs, NUGs, private utilities, and PLN, and at least cost.

CHAPTER 1: INTRODUCTION

1.1 BACKGROUND AND STUDY OBJECTIVES

On November 30, 1985 the Government of Indonesia (GOI) enacted a "Law on Power Sector" (Law No. 15). In Article 7 of the law, the GOI set forth its policy to encourage the granting of Power Enterprise Permits (PEPs) to enterprises other than the national electric utility, Perusahaan Umum Listrik Negara (PLN):

> ...insofar as the interests of the Government are not harmed, the widest possible opportunity shall be given to entrepreneurs and other enterprises to provide power based on the PEP.

Under Article 2, such enterprises were defined to include those engaged in the provision of power generation, power transmission, and power distribution.

Law 15 represents a significant legislative development in the Indonesian power sector's nearly 100-year history.[1] In essence, Law 15 reaffirms the GOI's desire to see private sector participation in the power market. The law formally recognizes the potentially important role of non-utility (i.e., non-PLN) power supplies alongside PLN generation in helping to ensure an adequate and economical supply of electricity to sustain the rapidly growing development needs of the nation.

This legislative initiative, if properly implemented, can have far-reaching and beneficial implications for the sector by creating the necessary environment for mobilizing additional resources from the private sector -- capital, technical, managerial, and entrepreneurial. In addition, the injection of competitive elements in the present market, which can essentially be characterized as monopsony (i.e., many buyers and one seller), should provide a benchmark for technical performance, cost and efficiency. This benchmark can serve as a comparative yardstick for all power producers -- PLN as well as non-PLN -- and help establish a market-based self-discipline, leading to more efficient sector performance than can be achieved by regulatory oversight alone. Among other expectations of the GOI is the speedier implementation of new power projects.

[1] Before the law was enacted, the power sector had been regulated under an ordinance dating back to 1890 that was updated occasionally. In addition, in recent years, several Presidential decrees have guided power sector policy and evolution.

If the promise of efficiency gains from private sector participation are to be realized and sustained, a substantial amount of preparatory groundwork and sustained follow-on work will need to be carried out. Key among these initial efforts is the formulation and timely release of the following documents that we understand are being developed by the Private Power Team:[2]

- *A policy statement* (KEPRES) that more explicitly spells out the GOI's objectives with respect to private power, and provides the guiding principles for its development. The KEPRES would also identify institutional responsibility for the coordination of private power efforts and define the manner in which cabinet oversight would be carried out.

- *Implementation guidelines.* This document expands the policy guidelines, directions, and tone set in the KEPRES. It will establish the policy framework that ensures private sector enterprises a reasonable and fair rate of return while simultaneously protecting the public interest. This will require clarification, in sufficient detail, of the whole spectrum of key issues in order to ensure that the private power program can be implemented in a fashion that leads to beneficial and sustained development of the private sector. Such issues include the GOI's positions on:

  -- selection criteria for projects to be made available for private sector participation
  -- criteria and process for pre-qualification and bid evaluation
  -- project financing
  -- risk sharing
  -- guarantees and commercial details
  -- major clauses and provisions in any contract to be negotiated
  -- institutional and regulatory framework.

- *Draft power purchase and implementation agreements.*

[2] The Private Power Team was established pursuant to a decree by the Minister of Mines and Energy (#0666/K/702/M.PE/1990) on June 16, 1990 and subsequently amended on November 26, 1990 (#1649/K/702/M.PE/1990). The major responsibilities of the Private Power Team include (1) research and reestimation of electric power demand growth projections, (2) review of all effective laws and regulations, (3) preparation of terms of reference for private power projects, (4) requesting of proposals from private investors, (5) evaluation of proposals submitted, and (6) submission of proposal evaluation results and recommendations to the government.

The successful integration of non-PLN[3] generated power supplies with PLN generation in meeting national electricity demand in a least-cost mode will require the formulation and implementation of a framework and methodology for rationalizing the pricing of power purchase and sale transactions that are likely to take place. In addition to a well-defined methodological rationalization, it is essential that the process for project identification, bid evaluation, contractor selection, price setting, and enforcement be transparent and fair.

With the preceding as a brief background, the objectives of this effort are to:

- Identify and characterize potential power transactions within the context of an emerging power market where some entry restrictions to private power suppliers have been lifted.

- Recommend a framework and implementable methodology for rationalizing the pricing of potential transactions; such a framework should offer explicit pricing guidelines that emphasize the "correct" price signals. Such prices would foster the efficient utilization of existing generation, the optimal development of energy resources for power generation and transmission in the long run (i.e., diversification of supply, adequate reliable and efficient supply, and at least cost) and should be perceived as being fair and equitable. Finally, the emphasis is on power transactions that are likely to provide the most efficiency gains in the near to mid term.

- Review existing data and readily available information in light of the recommended pricing approach and scope out the next steps to be taken by the Private Power Team in implementing the recommended pricing framework.

1.2 ORGANIZATION OF THE REPORT

This report is organized as follows. The remainder of this chapter (Section 1.3) contains an overview of background and historical information about the power sector that is of relevance to the task at hand. Next, Chapter 2 describes an efficient pricing framework for the range of transactions likely within the context of a specified market structure. Chapters

[3] The term non-PLN generation encompasses non-utility generators (NUGs) and independent power producers (IPPs), and is used synonymously and interchangeably throughout this document with the term "private power." The term IPPs refers to owners and operators of large and dedicated power projects likely to be operated under a build-own-operate (BOO) contractual arrangement. The term NUG is used to refer to cogenerators' projects, captive power projects, and other power supply sources that are built primarily to meet or supplement the customer's own needs rather than for the express objective of selling power to the grid.

3 and 4 focus on describing a methodology for implementing the pricing framework for the different types of power transactions identified in Chapter 2.

A major objective of this effort was to identify and scope out an action plan for supplementing the pricing framework. This is discussed in Chapter 5. Finally, Chapter 6 identifies specific references, and several appendices provide supporting information.

1.3 POWER SECTOR OVERVIEW

Organization and Evolution

The National Electricity Authority of Indonesia, PLN, was legally established in 1972 as a public corporation under Presidential Decree No. 18, elevating its earlier status as a department of the Ministry of Public Works and Electric Power. PLN is responsible for the generation, transmission, and distribution of electricity as well as the planning, construction, and operation of facilities required to provide electricity. Beginning with the early 1980s, the Ministry of Mines and Energy (MME), through the Directorate General of Electricity and New Energy (DGENE), has granted licenses to a few rural electric cooperatives to generate and distribute power in areas not connected to PLN's network. In addition, during the late 1970s and early 1980s, because PLN was unable to meet a significant portion of industrial demand, a large number of such establishments were given permits by MME and installed captive generation plant to meet their electricity needs.[4]

With a share of almost 60 percent in the country's total power generation and about 55 percent of national installed capacity, PLN has the dominant role in the sector. Specifically, the ownership of generation is distributed as follows:

- the government-owned PLN with an installed capacity of about 8,800 MW as of October 1990, of which 6,300 MW is connected to the Java-Bali grid

[4] Since 1983, DGENE has been administering a business license or permit process for non-PLN power generators producing power for their own use or for public use. The existing procedures are outlined in Decisions of the Director General for Power (DGENE). DGENE Decision No. 0236/47/500/1983 relates to "Business Permits for Public Benefit" (also translated as "Electricity Undertaking License for Public Interest" or "IUKU"); DGENE Decision No. 0237/47/500/1983 relates to Business Permits for Own Use, also translated as "Electricity Undertaking Authorization for Own Interest" or "IUKS." These licensing procedures are being revised to reflect the subsequent authority and role of the Private Power Team as well as providing more detailed direction to license applicants.

- a large number of captive plants (approximately 10,000) installed and operated by industries for their own use (6,700+ MW; of this capacity, more than 45 percent is located in Java)
- a small number of electric cooperatives in rural areas (about 20 MW)
- a large number (over 10,000) of unregistered micro-enterprises at the village level (about 300 MW).[5]

Installed Capacity and Mix

Exhibit 1-1 indicates that as of the end of fiscal year 1990/91 (March 31, 1991), PLN had a total installed capacity of 9,275 MW.[6] Energy generation of 34,012 GWh supported final sales of 27,741 GWh. The system-wide annual load factor has hovered around 65 percent in recent years. Network losses for the most recent year for which data were available were about 17 percent of gross generation and 18 percent of net generation.

Exhibit 1-2 provides a breakdown of the generation capacity mix, which can be seen to be predominantly (55 percent) oil based. However, the present situation represents a considerable improvement over the situation in the 1970s and early 1980s. Since that time, substantial amounts of coal-fired generating capacity have been commissioned, consisting of the 4 x 400 MW coal-fired Suralaya units (commissioned in August 1984, June 1985, February 1989, and November 1989, respectively). In addition, during 1985 and 1989, respectively, the hydro plants at Saguling (700 MW) and Cirata (500 MW) were commissioned. As a consequence, during FY 1990/91, oil-fired plants accounted for 46 percent of total generation (compared with 75 percent four years ago), while coal- and gas-fired plants had a combined share of 27 percent. Twenty-four percent was derived from hydropower and geothermal plants, and the remaining 3 percent was purchased.

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[5] Each enterprise is reported to typically consist of one entrepreneur operating a 2 to 5 kVA genset (costing $1,000 to $2,000), operating 4 to 5 hours/day, serving 15 to 70 households, and charging 400 to 800 Rp./kWh. According to the law, such entrepreneurs providing under 5 kVA of supply need not be licensed and can set tariffs without any outside oversight. By contrast, PLN's residential tariff yield (for classes R-1 through R-4) following the recently announced tariff increase is approximately Rp. 133/kWh.

[6] In addition, PLN purchased 265 MW from three large captive plants, namely, the Asahan and Juanda hydropower stations and the Krakatau steam power plant.

The high operating capacity margins -- on the order of 45 percent -- appear to reflect PLN's operating environment: a substantial amount of capacity derating of older generating units coupled with the reality that PLN is responsible for operating over 600 isolated power systems scattered over the entire archipelago.

Exhibit 1-1
PLN Installed Capacity, Generation, Sales, and Losses

Fiscal Year	Installed Capacity			Peak Demand **	Capacity Margin		Energy Generation ++	Station Use		T&D Losses		Energy Sales	Load Factor	No. Consumers	Connected Load
	PLN	Pur.	Total												
	MW	MW	MW	MW	MW	% +	GWh	GWh	% †	GWh	% †	GWh	%	10^3	MVA
1974/75	922	100	1,022	602	420	41.1	3,345	96	2.8	807	24.1	2,444	63.4	1,806	1,253
1975/76	1,129	100	1,229	638	591	48.1	3,770	106	2.8	861	22.8	2,804	67.5	1,141	1,426
1976/77	1,377	100	1,477	734	743	50.3	4,127	114	2.8	932	22.5	3,082	64.2	1,209	1,594
1977/78	1,863	100	1,963	835	1,128	57.5	4,725	137	2.9	1,061	22.5	3,527	64.6	1,413	1,934
1978/79	2,288	100	2,338	1,033	1,355	56.7	5,723	186	3.3	1,250	21.8	4,287	63.2	1,784	2,449
1979/80	2,536	100	2,636	1,276	1,360	51.6	7,004	358	5.1	1,303	18.6	5,343	62.7	2,247	3,063
1980/81	2,555	260	2,815	1,577	1,238	44.0	8,420	343	4.1	1,517	18.0	6,560	61.0	2,745	3,744
1981/82	3,032	285	3,317	1,876	1,441	43.4	10,138	395	3.9	1,898	18.7	7,845	61.7	3,232	4,503
1982/83	3,406	285	3,691	2,285	1,406	38.1	11,846	528	4.5	2,217	18.7	9,101	59.2	4,406	5,270
1983/84	3,935	285	4,220	2,413	1,807	42.8	13,392	580	4.3	2,812	21.0	10,000	63.4	5,135	6,127
1984/85	4,515	265	4,780	2,715	2,065	43.2	14,777	694	4.7	3,042	20.6	11,041	62.1	5,133	7,122
1985/86	5,635	265	5,900	2,966	2,934	49.7	16,899	855	5.1	3,338	19.7	12,706	65.0	5,953	8,150
1986/87	6,200	265	6,465	3,403	3,062	47.4	19,455	855	4.4	3,814	19.6	14,786	65.3	6,966	9,282
1987/88	7,237	265	7,502	3,890	3,612	48.1	22,306	1,051	4.7	4,178	18.7	17,077	65.5	8,203	10,711
1988/89	8,529	*265	8,794	4,497	4,297	48.9	25,623	1,269	4.9	4,327	16.9	20,027	65.0	9,276	12,234
1989/90	9,088	265	9,353	--	--	--	29,567	--	--	--	--	23,435	--	10,312	13,951
1990/91	9,275	265	9,540	--	--	--	34,012	--	--	--	--	27,741	--	--	--

Source: Reference [1] and PLN.

* 125 MW from the Juanda Hydropower Station, 90 MW from Krakatau Steel Steam Power Station in West Java, and 50 MW from the Asahan Hydropower Station in North Sumatra

** Arithmetic sum of not necessarily coincident peak demands in the individual systems

\+ As percentage of installed capacity (not reserve margin)

\+ + Including purchase

† As percentage of gross energy generation

Exhibit 1-2
PLN's Capacity and Generation Mix in 1990/91

Plant Type	Fuel	Installed Capacity		Energy Generation	
		MW	%	GWh	%
Steam	Oil	2,081	22	10,284	30
	Coal	1,730	18	10,910	31
	Gas	130	1	235	1
Gas Turbine		1,230	13	2,175	6
Diesel	Oil	1,870	20	3,608	10
Hydropower	-	2,095	22	5,675	16
Geothermal	-	140	1	1,125	3
Purchase	-	265	3	856	3
Total		9,541	100	34,868	100

Source: PLN

Exhibit 1-3
PLN's Regional Operations, 1988/89

	Java	Outside Java	Total
Installed Capacity (MW)*	6,201	2,593	8,794
Peak Demand (MW)	3,372	1,125	4,497
Energy Generation (GWh)**	20,066	5,557	25,623
Energy Sales (GWh)	15,692	4,335	20,027
Energy Losses (%)***	21.8	22.0	21.8
Annual Load Factor (%)	67.9	56.4	65.0
Number of Customers (million)	6.2	3.1	9.3

Source: Reference [1].
* Including a purchase of 265 MW
** Including a purchase of 683 GWh
*** As percentage of energy generation, including power station use

Regional statistics on power system operation shown in Exhibit 1-3 indicate that PLN's operations are concentrated in Java, which accounts for over three-fourths of total capacity, generation, and sales, and two-thirds of all customers.

Power Market

PLN's national energy sales increased from 2,444 GWh in 1974/75 to 27,741 GWh in 1989/90, at an average growth rate of 16.3 percent. Over the same period, the number of customers showed an average annual growth rate of 16.2 percent.

The data in Exhibit 1-4 reveal that the overall sales growth was caused by the increase in the number of connections rather than in average usage per customer. Indeed, the slight drop in average usage is a result of expanded rural electrification program coverage.

It is interesting to note that the GDP growth over the period 1975/75 to 1988/89 was 8.1 percent per year. This implies an extremely high "income elasticity" of electricity demand at 2.7.

The data also show (Exhibit 1-5) that PLN's sales in Java have traditionally represented the overwhelming share of national sales (on the order of 80 percent), but that this share has shown a declining trend because of the emphasis on the electrification of other islands. Further, the data reveal that sales growth rates have been marginally higher outside Java.

Exhibit 1-6 indicates consumption shares and growth rates in consumption by major consuming categories. At present, industry's consumption share of total PLN sales is the highest at 51 percent, followed by residential consumers (32 percent). Further, sales to industry have risen at the fastest rate (20.0 percent) and well over the average system-wide sales growth of 16.2 percent.

PLN's record in achieving a high connection rate for new consumers is remarkable. Over the decade 1979/80 to 1989/90, PLN added over 8 million new customers, or over 800,000 connections per year. In spite of this impressive record, the potential for electricity sales growth in the future remains high.

For one, despite the record noted above, the electrification ratio is still below 28 percent even in Java, the most heavily electrified island. Further, the per capita electricity generation, which is estimated to be about 250 kWh per year, is low when compared with other developing countries with similar or lower income levels.

Exhibit 1-4
PLN's Sales and Consumer Growth

Fiscal Year	Energy Sales		No. of Customers		Average Consumption	
	GWh	% p.a.	'000	% p.a.	kWh/con.	% p.a.
1974/75	2,444		1,086		2,250	
1975/76	2,804	14.7	1,141	5.1	2,457	9.2
1976/77	3,082	9.9	1,209	6.0	2,549	3.7
1977/78	3,527	14.4	1,413	16.9	2,496	(2.1)
1978/79	4,287	21.5	1,784	26.3	2,403	(3.7)
1979/80	5,343	24.6	2,247	26.0	2,378	(1.0)
1980/81	6,560	22.8	2,745	22.0	2,390	0.5
1981/82	7,845	19.6	3,232	17.7	2,427	1.5
1982/83	9,101	16.0	3,802	17.6	2,394	(1.4)
1983/84	10,000	9.9	4,406	15.9	2,270	(5.2)
1984/85	11,041	10.4	5,133	16.5	2,151	(5.2)
1985/86	12,706	15.1	5,953	16.0	2,134	(0.8)
1986/87	14,786	16.4	6,966	17.0	2,123	(0.5)
1987/88	17,077	15.5	8,203	17.8	2,082	(1.9)
1988/89	20,027	17.3	9,276	13.1	2,159	3.7
1989/90	23,435	17.2	10,317	11.2	2,217	5.2
1990/91	27,741	18.4	--	--	--	--
Average						
74/75 - 89/90	--	16.3	--	16.2	--	0.0
74/75 - 79/80	--	16.9	--	15.7	--	1.1
79/80 - 84/85	--	15.6	--	18.0	--	(2.0)
84/85 - 89/90	--	16.2	--	15.0	--	1.1

Source: PLN.

Exhibit 1-5
Regional Breakdown of Energy Sales

Region	1974/75		1988/89		Average Growth Rate % p.a.
	GWh	%	GWh	%	
Java	1,988	81	15,692	78	15.9
Outside Java	456	19	4,335	22	17.5
Total	2,444	100	20,027	100	16.2

Source: Reference [1].

Exhibit 1-6
Energy Shares and Growth Rates by Consumer Category
(PLN Sales)

Customer Category	1974/75		1990/91		Average Growth Rate % p.a.
	GWh	%	GWh	%	
Residential	1,163	48	9,004	32	13.6
Industrial	738	30	14,166	51	20.3
Commercial	225	9	2,328	9	15.7
Public	318	13	2,224	8	13.0
Total	2,444	100	27,741	100	16.4

Source: PLN.

Captive Power Development

During the 1970s, industrial enterprises installed captive generation on a large scale because of inadequate supply and the poor reliability of grid supply. Captive plant capacity of approximately 6,922 MW accounts for approximately 43 percent of the nation's total installed capacity, as of 1990/91.

Exhibit 1-7 shows the captive generation capacity and mix in Indonesia. The predominant fuel for captive generation is oil (83 percent in Java and 69 percent outside Java) is diesel with fuel oil's share being a mere 2 percent in Java and 3 percent outside Java. Other fuels used in significant amounts are gas in Java (14 percent) and hydro and wood outside Java (20 percent and 8 percent, respectively).

Exhibit 1-7
Captive Generation: Estimated Installed Capacity and Mix

Location	Installed Capacity 1990/91 (MW)	Generation Capacity Mix (%), 1988/89							
		Diesel	Steam					GT	Total
			Hydro	Coal	Oil	Gas	Wood		
Java									
East	641								
Central	571								
West	1,154								
Jakarta	856								
Subtotal	3,224	82	--	--	2	14	1	1	100%
Outside Java	3,700	46	20	--	3	0	8	23	100%
Total	6,922	62%	11%	-	2%	7%	5%	13%	100%

Sources: PLN and references [2], [3].

In the case of oil products, the overwhelming preference for diesel (No. 2) over residual fuel oil (No. 6 oil) can be surmised to have come about for two primary reasons: technical considerations as regards performance characteristics available captive generation plant and

the GOI's policies that historically distorted the relative prices of petroleum products by under-pricing diesel oil and over-pricing fuel oil. These price distortions have also contributed to the growth of captive power plant capacity because it was frequently cheaper for individual consumers to self-generate than to buy from PLN, whose predominant energy source was fuel oil.

Subsequent to the domestic price adjustments in May 1990, distortions in product prices have been reduced, with automotive diesel oil (ADO) priced at Rp. 245/liter (a 4 percent premium over border prices as of June 1990), industrial diesel oil (IDO) priced at Rp. 235/liter (a 5 percent premium over June 1990 border prices), and marine fuel oil priced at Rp. 220/liter (an 83 percent premium over June 1990 border prices).

The 6,922 MW of estimated generation capacity is spread over approximately 10,000 units split almost evenly between Java and outside Java. More than 90 percent of these installations are under 1 MVA each, and together they account for approximately 25 percent of installed captive generation capacity. On the other end of the spectrum (see Annex 1), the 34 companies each with an installed capacity of 20 MVA or greater, together account for 3,300 MW (approximately 50 percent of national captive generation capacity). Within this segment, the generation mix is as follows: 30 percent diesel, 30 percent gas turbines, 23 percent hydro, 13 percent gas steam, and the remaining 4 percent almost evenly split between fuel oil-steam and wood-steam capacity.

Of the national total captive generation capacity of 6,922 MW, approximately 2,000 MW are estimated to be operated in a "standby plant mode," i.e., predominantly for reliability support.

Finally, the energy generation mix for 1989/1990 is estimated to be 50 percent from diesel generation, 32 percent from steam, and 15 percent from hydro, with the remainder from all other sources.

Projected Power Demand

Exhibit 1-8 summarizes PLN's base case load forecast model. Load is projected to grow at an annual rate of about 12 percent in Java and 13 percent outside Java. The forecasts in Exhibit 1-8 are best interpreted as supply forecasts and not demand forecasts. Because of resource constraints on PLN -- manpower and financial -- the electrification ratio of substantially below 100 percent will prevail throughout the end of the forecast horizon. In addition, PLN has reduced, if not completely deferred, for a four-year period, the takeover of captive power in industry. The latter capacity is projected to rise significantly in the

Exhibit 1-8
Generation Load Forecast, Base Case

Year	Java-Bali		Other		Total	
	Peak Load (MW)	Energy Production (GWh)	Peak Load (MW)	Energy Production (GWh)	Peak Load (MW)	Energy Production (GWh)
1991/92	4,888	29,588	1,663	8,036	6,551	37,624
1992/93	5,684	34,406	1,881	9,162	7,565	43,568
1993/94	6,488	39,318	2,131	10,451	8,619	49,769
1994/95	7,578	45,973	2,410	11,916	9,998	57,889
1995/96	8,780	53,314	2,725	13,582	11,505	66,896
1996/97	10,129	61,555	3,082	15,474	13,211	77,029
1997/98	11,238	68,313	3,482	17,608	14,720	85,921
1998/99	12,273	74,607	3,928	19,997	16,210	94,584
1999/00	13,315	80,938	4,427	22,667	17,742	103,605
2000/01	14,443	87,793	4,976	25,619	19,419	113,412
2001/02	15,655	95,151	5,584	28,890	21,239	124,041
2002/03	16,965	103,108	6,256	32,516	23,221	135,624
2003/04	18,383	111,717	7,002	36,555	25,385	148,274
Growth Rate	11.7%	11.7%	12.7%	13.5%	11.9%	12.1%

Source: PLN (R6-Base), July 3, 1991

decade because of PLN's inability to meet new demand, let alone the takeover of existing captive capacity.

Power Development Program

Under PLN's expansion plan, there are approximately 5,800 MW of committed projects. The specific projects and the planned commissioning dates are indicated in Exhibit 1-9. The data reveal the following major PLN capacity additions by 1995/96: 9 x 120 MW of gas-fired combined-cycle plant capacity (Gresik), 2 x 400 MW of coal-steam capacity (Paiton-1 and -2), 4 x 55 MW of geothermal, and 4 x 125 MW of hydro. Beyond 1995/96, the committed plant consists of the 3 x 600 MW coal steam units at Suralaya.

PLN's least-cost generation expansion program beyond the committed plant shown in Exhibit 1-9 is discussed in Chapter 4 for the base load growth scenario and consists of the following major additions (12,000 MW) by the year 2003/04:

- 3,200 MW of coal-steam at Paiton (units 5 through 8)
- 4,200 MW of coal-steam in Central Java (7 x 600 MW)
- 1,800 MW of coal-steam in West Java (2 x 600 MW)
- 1,500 MW of coal-steam in East Java (3 x 500 MW)
- 960 MW of gas turbines (8 x 120 MW)
- 570 MW of hydro.

Some of these plants are to be offered to the private sector for development. The location of these plants as well as those of some of the major committed projects are identified in Exhibit 1-10.

PLN's expansion plan reflects the objective of the diversification of its resource base away from oil and towards cost-effective indigenous energy resources -- natural gas, coal, geothermal, and hydro -- and where appropriate, to realize economies of scale by building large power stations and larger-sized generating units.

PLN's power development plan for outside Java calls for more than doubling the existing installed capacity of 2,500 MW by the year 1998/99. Of this increment, about half is projected to be hydro plant, 30 percent is projected to be combined cycle, and 20 percent wood-steam.

