Project Finance for Independent Power Producers in Developing Countries: The Paiton I Power Generation Project in Indonesia

by

Diana Yuliyanti

B.S., Civil Engineering
University of Indonesia, 1998

Submitted to the Department of Civil and Environmental Engineering
in Partial Fulfillment of the Requirements for the Degree of

Master of Science in Civil and Environmental Engineering

at the

Massachusetts Institute of Technology

February 2001

Signature of Author...
Department of Civil and Environmental Engineering
February 1, 2001

Certified by.........................
Professor Massood V. Samii
Thesis Supervisor
Lecturer, Center for Construction Research and Education

Accepted by..
Professor Oral Buyukozturk
Chairman, Department Committee on Graduate Studies

Project Finance for Independent Power Producers in Developing Countries: The Paiton I Power Generation Project in Indonesia

by

Diana Yuliyanti

Submitted to the Department of Civil and Environmental Engineering
on February 1, 2001, in Partial Fulfillment of the
Requirements for the Degree of Master of Science in
Civil and Environmental Engineering

ABSTRACT

Private investments for independent power producers (IPPs) in developing countries have grown substantially since 1990s as public utilities were unable to keep pace with the countries' electricity demand. The private investors' experiences, however, have not been as smooth as expected with the possibility of deterioration of relationship between the investors and the host governments. The investors' tendency to get high returns to compensate for the risks they perceive as high when investing in developing world sometimes supercedes the main concern of the host government, which is to satisfy the public demands with as low a cost as possible. Some agreements between the investors and the public entity that are crafted to stabilize returns to investors regardless the economic conditions of the host country have been ineffective when the initially anticipated conditions change sharply.

The thesis develops a risk-sharing framework between private investors and host governments or public entities to provide mechanisms when the initially anticipated economic condition turns adverse. The framework is developed as a modification of the current model of agreements, with a particular focus being on power purchase agreements (PPAs). The Paiton I project, a coal-fired power generation project in Indonesia, serves as a case study. The Paiton I model PPA have been ineffective in dealing with the inability of the Indonesian public utility to honor the contract when the mid-1997 Asian crisis occurred.

Several key lessons arise from the case analyses. The *take-or-pay* level in the tariff structure is high while the demand projection is over optimistic; the risk arrangement is imbalanced, with the public utility assuming the majority of market risks, currency risks, and force majeure risks; the politically well-connected local participant turned out to be liabilities when government changes; efforts to pursue settlement in the international arbitration resulting in decisions favorable to investors have been difficult to implement in times of crisis. Certain analyses and recommendations covering lessons for better arrangements are outlined. Competition, transparency, and appropriate risks mitigation efforts are the key factors. The thesis closes with a tariff benchmarking analysis to aid the contracted parties in the tariff renegotiation process.

Thesis Supervisor: Professor Massood V. Samii
Title: Lecturer, Center for Construction Research and Education

Acknowledgements

I would like to thank Prof. Massood V. Samii for his guidance and supervision of this thesis. His remarkable patience and flexibility in my enhancing ideas and issues have resulted in the thesis's best possible outcome. He supported my entire research effort and taught me well during the intensive review of literature. It is especially reassuring to have his support during the final thesis push.

I am grateful to