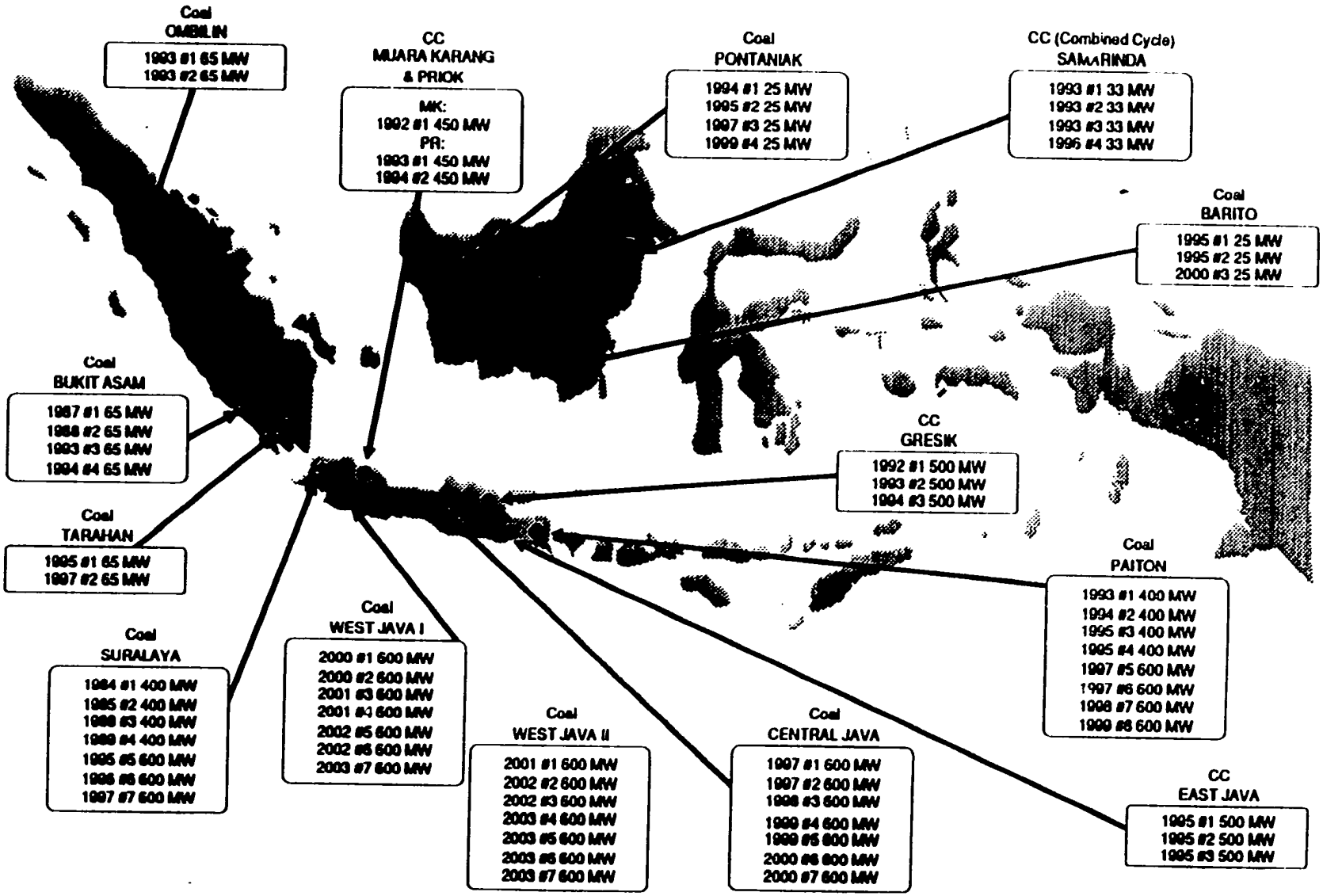
Finally, the capital requirements for the national power development plan -- generation and network -- are estimated to be on the order of US $2+ billion per year, or US $25 billion

Exhibit 1-9. Committed Projects and Commissioning Dates: Java-Bali System

Project Name		Capacity (MW)	Commissioning Date
1. GTPP ex Tosan Prima		3 x 20	December 1991
2. HEPP Tulung Agung		2 x 18	March 1993
3. CCPP Open Cycle Muara Karang	#1	1 x 100	September 1992
	#2	1 x 100	October 1992
	#3	1 x 100	November 1992
4. CCPP Steam Cycle Muara Karang		1 x 150	September 1994
5. CCPP Open Cycle Gresik	#1	1 x 120	March 1992
	#2	1 x 120	April 1992
	#3	1 x 120	May 1992
	#4	1 x 120	June 1992
	#5	1 x 120	July 1992
	#6	1 x 120	August 1992
	#7	1 x 120	September 1992
	#8	1 x 120	October 1992
	#9	1 x 120	November 1993
6. HEPP Tulis		2 x 6.5	1993/94
7. HEPP Ciliman		1 x 10	1993/94
8. HEPP Kedung Ombo		2 x 11.5	May 1993
9. Geothermal PP Salak		2 x 55	1993/94
10. CCPP Steam Cycle Gresik I		1 x 166	July 1993
11. CCPP Steam Cycle Gresik II		1 x 166	January 1994
12. CCPP Steam Cycle Gresik III		1 x 166	July 1994
13. STCPP Paiton 2		1 x 400	January 1994
14. STCPP Paiton #1		1 x 400	July 1994
15. Geothermal PP Drajat		1 x 55	1994/95
16. Geothermal PP Dieng		1 x 55	1994/95
17. HEPP Kesamben		1 x 33	1995/96
18. HEPP Cirata II		4 x 125	1995/96
19. STCPP Suralaya #5		1 x 600	March 1996
20. STCPP Suralaya #6		1 x 600	December 1996
21. STCPP Suralaya #7		1 x 600	September 1997

through 2003/04, excluding price escalation and interest during construction. Slightly over US $2 billion per year of this amount, about 65 percent, represents foreign exchange-related capital requirements.

Exhibit 1.10
PROSPECTIVE MAJOR THERMAL POWER PLANTS IN INDONESIA AND THEIR LOCATIONS



CHAPTER 2: PRIVATE POWER MARKET DEFINITION AND PRICING FRAMEWORK

The purpose of this chapter is to more explicitly delineate the notion of a "private power market" in Indonesia (Section 2.1). Following this market definition, Section 2.2 formulates an appropriate pricing framework.

2.1 PRIVATE SECTOR ROLE

"Private power" has a long and continuing history in Indonesia. Three privately owned Dutch electricity companies operated in Java during the first half of this century. In 1954, the government began a process of nationalizing these companies. Starting in 1958, responsibility for the provision of electricity supply was transferred to PLN, which functioned as a department within the Ministry of Public Works. In 1961, the status of PLN was altered to that of a government-owned company, and in 1972, PLN became a full-fledged public corporation.

From 1961 to 1979, PLN operated as a government-sanctioned and regulated monopoly. However, even during this period, substantial amounts of privately owned power generation were licensed and installed by industry and other electricity consumers, stemming from PLN's inability to keep pace with demand and because of poor grid reliability in some instances. Indeed, in 1974/75, privately owned (i.e., non-PLN) installed generation capacity represented just under 60 percent of the nation's total installed generation capacity. At present, this share stands at approximately 45 percent.

Whereas private ownership of generation capacity was substantial in the 1970s, the power market was or is still functioning as a monopoly, i.e., one seller (PLN) and many buyers. Power from captive generation functioned in a passive role as a grid demand reduction measure. With few exceptions, and even today, significant amounts of power purchase transactions (i.e., sales of captive generation power to the grid) have not taken place to any significant extent. This can be attributed to the lack of the appropriate institutional, regulatory, and pricing framework.

In 1979, PLN's monopoly charter was amended to allow private utilities and cooperatives under license from MME to generate and sell power in areas not accessible to PLN's grid

or where PLN could not satisfy demand. The first licenses under this law were issued starting in 1983.

Finally, in 1985, Law No. 15 was enacted to consolidate earlier decrees, and to reiterate both the dominant role of PLN and the right of private enterprises and cooperatives to engage in power generation, transmission, and distribution.[1]

The rationale for encouraging private sector participation in Indonesia's power sector appears to be primarily two-fold:[2]

- increase sector efficiency and responsiveness by introducing competitive pressures and reducing monopoly power
- reduce the demand on public funding for infrastructure development and attract private capital that provides real additionality of funds to the nation.

Non-utility generation already plays an important role in the industrial sector and in some rural areas, a point discussed earlier. However, Law 15 appears to recognize a key point that significant efficiency gains -- including capital additionality -- can potentially be achieved by creating a power market and industry structure that induce a market-type discipline on its participants more by market pressure and less by a central command and control regulatory approach. Such a market would be accessed by larger numbers of sellers of power who are allowed to operate within a transactional environment -- pricing, regulatory, legal -- that is transparent, economically rational and fair.

More specifically, the power sector efficiency and capital additionality objectives can be enhanced by facilitating the contributions of private sector enterprises in the following manner:

[1] In the case of non-PLN power supplies, three categories of "IUKU" are to be permitted: Category 1 projects would be generation only projects, Category 2 would entail generation and transmission, and Category 3 projects would entail distribution as well. The upcoming bids for Paiton units 7 and 8 and such "Paiton-like projects" would typically fall under IUKU Category 1 and IUKU Category 2.

[2] A third objective that does not appear to be a consideration in the present context, but that is relevant in some other countries, is to utilize the proceeds from asset sales to the private sector to redeem government debt.

- Coordinated and integrated use of existing captive generation with PLN capacity to enhance PLN's grid system reliability.[3]

- Promote additional investment in non-utility generation plant in situations where that is the least-cost supply option, i.e., where generation costs of non-PLN supply are competitive to supply the load. This condition may prevail in cases involving cogeneration plants.

  Elsewhere, the private supplier can tap certain unique and site-specific advantages, e.g., privately owned hydro sites, use of on-site waste (such as bagasse, rice husks, saw mill waste), large industrial facilities in remote locations that have captive generation or can develop a local resource for power generation (such as hydro, peat, geothermal, coal) to meet their own needs and supply the excess to PLN or directly to meet the local load.

- Introduce competitive market-type discipline and pressure for efficient performance by creating a "contestable power generation market": a market environment where non-utility owned and operated power plants (IPPs) can compete with public utility generation on an "equal and fair" basis, e.g., on a competitive bid basis, with those selected to participate under a build-own-operate (BOO) scheme.

- Facilitate the formation of new and more effective participation of existing rural distribution companies, as well as small project entrepreneurs who can meet certain minimum operational performance standards, thereby contributing not only to rural development but also in containing costs for such development.

Market Definition

Broadly speaking, a "power market" can be defined by the collection of economic agents (buyers and sellers) and the institutions and regulatory rules in place that collectively define one or more mechanisms for effecting a variety of power purchase and sale transactions in

[3] This is really a load management option that PLN would pursue as part of its demand-side management (DSM) program.

a relatively open manner as regards information on the terms of such transactions, including pricing and risk sharing.

There exists a wide range of power transactions that buyers and sellers can potentially engage in within a power market, once there is more than one supplier. Some examples of power transactions include short-term (i.e., 15 minutes up to to a few hours) economy energy exchange, short-term (a few hours to days) firm power sales, long-term (over three to five years) firm power contracts, medium-term (one to three years) seasonal diversity exchange, and long-term firm power capacity.

Associated with each of these and other transactions is a different pricing mechanism. Thus, it is necessary to first identify the potential range of transactions of relevance in the present context. This depends largely upon the legislative intent of Law 15. This intent, as far as we are aware, has not been clarified officially in a written and definitive form. However, based upon information revealed during the course of our mission to Jakarta, we have surmised that the following market organization model is envisioned, at least for the foreseeable future:

- Independent power producers (IPPs) and non-utility generators (NUGs) will be permitted to sell electricity to PLN's grid. These suppliers potentially include dedicated power projects operating under a BOO scheme, excess output of cogenerators, and power sales by other customer-owned power generation.[4]

- In areas not adequately served by PLN, IPP and NUG power generation will be permitted to be sold directly to final consumers and via their own transmission and distribution network if necessary. IPPs/NUGs in these situations could potentially be organized as rural distribution cooperatives or independent utilities. In addition, commercial sales of power from a large industrial estate to other loads in proximity could qualify in this category of transactions between third parties.

In this market model, PLN assumes the responsibility for meeting final consumer demands in areas that are within economic transmission distance of its grid. In other words, such

[4] A small "third-tier" also exists. We understand that in a few instances, NUGs are located in the service area of a cooperative, that in turn buys from PLN.

customers are "full requirements" customers of PLN and cannot "shop around" for their power needs to be met directly by a source other than PLN.[5] They may, however, engage in self-generation to supplement PLN supplies or for reliability purposes. Further, any excess supply from such NUGs can be sold to PLN's grid.

The schematic in Exhibit 2-1 highlights the major power transactions that are consistent within the private power market model outlined above. From the perspective of the evolving power market through the mid term (i.e., through the end of this decade), the most significant transactions -- in terms of potential numbers and megawatts involved -- are potentially those shown by the bold lines in Exhibit 2-1, i.e., transactions labelled as categories 1, 2, and 3.

Transactions in category 1 represent potential power purchases from large private power projects, typically under a BOO contractual arrangement, and with the additional but important qualifier that such projects are identified in PLN's least-cost expansion plan. By contrast, categories 3 and 4 represent the potentially large number of medium (category 3) and small size (category 4) power purchase transactions from IPPs that have access to an economic resource on-site (such as hydro, peat, agricultural residue, by-product waste, and wind), excess power purchases from industry with captive generation, and excess power output of cogeneration plant installed by industry.

[5] An alternate market model (2) would require the vertical disintegration of the industry and market structure, i.e., a bulk power grid could be operated by, presumably, a state-owned transmission company (TRANSCO) with multiple generation companies (GENCOs/IPPs) competing in the bulk power market, and distribution companies (DISCOs) with monopoly franchise areas. In one version of this model (2A), the TRANSCO could have responsibility for securing the necessary power supplies to meet consumer demands, with the GENCOs competing for providing such supplies. The TRANSCO would then add a fair markup and in turn sell to the various DISCOS. In another version of this model (2B), the buy and sell transactions would be directly negotiated between DISCOs and GENCOs, with the TRANSCO serving as a "common carrier" with established wheeling rates.

As a point of reference and informational interest, the power market organizations and transactional structure in Sweden, and those recently introduced in England and New Zealand, can be characterized as hybrids of models 2A and 2B, with some features of model 1 as well. The U.S. power market is closer to model 1 above in that TRANSCOs do not yet exist as stand-alone entities. However, the market for new generation has become increasingly competitive in recent years, with NUGs, cogenerators, and GENCOs/IPPs competing with utilities for new supplies. Furthermore, the pressure from very large consumers has intensified to engage in "rate shopping" from different sources and have the utility wheel the power. This issue of transmission access and pricing is at the forefront of the current policy issues being debated today in the U.S.

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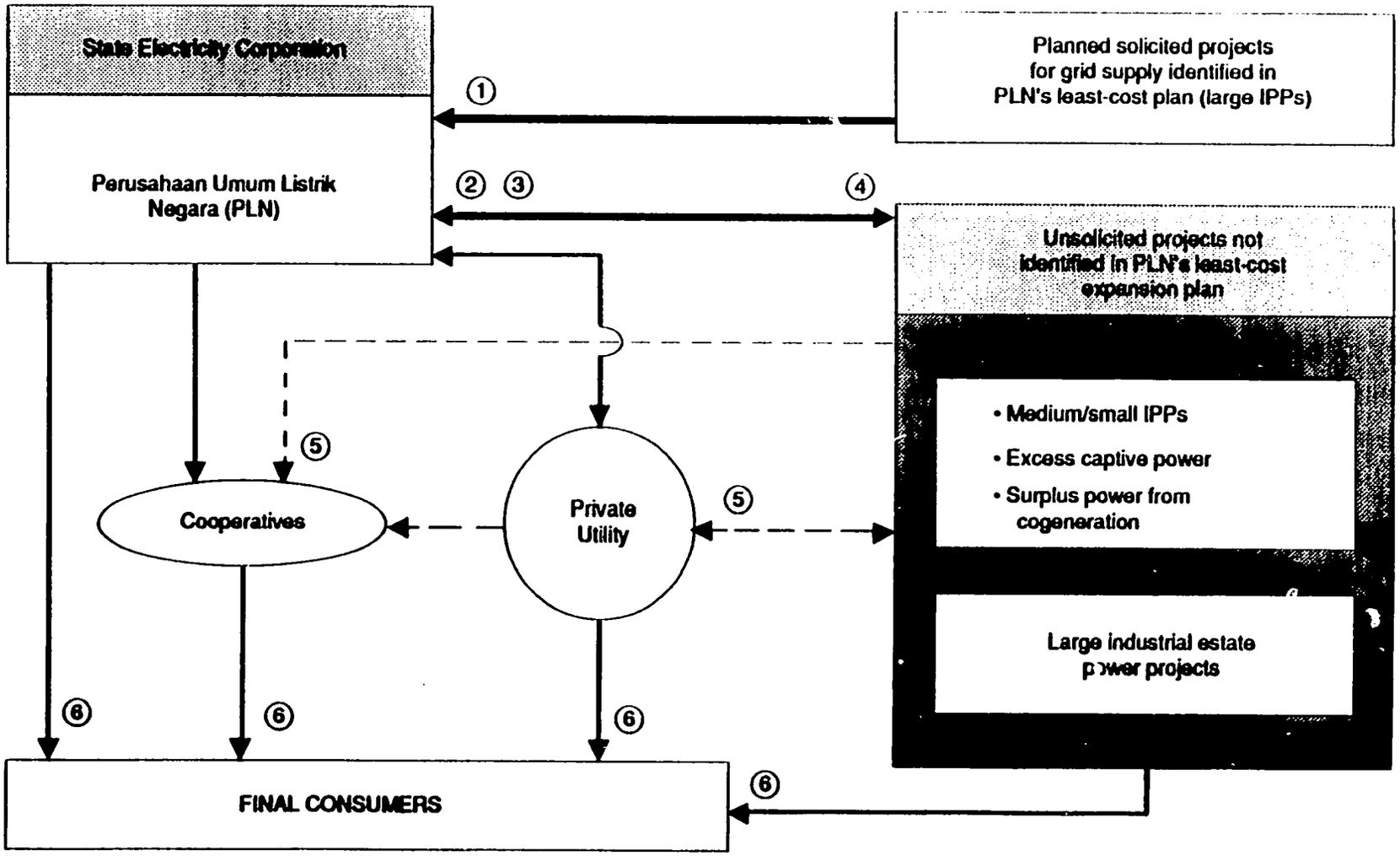
Exhibit 2-1
MAJOR POWER TRANSACTION CATEGORIES WITHIN A PRIVATE POWER MARKET IN INDONESIA



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Also included in categories 2 and 3 are potential power purchases from power plants that are being proposed for development to serve large industrial estates. Some of the proposed projects in this category are large projects and would have surplus capacity during off-peak hours as well as possibly during the evening hours of the system peak. Such large sized plants should achieve conversion efficiencies typically realized by baseload utility plants and since they would be located in proximity to the loads, the 16+ percent network losses would be avoided as well. Therefore, it should be a matter of high priority from the national efficiency perspective to provide the right price signals in order to foster optimal development of this private power supply potential.

In the near to mid term, category 2 and 3 transactions together may represent a more fertile ground for the development of the private power market in Indonesia than category 1-type transactions. This view is based upon the following considerations:

- Worldwide experience with category 1 transactions clearly indicates that only a few large-size BOO/BOT power projects have been implemented thus far. Whereas there has been a lot of interest and the number of countries interested in such projects has grown in recent years, for a variety of reasons -- such as lack of a clear, unambiguous, fair and transparent regulatory, institutional, pricing, and legal framework in place, high perceived in-country risk relative to return on investment, better investment opportunities in more traditional investments in the industrial sector -- the private sector has been slow to enter the power market in a big way in any developing country thus far.[6]

- Direct foreign investment in the power sector may not be as easy to attract, in contrast with its role in the industrial sector. Direct foreign investment flows to a developing country industrial sector are generally motivated by one or more economic considerations such as access to cheap labor, availability and cost of key raw material inputs, proximity to regional markets, pro-business climate, etc. If grid power supply is inadequate, foreign investors will consider investment in a captive power plant to facilitate the project as a means to the goal of realizing their business

[6] Even in the U.S. power market, where competitive market forces have been at work for a substantial period of time, the overwhelming share of private power purchases by utilities comprises transactions in categories 2 and 3.

objectives. However, most of the very same investors will not view direct investment in a stand-alone power project as an alternative investment because of the reasons already noted above.

2.2 FRAMEWORK FOR PRICING

This section describes the overall approach for rationalizing the pricing of power transactions of interest and within the market model structure identified in the preceding section. The proposed framework draws upon the economic theory of efficiency pricing as the primary guiding philosophy. It is instructive to begin with an overview of this concept.

Economic Efficiency

Economic efficiency is synonymous with the allocation and use of resources in a manner that most benefits society, i.e., maximum output at least cost. Economic theory suggests that to achieve efficiency, two conditions must be met. First, the production and delivery of power should occur at a minimum cost. This corresponds to *productive efficiency*. Second, resources should be allocated where they provide the highest benefit (value). This corresponds to *allocative efficiency*.

Prices play a significant role in consumer consumption decisions. Thus, efficient prices should signal to consumers the correct economic costs of their purchase decision. Efficient pricing seeks to ensure that economic waste and resource misallocation are minimized, and that the efficient utilization of resources -- in the production and consumption of electricity -- are maximized.

Efficient prices -- at all stages including energy conversion for power production, network transfer, and retail delivery -- are necessary to provide clear signals to energy consumers regarding the true resource costs to the nation of their consumption decisions. Thus, pricing distortions in key fuel inputs for electricity production -- e.g., prices of coal, geothermal, fuel oil, diesel -- will result in a non-optimal mix of generation that distorts all downstream prices, transfer prices, and eventually, retail prices as well. Such a distorted situation, if unchecked for long, inevitably results in a gross misallocation of resources and the inefficient utilization of scarce capital.

Achieving *long-run productive efficiency* within the context of the market structure described in the preceding paragraphs means that PLN, as the primary provider of generation and bulk transmission, should strive to ensure that its power development plan results in the implementation of a least-cost expansion program for supply- and demand-side resources. PLN's supply planning staff is highly professional in this regard and utilizes a series of sophisticated models and analytical procedures in the planning process to revise the least-cost expansion program regularly. In the future, as PLN embarks more aggressively on utilizing cost-effective demand-side management (DSM), the impact of these programs will need to be optimally integrated within the supply planning framework.

In the case of rural electrification, the long-run productive efficiency objective argues for the introduction of electricity to rural areas, utilizing the least-cost means of providing power. In many instances -- where the areas are within economic transmission access of the existing grid -- this may be accomplished by a simple extension of the network. However, it is a mistake to view rural area electrification as synonymous with grid extension. This can result in substantial deviations from the cost minimization principle. In many instances, decentralized generation sources may be the least-cost means of supply rather than grid extension. Alternatively, an industrial facility with excess captive generation may offer the least-cost means of meeting the remote load. In other instances, a rural electricity cooperative may be the best option.

Short-run productive efficiency focuses on operational aspects, many of which are primarily (although not exclusively) as short-run in nature. These can be broadly classified as:

- technical operational efficiency
  - economic dispatch
  - generating unit availability
  - unit heat rates
  - technical losses
- human efficiency
  - manpower productivity

- managerial efficiency[7]
  - non-technical losses
  - financial performance
  - days of accounts receivable
  - cash management.

Short-run productive efficiency in the present context means that the pricing framework established for power purchases from non-utility generators should ensure that such generators receive unambiguous and strong economic signals for maximizing plant availability and fuel conversion efficiency, and simultaneously give PLN the flexibility to optimally integrate the operation of such plants into the overall power system from the perspectives of minimizing total cost and enhancing system reliability.

Determining Efficiency Prices

If the number of buyers and sellers engaged in the market for a given good is large, no participant is large enough to influence market price, and the participants are well-informed about alternatives, the market is likely to behave competitively, as this concept is generally construed in the economics literature. In this ideal paradigm of a perfectly competitive market, an equilibrium linkage between supply and demand is achieved via the market-determined (efficiency) prices that reflect the real resource cost of supply. Economic theory suggests that the relevant opportunity cost of a good -- such as electricity -- is its marginal cost, i.e., the cost of producing one more unit at a given point in time.

Marginal cost pricing assures that society's resources and needs are balanced in the most efficient manner. As noted by the Nobel Prize winning economist, Professor P. Samuelson of the Massachusetts Institute of Technology, "only when prices of goods are equal to marginal costs is the economy squeezing from its scarce resources and technical knowledge, the maximum output."

Efficiency prices provide both the incentive and financial means for suppliers to build and operate the optimal amount and mix of capacity and to meet consumer demand most

[7] In the final analysis, even technical efficiency and human efficiency are a reflection of the effectiveness of utility management.

efficiently, i.e., in the least-cost manner. To consumers, such efficiency prices signal the true resource cost of providing the good or service in question. This would be reflected in their respective consumption decisions in that the least-valued unit of consumption would have a benefit that equals the price paid, thus resulting in a minimization of wasteful use (Annex 2).

By contrast, in the case of a monopoly or even in the case of a market characterized by a dominant firm plus a competitive fringe,[8] absent administered transfer pricing guidelines and regulatory oversight to ensure enforcement of certain principles, inefficiencies can arise. For example, higher cost (or less efficient) suppliers could be over-producing whereas others would be supplying "too little" relative to economically efficient levels and prices. Or, productive efficiency -- e.g., time to completion or cost to completion of power plants, operational efficiency, etc. -- may be lower than otherwise achievable. An administered and efficient transfer pricing procedure would seek to minimize such distortions by attempting to ensure the equalization of marginal costs of the dominant supplier and the competitive fringe suppliers, while also simultaneously ensuring a least-cost power supply.

The term *administered pricing* is used above and in the following to denote the setting of prices for permissible power transactions between the various participating economic entities involved -- some of whom wield market power whereas others may not -- by extra-market forces such as regulators. Administered pricing is distinguishable from market pricing, wherein actually observed prices are the outcome of the dynamic interplay between supply and demand in the marketplace.

The need for administered pricing arises in the context of markets that lack strong competitive elements, as is the case with the way most power markets are organized today. Such a market organization is typified by a government sanctioned institutional monopoly that is vertically integrated vis-a-vis the generation and transmission functions, and may sometimes include distribution as well. An institutional monopoly is distinguishable from a natural monopoly, which has an economic basis -- economies of scale -- that makes it self-sustaining.

[8] A situation that would prevail in the Indonesian power sector in the foreseeable future, if a few IPPs and NUGs enter the bulk supply market.

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The traditional form of market organization of the power sector has been predicated on the view that the business of supplying electricity is a natural monopoly where strong economies of scale result in consumer benefits.[9] These benefits could be realized by customers if government regulation of the monopoly prevents it from collecting undue monopoly profits (rents). Such monopoly profits theoretically stem from the monopolies' motivation to set prices higher than what would be observed in a competitive market situation and consequently to produce less as well. Another way a monopoly can extract its monopoly profits -- and one that appears to be more prevalent in the power sector -- is in the form of reduced productive, and hence, reduced cost efficiency, and a slower pace of innovation.

Against the textbook prototype of a single-product natural monopoly discussed above is the reality of the multi-product nature of the power sector, in which case the economies of scale argument is neither necessary nor sufficient for a monopoly to be rationalized. Furthermore, emerging developments and experience from some of the more highly developed power markets[10] has lent credence to the view that whereas transmission and distribution may be intrinsically natural monopolies,[11] the generation function offers opportunities for efficiency gains from a more competitive market structure.

Even with the market opening to IPPs and NUGs, for the foreseeable future, market power and concentration in the generation power market will continue to be heavily skewed, a situation that is fundamentally different from a purely competitive market paradigm. Thus, power suppliers are not exposed to the market risks of insufficient demand and inadequate cost recovery because of market fluctuations. For example, potential IPPs, and even PLN, are ensured recovery of fixed costs irrespective of demand. In addition, because of

[9] Another often cited rationale for creating an institutional monopoly stems from vaguely articulated political and ideological beliefs that declare the provision of electricity as "essential," "socially necessary," "vital," "basic," etc. Therefore, the argument goes that the protection of the public good is best handled by a publicly owned and controlled monopoly.

[10] The bulk power market in some regions of the U.S. for short-term energy transactions is an example of a competitive power market segment. As noted previously, the market for new generation to meet load growth is being increasingly deregulated to become more competitive. More and more U.S. utilities are required to engage in competitive bidding for the procurement of new supplies. In this emerging era of "least-cost planning," bidding programs are also being extended to cover the purchase of load reduction through DSM.

[11] This does not mean that transmission and distribution need be a vertically integrated institutional monopoly. Rather, the functions are naturally separable and the retail distribution function could be granted to one of several bidders.

recovery mechanisms such as fuel adjustment clauses and various indexation schemes, power suppliers are buffered from market risk by ratepayers.

One effect of this lack of market risk in power markets is that absent effective regulation, it cannot be ensured that a least-cost expansion path for sector expansion is achieved. The mere presence of more than one supplier in the power market does not guarantee a least-cost expansion path. If the price paid to IPPs, as an example, is based on marginal costs as reflected by a disoptimal expansion plan, then the entry of more suppliers will merely perpetuate the inefficiency, but with private sector players now being able to "share" in the process.[12] For the reasons noted above, and even under situations involving competitive market conditions as in the U.S., an administered pricing approach with the supporting regulatory oversight becomes necessary.

Ultimately, the success -- i.e., efficiency and continued validity -- of any administered pricing scheme will depend upon the degree to which it is successful in transplanting but also adapting the essential features of a competitive market discipline to the environment of a generation power market that is exposed to a limited degree of deregulation and competition.

In particular, the four major features of a pricing regime in a competitive market are:

1. Prices are a direct reflection of the least-cost means of providing the good or service (including the proper internalization of the relevant externality costs)

2. The pricing regime exposes those economic agents to risk who can exercise significant control over their costs.

3. Prices are flexible to changing market conditions such as demand-supply imbalances, factor input cost fluctuations, and technological innovation.

4. Transparency.

[12] In contrast, a competitive market is unforgiving to inefficient producers. Because no one producer has market power, this means that the inefficiencies of any producer -- in plant operation, productivity, plant scale and technology choice, etc. -- will only affect his financial viability-profitability and survival. In other words, the marginal cost of supply (efficiency price) is determined by the least-cost supplier.

Because of these features, prices can self-regulate competitive markets instead of requiring outside regulators to ensure efficient and least-cost output.

The proposed adaptation of these features to the power market context at hand is that an administered price regime be implemented to ensure the following goals:

1. Efficiency and Accountability
   - help maintain an efficient national market (i.e., satisfy consumer demand and growth, and at least cost)
   - efficient utilization of existing productive assets
2. Transparency
   - price validity
   - rules of the game are well defined and known to all
   - fair and equitable
   - easy to implement.
3. Maintain Financial Viability of Efficient Producers

Of the three goals noted above, the third is unique to the power market. Financial viability is not guaranteed in competitive markets, which favor survival of the economically fittest. Indeed, it is this feature that provides the built-in incentive for efficiency and accountability in a competitive market. In contrast, for a variety of reasons -- including the fact that the power sector is extremely capital intensive -- at least in an initial deregulation scenario, which is the case in Indonesia, guarantees of financial viability for *efficient* IPPs will be expected to be provided. Under these conditions the power project developer would be granted annual recovery of all fixed costs (including a fair return) as well as any variable costs. In essence, the market risk associated with demand fluctuations and fuel price

fluctuations and possibly labor cost changes would be transferred and shouldered by ratepayers.[13]

Of the other two goals noted above, the efficiency and accountability goal -- both long run and short run -- is derived from features #1 and #3 of a competitive market, as mentioned previously. However, the manner in which the goal is achieved in the power market context is quite different. Instead of the market, regulators will need to oversee the calculation and setting of administered prices and to ensure that such prices, as well as the development of private and PLN power supplies, conform to a least-cost expansion plan.

The objective of the short-run efficient utilization of existing productive assets refers to the use of power supplies from all sources in accordance with the principle of merit order dispatch. To ensure this, energy price payments to NUGs and IPPs should reflect PLN's *short-run marginal energy costs*.

Finally, the transparency principle is extremely important in the power market context as well. Transparency in a competitive market price system means that prices are publicly known to all economic agents, they are direct in that they represent the actual cost of resources expended (price validity), and whereas prices may vary by market segments, such differential pricing is not discriminatory, but is justified by the different market characteristics. Furthermore, if differences arise between various economic agents, fair and speedy recourse is available through a legal system. In the power market, transparency is interpreted more or less analogously.

The importance of transparency cannot be overstated. Transparency facilitates more rational and long-term oriented decision making. With less guesswork, transaction costs can be lowered because less time needs to be devoted to figure out the market and more importantly, the perceived risk is reduced. Ultimately, this will also translate into more IPPs and NUGs willing to "come to the table," and result in increased additionality of power, financial resources, and in the case of IPPs, in a lower cost of capital, as well as requiring fewer guarantees.

By contrast, a potential market participant may perceive that the market rules -- pricing, regulation, bid evaluation criteria, contractor selection, risk sharing, legal recourse, etc. --

[13] This aspect makes it necessary that the Private Power Team initiate an examination of the financial linkage between PLN's retail tariff yield and the cost of power purchases from private power projects.

are not defined, are improperly defined (i.e., not rational), are not fair, or even if such rules are well defined (i.e., rational and valid) and fair, but the process is being subverted by the bending of rules, or by circumventing and short-circuiting the regulatory process and authority; in which case the promise of a gain from private sector participation will remain as such and not be realized to any significant extent. Furthermore, transparency of the financial and oversight relationship between the GOI and PLN will be important to potential supplier entrants to the power market.

Administered Pricing Basis for Selected Power Transactions

Exhibit 2-2 lists the five broad categories of potential power transactions identified in Exhibit 2-1. The remainder of this section provides a brief overview of the basis for setting administered efficiency prices for transactions within each category. More detailed discussions of how the approach would be implemented for the first three categories, based upon a review of existing data and information in Indonesia, is contained in the following chapter of this report.

Category 1: Large Independent Power Producers

The first type of transaction represents a power purchase by PLN from a dedicated power project identified in PLN's unconstrained least-cost expansion plan (LCEP) and sponsored by an independent power producer (IPP). Such projects potentially include the coal-fired Paiton projects (Units 7 and 8), and the baseload coal projects in Central Java (2 x 600 MW) and in West Java (1 x 400 MW).

The recommended methodology for transfer pricing related to such power purchases is a blend of two concepts:

- "avoided cost pricing" and
- bidding.

Put simply, avoided cost represents the incremental resource savings -- fuel, labor, capital, etc. -- that would occur as a consequence of the contemplated power purchase.

Exhibit 2-2

Efficiency Pricing of Selected Power Transactions: Private Power Program, Indonesia

Seller/Project	Buyer	Nature of Transaction	Suggested Basis of Pricing
1. Independent Power Producer (IPP) Planned large projects (typically > 100 MW) identified in PLN's unconstrained least-cost generation and network expansion plan.	PLN	Long-term (20+ years) firm power from dedicated project, possibly with associated transmission. Bulk power sales of total output to PLN.	Bidding and negotiating process. Selling price not to exceed avoided cost. Reference benchmark avoided costs established by combination of the following estimates: A. Avoided cost of PLN-owned comparable peer plant: - "financial avoided cost" - "economic avoided cost" (i.e., PLN's financial cost adjusted for subsidies and other distortions) B. International peer plant avoided cost, adjusted for local conditions
2. Medium-Size Non-Utility Generators (NUGs), IPPs, and cogenerators (>5 MW) Power project <u>not</u> identified in PLN's least-cost plan	PLN	2A. Non-firm power - Plant selling excess power on as-available basis	Standard offer (i.e., posted price) based on avoided cost estimated as in 3A below
		2B. Firm power (minimum contract duration 5 years) - Plant offering guaranteed amount of capacity and energy, but not necessarily its maximum capability	*Option 1.* Standard offer described in 3B below *Option 2.* For larger purchases (i.e., 100+ MW), seller can elect to negotiate selected terms of contract, but price cannot exceed avoided cost

Exhibit 2-2 (continued)
Efficient Pricing of Selected Power Transactions: Private Power Program, Indonesia

Seller/Project	Buyer	Nature of Transaction	Suggested Basis of Pricing
3. Small NUGs, IPPs, and Cogenerators (< 5 MW) Power projects not identified in PLN's least-cost plan	PLN	3A. Non-firm power, as in 2A 3B. Firm power (minimum contract duration 3 years)	Standard offer. Energy price based on short-run marginal energy costs Standard offer * Energy price at short-run incremental fuel cost * Capacity valued at long-run marginal capacity costs (LRMC)
4. PLN	Industry with some self-generation/ captive generation or cogeneration	4A. Supplemental power as per contract demand 4B. Maintenance power 4C. Standby/backup power	PLN applicable tariff * Demand charge based on LRMC applied to demand in excess of contract demand * Time-of-day energy charges based on marginal energy costs * *Firm Service Option* Capacity reservation charge plus demand charge plus time-of-day energy charge * *Non-Firm Service Option* Time-of-day energy charges based on marginal energy cost plus some adder

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Exhibit 2-2 (continued)

Efficiency Pricing of Selected Power Transactions: Private Power Program, Indonesia

Seller/Project	Buyer	Nature of Transaction	Suggested Basis of Pricing
5. Non-PLN Producers	Cooperatives, private utility	Direct sales between third parties	Same principles as in the corresponding categories 1 through 4 above
6. Non-PLN Producers	Final Consumers		*Some Options* 6A. Cost of service plus allowable rate of return 6B. PLN national tariff

Equivalently, it represents the incremental cost that would otherwise be incurred absent the power purchase in question.[14]

Whereas specific aspects vary, a bidding process works as follows. Periodically, (e.g., annually) the utility (in the present context, PLN) would update the load forecast and determine the need for additional resources based upon a least-cost planning study.

Next, the capital expenditure requirements for the least-cost plan would be estimated. These requirements would be assessed against clearly articulated guidelines on the amount of financing PLN can count on from the GOI and the amount of additional debt PLN is permitted to incur within a time frame encompassing a minimum of the next five years of the planning horizon. Within such a framework, PLN would determine the amount of capacity it can finance and therefore build. The remaining resource requirements would be offered to the private sector by issuance of "requests for proposals" for additional resources specified by variables such as plant capacity, unit size, fuel type, timing, dispatchability, availability, and other performance and design characteristics.[15]

The implementation of such a framework would require the GOI to implement and adhere to a multi-year capital expenditure program agreement that provides a more predictable and longer-term financial basis for PLN management to make long-term investment decisions. In particular, because of the long lead times involved in power plant construction (typically from four to five+ years for major baseload units), PLN needs clear and stable policy guidance as to the likely sources and magnitude of investment funds that will be made available by the GOI and the amounts it will be authorized to raise in local and foreign capital markets for at least a five-year forward horizon.[16]

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[14] The *avoided cost pricing* approach first achieved prominence in the context of the 1978 "PURPA" legislation in the U.S., which required utilities to purchase excess power from cogenerators under "avoided cost principles." *Bidding* procedures have also been instituted in several states in the U.S. in recent years.

[15] By contrast, in some jurisdictions in the U.S., the bidding framework for resource acquisition is structured such that the utility is essentially the provider of last resort, i.e., all incremental resource requirements are offered for bidding. Bids above the utility's avoided cost are not accepted. Any unmet resource needs are then built by the utility.

The model in the main text above is better suited in Indonesia, at least for the foreseeable future.

[16] By contrast, the World Bank, in its comprehensive intitutional development review of the power sector, has characterized PLN's annual budget process as involving unnecessarily cumbersome and lengthy consultations with multiple reviewing bodies, including the Supervisor Board, the Ministry of Finance, and BAPPENAS; the process is mechanistic,

Category 2: Medium Size NUGs, IPPs, and Cogenerators (>5 MW)

The second class of power transactions identified in Exhibit 2-2 deals with power sales by NUGs in the mid-size range (typically in the 5 to 50 MW range). Individual projects in this category are unlikely to be identified in PLNs' least-cost expansion plan. However, had PLN known about these site-specific projects, they would have been explicitly incorporated in the least-cost plan.

For non-firm sales, a "standard offer" is proposed. A standard offer simply refers to a tariff that is publicly posted by PLN, as are all other tariffs for retail power sales. PLN's power purchase price for this type of transaction would be a posted tariff based on the "short-run marginal energy cost"; this being the system avoided cost.

For firm power purchases, it is recommended that the seller be given the choice of a standard offer under which PLN posts a two-part tariff; energy prices are set at short-run marginal costs, and a capacity payment is pegged to long-run marginal capacity costs (LRMC).

In situations where the firm capacity offered for sale to PLN is at least 100 MW, then it is recommended that the seller be given an option to negotiate selected terms of the contract, and in particular, the capacity payment if conditions indicate that more favorable terms than those available under the standard offer may be warranted. For establishing the latter, it may be necessary to undertake a detailed avoided cost analysis that estimates the present value of the difference in revenue requirements, between the base case least-cost expansion plan and a supply plan augmented by the power capacity purchase under consideration. This calculation, sometimes referred to as the differential revenue requirements (DRR) method, is discussed in Chapter 3 of this report.

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duplicative, and inefficient. Rather than establishing broad but clearly articulated policy guidelines that derive from national objectives, and tracking a few key performance indicators to evaluate the extent to which PLN is able to meet such objectives, Bank's institutional review notes the existence of a complex web of excessive supervision and all-pervasive review-management of virtually all major and many minor aspects of the planning and operations that has stripped the corporate autonomy that is vital for PLN management to efficiently run the organization. As matters stand, the distinction between "supervision and oversight" and "management" is blurred, leaving virtually no degree of real decision making freedom for PLN, a situation whereby decision making is effectively in the hands of those (outside PLN) who bear no direct responsibility for PLN's performance results.

Category 3: Small NUGs and IPPs (< 5 MW)

Two standard offers are recommended for this category of transactions: non-firm and firm. For sellers in this category, negotiated tariffs are not recommended. These offers should be developed with the pricing basis identified in Exhibit 2-2. In this manner, small power producers and cogenerators can avoid protracted and potentially costly negotiations that would otherwise require utilizing legal and technical experts in dealing with PLN.

Category 4: Sales by PLN to Industry with Captive Generation

Industrial customers with self-generation may require supplemental power supplies to augment their generation, maintenance power (when their generators are down for maintenance), or standby/backup power service (when their generator is down on forced outage). Tariffs must be developed for these transactions because they are an essential part of a power market wherein there are non-utility power producers. These tariffs should not be discriminatory for otherwise, they will restrict the optimal development of private supplies and their interconnections and synchronization with the grid.

Category 5: Third-Party Sales between Non-PLN Producers, Cooperatives, and Private Utilities

Transactions in this category will mirror some or all of the transaction categories 1 through 4 identified above, except that the buyer is not PLN. The pricing principles applicable for such third-party transactions are the same for the corresponding transactions 1 through 4 described above.[17]

Category 6: Final Consumer Sales

As can be seen from Exhibit 2-1, category 6 transactions refer to sales made to final consumers by PLN and non-PLN producers.

[17] As a practical matter, category 1-type transactions within the third-party sales category are unlikely for the foreseeable future. Rather, any third-party transactions will mirror those in categories 2, 3, and 4.

The first option is the traditional accounting cost-of-service based approach, under which the tariff yield/average price is set to recover these costs. However, the tariff structure should reflect the marginal cost structure. This method will typically lead to price differentiation across islands and possibly even within an island. Another major underlying principle in this context is to establish a direct link between costs and tariffs, thereby obviating the need for subsidies.

System Development Program: Establishing the Reference Benchmark

The proposed administered pricing framework discussed in the preceding is fundamentally anchored to the principle of economic efficiency. The equivalency of efficiency prices in competitive markets to marginal cost, i.e., prices that result in the maximization of economic efficiency, provides the basis for estimating administered prices for various power transactions of interest.

It is critical that the estimation of marginal cost (and the closely related notion of avoided cost) be calculated based upon a least-cost system development program. Otherwise, estimates of marginal cost (avoided cost) will simply reflect all the embedded cost inefficiencies inherent in the expansion plan and will convey the incorrect price signals. From a regulatory standpoint, the implication is that oversight is necessary in the power market to ensure 1) that PLN's least-cost expansion program is indeed that, and 2) that the administered prices are based on that plan.[18]

In this regard, a review of PLN's system planning procedures indicates that this function is conducted at a high level of professional competency and utilizing advanced computer models for optimal supply system expansion planning.

[18] By contrast, in the paradigm of a perfectly competitive market, such regulatory oversight is unnecessary. The market dynamics and supplier exposure to risk provide ongoing and self-correcting mechanisms to steer each profit-maximizing supplier towards the least-cost supply option. These pre-conditions will not exist in the power market in Indonesia in the foreseeable future.

PLN has developed an unconstrained least-cost generation and network expansion plan (LCEP).[19] This plan should be the official blueprint for system expansion. Clearly, this plan would need to be updated periodically, say, once a year. Such annual revisions offer the opportunity to incorporate the best current assumptions about key exogenous variables such as load growth and fuel prices.

In between these updates, the least-cost plan must be "frozen." The private power development program, estimates of standard offers, and bid evaluations should be the outcome that is determined from the current unconstrained least-cost expansion plan as the reference benchmark, and not vice versa. To do otherwise could be to grossly undermine the development of significant levels of private sector participation.

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[19] A related matter but one that is not directly germane to the pricing issue deals with the criteria for deciding which projects are to be undertaken by PLN, and which projects are to be offered to the private sector. These must be rationalized. This matter deserves immediate consideration by the Private Power Team. Multi-purpose projects are one category of projects that private developers will shy away from and that should be developed by PLN. Furthermore, prudence indicates that the private power projects selected initially be such as to have little technical or commercial risk of failure. Ideally, such projects should be small to medium-size projects only (i.e., plant sizes of up to 200 MW) and that would exploit some site-specific fuel source advantage, i.e., low-head hydro, peat, agricultural residue, biomass, geothermal, cogeneration. Additionally, power projects that are intended to primarily serve an industrial estate also offer a testing ground for gaining more experience with various types of private power projects and clarifying the major issues involved such as:

- additionality of financing
- implications for repatriation of foreign debt service and return on investment
- risk sharing arrangements
- contractual and legal accountability and enforcement
- impact on PLN operations and planning.

It is also recommended that over the longer term, PLN not designate specific power project categories as the sole reserve for itself or for private power development. For example, during our mission, one criterion we heard voiced was that PLN focus on less capital-intensive projects such as gas turbines and combined cycles. One apparent rationale underlying this philosophy is the financing constraint being imposed on PLN by the GOI. Thus, this criterion would maximize the amount of generating capacity (MW) developed by PLN. From an operational standpoint as well, there is some merit to this approach. However, one should not lose sight of another objective of allowing private power entry in the market; to enhance efficiency in plant operations by creating a more competitive environment, thereby establishing comparative performance yardsticks that are market based. In particular, if PLN is to continue playing a major role in the nation's power sector, as everyone expects it should and will, then it is important that in the long run, PLN not arbitrarily restrict itself -- or the private power developer -- to certain types of power plants (i.e., to designated fuel types, sizes, or to type of operation such as peaking, intermediate, or baseload). It will be important to establish competitive pressures and to track comparative performance measures for generating plants in as many categories as possible (with the likely exclusion of multi-purpose projects and nuclear power projects).

Opportunity Cost, Not Developer's Cost Is Key to Efficiency Pricing

In closing this chapter, it is worth underscoring a key implication of the framework presented above for the pricing of private power purchases. Namely, the purchase prices should not exceed the benefits to the economy of securing such supplies. These benefits are determined by the opportunity cost (marginal cost/avoided cost) to the nation from having to develop the *optimal* alternatives to the offered supply. Where such least-cost alternatives cost more to develop than the private supply under consideration, private supply transactions should be encouraged since they offer the potential for efficiency gains.

CHAPTER 3: STANDARD PRICE OFFERS FOR SMALL TO MID-SIZE POWER PURCHASES

This chapter discusses price estimation methods and related implementation needs for developing standard price offers for small to mid-size power purchase transactions in accordance with the theoretical basis described in Chapter 2, i.e., transactions in categories 2 and 3 in Exhibit 2-2. The chapter is organized as follows. Following a brief introduction, (Section 3.1), Section 3.2 describes the proposed price determination methodology. This is followed in Section 3.3 with an assessment of the ability of currently available data and information to support the recommended methodology and an identification of the follow-on work required.

3.1 INTRODUCTION

A "standard offer" refers to a power purchase price and associated provisions that are publicly posted, as are other retail tariffs. This approach is in keeping with the principle of transparency discussed in Chapter 2. In particular, smaller IPPs and NUGs are likely to find a standard offer power purchase tariff[1] advantageous because they can avoid cumbersome, time consuming, and potentially costly negotiations with the utility.

Standard offers establish a floor price for power purchase transactions that meet the stipulated provisions of the tariff. Some of the larger projects ($\geq$ 100 MW) may have certain unique features that make them more advantageous to the grid. If these claims are valid -- i.e., the additional cost savings to the grid can be documented -- then the project sponsors may wish to consider entering into a negotiation process for negotiating contract terms that are more favorable than the corresponding standard offer, and yet economically justifiable.

Before discussing the pricing methodology for setting standard offers, we note that if properly implemented and promoted, power purchases from existing and future NUGs in this size category offer the potential for significant efficiency gain. As noted earlier, a substantial portion of the existing captive power market -- about 6,900 MW installed

[1] As discussed subsequently, multiple standard offers should be designed to accommodate a range of power purchase conditions, with prices dependent on local grid conditions and the corresponding avoided cost.

capacity -- offers such potential,[2] primarily as a demand-side management (DSM) option for enhancing grid reliability during on-peak hours in the short to mid term. Further, the amount of captive generation is likely to continue growing for a few years, and this resource should be tapped for the national good. The development of such a DSM program merits immediate consideration given the power supply conditions Indonesia faces. In addition, care must be exercised to ensure that program benefits are not mis-calculated because of distortions in diesel and other fuel prices to the private sector and the utility sector.

The availability of standard offers would encourage the development of distributed power supplies. This is advantageous from the national standpoint. Such sources are too numerous and dispersed for PLN develop, and in many instances, the site ownership may be in private hands. Furthermore, the development of large numbers of dispersed and small power projects is not an activity that a large utility like PLN should be encumbered with, nor one it could handle in an efficient and cost-effective manner.

3.2 PRICING METHODOLOGY

This section discusses the proposed price determination method for power purchases under standard offer contracts. The underlying pricing basis -- rationalized in Chapter 2 -- is the concept of marginal cost and the related concept of avoided cost. We begin by first clarifying the notion of marginal cost and then indicate the relationship between the two. This is followed by a description of the proposed method for estimating marginal/avoided costs.

Marginal Cost of Electricity Supply and Avoided Costs

Put very simply, the marginal cost of electricity represents the economic cost of an increment of demand. Whereas the interpretation of marginal cost is not unique, the alternative definitions are similar in that they are all forward looking and represent the true resource cost to the economy. These methods consider only future costs related to future output as opposed to some derivative of historic accounting costs.

[2] At present, PLN has power purchase contracts with only a handful of industrial plants for the purchase of power. These are reviewed later in this chapter. The power purchase prices offered to sellers under these existing contracts are well below economic efficiency price levels. This has the inevitable effect of restricting suppliers from such sources, and also, together with other contributing factors, inhibits the optimal development of new sources of cogeneration and customer-owned power production.

A crucial distinction exists between short-run marginal cost (SRMC) and long-run marginal cost (LRMC). Briefly, LRMC can be defined as the incremental costs for meeting an incremental increase in demand that is sustained indefinitely into the future. The latter requirement distinguishes LRMC and SRMC; for in the case of temporary demand increments, a different set of adjustments may be optimal.

Traditional practice has been to measure marginal output of electricity in terms of capacity -- i.e., kilowatts (kW) -- and energy -- kilowatt hours (kWh). Thus, it becomes meaningful to differentiate between the long-run marginal capacity cost and long-run marginal energy cost. This distinction is not relevant in the short-run context where capacity is fixed.

"Avoided costs" are the costs that the buyer -- typically PLN -- can avoid as a result of the power purchase. The equivalence of avoided capacity cost and long-run marginal capacity cost can be illustrated by the following example. If PLN can defer (avoid) building 1 kW of additional generating capacity because of a 1 kW firm power purchase, then the avoidable costs to PLN of the incremental capacity purchase is the cost it would have incurred to build that capacity itself, i.e., its long-run marginal generation capacity cost.[3] Such a power purchase will also result in displacing PLN generation. Avoided energy costs are reflected by the incremental fuel and O&M cost (running cost) of the displaced generation.

In the case of firm capacity purchases, there may be an additional benefit (avoided cost) to PLN that stems from network capacity. Decentralized generation, if located in proximity to load centers and used to directly serve these loads, may result in deferring the need for network capacity, if central station supply were the alternative. In these instances, the long-run marginal capacity cost would have a component for transmission as well.

For non-firm power purchases, the major avoidable cost for PLN will be any incremental fuel and other variable expense from backing down its most expensive generator at the time. Additionally, the incremental purchase also has a beneficial impact on the system's operational reliability. This benefit to the power system (avoided cost from an economic standpoint) can be estimated by the reduction in expected outage cost. Outage costs

[3] This equivalence presumes that the power purchase under consideration is "firm" in nature, i.e., availability, dispatchability, and duration of power supplies are predictable in magnitude and in outcome.

If the utility (i.e., PLN) had more than adequate capacity in a certain region and was not planning to build new generation capacity for the time being, then the value to PLN (its avoided cost) of even a firm capacity purchase, will be significantly less. This would be reflected by a lower estimated value for long-run marginal generation capacity cost.

represent the economic costs to electricity consumers of interruptions in electricity supply. This concept is variously referred to in the literature as failure costs, cost of unserved energy, interruption costs, reliability worth, rationing costs, cost of energy not supplied, shortage cost, etc.

Thus, the reliability benefit component of short-run marginal energy cost can be estimated as:

reliability benefit (Rp./kWh) = outage cost (Rp./unserved kWh) x loss of load probability (LOLP)

Estimates of outage cost can be developed in at least one of two ways:

- direct measurement[4]
- combustion turbine (CT) proxy value adjusted for prevailing short-term reliability conditions.

The second (adjusted CT proxy) approach for estimating the reliability benefit it simpler to implement and therefore somewhat simplistic.[5] The starting premise here is that for a power system in optimal equilibrium, the least-cost means of providing the last kW of generating capacity purely for reliability support is a combustion turbine (CT).

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[4] For business and industry, outage costs are reflected in the opportunity cost of forcibly idled productive resources such as labor, land, and capital. In addition, spoilage, damage, and process restart costs could be significant. Outage costs to these non-residential customer segments can be estimated by a sample survey of businesses, wherein the survey instrument incorporates the "economic worksheet" method to collect itemized information about wages, output losses, damage, restart costs, etc.

In the case of most households, the primary adverse impacts of supply interruptions of short duration (i.e., under 3 hours) are intangibles such as discomfort, annoyance, and disruption. The economic cost of outages to this segment can be mea[illegible] conducting surveys that employ the contingent valuation technique to directly measure household wil[illegible] the adverse effects of such interruptions. In recent years, such studies have been successfully c[illegible] of the largest U.S. utilities and for the Electric Power Research Institute (EPRI).

An outage cost study to measure customer interruption costs for the major consumer segments in Indonesia merits serious consideration. Information developed during the course of such a study will be useful in establishing short-run marginal energy costs for power purchase prices. The data can be utilized by PLN's system planners as well in selecting the economically optimal generation planning reliability standard for the least-cost planning studies. Furthermore, data from the proposed customer outage cost study will be useful to PLN operations in rationalizing a more effective shortage management strategy to cope with situations involving power shortages.

[5] This method has been used by the Pacific Gas & Electric Company (PG&E) in California, at the direction of the California Public Utilities Commission (CPUC). PG&E has indicated its preference for the first approach.

By applying the optimal marginality condition, it can be theoretically inferred that for a system in equilibrium, i.e., with optimal reliability,[6] the annual carrying charge of a CT (Rp/kW-year) is equal to the avoided expected outage cost (see Annex 3). Once this equivalence is established, an adjustment factor needs to be calculated to reflect the actual reliability situation.

Exhibit 3-1 shows conceptually, the non-linear nature of the theoretical relationship between the operating reserve margin (reliability) and the adjustment factor.[7] If the operating margin is equal to the optimal, then the adjustment factor is 1.0., i.e., the full CT value reflects the reliability benefits of a power purchase. However, if the operating margin is higher than optimal, say 40 percent, this reflects a situation when the system has more than adequate capacity from a reliability perspective, and therefore, the reliability benefit component of the power purchase is substantially lower than the full CT value. By the same token, at operating reserve margin lower than optimal, the reliability benefit is higher than the full CT value.

The preceding discussion talks about estimating the generation reliability component of SRMC. In some instances, the power purchase may improve reliability in a regional load center in close proximity, that presently faces a generation supply deficiency because of a transportation bottleneck. In such cases, a network related reliability premium would be appropriate.

Pricing Non-Firm Power Purchases: Short Run Marginal Costs

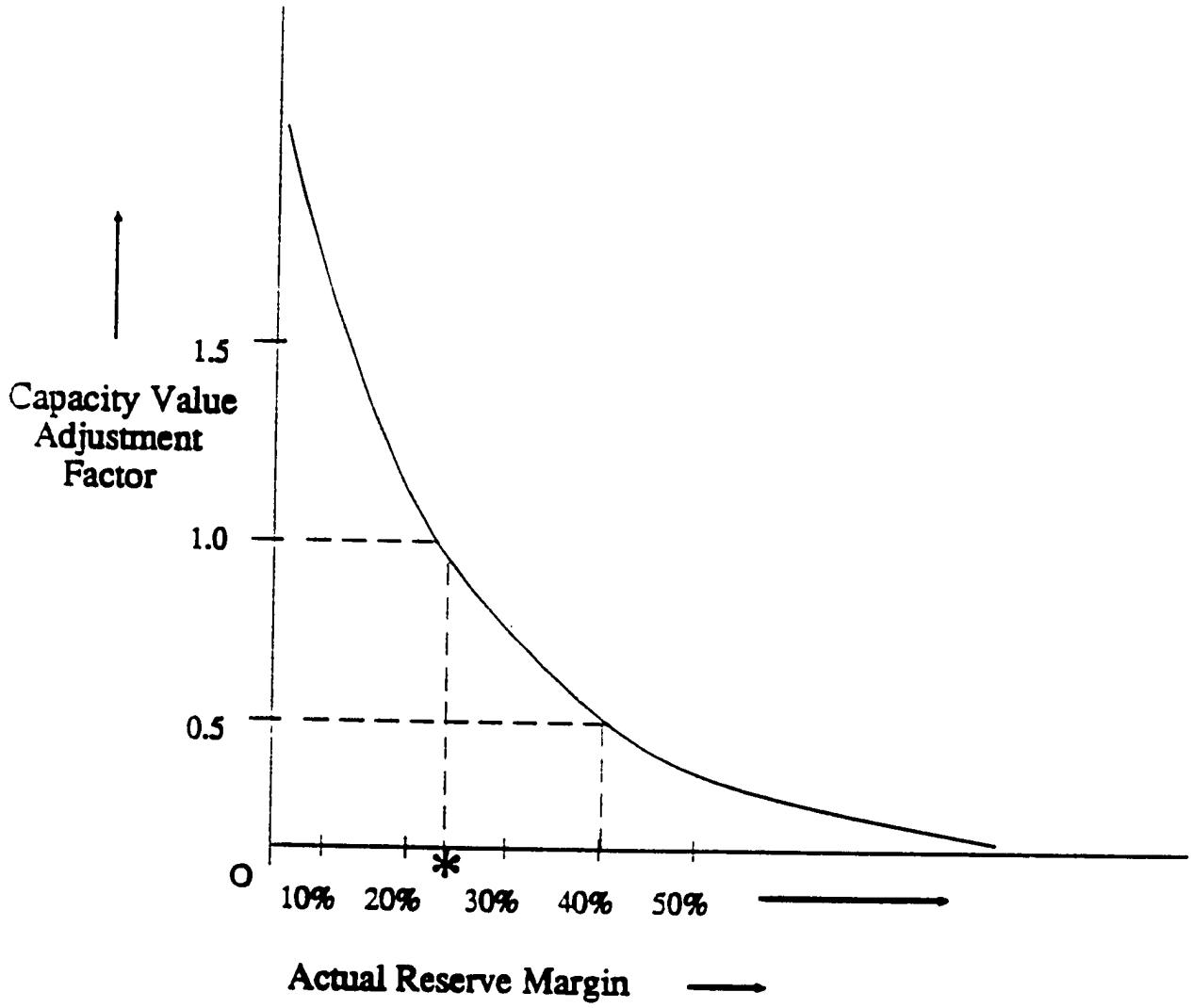
The avoided cost associated with a non-firm power purchase by PLN is determined by PLN's short-run marginal energy cost SRMC, which in any period t, when the purchase takes place, can be defined as follows:

$$SRMC(t) = \lambda(t) + L(t) + R_G(t) + R_N(t)$$

[6] e.g., when the actual LOLP (or reserve margin) is equal to the economically optimal LOLP (reserve margin).

[7] To those familiar with the technical details of power system reliability evaluation, the exponential shape of the curve in Exhibit 3-1 mirrors the relationship between the generation system reserve margin and LOLP.

Exhibit 3-1
CT Proxy Value Adjustment Factor
(Illustrative)



* Optimal (Target) Reserve Margin

SRMC(t)	=	short-run marginal energy cost
$\lambda(t)$	=	incremental generation fuel and variable maintenance costs[8]
L(t)	=	marginal network loss cost
$R_G(t)$	=	generation reliability benefit
$R_N(t)$	=	network reliability benefit

Exhibit 3-2 helps to illustrate the concept of incremental fuel cost and its variation by time-of-day (TOD). The exhibit depicts a schematic of the peak day load curve for the Java-Bali system. Also shown in the exhibit is the merit order stacking of generating units classified into six homogeneous groups, ranked from the cheapest to the most expensive fuel group. At the bottom (i.e., the first to be dispatched) is the base hydro energy. The variable cost of operation for this group is essentially any non-fuel variable O&M expense. Therefore, the total variable cost for this group is close to zero.

Stacked immediately above the base hydro are the coal units. As one goes higher up in the stacking order, the variable (fuel plus other O&M) costs become progressively higher. In practice, a production simulation model can be utilized to determine the optimal stacking.

The data suggest that the incremental generation cost on-peak is determined largely by the incremental fuel cost of gas turbine generation,[9] whereas the off-peak incremental energy cost is determined by a weighted combination of the incremental cost of oil-steam plant and the incremental cost of gas turbine plant.[10]

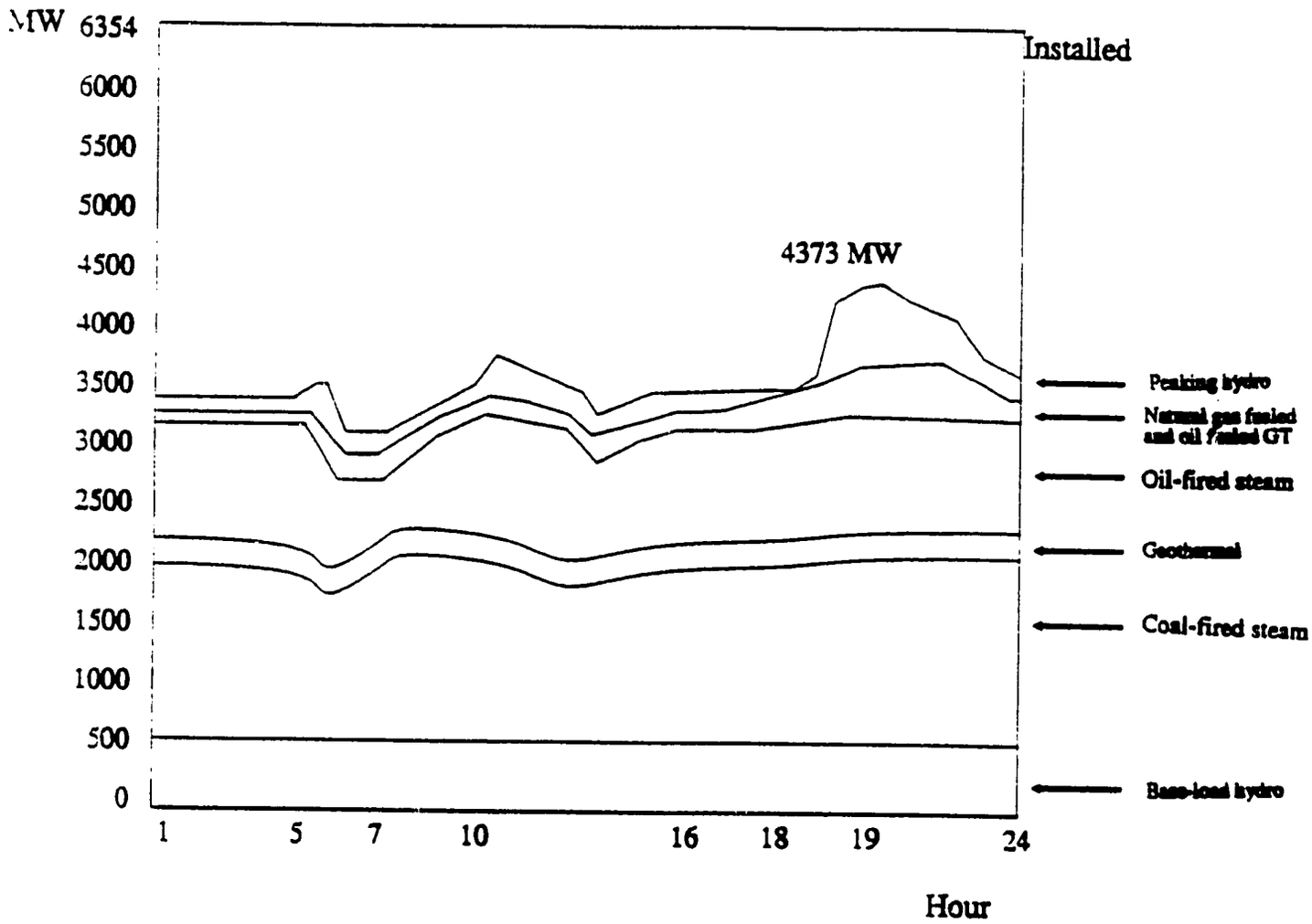
For developing standard price offers, a production simulation model can be utilized to estimate the incremental fuel cost $\lambda(t)$. If such a model is not readily available or cumbersome to use, then a proxy plant can be identified from actual operating experience and a theoretical calculation performed to estimate $\lambda(t)$ by multiplying the incremental heat rate for the proxy plant, the heat content of the fuel, and the unit fuel price.

[8] Under an economic dispatch regime, this "plant at the margin" would be one of the most expensive plants on line and its incremental cost of operation defines the "system lambda" in the given hour.

[9] This being the value of peaking hydro.

[10] In addition, the reliability benefit component should be added as well, but under the present power balance in the Java-Bali grid, this component may be low, at least for generation.

Exhibit 3-2
Schematic Peak Day Load for Java-Bali System
October 19, 1990*



* Peak load in June 1991, 4544 MW

Losses can be modelled as a quadratic function of demand such that:

$$\text{Losses} = B_{loss} \times D(t)^2$$

where B_{loss} = loss constant.

The marginal cost of losses is the marginal production cost times the marginal losses. Marginal losses are calculated by taking the derivative of the equation above and are equal to $2 \times B_{loss} \times D(t)$. Alternately, loss estimates may be available from other data and can be applied directly.

The reliability benefit components can be estimated using the approach discussed in the preceding pages, i.e., direct measurement of outage cost, or the adjusted CT proxy value-based method.

Pricing Firm Power Purchases: Long-Run Marginal Costs

Marginal Generation Capacity Cost

The "peaker method" is recommended for estimating this cost. It is rationalized on the basis that the least-cost means of securing capacity is a peaking unit and the reason any other type of generation is built is to derive the energy savings. The annualized cost of such a unit -- adjusted for reserve margin and losses, and appropriately discounted from the year of first need to today -- is the marginal cost of generation capacity. The following equation captures this calculation:

Marginal Generation Capacity = [(K) (1 + RM/100)/(1 - SL/100)]
Cost (Rp./coincident kW/yr)

where K = Annualized cost of peaking unit (Rp./kW/yr)
RM = Planning reserve margin (%)
SL = Station losses (%)

This cost (in constant prices) is subsequently discounted from the first year in the future when the reserve margin constraint (or the design loss-of-load probability criterion) is binding, and adjusted upwards for incremental fixed O&M expenses, as well as any downstream losses up to the point of delivery. Finally, this cost can be allocated to

different rating periods in the study (e.g., peak and off-peak) using a number of different methods. A common allocation method is on the basis of the contribution of each rating period to the annual loss-of-load probability (LOLP).

A second approach, the differential revenue requirements method (DRR), re-optimizes the entire expansion plan and estimates the incremental difference in the present value of two expenditure streams. Re-optimization of the expansion plan requires the use of sophisticated optimization expansion planning models.[11]

The implementation of the DRR method requires a substantial commitment of resources and is most often utilized in the context of estimating avoided costs for estimating payments for power purchases from large-sized independent power projects and cogeneration projects, i.e., where the impact of the plant on system operation and expansion is likely to be more than marginal. As a rule of thumb, such an analysis is warranted only when the size of the private power project under consideration (MW) is at least 3 to 5+ percent of the system being modelled. Anything smaller is likely to be within the "noise band," with the model(s) being unable to discriminate the incremental impact of the resource addition.

Marginal Network Capacity Cost

The transmission and distribution (T&D) network's capacity is designed to accommodate peak demand power flows from generation to end users. Further, in a growing system, such network capacity is sized and sequenced recognizing future growth potential as well. Generally, all investment costs for T&D are allocated to incremental capacity because the designs of these facilities are determined principally by the peak kilowatts that they carry rather than by kilowatt-hours. The most frequently used approach for estimating marginal

[11] For example, the International Atomic Energy Agency's WASP model for optimal generation expansion planning. Specifically, three "WASP model runs" are required as follows. Run 1 corresponds to optimizing the system generation expansion plan to run the base load forecast. Model run 2 re-optimizes the system expansion plan with the peak load forecast used in run 1 incremented by the equivalent one year's load growth. Finally, run 3 is a production simulation (e.g., WASP in a "pre-specified pathway" mode) to estimate the fuel costs associated with the load forecast used in run 1, but unit stagings determined in run 2. Thus, LRMC for generation capacity can be estimated by calculating the following quantity and levelizing it:

$$[(CR_1 - CR_2) + (FC_3 - FC_1]/DMW$$

Where CR_i is the capital investment associated with model run i (i - 1,2,3), FC_i is the fuel (production) cost associated with the expansion plan model run 1, and DMW is the megawatt incremental difference in peak load between runs 1 and 2.

T&D capacity cost, and the one recommended in the present context, is the long-run average incremental cost (LRAIC) method.

The LRAIC represents the present value of all T&D investments over the planning horizon divided by the present value of the corresponding annual increments in peak load. This value, expressed in Rp. per incremental kW, is then annuitized over the life of the facilities, resulting in the annuitized capacity cost, expressed in Rp./kW/year.

Separate LRAICs should be estimated for each major voltage level of the network -- e.g., very high voltage (VHV), high voltage (HV), medium voltage (MV), and low voltage (LV).

Standard Offer Contract Pricing

For simplicity, two standard offers are recommended that differentiate between:

- non-firm power purchases and
- firm power purchases.

The former refers to the purchase of kWh in cases where such supplies are intermittent, cannot be assured, or their magnitude and/or temporal profile cannot be predicted with any degree of certainty. The "acid test" to gauge whether such a purchase is non-firm is whether such supplies can be counted upon to defer resource additions. If this is not the case, then the prices for such purchases would be based solely upon the short-run marginal energy cost to be calculated as indicated in the preceding pages.

In the case of firm power purchases, the IPP or cogenerator should be prepared to deliver a specified amount of firm capacity, and specify the times -- of year and day -- at which such capacity would be made available, the expected annual availability, as well as the duration (number of years) of the contract. A minimum contract duration of one year is suggested for such standard offer contracts. Under these conditions, the capacity payments should be pegged to estimates of long-run marginal generation capacity as determined by the peaker method described earlier. Energy prices would be estimated by the incremental fuel and other variable costs.

It is recommended that energy prices under both types of standard offers -- should be updated and posted regularly.[12] Further, energy prices for firm as well as non-firm power purchases should be time differentiated into a minimum of two periods -- peak and off-peak. For all but the very small NUGs/IPPs, time-of-day (TOD) metering is recommended.

To enhance transparency, the idea of using a simple formula-based adjustment for fuel costs should be evaluated; such a formula might work as follows. In period i, where i denotes peak or off-peak:

$$\text{Incremental fuel cost}_i = \text{Incremental heat rate}_i \text{ (Btu/kWh)} \times \text{weighted average fuel price}_i \text{ (Rp./Btu)}$$

The first term represents the weighted average heat rate of all units on the margin in period i, and the second term is the weighted average fuel price utilized by these units. The output of production simulation runs would be used to determine the marginal plant mix expected to be representative for the period and the incremental heat rate. Fuel prices could be pegged to a credible and independently published official source. For facilitating long-term planning and scheduling by the NUG/IPP, consideration should be given to the feasibility of providing non-binding forecasts of marginal energy costs for a 12-month forward period.

Capacity cost payment posting will also need to be updated, though less frequently. A bi-annual update is suggested initially. Once the appropriate staff resources and institutional and modelling capability is in place, the feasibility and desirability of more frequent updates for capacity price posting could be evaluated.

3.3 REVIEW OF AVAILABLE INFORMATION

PLN's review of its long-run marginal costs was last conducted in April 1990. Exhibit 3-3 presents summary estimates of LRMC -- capacity cost and prevailing marginal energy cost -- based upon the projected least-cost mix of plant in operation during 1995/96.

[12] Initially, a six-month update may be appropriate. An annual update may not closely track the energy cost structure variations, which are primarily determined by fuel cost fluctuation, generation unit maintenance, and unit availability. On the other hand, quarterly updates would impose substantial staff resources to execute.

Exhibit 3-3
Estimates of Long-Run Marginal Costs: Java System

Voltage	Capacity (Rp./Coincident kW/Month)	Energy (Rp./kWh)	
		Peak	Off-Peak
H.V.	4,720	106	70
M.V.	9,393	113	75
L.V.	17,246	134	89

Source: PLN.

The PLN report does provide a good starting point for more detailed and appropriate calculations of marginal/avoided cost. However, in and of themselves, these estimates cannot be used for developing the standard offer price offerings for actual implementation. This is because of the following:

- The PLN study estimates are dated.
- The marginal generation capacity cost calculation utilizes the differential revenue requirements (DRR) method. As noted previously, the DRR method produces estimates best interpreted as long-run average incremental costs. These represent a weighted average of the capacity cost of baseload, peaking, and intermediate plant costs, i.e., plants that are marginal and inframarginal. The peaker method is the appropriate method to use for calculating the LRMC of generation capacity.
- The marginal energy cost estimates reported in the PLN study were developed by an hourly production cost model utilized by the dispatch center.[13] However, for setting this energy price component of the standard offer, what is required are projections for the next twelve months, not the long-term marginal energy cost in 1995/96, as shown in Exhibit 3-3. As

[13] This model was reviewed with the control center staff. It is essentially a spreadsheet model employed for short-term scheduling and operation. The model performs a deterministic stacking of all available plant in each hour after accounting for scheduled maintenance and unit deratings for those on forced outage status. The unit at the margin in each hour is simply the highest operating cost unit in the stack.

noted in the preceding section, energy prices need to be updated and posted prior to the start of every quarter.

- The marginal energy cost calculations undertaken by PLN also do not include a reliability benefit component.

- Separate estimates of marginal costs are required for all the islands. The PLN study focuses in on the Java system.

The above observations lead us to recommend that:

- A comprehensive marginal cost study be undertaken -- separately for each grid and island -- in order to provide the basis for establishing the administered prices to be applicable under the standard offers. The capability to undertake regular updates of this study should be installed within working groups of the Private Power Team, which would also have active participation from PLN staff in tariffs, system planning, and operation.

This study is scoped out further in a subsequent chapter of this report.

3.4 EXISTING POWER PURCHASE AGREEMENTS BETWEEN PLN AND NUGs/IPPs

PLN has entered into several letter agreement-type contracts to purchase excess power supplies from several NUGs. The essential features of the contracts reviewed -- especially pricing provisions -- are summarized in Exhibit 3-4.

As regards pricing, the following points stand out based on our review:

- With one exception, there are no capacity payments. In the case of Krakatau Steel, we understand that since 1989, increased steel production has resulted in no excess power sales to PLN.

- With two exceptions, the marginal energy costs typically range from 10 to 30 percent of PLN's long-run marginal energy cost estimates indicated in Exhibit 3-3.

The Pertamina contract energy price is about 75 percent of the off-peak and 50 percent of the on-peak PLN-estimated long-run marginal energy cost, whereas in the case of Krakatau Steel, these are 70 percent and 90 percent, respectively, of PLN's long-run marginal energy cost estimate.[14]

In other words, even the energy price payments tend to be far below efficiency purchase prices.[15]

- Tariff adjustment mechanisms/formulae are not clearly spelled out and as a practical matter, have been denied in many cases despite repeated requests.

- It appears that purchase prices have generally been arbitrarily set with some consideration to the supplier's cost of production. This pricing basis is fundamentally at odds with the concept of efficiency prices based upon opportunity costs.

This pricing philosophy, if maintained into the future, will have the adverse effect of drastically restricting the optimal future development of cost-effective power supplies from cogeneration, from the smaller IPPs, and will curb the development of new and renewables-based indigenous and decentralized resources for power generation.

In addition, under the present pricing structure and level, there is no incentive for DSM, i.e., absent capacity payments and time-differentiation of capacity and energy prices, there is no incentive for NUGs and IPPs to maximize their sales at times when they are most beneficial to the grid.[16]

[14] A comparison with PLN's current short-run variable cost of production and these energy price payments is also relevant. An earlier exhibit in this chapter highlights the merit order stacking of PLN's plants during the peak day of October 19, 1990 for the Java-Bali system. These data suggests that in fiscal year 1990/91, gas turbines (gas or oil-fired) determine the marginal energy costs during the evening peak hours, and a weighted combination of oil-steam plant and gas turbine determined the marginal energy cost during off-peak hours.

[15] At prevailing exchange rates of Rp. 1950 to the US dollar, an energy price of 18 Rp./kWh approximately translates to under one US cent per kilowatt hour.

[16] We recognize that the tapping of existing and future captive cogeneration capacity at times of system peak is better viewed as a DSM/load management program and not as a "private power" program.

Exhibit 3-4
PLN Power Purchase Contracts in Effect

	Company/ Location	Type of Plant	Installed Capacity	Expected Purchase for Next Year*	Current Purchase Price		Arrangement
					Capacity (Rp./kVA/mo)	Energy (Rp./kWh)	
1.	P.T. AAF and P.T. PIM/Aceh, Sumatra	Diesel	--	--	--	30.00	Inactive
2.	P.T. Inalum/Arahan North Sumatra	Asahan Hydro	604 MW	29 GWh	--	17.72	Originally a take-or-pay contract with price adjustment provision. However, latter is not applied.
3.	P.T. Anggrek Mekar Sari/Sumatra	Mini Hydro	3 x 350 kW	2000 MWh	--	23.00	Letter agreement
4.	Perum Tambang Batubara Ombilin/West Sumatra	Steam	--	4000 MWh	--	30.00	Letter agreement
5.	Pertamina/ Balikpapan, East Kalimantan	Diesel	--	0	--	65.64	Letter agreement. No longer active. PLN is now a seller only.

Source: 1991/1992 PLN Budget and PLN T&D Operations Planning Subdivision

Exhibit 3-4 (continued)
PLN Power Purchase Contracts in Effect

Company/ Location	Type of Plant	Installed Capacity	Expected Purchase for Next Year*	Current Purchase Price		Arrangement
				Capacity (Rp./kVA/mo)	Energy (Rp./kWh)	
6. P.T. Inco/ Southeast Sulawesi	Hydro	207 MW	2000 MWh	--	16.70	No price agreement in place at present. Negotiations underway. Supplier needs money to rehab project.
7. PTP XXX, Subang	Hydro	--	0	--	20.50	Letter agreement. PLN is a net seller now.
8. P.U. Jatiluhur/East Java	Juanda Hydro	6 x 25 MW	800 GWh	--	18.00	--
9. P.T. Krakatau	Oil/Gas Steam	5 x 80 MW	No excess production since 1989	Rp.* 3,960/kVA/ month	Peak:* Rp. 188.50/kWh Off-Peak: Rp. 76.50/kWh	PLN is a net seller at present
10. Yayasan Pelayanan Kesehatan dan Sosial Bethseda/West Kalimantan	Hydro	90 MW	25 MWh	--	10.00	--

* Identical to PLN's tariff.

CHAPTER 4: PRICING OF POWER PURCHASES FROM DEDICATED PROJECTS AND OTHER LARGE-SIZED NEGOTIATED POWER PURCHASES

This chapter discusses the pricing determination approach for pricing large power purchases from IPP projects under BOO/BOT type contract schemes. Section 4.1 contains some introductory remarks. This is followed in Section 4.2 by the discussion on the pricing methodology.

4.1 PROJECTS OFFERED FOR PRIVATE-SECTOR DEVELOPMENT

PLN's least-cost expansion plan (LCEP) calls for approximately 12,000 MW of additional generating capacity to be built by the year 1999/00. Exhibit 4-1 provides some details of this plan as regards the capacity type, timing, and magnitude of each of the planned additions:

- Of the total additional requirement of 12,000 MW, 5,000 MW are accounted for by presently committed projects, leaving about 7,000 MW of planned new capacity requirement by the end of this decade.

We are not aware of any formally rationalized and declared policy regarding the selection of specific projects from the planned capacity requirements that are to be offered to the private sector; though as of this writing, two project sponsors are expected to submit bids for 2 x 600 MW coal-fired units, 7 and 8, to be located next to PLN's existing site at Paiton. Prequalifications are underway for five other projects.

Presumably, one important criterion for deciding upon the magnitude of total capacity additions to be offered is the amount of capacity that PLN can finance and build itself. Estimates of 5,000 MW are being mentioned in connection with the capacity to be offered for private sector development. These numbers, if true, are indeed astonishing in that they imply a private power program in magnitude and scope -- i.e., numbers of plants and the fact that large-size baseload units are involved -- that has not been achieved elsewhere yet. Furthermore, very little if any quantitative analysis appears to have been undertaken to date to examine the financial implications of such a program on PLN and the national economic implications given that one way or another, the amount of foreign exchange required to

Exhibit 4-1

Capacity Expansion Plan of the Base Load Forecast Scenario (1991/92 - 2003/04)

R6-Base

01/01/91

No.	Description	Units	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04
1.	**Demand**															
	- Energy Production	(GWh)	27788	29588	34406	39318	45973	53314	61555	68313	74607	80938	87793	95151	103108	111719
	- Peak Load	(MW)	4565	4888	5684	6488	7578	8760	10129	11238	12273	13315	14443	15655	16965	18383
	- Growth rate (En. Prod.)	(%)	16.3	7.1	16.3	14.1	16.8	15.9	15.4	10.9	9.2	8.5	8.5	8.4	8.4	8.4
2.	**Capacity**															
	- Installed Capacity	(MW)	6357	6357	6357	6357	6357	6232	6182	6057	5757	5757	5757	5757	5757	5732
	- On going/Committed Projects	(MW)														
	Kesamben HEPP		-	-	-	-	-	33	33	33	33	33	33	33	33	33
	Citiman HEPP		-	-	-	10	10	10	10	10	10	10	10	10	10	10
	Tulungagung HEPP		-	-	-	36	36	36	36	36	36	36	36	36	36	36
	Kedungombo HEPP		-	-	23	23	23	23	23	23	23	23	23	23	23	23
	Tulis HEPP		-	-	-	13	13	13	13	13	13	13	13	13	13	13
	Cirata-2 HEPP		-	-	-	-	-	500	500	500	500	500	500	500	500	500
	Diesel		6	6	6	6	6	6	6	6	6	6	6	6	6	6
	Suralaya #5-7 SCPP		-	-	-	-	-	-	1200	1800	1800	1800	1800	1800	1800	1800
	Paiton #1-2		-	-	-	400	800	800	800	800	800	800	800	800	800	800
	Ex Tosan Prima GTPP		-	60	60	60	60	60	60	60	60	60	60	60	60	60
	Bali GTPP		-	-	60	60	60	60	60	60	60	60	60	60	60	60
	Saiak #1-#2 GEPP		-	-	-	110	110	110	110	110	110	110	110	110	110	110
	Drajat GEPP		-	-	-	-	55	55	55	55	55	55	55	55	55	55
	Dieng GEPP						55	55	55	55	55	55	55	55	55	55
	Gresik #1-3 CCPP		-	-	1080 *)	1412 **)	1578	1578	1578	1578	1578	1578	1578	1578	1578	1578
	Muara Karang #1 CCPP		-	-	300 *)	450	450	450	450	450	450	450	450	450	450	450
	Priok #1-2 CCPP		-	-	-	600 *)	900	900	900	900	900	900	900	900	900	900
	Sub Total	(MW)	6363	6423	7886	9537	10513	10921	12071	12546	12246	12246	12246	12246	12246	12221
3.	**Planned Projects**	(MW)														
	Jatigede HEPP		-	-	-	-	-	-	-	-	175	175	175	175	175	175
	Cimandiri HEPP		-	-	-	-	-	-	-	-	351	351	351	351	351	351
	Ayung HEPP		-	-	-	-	-	-	-	-	44	44	44	44	44	44
	Paiton #3-#4 SCPP		-	-	-	-	-	800	800	800	800	800	800	800	800	800
	Paiton #5-#8 SCPP		-	-	-	-	-	-	-	-	-	600	1200	2400	2400	2400
	Central Java #1-#7 SCPP		-	-	-	-	-	-	-	-	600	1200	1800	2400	3600	4200
	West Java I, #1 - #2 SCPP		-	-	-	-	-	-	-	-	-	-	-	-	-	1200
	GTPP #1-#8		-	-	-	-	-	-	-	-	-	120	360	360	720	960
	East Java #1-#3 CCPF		-	-	-	-	-	-	-	500	1000	1500	1500	1500	1500	1500
	Sub Total	(MW)	0	0	0	0	0	800	800	1300	2970	4790	6230	8030	9590	11630
4.	**Total Capacity**	(MW)	6363	6423	7886	9537	10513	11721	12871	13846	15216	17036	18476	20276	21836	23851

*) Open cycle operation of CCPP

**) Summation of 2 blocks of CCPP (2 x 526 MW) and 3 units of GT (3 x 120 MW) .

1/r6base

Source: PLN

meet the projected electricity demand will not reduce from national perspective; and indeed, is likely to be higher for private sector participation.[1]

4.2 PRICE DETERMINATION

For specific power projects identified in PLN's LCEP, the pricing framework developed in Chapter 2 recommends a competitive bidding process wherein prequalified project sponsors are invited to submit tenders on project design, technical specifications of key elements, cost buildups by major components, and a pricing arrangement in response to a solicited terms of reference (TOR).

The GOI is currently leaning toward a contractual arrangement commonly known as BOO, under which the private sponsor is responsible for building, owning, and operating the power plant for a stipulated long-term (typically 20+ years) period and under certain agreed-to performance guarantees.

For such identified power projects, the pricing for power purchases should be negotiated with the outcome not to exceed the "price cap" determined under the avoided cost principle discussed at length earlier. In the situation of a dedicated power project such as Paiton and "Paiton-like projects," the avoided costs are determined by triangulation of the following estimates of costs associated with a "peer plant," i.e., a comparable existing but recently built power plant for which actual cost data are available:

1. PLN-owned and operated peer plant cost
   - PLN's financial cost
   - economic cost
2. International peer plant cost.

If a PLN peer plant exists, then financial and cost accounting data specific to the plant will provide a factual basis for establishing a financial avoided cost estimate. For example, in the case of pending bids for the Paiton coal plant bids (for units 7 and 8), PLN's recently completed Suralaya units 3 and 4 and Paiton units 1 and 2 that are under construction come closest to qualifying as peer plants. After the first step of ascertaining PLN's financial cost for a peer plant, adjustments must be made to correct for distortions such as subsidies and

[1] The problem does not necessarily have to do with sector development cost being possibly higher under a certain strategy, but rather, with the lack of a thorough quantitative understanding of the sector-level financial implications for PLN's continued viability, the national-level budgetary and external account implications as well as the overall macroeconomic implications of a private sector participation strategy of the massive scale that is envisioned.

distortions in the cost of capital to develop the economic avoided cost for each peer plant. It is this latter value that serves as the appropriate basis for evaluating bids by private suppliers on a "level playing field" basis.

International data sources should be utilized to identify recently built coal plants in the 600 MW range[2] that can serve as peer plants for the upcoming Paiton bid evaluation.

In the final analysis "no two power plants are alike." Therefore, the purpose of identifying peer plants is to establish cost benchmarks by a process of triangulation since no one peer plant is likely to be identical in every respect to the prospective plant. Further, to facilitate more direct comparability between the peer plant(s) and the prospective plant, the peer plant avoided costs should be developed by major components, as should the bidder's estimates.

Some components will be more directly comparable between a peer plant and the prospective plant. If only a total plant cost estimate is available, then a comparative evaluation is not likely to be very useful. However, the opportunities for meaningful comparisons -- and hence better bid evaluation -- will increase substantially when plant cost data are available by major components.

For example, if available, the financing cost component of the power plant(s) and the plant bid under evaluation can be compared to gauge whether the differences are justified because of the private sponsor's capital cost structure as well as any differences in market conditions in the two cases. Similarly, if site preparation costs are separated out, then adjustments can be made for local differences to facilitate a comparative evaluation of bids.

Discussions were held with PLN during the course of the team's second mission to Jakarta in August, in an attempt to obtain data on PLN's actual costs for the recently completed Suralaya units as well as bid costs for Paiton units 1 and 2 that are under construction. Whereas units 3 and 4 have been completed, we understand that the results of a financial audit of actual costs to completion have not yet been released.[3] As regards the bid cost of Paiton units 1 and 2, we understand that four out of the 24 "packages" have not been bid out yet. With firm bids for 20 packages, the projected completion cost is estimated to be

[2] In the U.S. alone, approximately 40 coal and combined cycle plants have been built in the last five years.

[3] The IBRD's project completion report for Suralaya units 1 and 2 indicates that the actual cost to completion was US $510 million, or equivalently, $638/kW. Cost estimates for units 3 and 4, as per IBRD's Fourteenth Power Project Financial Plan (Staff Appraisal Report No. 4949-IBRD) are US $502 x 10^6, or equivalently, $628/kW. However, it is not yet known how actual costs compared with these numbers.

around U.S. $1.1 billion, or equivalently, about $1,375/kW. Some of this cost is a joint cost in that it includes the coal handling facility as well as some other joint facilities to be shared by future units at the same site.

The development of actual peer plant cost estimates was beyond the scope of this initial effort and should be a matter of high priority in the follow-on phase scope that is identified in Chapter 5 of this report. Such an undertaking will need to begin with a review and thorough understanding of PLN's cost accounting and reporting system and its ability to accurately record, track, and report all of the cost elements involved by major categories in the total.

A matter of particular concern would be to assess the extent to which some costs may not be recorded or distorted because of the complicated and non-transparent nature of the financial relationship between PLN and the GOI. For example, on the one hand, the GOI, as sole owner and shareholder, has historically

- not required PLN to pay dividends on its cumulative equity contributions as paid-in capital[4]
- exempted PLN from duties, taxes, and VAT
- directly made debt service payments and absorbed foreign exchange risk[5]
- subsidized the price of diesel paid by PLN.

On the other hand, the GOI imposes costs on PLN by a variety of means, the most important of which are subsidies in the retail electricity tariff to small residential and small industrial customers, and selected other consumer segments, and by charging higher prices for marine fuel oil.

Contract Pricing Structure

In the Power Purchase Agreement, a number of different contractual arrangement options can be utilized. One form of contract that is mentioned often is a "take or pay" contract. To illustrate this, consider a take or pay contract for a 100 MW baseload plant.

[4] IBRD has estimated this amount at Rp. 4,282 billion through 1987/88.

[5] IBRD estimates this amount to be Rp. 194 billion just for the year 1987/88.

Under such a contract the terms might call for 613 GWh of electricity to be supplied to the grid each year for 25 years (an effective annual load factor of 0.70), and at a first-year fixed price of Rp. 115/kWh, with an adjustment factor for fuel cost increases in future years. Suppose further that the first-year price of Rp. 115/kWh consists of Rp. 75/kWh for capacity and Rp. 40/kWh for fuel and other variable costs. Under this contract, the project sponsor would have to be paid Rp. 70,495 million annually for the contracted supply. The unit price of Rp. 115/kWh would be adequate to allow recovery of depreciation, other fixed expenses, return on investment, and fuel costs and other variable costs, as long as a load factor of 0.70 is maintained. If the plant could only operate at a load factor of 0.65, because of operational problems, the project developer would not recover all fixed costs for the year, because fewer kilowatt hours were sold. By the same token, if the plant were asked to operate at any load factor higher than 0.70, and could, the project company would be permitted the recovery of all variable costs plus some additional profit. From PLN's perspective, however, the resource acquisition cost is Rp. 115/kWh under this type of contract.[6]

This type of contract, despite its apparent simplicity, has several operational shortcomings that compromise economic efficiency. First, it is not desirable from the national power system's operational standpoint to commit a plant to operate for 25 years at a load factor of 0.70. Over the longer term, new and more efficient plants would be built, pushing this plant up in the merit order to economic dispatch and therefore requiring a lower load factor duty, or simply a change in its position in the loading cycle.

Also, because of oil price fluctuations, some oil-fired plants may be cheaper to operate during certain years. Further, new supplies of distribution cogeneration could become available and cheaper to utilize. All these unpredictable situations would call for changing a plant's loading order if an economic dispatch regime is to be followed. This would result in a higher heat rate for the plant. Such efficiency changes can easily result in several millions of dollars of additional fuel costs and would represent a substantial risk to the project sponsor. A provision would have to be made in the contract for this type of variance, by anticipating unforseen conditions. The alternative is that PLN has little flexibility in changing the position of the plant in the loading cycle. This would inevitably compromise its ability to closely adhere to a least-cost unit commitment and merit-order dispatch regime.

[6] With side payments and adjustments made to balance out any financial effects of production over or under 70 percent. Such "true ups" could be done quarterly, for example.

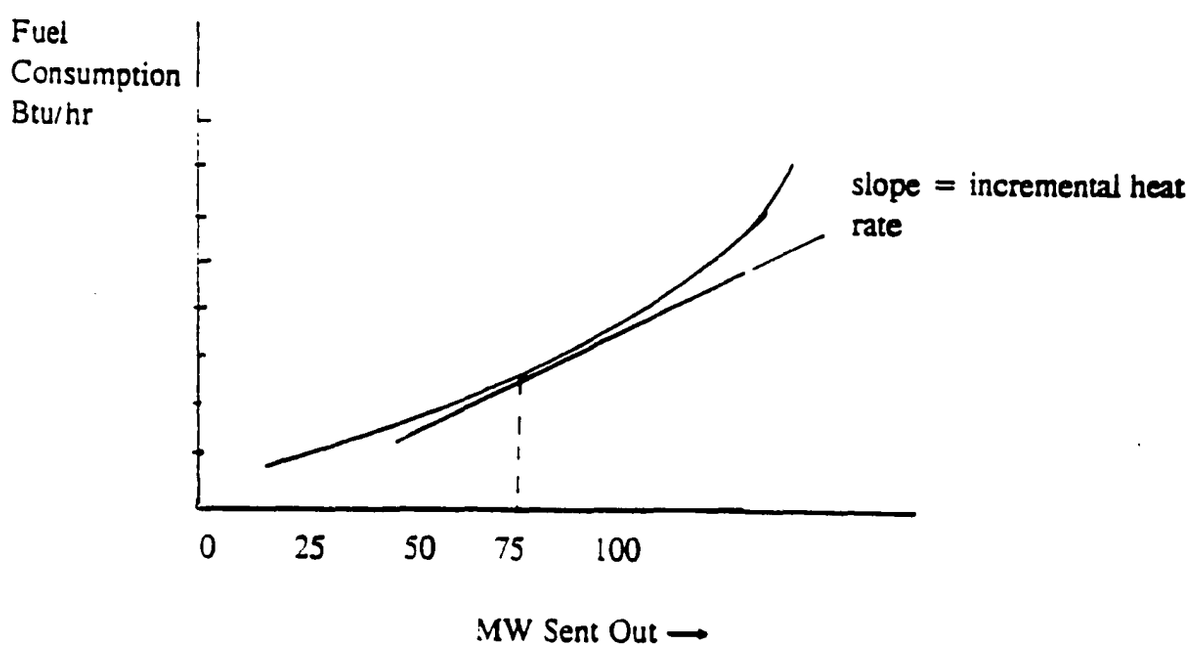
Another (and the preferred) contract form is to employ a two-part pricing structure, where there would be

- a fixed payment per kilowatt of available capacity
- a unit price per kilowatt hour purchased that is mainly fuel related

The former is somewhat akin to a capacity reservation charge (also referred to as a "standing charge"). It represents all the agreed-to fixed costs and return of the project company that PLN must pay to maintain the sole right to receive electricity from the plant when called upon. The second component of the purchase is a unit charge per kWh of electricity purchased. This component essentially represents incremental fuel and other variable costs. Indeed, this could be specified in the form of a cost curve (or a family of cost curves) -- as other PLN plants are characterized for dispatch purposes -- that defines the unit price at a loading position, loading level, and specified operating regime.

For example, the figure below shows schematically the relationship between the incremental heat rate and loading level.

Plant Fuel Consumption Varies as a Function of Loading Level



In summary, a major economic inefficiency embedded in the take-or-pay contract structure stems from the fact that PLN dispatch will treat the given power plant as a "must run unit," i.e., it will be dispatched first even if this results in a higher than least-total cost system operation. By contrast, under the economically efficient two-part pricing structure, the PLN operator "sees" the true marginal price of Rp. 40/kWh, thereby optimally integrating (i.e., dispatching) the power plant into grid operation. In addition, as noted earlier, the actual marginal price will change over time for the given plant and in relation to the marginal price of other plants that are dispatched. Under the two-part pricing structure, grid dispatch and operations will continue to optimally integrate all non-utility power plant operations. This obviously will not happen under the take-or-pay structure since the pressure will be on PLN to dispatch the plant first regardless of its cost and efficiency vis-a-vis other plants.

The primary advantage of a take-or-pay contract appears to be that on the surface it is simple and therefore perhaps more readily understood by non-utility personnel. However, from an economic efficiency standpoint, a two-part contract pricing structure is clearly superior. This type of contract pricing structure offers the following benefits:

- incentive to maintain high plant availability at all times.
- generation efficiently scheduled accordingly to actual marginal cost
- generation unit operation -- commitment, loading levels, dispatch -- in the same manner as all other PLN plants on the grid
- minimization of total cost of system operations.

By contrast, the take-or-pay contract structure only offers the first of these three benefits identified above. Finally, the take-or-pay contract pricing structure can be made even more efficient, but at the cost of introducing some complexity, by expanding it to a multi-part price structure, wherein one or more of the following variable cost components are priced separately in addition to a per kWh fuel cost charge discussed above:

- unit startup cost (Rp./startup)
- unit commitment charge (Rp./hour)
- charge for maintaining unit on hot standby (Rp./hour).

Annex 4 provides further details about the recommended payment structure and general structure of the formulae to be utilized in calculating payments to the seller under the recommended two-part tariff.

4.3 ILLUSTRATIVE EXAMPLE OF PRICING UNDER A BOO SCHEME

This section presents a numerical example to highlight the linkage between project financing structure and the power purchase price. The exampie is intended to be illustrative only; though the specific data inputs have been selected to be indicative of the respective magnitudes involved.

A 1,200 MW coal-fired plant is considered under a 25-year BOO scheme. Exhibit 4-2 highlights some of the key assumptions utilized in the following analysis. "Overnight" costs of $1,217/kW represent all costs of equipment, services, and installation, but excluding financing costs. The total project costs of $1929/kW were developed based upon the financing structure shown in Exhibit 4-2.

The key assumptions indicated in Exhibit 4-2 together with other assumptions were input in a financial project evaluation model (PROJEV) developed by RCG/Hagler, Bailly, Inc.[7]

Again, it is important to emphasize that the financing structure utilized for the analysis (as shown in Exhibit 4-2), as well as other assumptions are for illustrative purposes. They do not necessarily reflect precisely the specific and prevailing capital market conditions at the time this analysis was undertaken. However, the data inputs are within the realm of reality, and therefore useful in capturing and illustrating some of the key linkages between the financial and economic aspects of such large and dedicated power projects.

The PROJEV model was utilized to iteratively search and estimate a two-part payment structure -- consistent with the economically efficient pricing structure discussed in section 4.2 -- and that yields an internal rate of section (IRR) of 20 percent to the equity holders, based upon the after tax cash flow from the corresponding revenue stream. The IRR is a user-specified input.

In this connection, a key observation is that the capacity and energy payment profiles -- i.e., payment levels expressed as $ or Rp. per kW for capacity, and $ or Rp. per kWh for energy and for each year of the 25 year contract period -- that meet the 20 percent desired IRR are not unique. There exist potentially a very large number of such payment profiles (trajectories) that are equivalent in the sense that each will provide a 20 percent IRR to the equity holders. However, such payment profiles over time may have vastly differing risk and other implications for the different stakeholders in the project, i.e., PLN, GOI, consumers, equity holders, and debt holders.

---

[7] Annex 5 presents a brief description of the PROJEV model. Annex 5 also contains a detailed printout of the input assumptions.

Exhibit 4-2

LINKING PROJECT FINANCING STRUCTURE AND CAPACITY PAYMENTS (Illustrative Example)

- 1200 MW coal-fired power plant
- BOO, 25 years
- Startup year: 1997
- Design and construction period: 1991-1996

Project Cost

- Overnight costs excluding financing $1217/kW in 1991 dollars
- Total project costs including financing $1929/kW in nominal dollars
- Coal (25 million Btu/ton) price: $35/ton in 1991 dollars
- Heat rate: 9,500 Btu/kWh

Financing Structure

- 80% debt, 20% equity
- Desired internal rate of return by equity holders 20%
- Debt sources: Equal percentage of
  - -- 10-year commercial debt, 12% interest
  - -- 15-year commercial debt, 12.5% interest
  - -- 20-year debt, 11% interest
  - -- 25-year IBRD/ADB debt, 11% interest
- Construction period financing is provided by long-term lenders, with 80% debt ratio.

To illustrate this key aspect, we have focused on the four alternative capacity payment profiles shown in Exhibit 4-3, and labelled 1 through 4. Option 1 corresponds to capacity payments that increase with the assumed world inflation rate of 4 percent per year. A second option represents level nominal capacity payments over the 25-year lifetime of the contract. The third option is a three-step declining profile which follows the assumed debt profile in the financing structure, i.e., since capacity payments are pegged to recovery of the capital cost of the project, as the various blocks of debt are retired -- 10-year debt, 15-year debt, etc. -- the capacity payment is correspondingly reduced. The fourth option illustrated in Exhibit 4-3 is a variant of Option 3. Whereas Option 3 levelizes payments within the maturity periods corresponding to the four blocks of debt defined in Exhibit 4-2, Option 4 mirrors the annual debt repayment profile.

The energy payments corresponding to the four cases 1 through 4 are identical and are shown in Exhibit 4-4 in nominal terms. To illustrate, the year-1 (1997) energy payment of approximately 2.07¢/kWh is derived from the assumed coal price of 35$/ton, heat rate of 9,500 Btu/kWh and other non-fuel variable O&M costs. At the assumed exchange rate of 1950-to-1 US$ this corresponds to about Rp. 40/kWh for energy in 1997. In 1991 currency this is equivalent to Rp. 31.90/kWh. Future year payments are estimated similarly, but with coal prices increasing at the 4 percent rate of world inflation assumed in the analysis.

Whereas the four capacity payment profiles are divergent, each yields an IRR of 20 percent for the equity holders. However each profile has vastly differing implications for the stakeholders. Exhibit 4-5 illustrates the tradeoff along one such dimension; the first year average[8] power purchase price PLN would have to pay versus the present value (to PLN), of all payments made to the project developer, assuming a 70 percent plant availability factor.

Exhibit 4-5 clearly shows that the lower the first year price, the higher is the NPV of payments made for power purchases over the contract lifetime of 25 years. This arises because the discount rate assumed for PLN, 14 percent, is lower than the discount rate of the equity holders, 20 percent.[9]

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[8] In reality the tariff would have a two-part structure as discussed previously, with separate prices for capacity and energy.

[9] The first year average power purchase cost of Rp. 110.30/kWh shown in Exhibit 4-5 for Option 1 is the sum of an energy charge of Rp. 31.90/kWh noted above plus an effective capacity charge of Rp. 78.45/kWh. The latter is derived from the first year (1997) capacity value of $26.01/kW-mo calculated in the PROJEV model, discounted at 4 percent to a 1991 value of $20.56/kW-mo., and converted to a per-kWh basis by assuming a 730 hour month, availability of 0.7, and exchange rate of 1950-to-1.

Exhibit 4-3
ALTERNATIVE CAPACITY PAYMENT PROFILES
(All yield IRR of 20% to equity holder)

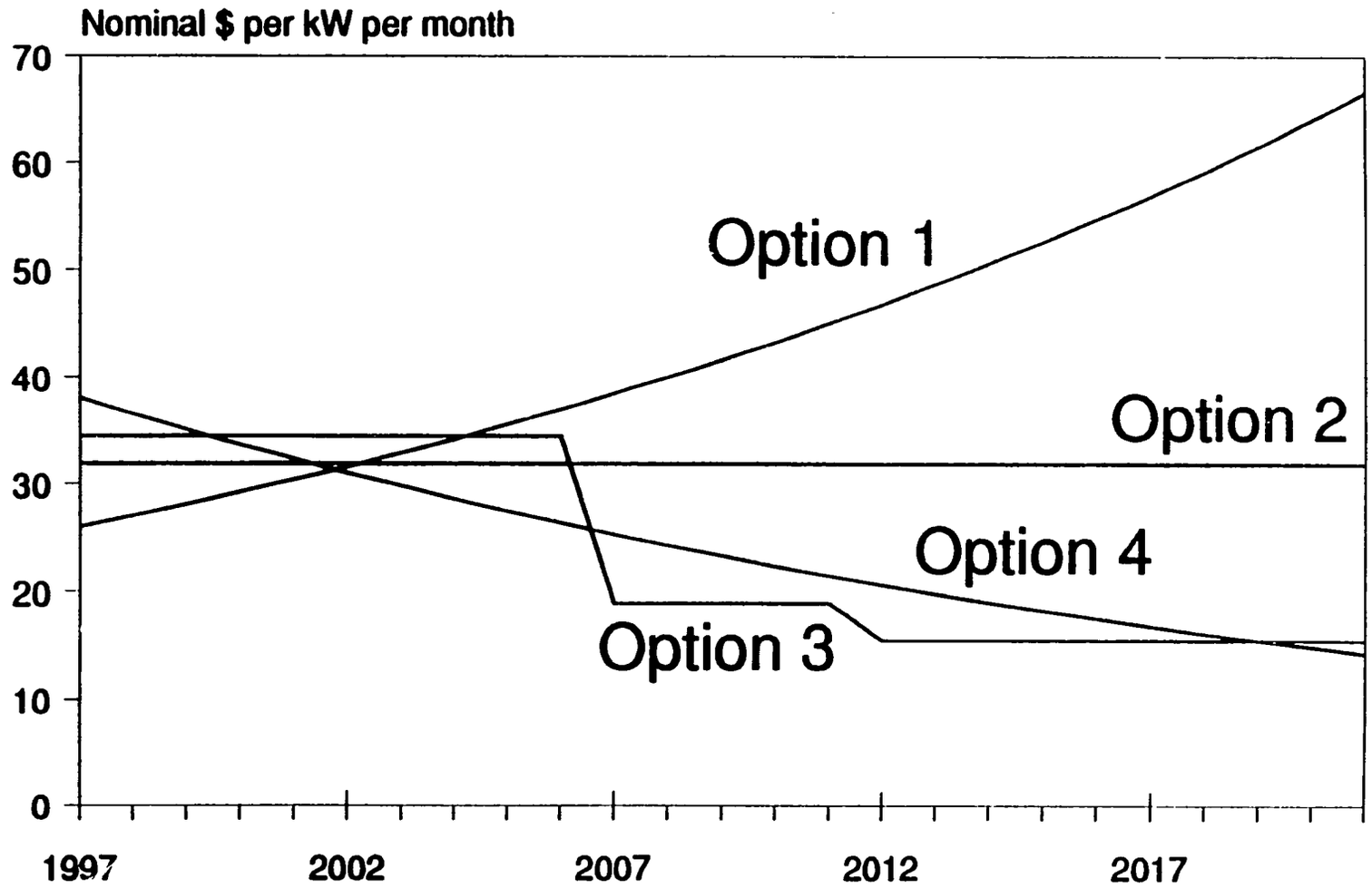


Exhibit 4-4
ENERGY PAYMENTS

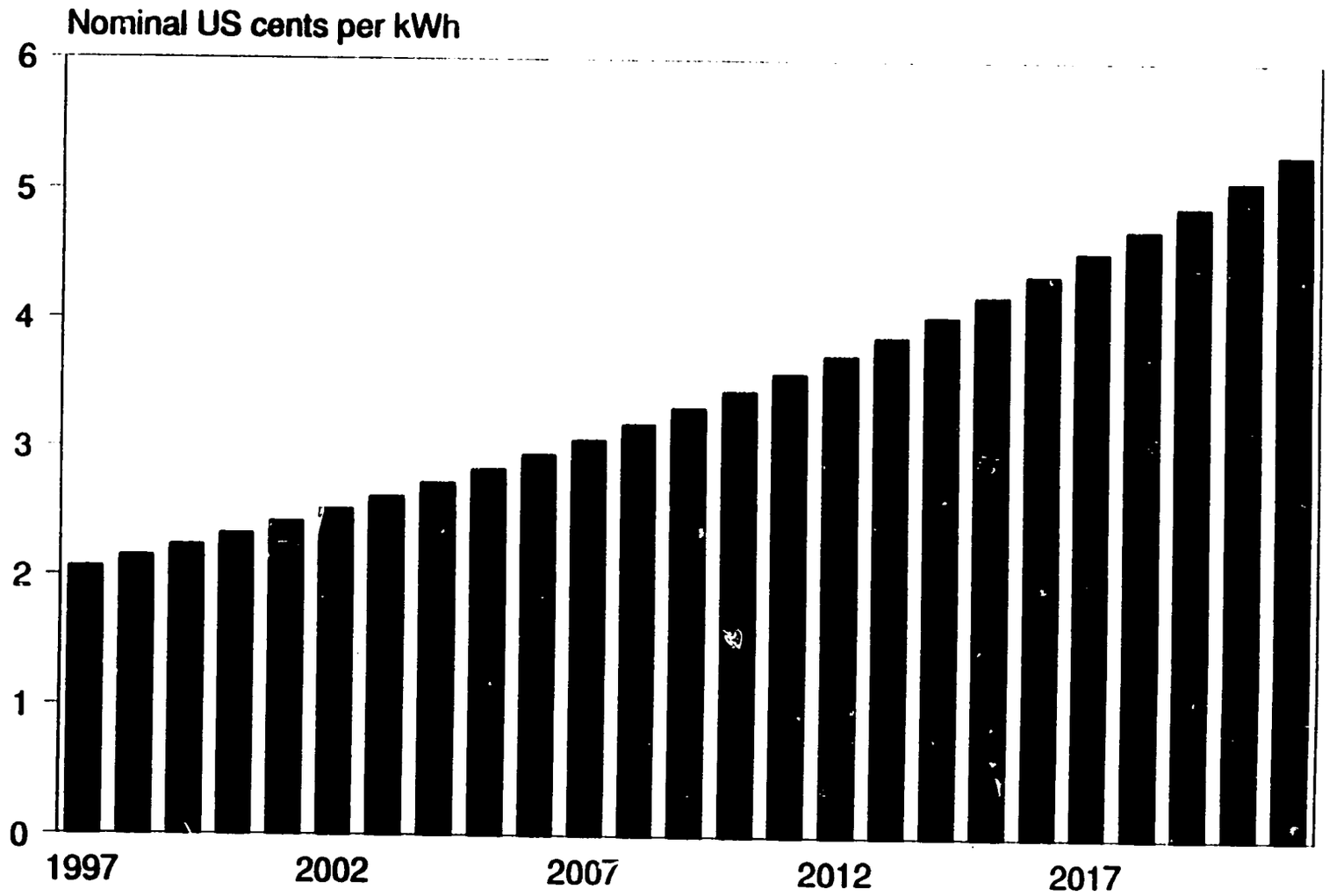
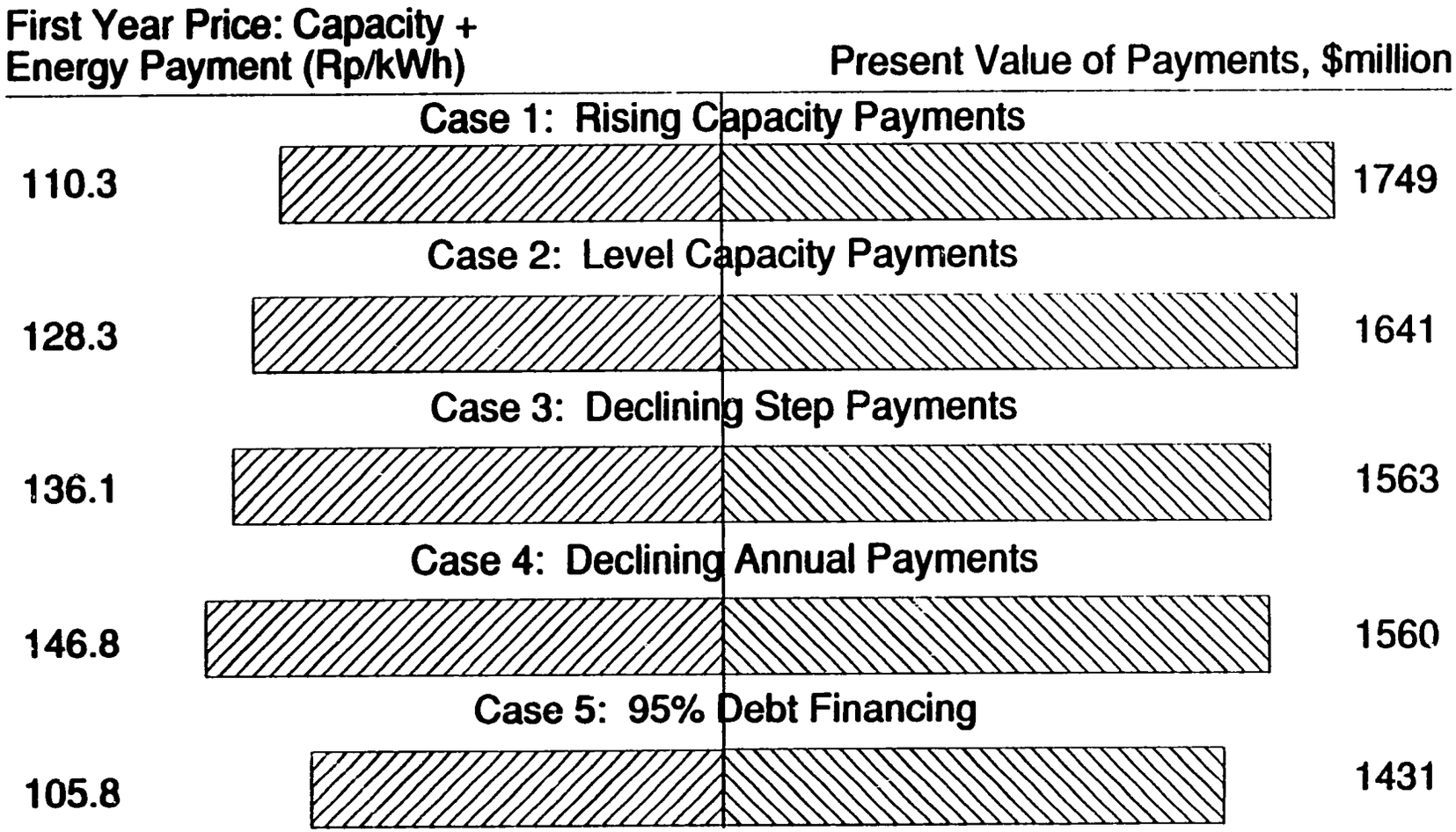


Exhibit 4-5

TRADEOFF BETWEEN FIRST YEAR PURCHASE PRICE AND NPV OF PAYMENTS



Discount rate used to compute IRR: 20%
Discount rate used to compute PVRR: 14%

Exchange rate: $US 1 = 1950 Rupiah

By way of comparative interest, Exhibit 4-5 also shows a case 5 which more closely approximates a power project financed mostly by debt from multilateral development finance institutions such as the IBRD and ADB. It should come as no surprise that this case (5) leads to lowest first year cost as well as lowest cost on a NPV basis, though the first year price is not substantially lower than the first year price under Option 1.

Exhibit 4-6 through 4-9 help to illustrate another key aspect of the divergent implications for project risk and stability under capacity price payment profiles 1 through 4. These exhibits display the after tax revenue per kWh in constant 1991 currency over the 25 year life. Of particular interest is the after tax flow profile which generates the IRR for the equity holders.

A fundamental difference between cases 1 and 2 on the one hand, and cases 3 and 4 on the other, is that in the former equity holders receive most of their return in later years of the 25-year contract period; whereas in the latter cases, returns to equity holders are more front-end loaded. From the lenders' perspectives, cases 3 and 4 are unlikely to be viewed favorably. This view would be shared by PLN and GOI as well. Lenders' risk increases if equity holders receive a substantial portion of their return before debt is substantially paid off. Similarly, PLN and GOI interests are jeopardized in that the incentive to efficiently manage and operate the facility during the latter part of the contract period is substantially diminished under such circumstances. Such risk considerations argue for capacity payment profiles of type 1, even though over the project life this implies an additional cost (Exhibit 4-5).

Capacity Payment Rate

On a final note, this section clarifies the linkage between the capacity payment value calculated in the preceding with the capacity payment rate (CPR) defined in contract pricing formula in Annex 4. Specifically, section 2-1 of annex 4 indicates that <u>one</u> element of capital cost recovery (component A) is the monthly billing computation (CPR * DC * AR), where CPR is the capacity payment rate per kW per month, DC is the dependable capacity, and AR is the availability rate, both of which are defined in Annex 4.

For the sake of illustration we assume here that DC is 1200 MW in the given billing month of interest. The CPR for a given year and month is then determined by the annual capacity payment for the year under consideration and as defined in the previous section. This number is divided by the expected availability target. The latter should correspond to a value that is reflective of the availability of an efficient power plant of the type under

Exhibit 4-6
REVENUE PER KWH ADJUSTED FOR INFLATION
Rising Capacity Paymenrs (Case 1)

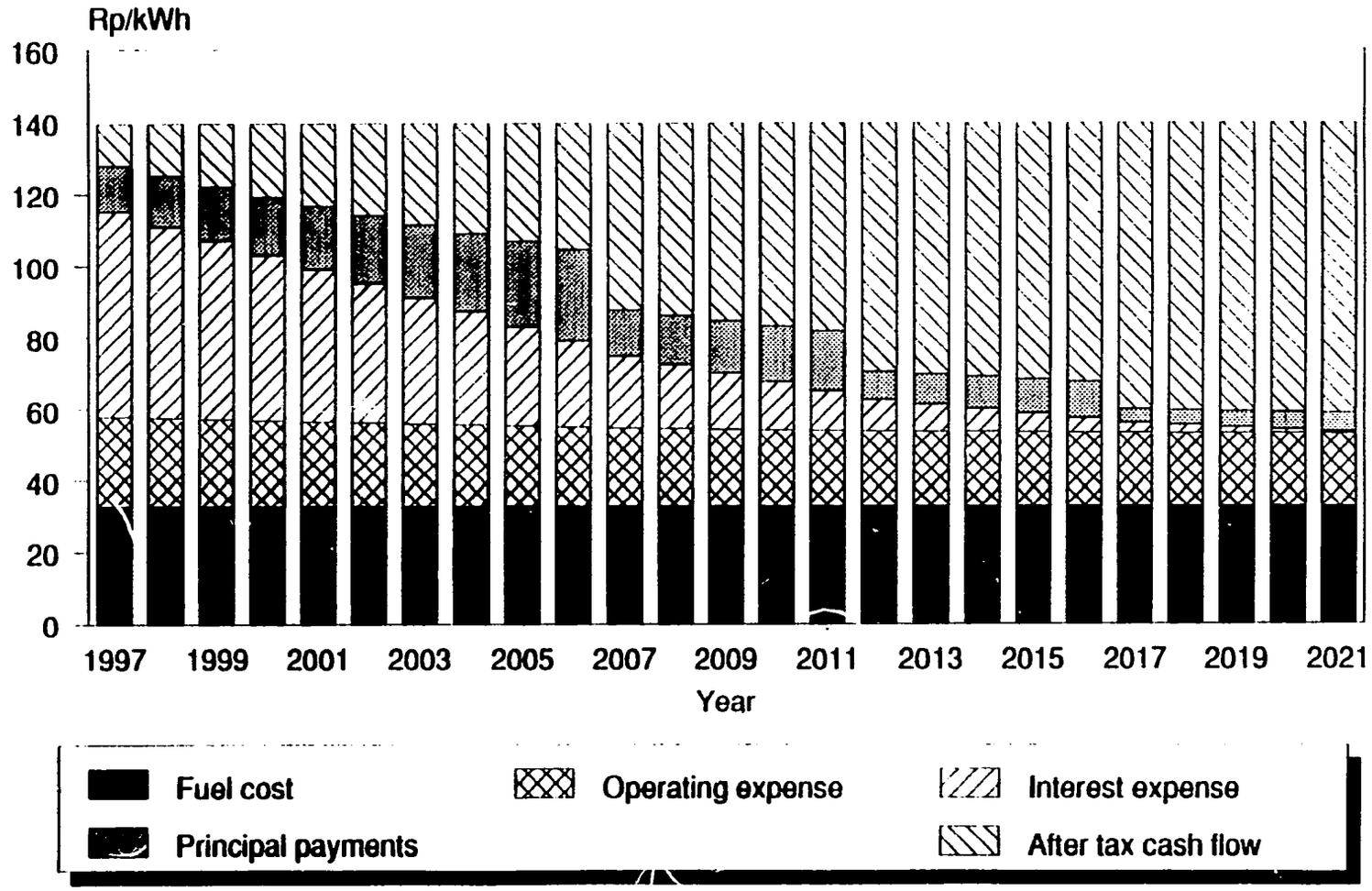
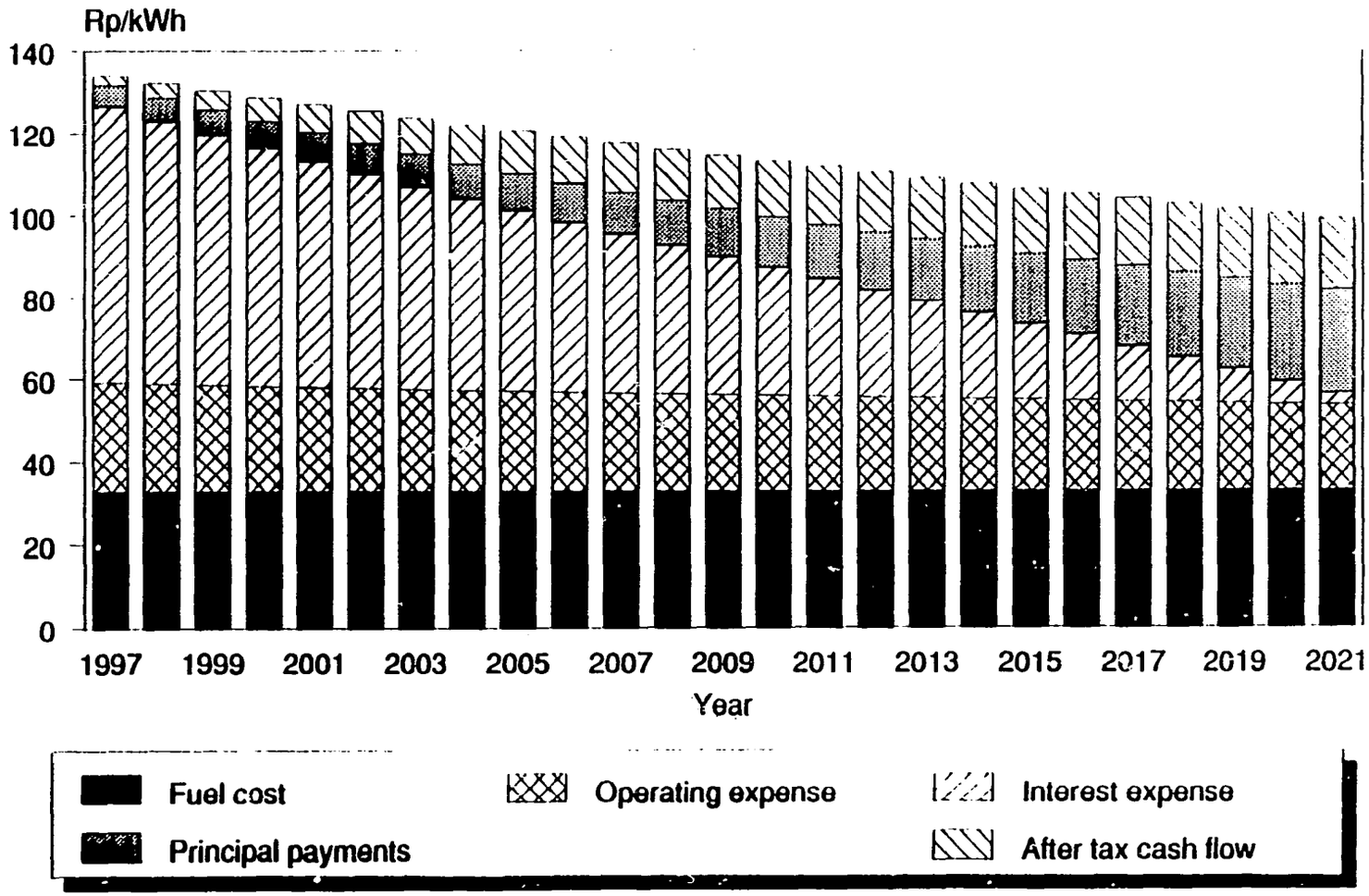


Exhibit 4-7
REVENUE PER KWH ADJUSTED FOR INFLATION
Level Capacity Payments (Case 2)



95

Exhibit 4-8
REVENUE PER KWH ADJUSTED FOR INFLATION
Declining Steps Payments (Case 3)

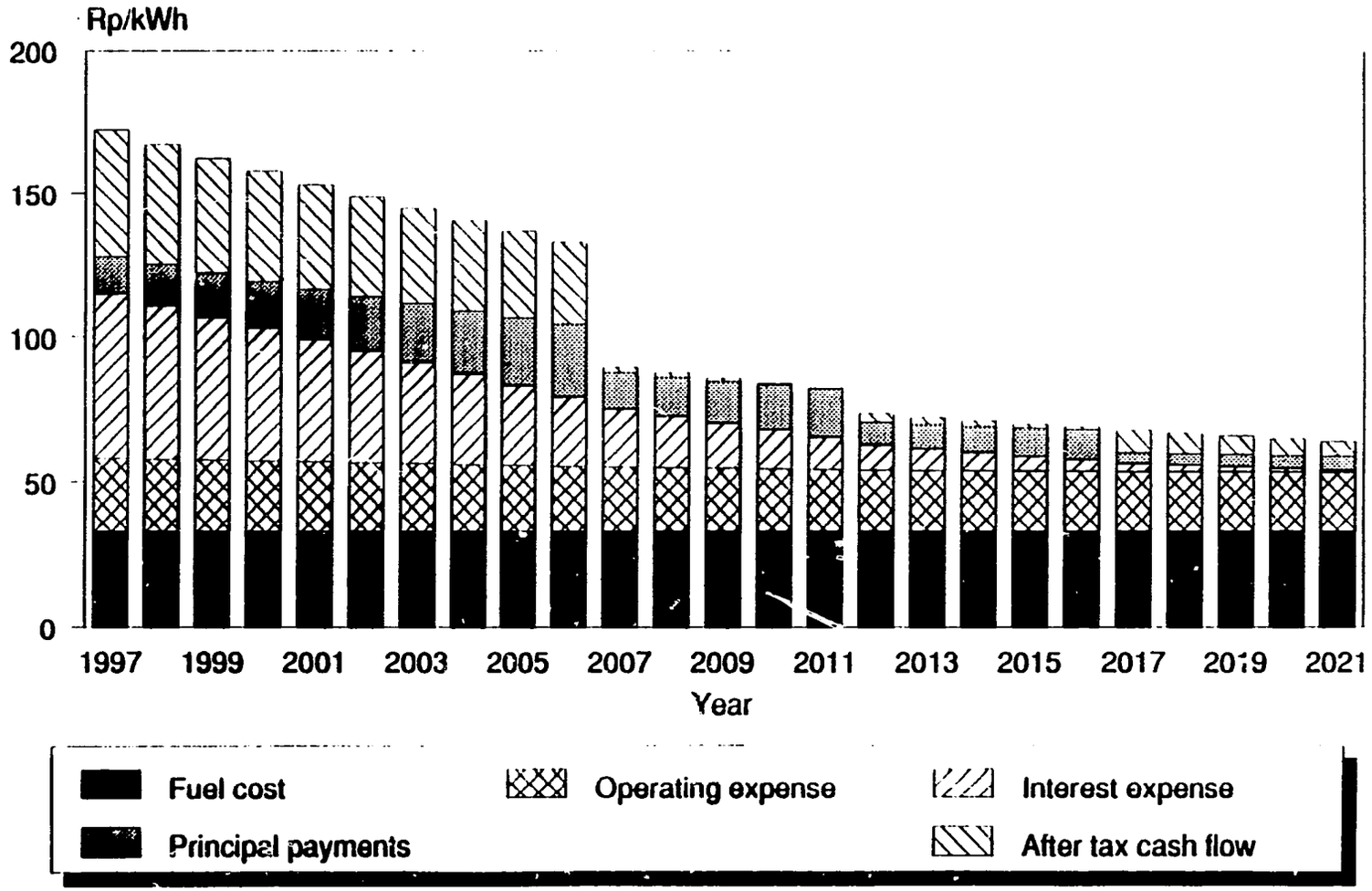
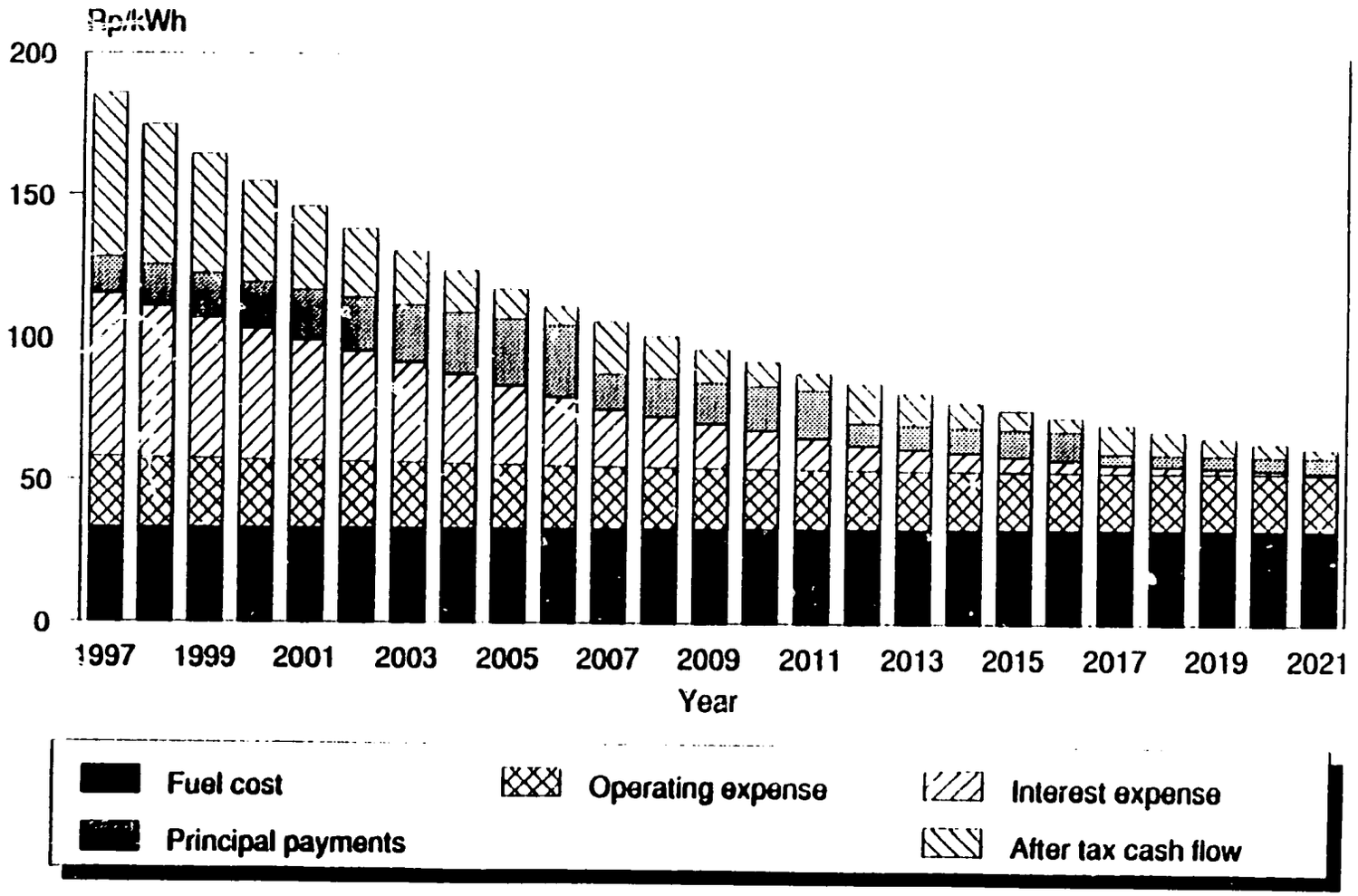


Exhibit 4-9
REVENUE PER KWH ADJUSTED FOR INFLATION
Declining Annual Payments (Case 4)



consideration, as per industry performance norms. For the coal plant in the present example, this number would be negotiated between PLN and the project developer but should be in the range of 0.7 to 0.75+. If 0.7 is the agreed to target, and capacity payments to be determined by Option-1 profile discussed above, then the monthly CPR value for the first year payment would be 29.37 $/kW-mo (calculated as capacity value of 20.56 $/kW-mo in the PROJEV model divided by 0.7 the availability factor). In a month where the power plant achieves AR = 0.7, the project sponsor will receive 29.37 x 0.7 = 20.56 $/kW-mo.

If AR in a month is lower (say 0.65) than the target value of 0.7, the capacity payment per kW of dependable capacity will be lower at, 19.09 $/kW-mo (calculated as 29.37 x 0.65). However, if the AR for a given billing month exceeds the target value 0.7, say it is 0.72, then the capacity payment per kW of dependable capacity in that month will be higher at 21.15 $/kW-mo (calculated as 29.37 x 0.72).

Finally, the following example highlights the determination of AR for a given month in the case of the 2 x 600 MW plant. The calculation assumes a 30-day (720 hour) billing month and dependable capacity of 1200 MW.

Unit Status	Hours in Month	
	Unit 1	Unit 2
1. Forced outage	15	0
2. Scheduled maintenance	100	168
3. Derating	0	120 hours @ 300 MW

In this month AR = 0.76 (calculated at 658,200/864,000).

CHAPTER 5: NEXT STEPS

This chapter identifies follow-on activities in the pricing area that are essential if a "private power program" is to be successfully implemented in Indonesia.

An important aspect of the proposed follow-on effort is to develop a continuing capability within the Ministry to undertake regular updates of the requisite analyses in the future:

1. Marginal/Avoided Cost Analysis and Development of Standard Offers, and Pricing of Large Industrial Estate and Geothermal Power Projects

Under this effort, the major tasks to be accomplished are:

- Undertake separate marginal cost analyses for the Java-Bali grid and for each of the other islands' major regional grids.
- Develop standard offer prices for non-firm and firm power producers by PLN for small and medium-sized IPPs and NUGs, differentiated by grid.
- Establish tariffs for appropriate standby and maintenance power service.
- Evaluate the pricing terms of existing PLN contracts in light of the preceding analysis and recommend appropriate changes.
- Transfer training and installation of the modelling and analysis capability -- including any software -- within a working group of the Private Power Team.
- Provide continuing support on an ongoing basis as necessary.
- Formulate pricing policy for large private power projects built primarily to serve industrial estates.
- Establish appropriate pricing framework for power purchases from geothermal power porjects.

The analysis portion of this effort can be accomplished over a nine-calendar month time frame. The transfer and ongoing support is more open-ended. This would require a

pricing expert, power system economist, power system planner and reliability expert, and a legal/regulatory/power contracts specialist.

2. Financial Modelling and Evaluation of IPP Power Project Bids for Negotiated Offers

The following represent major tasks that need to be accomplished simultaneously with the workscope identified in point 1 above:

- Review PLN's cost accounting and reporting system.
- Assemble, interpret, and analyze generation plant cost data by cost component.
- Estimate PLN's financial avoided cost structure for power supply from selected plant(s).
- Estimate economic avoided cost(s) from a national perspective for the plant(s) selected above.
- Develop cost of power supply from a reference international coal plant.
- Implement a project financial model to be utilized in the evaluation of large IPP bids.
- Implement a financial model for PLN and evaluate the impact of potential power purchases on PLN's financial performance.
- Provide technical assistance related to the evaluation and negotiation of actual bids received.

3. Design Program for Optimal Coordination and Integration of Capacity from Existing Captive Generation Plant to Enhance PLN's System Reliability

This project is in essence a demand-side management (DSM) program to develop special load management tariffs to utilize existing captive generation capacity in a standby mode during peak times. The major tasks in this effort are as follows:

- Develop the appropriate load management pricing scheme based upon the marginal cost study in 1 above.
- Estimate "supply curve" of capacity available from captive generation during peak periods at different prices.
- Identify any institutional and other barriers and recommend approaches for overcoming such hurdles.
- Design program delivery mechanisms to elicit customer cooperation and participation, and to monitor program performance.

This effort can be accomplished with a nine- to twelve-calendar month time frame.

4. Measurement of Electricity Supply Interruption Costs to Consumers

The primary objective of this effort is to conduct the necessary customer surveys and statistical analysis to develop estimates of the cost of load shedding ("outage cost") to the different consumer segments. These data once available will be useful input in many applications including short run marginal energy cost calculations for standard offer pricing, developing interruptible tariffs for demand side management, establishing shortage management strategies, and justifying the optimal amount of expenditure for power system expansion.

CHAPTER 6: REFERENCES

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ANNEX 1: OWNERS OF CAPTIVE POWER GENERATORS WITH COMBINED INSTALLED CAPACITY EXCEEDING 20 MVA

Owners of Captive Power Generators with Combined Installed Capacity Exceeding 20 MVA

Owner	Type of Generator						Total
	Diesel (MVA)	Hydro (MVA)	Steam/ Gas (MVA)	Steam/ Oil (MVA)	Steam/ Wood (MVA)	Gas Turbine (MVA)	Installed Capacity (MVA)
1. PT Arun NGL Co.	3	-	-	-	-	318	321
2. PT Pupuk Iskandar Muda	2	-	-	-	-	24	26
3. PT Asean Aceh Fertiliser	2	-	-	-	-	28	30
4. PT Kraft Kertas Aceh	4	-	-	-	-	45	49
5. PT Semen Andalas	39	-	-	-	-	-	39
6. PT Inalum	-	670	-	-	-	-	670
7. PT Pupuk Sriwijaya	10	-	-	-	-	68	78
8. PT Tambang Timah	132	-	-	-	-	-	132
9. PT Semem Baturaja	26	-	-	-	-	-	26
10. Pertamina	30	-	-	56	-	210	296
11. PT Petrokimia Gresik*	14	-	-	54	-	-	68
12. PT Aneka Tambang	42	-	-	-	-	-	42
13. PT Badak NGL Co.	-	-	-	-	-	111	111
14. PT Krakatau Steel*	46	-	400	-	-	-	446
15. PT Semen Tonasa	30	-	-	-	-	114	144

Owners of Captive Power Generators with Combined Installed Capacity Exceeding 20 MVA

Owner	Type of Generator						Total
	Diesel (MVA)	Hydro (MVA)	Steam/ Gas (MVA)	Steam/ Oil (MVA)	Steam/ Wood (MVA)	Gas Turbine (MVA)	Installed Capacity (MVA)
16. PT Pupuk Kaltim	26	-	-	-	-	-	26
17. PT Perkebunan II	36	-	-	-	-	-	36
18. PT Inti Indorayon Utama	42	-	-	-	-	-	42
19. PT Indah Kiat Pulp & Paper	23	-	-	-	54	-	77
20. PT Total Indonesia	51	-	-	-	-	-	51
21. Huffco Indonesia	12	-	-	-	-	13	25
22. Freeport Indonesia Inc.	53	7	-	-	-	-	60
23. PT Caltex	-	-	-	-	-	273	273
24. PT Inco	-	207	-	-	-	-	207
25. PT Indocement*	300	-	-	-	-	-	300
26. TP Tifico	25	-	-	-	-	-	25
27. PT ITS	27	-	-	-	-	-	27
28. PT Dan Liria	23	-	-	-	-	-	23

Owners of Captive Power Generators with Combined Installed Capacity Exceeding 20 MVA

Owner	Type of Generator						Total
	Diesel (MVA)	Hydro (MVA)	Steam/ Gas (MVA)	Steam/ Oil (MVA)	Steam/ Wood (MVA)	Gas Turbine (MVA)	Installed Capacity (MVA)
29. PT Gula Putih Mataram	2	-	-	-	18	-	20
30. PT Gunung Madu	2	-	-	-	18	-	20
31. PT United Sumatera Plant	29	-	-	-	2	-	31
32. PT Dipasena Citra Darima	50	-	-	-	-	-	50
33. PT Unical Indonesia Ltd.	23	-	-	-	-	-	23
34. PT Semen Nusantara*	32	-	-	-	-	-	32
Total	1,136	884	500	110	92	1204	3926

* Located on Java

ANNEX 2: EFFICIENCY MAXIMIZATION PRINCIPLE

A necessary condition for the maximization of economic efficiency is that price be equal to marginal cost. This is schematically illustrated in Exhibit A2-1, which shows the intersection of a supply (marginal cost) curve MC(q) and the market demand curve. The upward slope of the former reflects the fact that for a fixed system capacity, the incremental cost of supply rises as less-efficient plant has to be utilized. The downward sloping nature of the demand curve simply reflects the decreasing valuations of customers (i.e., willingness to pay) as more units are consumed.

The measure of net economic benefit (NEB) commonly employed in consumer welfare is the difference between the total consumer benefit derived from a given level of consumption and the total societal cost of maintaining that consumption. At the market price clearing consumption level Q, the former is the area OBCQ under the demand curve and the cost of supply is OACQ. The net economic benefit is therefore the difference, represented by the shaded area ABC. More generally, in algebraic form, this can be stated as:

Net Economic Benefit = willingness to pay - cost

$$i.e.,\ NEB(Q) = {}_{O}\int^{Q} p(q)dQ - {}_{O}\int^{Q} MC(q)dq$$

This benefit is maximized when its first derivative is set equal to zero, i.e., when

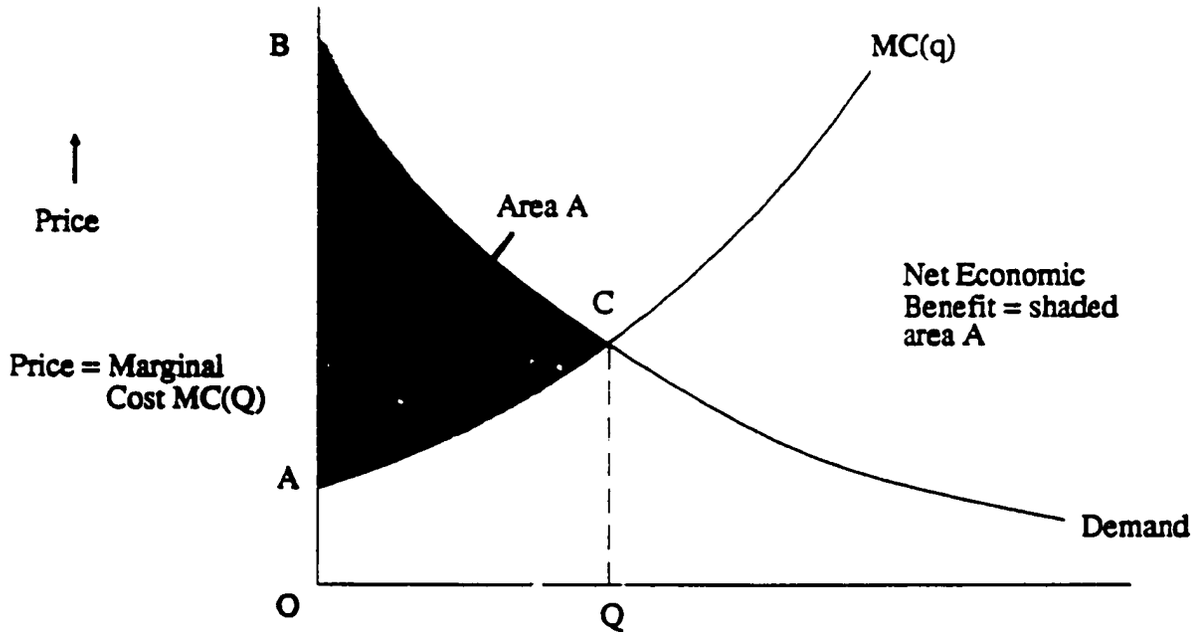
$$\frac{dNEB(Q)}{dQ} = P(Q) - MC(Q) = O$$

or in other words, when P(Q) = MC(Q), or when price = marginal cost

In a properly functioning competitive market, price will be approximated by the marginal cost of the good, i.e., the incremental cost of producing an extra unit of output. Under these circumstances, the value to consumers of the last unit consumed -- their willingness to

Exhibit A2-1

Consumer Welfare is Maximized When Price = Marginal Cost

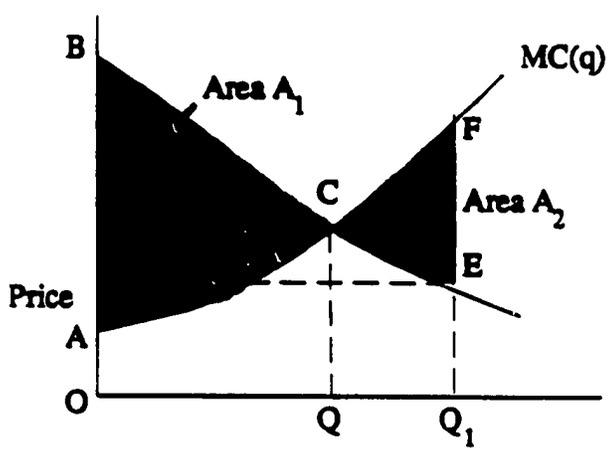


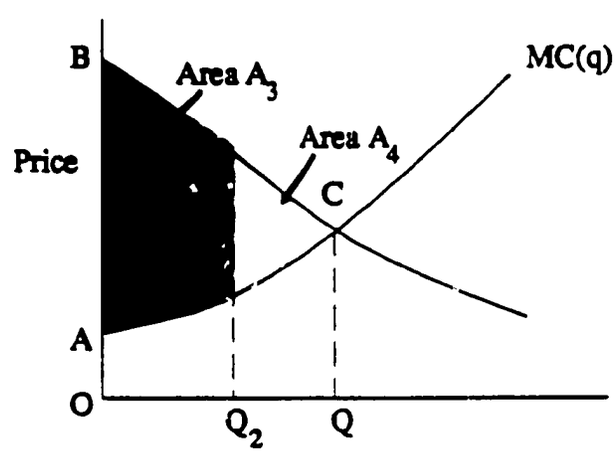
Case 1: Market Price < Marginal Cost

Net Economic Benefit (NEB_1) = (Area A_1 -- Area A_2)< Area A

Case 2: Market Price > Marginal Cost

Net Economic Benefit (NEB_2) = Area A_3 < Area A





pay -- will be equal to the value of resources used to produce that unit of good (its marginal cost).[1] Thus, competitive markets ensure that under marginal cost pricing that society's resources and needs are balanced in the most efficient manner.

Further, because of the stochastic nature of supply and demand, prices continually fluctuate to clear the market. Such external influences in the environment are part of the normal risk of doing business in a competitive market, and varying prices provide the balancing mechanism between supply and demand, fluctuating typically between short-run marginal cost (SRMC) and long-run marginal cost (LRMC). The former represents the variable cost of the last unit of output given existing capacity and establishes floor prices because there is no provision for contribution to overhead, depreciation, and profit margin at that price. Over time, however, producers' costs for efficient output will change as the industry and each producer adjust their technology and scale to capture changing cost efficiencies from technological change and innovation. This cost of efficient output in the long run will reflect the long-run marginal cost (LRMC). It differs from the SRMC in that it incorporates this recovery of capital investment for new technology. At the market clearing price, the most efficient producer will be the most profitable and other producers will strive to become more efficient to increase their profits at market prices.

The equivalency of efficiency prices to marginal cost provides the basis for estimating such prices, since methods are available to numerically estimate marginal costs for a power system.

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[1] Under Case 1 when price is set below marginal cost, there is a "deadweight" loss to the economy represented by the area A2. This represents the loss incurred from over consumption in the amount of (Q_1-Q) units. For example, on the last unit of consumption Q_1 there is a net loss to society equal to the amount EF which represents the cost of providing that unit (Q_1F) less the value to the consumer of unit Q_1 (the willingness to pay, Q_1E).

When price is set above marginal cost (Case 2 in Exhibit 2-1-1), the national net economic benefits can be increased by an amount equal to the area A2.

ANNEX 3: LINKAGE BETWEEN COMBUSTION TURBINE (CT) COST, OPTIMAL GENERATION RELIABILITY STANDARD, AND CUSTOMER OUTAGE COST

The optimal generation reliability standard can be defined by the optimality condition, which states that for capacity added purely for the last increment (kW) of reliability support, the marginal cost should be equal to the expected marginal benefit, i.e., to the expected reduction in outage cost because of that kW. In other words,

Marginal Cost = Marginal Benefit, or
K = (H) (Outage Cost) (1)

where

K = annual carrying charge on the last increment of capacity providing pure reliability support ($/kW - year)

H = expected duration per year for which this increment of capacity will be used (hrs/yr). Note that for the last kW of capacity under issue here, H is equivalently the avoided expected unserved energy (EUE) in kWh/yr.

From a planning perspective, a reasonable estimate for the quantity K is provided by the familiar combustion turbine (CT) proxy, since the last increment of CT capacity would be used after no further emergency interconnection assistance is available. Thus, K can be estimated as the following product:

(Installed capital cost $) x Capital Recovery Factor (CRF)

where

$CRF = (r)/[1-(1+r)^{-N}]$

where r is the discount rate, and N is the life of the unit

The marginality condition (1) can be used in one of two ways. First, given estimates of K and outage cost, a reliability standard defined by H (measured either as hrs/yr or equivalently as EUE in kWh/yr) can be arrived at.

Alternately, if outage costs are not known, then for a given resource, H can be estimated using a reliability evaluation model. This information together with a value for K defines an implicit outage cost value ($/kWh) which can be used to judge if the given resource plan is over- or under-resourced from a reliability perspective.

Under the marginal approach, reserve requirements would also be developed to establish the level of capacity required to just meet the established reliability target level H hrs/yr (or equivalently kWh/year of EUE), taking into account the key uncertainties in load growth, resources, interconnection assistance, weather effects, lead times for construction of new plant, etc. This reserve level establishes a minimum requirement in resource planning. Production cost considerations may dictate higher reserve levels.

ANNEX 4: CALCULATION OF TARIFF UNDER TWO-PART CONTRACT PRICING STRUCTURE

This annex defines the general structure and formulae to be employed for calculating payments to sellers for power purchases made by PLN from large dedicated power projects. Much of the material in this annex can be suitably modified and incorporated into an annex to the Power Purchase Agreement.

1. General Payment Structure

Payments of power purchases by PLN shall be based on a two-component tariff structure: (a) payment for Seller's fixed costs ("Capacity Payment"), and (b) payment of Seller's variable costs ("Energy Payment'). The formulae and calculation of these components are specified as follows (example case is for a coal-fired project).

2. Capacity Payment

The Capacity Payment shall reflect the recovery of Seller's capital cost (including return on investment) and the costs of operation and maintenance ("O&M"). Capacity Payments shall be computed as follows for each (monthly) Billing Period:

Capacity payment = A + B + C

where, A = Fixed payment to recover capital costs for the Billing Period.

B = Payment to recover fixed costs of operations and maintenance for the Billing Period, costs that are independent of the amount of kWh generated.

C = Payment to recover other fixed costs for the Billing Period.

2.1 Capital Cost Recovery (Component "A")

Capital costs are to be paid in the elected currency(ies) of Seller and calculated as follows:

A = [CPR * DC * AR] - [(y * 1.1) (CPR) (CC-DC)]

where, CPR = Capacity Payment Rate per kW per Billing Period in the elected currency(ies) of Seller

DC = Dependable Capacity for the Billing Period, shall mean the maximum dependable load carrying capability of the facility, exclusive of capacity required for facility use. Dependable capacity shall be expressed in kW and shall be determined by tests conducted in accordance with a mutually agreed test criterion on a periodic basis. Dependable capacity shall not exceed the contract capacity.

CC = Contract capacity (kW), shall mean the net amount of power offered by Seller during the Contract Period as measured at (a specified interconnection point)

AR = Availability rate defined as the net amount of electricity that the Project is capable of generating during the Billing Period in kWh and taking into consideration actual downtime for forced outages, maintenance and any capacity deratings during the billing period, divided by the product of the Dependable Capacity and the number of hours in the Billing Period.

y = A factor that is equal to 0 if $(0.95 * CC) \leq DC \leq CC$, and otherwise equal to 1.0

2.2 Fixed O&M Cost Recovery (Component "B")

Fixed O&M costs are O&M costs that are not dependent on the amount of kWh generated. These costs shall be paid in local and elected currency (ies) for each Billing Period and calculated as follows:

$$B = [OMR1 * DC * AR]\, a_F + [OMR2 * DC * AR]\, a_L$$

where, OMR1 = Fixed O&M Payment Rate per Billing Period in the elected currency(ies) of Seller.

OMR2 = Fixed O&M Payment Rate per kW month in Rupiah, for local labor and materials.

DC = Dependable Capacity (kW) for the Billing Period, defined above.

AR = Availability rate defined above.

F^a = Adjustment for escalation in foreign labor and equipment costs, to be based on an agreed to index (e.g., Handy-Whitman). Adjustment of foreign costs to be made semi-annually and constant for all Billing Periods within each semi-annual period.

L^a = Adjustment for escalation in local wages, to be based on an agreed to Indonesian index (e.g., the cost of living index, GDP inflator, etc.). Adjustment of local costs to be made semi-annually and constant for all Billing Periods within each semi-annual period.

OMR1 and OMR2 are to be negotiated based on one of several possible options:

Option 1: Build-up monetary values for OMR1 and OMR2 over Project lifetime are agreed to in base year currency (see illustrative Table 1 below);

Option 2: OMR1 and OMR2 are negotiated on an annual basis for the following year; or

Option 3: Hybrid of Option 1 and 2 above (e.g., fixed schedule for first 10 years, subject to escalation,and Option 2 for remaining 15 years of 25-year contract term).

Table 1 - Fixed O&M Cost schedule (illustrative)

	Foreign 1991 ($/yen/DM)			Local (1991 Rp.)		
	1	2	3 = 1+2	4	5	6 = 4+5
Year	materials	labor	OMR1	materials	labor	OMR2
1						
2						
•						
•						
25						

2.3 Recovery of Other Costs (Component "C")

Other costs are negotiated as agreed-upon "pass-throughs" of actual costs. Other costs include, for example, insurance costs, taxes, which are not predictable with a acceptable degree of accuracy, and which are outside the control of Seller and such other costs which are not included in components "A" and "B."

3.0 Energy Payment

Energy payments are paid to Seller for each Billing Period in elected currency (ies), and shall reflect the costs for variable expenses incurred by Seller in the generation of electrical energy (kWh), in accordance with the dispatch instructions of PLN. Energy payments are calculated as follows:

$$D = E * F * \frac{1}{G} * H + VOM * H$$

where,

D = Energy Payment for the Billing Period in elected currency (ies).

E = (coal) fuel price per (metric tonne, or "MT") for Billing Period (to be negotiated as discussed below).

F = Plant net heat rate (Btu/kWh).

G = High heating value ("HHV") of (coal) utilized as Btu/MT.

H = kWh delivered in Billing Period

VOM = Variable O&M cost per kWh delivered.

3.1 (Coal) Fuel Price Options: In negotiating the (coal) fuel price, the following options are available:

Option 1: Actual contract price based on a competitive bid procurement, not to exceed C.I.F. price of comparable Australian coal.

Option 2: Agreed to starting price which is adjusted periodically (e.g., quarterly), based on a suitable (coal) price index and not to exceed C.I.F. price of comparable Australian coal.

Option 3: Average contract price based on last three purchases, not to exceed C.I.F. price of comparable Australian coal; or

Option 4: (not recommended) Fixed price for term of power purchase agreement.

3.2 Plant net heat rate (F) shall be estimated as follows.

Option 1: To be fixed for the term of the power purchase agreement.

Option 2 (Recommended): Based on an agreed upon Schedule with provision for a deterioration factor on an annual basis.

Under this option, plant net heat rate to be used for the fuel cost calculation shall be determined from an established and agreed to schedule which defines the rate (F) as a function of the average plant output (kW).

Calculation of the first term (E * F * 1/G * H) for a billing period shall be undertaken on a 24-hourly basis utilizing the recorded plant output averaged over the 24-hour period, and the corresponding heat rate as per the heat rate schedule.

On days when PLN requires for reliability reasons that both units operate, but at part load only, a different heat rate schedule, but specified and agreed to in advance, shall be used to establish the heat rate to be used for determining the fuel costs on such days.

3.3 Variable O&M costs per kWh del vered (VOM) shall be negotiated; options include the following:

Option 1: A flat percentage of fuel cost per kWh delivered; or

Option 2: (Recommended) A fixed amount per kWh delivered with an escalation provision.

ANNEX 5: PROJEV MODEL STRUCTURE AND INPUT ASSUMPTIONS

This annex contains an overview of the PROJEV model which is followed by a printout of the input data assumptions used for the model runs to generate the illustrative example results described in chapter 4.

CHAPTER 1

OVERVIEW OF THE MODEL

This chapter includes a general description of the capabilities of the PROJEV model in order to provide the user with information on the intended uses, range of assumptions, organization, custom menus, and hardware requirements of the model.

A. INTENDED USES

The PROJEV model was developed to provide organizations involved in private power development with a sophisticated tool for financial evaluation of proposed privately-owned power generation projects. The model can be used for multiple objectives:

- to evaluate the financial feasibility of an individual project;
- to compute a project's capacity payments and energy payments;
- to compute a project's internal rate of return (IRR), given a set of assumptions about capacity and energy payments, financial structure, and other variables;
- to compare the cost of power from different projects; and
- to test the sensitivity of the revenue requirements and IRR to different assumptions about fuel prices, power plant performance, and other variables.

The model is written as a LOTUS 123 spreadsheet for use with IBM-compatible personal computers (PCs), so that users can easily modify and expand the model. In its present version, the model has been kept to a relatively compact form, so that the user can add refinements without running out of memory on a PC-compatible computer. Unless the user needs to evaluate complicated tax provisions and ownership arrangements, or evaluate a cogeneration project, the model may be used without modification.

B. RANGE OF POSSIBLE ASSUMPTIONS

The model offers the following types of flexibility:

- Revenue: Capacity and energy payments can be levelized, so that they are the same throughout the lifetime of the project. Alternatively, these payments can vary over two or three different time periods. Within each time period, the capacity and energy payments escalate at user-specified rates. The time periods may vary in length.

- Fuels: Either a single fuel or a mix of fuels, including coal, residual fuel, diesel (or distillate fuel oil), natural gas, or other fuels can be used.

- Debt sources and debt/total capital ratio: Up to 9 lenders may be involved in the project, at different interest rates and lending terms. The relative contribution of each lender to long-term debt can readily be changed, simply by changing the initial estimate of the drawdown that various sources will provide to the project. Any debt/total capital ratio can be assumed. The debt/total capital ratio determines the split between total debt and equity financing for all debt sources.

- Time frame: A construction period of up to 6 years is assumed, followed by an operating period of up to 30 years.

- Depreciation: Up to three time depreciation schedules periods for different categories of capitalized project costs are allowed for tax purposes, and either straight-line or double-declining balance depreciation can be selected for each depreciation schedule.

- Project Costs and Inflation: The user may insert fuel costs, construction costs, and operations and maintenance costs in the dollars of the year in which the cost estimate is being made, and specify any escalation rates desired. The PROJEV automatically escalates these costs to the year in which those costs are incurred.

- Income Statement, Cash Flow Statement, and Balance Sheet: The PROJEV model calculates all of these annual financial statements, as well as other financial outputs, to enable the user to fully evaluate the financial status of a private power project.

- Revenue Requirements: Each year, the model calculates the amount that the utility would pay the owner of the project in cents per kWh to cover fuel costs, other operating expenses, interest and principal, working capital requirements, taxes, and return to equity investors. This calculation is performed in both U.S. dollars and in local currency. The model also calculates the present value of revenue requirements using a discount rate input by the user.

In addition, the more sophisticated user will be readily able to modify the model to reflect the specific tax, depreciation and other local regulations that apply to private power projects in their country. Chapter 3 describes several of these options.

To simplify the PROJEV model, the following limitations are imposed:

- Time periods used to measure cash flows are limited to one year. rather than shorter time intervals.

- Currency used is the U.S. dollar. All calculations (except for the revenue requirements mentioned above) are performed in U.S. dollars, and the model assumes that the exchange rate between the U.S. dollar and local currency remains constant. The model also assumes that all lenders and equity investors are repaid in the same currency and have equal ability to convert that currency into dollars.

- Because of certain complexities, cogeneration is outside the scope of the model. In order to compute an internal rate of return for a cogeneration project, one would have to assign transfer prices to the steam output and electricity used by the steam host. The value of this electricity would vary hourly and seasonally, depending on the cost and availability of power sold by the electric utility. In addition, if some electricity from the cogeneration project was used by the host, the user would have to determine the absolute amount of steam and electricity the steam host would require at different times, and vary the project's sale of electricity to the utility according to the host's consumption. Thus, the assessment of cogeneration project feasibility would require a more complex analytical procedure than appropriate for the PROJEV model.

C. ORGANIZATION OF THE SPREADSHEET

To enter the input data, it is helpful for the user to know how the top portion of the spreadsheet is organized. Note that throughout this manual, user selections from the various menus and specific keys from the computer keyboard are offset in "quotation marks." To move the cursor to the top of the spreadsheet, enter the model, and then select "Exit", followed by the "Home" key. As the user scrolls down, these six sections will appear:

1. The heading, beginning with:

   PROJEV: AN EVALUATION MODEL FOR PRIVATE POWER PROJECTS

2. Summary tables ("Summary of Project Financing"), showing the project's capital structure, revenue charges, internal rate of return, capital cost, and sources of capital.

3. Several lines showing the present value of revenue requirements over the project life.

4. Input data, down several screens, beginning with the heading:

   INPUT DATA

TECHNICAL SPECIFICATIONS
...and followed by other input sub-sections, including Fuel Specifications, Capital Costs Construction Period, Operating Costs, Revenues, Income Tax and Depreciation, Other Financial Assumptions and Initial Trial Values.

5. A checklist with the following heading:

INPUT DATA CHECKS

'To check the input data, make sure that the answers below are 'Yes'"

6. Several tables of output data, beginning with the heading:

OUTPUT DATA

CONSTRUCTION PERIOD FINANCING
...and followed by other output sub-sections including Operating Period Intermediate Calculations, Project Income Statement, Taxable Income, Equity Cash Flow Statement, Project Cash Flow Statement, Debt Service Coverage Ratios, Revenue Requirements, and a Simplified Balance Sheet.

The user does not need to be familiar with Section 6. Sections 1 through 5 contain everything the user needs to know to compute the effect of different technical and financial input assumptions on the IRR, the cost of the project, the energy and capacity payments, and the debt/equity ratio.

A more detailed description of the structure of the spreadsheet and a sample printout is presented in Appendix A.

D. CUSTOM MENUS

The PROJEV model contains a set of custom menus to support the user's analysis of a specific project. When the user touches the "Alt" and "M" keys simultaneously, the first menu to appear at the top of the screen is the main menu, with the following seven choices:

- Calculate;
- Input;
- View;
- Print;
- Save;

- Retrieve; and
- Exit.

If "Calculate", "View", "Print", or "Save" is selected, a secondary menu appears. The "Printer" option in the Print menu will invoke a third-level (tertiary) menu; in all other cases, menu selections stop at the second level.

When the user touches the "Alt" and "M" keys simultaneously, LOTUS 123 starts running a computer program called a "macro." The program takes control over the user's ability to type keyboard commands; initially, it instructs the computer to display the main menu. Selecting the "Exit" option will allow the user to exit the program. When the upper right-hand corner of the user's screen displays CMD or WAIT, the program is still in control; when the screen displays READY, the user can use LOTUS 123 in its "normal" mode of operation.

"Calculate" is the first item in the main menu because it is likely to be the most frequently used item. However, the standard procedure for using PROJEV does not begin with "Calculate". The first step is to specify the data inputs. The standard procedure is described in Chapter 3 below.

E. HARDWARE AND SOFTWARE REQUIREMENTS

To run the model, the user must have LOTUS 123 Version 2.2, 2.01, or 2.0. The model will run fastest in LOTUS 2.2. To produce printed results on a laser printer using the custom menus provided in the model, the user must use LOTUS 2.2, preferably with Allways attached.

One of the following hardware configurations is required:

1) An IBM-compatible PC running MS-DOS with at least 1 megabyte of RAM, and a Hewlett Packard LaserJet printer. A math coprocessor is recommended, to speed up recalculation time.

2) An IBM-compatible PC running MS-DOS with at least 640K of RAM and a dot matrix printer. This setup is not recommended, but it can be used.

Most portable PCs can be used to run the model. An older, 8088-based PC is not recommended; a high-speed, 80486-based PC is not necessary. An 80286-based PC with an 80287 math chip will be satisfactory.

The model is written in LOTUS 123 Version 2.2 with Allways attached. To produce printed results on a laser printer using the custom menus provided in the model, the user

must attach Allways. If the user modifies the spreadsheet when Allways is not attached, and moves cells or inserts or deletes rows or columns, the output may no longer be formatted correctly. Therefore, it is recommended that the user attach Allways before retrieving the spreadsheet, if planning to use a laser printer. If the user does not have Allways, but does have a laser printer, standard LOTUS 123 commands can be used to print the results of the model.

In conclusion, the PROJEV model is a flexible tool that can test the impact of a wide range of input assumptions on the financial performance of a specific project. It can readily be modified to suit the unique regulatory, tax and other circumstances of specific countries.

INPUT DATA

TECHNICAL SPECIFICATIONS

Rated system output (MW)	1200	
Percent auxiliary consumption	0.0%	
Initial year of operation	1997	
Project life (maximum 30 years)	25	years
Years in startup period	2	years
Capacity factor in startup period	70.0%	
Capacity factor in post-startup period	70.0%	
Cost estimate year	1991	year

FUEL SPECIFICATIONS

	Coal	Residual fuel oil	Diesel	Natural gas	Other
Percentage of kWh from this fuel	100.0%	0.0%	0.0%	0.0%	0.0%
Fuel cost units of measure	$/ton	$/bbl	$/bbl	$/000 cu m	$/ton
Fuel cost per unit (cost estimate year)	$35.00	$25.00	$25.00	$70.60	$30.00
Fuel cost escalation rate, % per year	4.0%	4.0%	4.0%	4.0%	4.0%
Heat content units of measure	Btu/ton	Btu/bbl	Btu/bbl	Btu/cu m	Btu/ton
Heat content per unit	25,000,000	6,000,000	6,000,000	28,000,000	16,000,000
Plant heat rate in Btu/kWh	9,500	9,800	9,800	8,500	11,000

CAPITAL COSTS – CONSTRUCTION PERIOD

(Cost estimate year dollars, excluding financing costs)

Project Development and Engineering	$50.00	million
Equipment	$800.00	million
Construction	$500.00	million
Taxes and import duties	$50.00	million
Land	$10.00	million
Other capital costs	$50.00	million
Total overnight cost	$1,460.00	million
Capital cost escalation during construction	4.0%	per year

Initial working capital, in startup year $ $50.00 million

Initial working capital is specified in startup year dollars. Working capital requirements in the first year of operation are a function of days receivable, days payable, capacity charges, energy charges, fuel costs, and other operating costs. The latest calculation of first-year working cap requirements is: $47.00 million

Capital expenditure schedule during construction:

1991	1992	1993	1994	1995	1996
10%	15%	15%	20%	20%	20%

OPERATING COSTS

(Initial values are specified in cost estimate year dollars.)

Variable O&M costs in startup period	0.300	cents/kWh
Variable O&M costs in post-startup period	0.300	cents/kWh
Fixed O&M costs	$30.00	/kW/yr
O&M cost escalation rate, %	4.0%	per year

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Annual land lease cost (with no escalation)	$0.00 million/yr
Annual insurance cost excluding loan fees	$1.00 million/yr
Annual insurance cost escalation rate	4.0%
Other annual costs	$1.00 million/yr
Other annual costs escalation rate	4.0%
Days receivable (for accounts receivable)	45 days
Days payable (for accounts payable)	30 days

REVENUE

Time periods	
1: 1st year of operation through year	25
2: End of period 1 through year	25
3: End of period 2 through project life	25
Capacity payment (The initial value may be calculated.)	
in the 1st year of the 1st time period	26.01 $/kW/month
in the 1st year of the 2nd time period	26.01 $/kW/month
in the 1st year of the 3rd time period	26.01 $/kW/month
escalation rate for the 1st time period	4.0% annual escalation
escalation rate for the 2nd time period	0.0% annual escalation
escalation rate for the 3rd time period	0.0% annual escalation
Energy payment (The initial value may be calculated.)	
in the 1st year of the 1st time period	2.07 cents/kWh
in the 1st year of the 2nd time period	0.00 cents/kWh
in the 1st year of the 3rd time period	0.00 cents/kWh
escalation rate for the 1st time period	4.0% annual escalation
escalation rate for the 2nd time period	0.0% annual escalation
escalation rate for the 3rd time period	0.0% annual escalation
Inflation rate used to express average revenue per kWh in constant dollars	4.0%
Discount rate used to compute PV of revenue	14.0%

INCOME TAX AND DEPRECIATION

1st income tax rate	0.0%
2nd income tax rate	0.0%
Are tax losses carried forward?	Yes (Yes or No)
Tax exemption period	0 years
Does tax depreciation occur in this period?	No (Yes or No)
Depreciation computed for tax purposes:	
1st category of depreciable assets	
Percentage of total project cost	60.0%
Schedule type (SLD=St.Line, DDB=Double)	SLD
Number of years in depreciation period	20 years
Salvage value	5.0% of the initial value of assets in this category
2nd category of depreciable assets	
Percentage of total project cost	20.0%
Schedule type (SLD=St.Line, DDB=Double)	SLD
Number of years in depreciation period	10 years
Salvage value	5.0% of the initial value of assets in this category
3rd category of depreciable assets	
Percentage of total project cost	20.0%
Schedule type (SLD=St.Line, DDB=Double)	SLD

Number of years in depreciation period	5	years
Salvage value	5.0%	of the initial value of assets in this category
Depreciation computed for book purposes:		
Schedule type (SLD=St.Line, DDB=Double)	SLD	
Number of years in depreciation period	25	years
Salvage value, % of depreciable base	5.0%	

Caution: DDB may not fully depreciate assets when salvage value < 15%

OTHER FINANCIAL ASSUMPTIONS

Target IRR for equity investment	20.0%
Target ratio of debt to total capital	80.0%
Exchange rate, local currency per $	1950.00

EQUITY FINANCING

Equity Sources	Share of equity
Investor A	60.0%
Investor B	20.0%
Investor C	10.0%
Investor D	10.0%

DEBT FINANCING

Debt Sources	Share of Total Debt	Levelized Debt (y/n)	Interest Rate (%)	Principal Grace Period (Yrs)	Total Loan Term (Yrs)	Annual Loan Insurance Fee	Other Financing Fees and Closing Costs	Annual Construction Loan Commitment Fees
10-Year Commercial Debt	25.00%	y	12.0%	0	10	1.0%	1.0%	1.0%
15-Year Commercial Debt	25.00%	y	12.5%	0	15	1.0%	1.0%	1.0%
20-Year Debt	25.00%	y	11.0%	0	20	1.0%	1.0%	1.0%
25-Year Debt	25.00%	y	11.0%	0	25	1.0%	1.0%	1.0%
	0.00%	y	0.0%	0	10	0.0%	0.0%	0.0%
	0.00%	y	0.0%	0	10	0.0%	0.0%	0.0%
	0.00%	y	0.0%	0	10	0.0%	0.0%	0.0%
	0.00%	y	0.0%	0	10	0.0%	0.0%	0.0%
	0.00%	y	0.0%	0	10	0.0%	0.0%	0.0%
Sum of shares shown above	100.00%							

INITIAL TRIAL VALUES

			Examples of trial values:	
Capacity payment in 1st year of operation	26.01	$/kW/month	15.00	$/kW/month
Energy payment in 1st year of operation -				
if fuel costs do not equal zero	2.07	cents/kWh	4.00	cents/kWh
if fuel costs equal zero	0.50	cents/kWh	0.50	cents/kWh
Total construction loan commitment	$1,401.60	million	1401.60	million

	1991	1992	1993	1994	1995	1996	1997
Initial trial values for drawdown schedule:	8.3%	12.0%	13.5%	18.9%	21.3%	26.0%	Startup

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PROJECT SUMMARY

Coal-Fired Power Plant in Indonesia

SUMMARY OF PROJECT FINANCING		
Source of capital	$ million	% of total
Total equity	463.78	20.0%
Total debt	1851.57	80.0%
Total capital	2315.35	100%

REVENUE	Startup Year: 1997	1st Full Pwr Year: 1999	Final Year: 2021
Capacity charge, $/kW/month	26.01	28.13	66.66
Energy charge, US cents per kWh	2.07	2.24	5.31
Average revenue, US cents per kWh	7.16	7.74	18.35

INTERNAL RATE OF RETURN	20.0%

CAPITAL COST	
Total project costs including financing	$ 1929/kW
Overnight costs excluding financing	$ 1217/kW

SOURCES OF CAPITAL		
Debt or equity source	$ Million	% of Total
10-Year Commercial Debt	$462.89	20.0%
15-Year Commercial Debt	$462.89	20.0%
20-Year Debt	$462.89	20.0%
25-Year Debt	$462.89	20.0%
Equity investment	$463.78	20.0%
Total	$2,315.35	100%

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The Office of Energy and Infrastructure

The Agency for International Development's Office of Energy and Infrastructure plays an increasingly important role in providing innovative approaches to solving the continuing energy crisis in developing countries. Three problems drive the Office's assistance programs: high rates of energy use and economic growth accompanied by a lack of energy, especially power in rural areas: severe financial problems, including a lack of investment capital, especially in the electricity sector: and growing energy-related environmental threats, including global climate change, acid rain and urban pollution.

To address these problems, the Office of Energy and Infrastructure leverages financial resources of multilateral development banks such as The World Bank and the InterAmerican Development Bank, the private sector and bilateral donors to increase energy efficiency and expand energy supplies, enhance the role of private power, and implement novel approaches through research, adaption and innovation. These approaches include improving power sector investment planning ("least-cost " planning) and encouraging the application of cleaner technologies that use both conventional fossil fuels and renewable energy sources. Promotion of greater private sector participation in the power sector and a wide-ranging training program also help to build the institutional infrastructure necessary to sustain cost-effective, reliable and environmentally sound energy systems integral to broad-based economic growth.

Much of the Office's strategic focus has anticipated and supports recently enacted congressional legislation directing the Office and A.I.D. to undertake a "Global Warming Initiative" to mitigate the increasing contribution of key developing countries to greenhouse gas emissions. This strategy includes expanding least-cost planning activities to incorporate additional countries and environmental concerns, increasing support for feasibility studies in renewable and cleaner fossil energy technologies that focus on site-specific commercial applications, launching a multilateral global energy efficiency initiative and improving the training of host country nationals and overseas A.I.D. staff in areas of energy that can help reduce expected global warming and other environmental problems.

The Office also helps developing countries speed their economic development through promoting technology cooperation between U.S. suppliers and developing country companies, institutions and governments. This effort involves Business Opportunity Identification to define and analyze the range of commercially viable trade and investment opportunities, technologies and services that have a positive impact on the environment and are appropriate for developing countries: Venture Promotion to encourage the involvement of the U.S. private sector: Innovative Finance: and Policy Development assistance to developing counties as they pursue policy and regulatory changes to provide market incentives for environmentally beneficial technologies.

To pursue these activities, the Office of Energy and Infrastructure implements the following six projects: (1) Biomass Energy Systems and Technology Project (BEST): (2) The Renewable Energy Applications and Training Project (REAT): (3) The Private Sector Energy Development Project (PSED): (4) The Energy Training Project (ETP): (5) The Energy Technology Innovation Project (ETIP): and (6) The Energy Efficiency Project (EEP).

The Office of Energy and Infrastructure helps set energy policy direction for the Agency, making its projects available to meet generic needs (such as training), and responding to short-term needs of A.I.D.'s field offices in assisted countries.

Further information regarding the Office of Energy and Infrastructure projects and activities is available in our Program Plan, which can be requested by contacting:

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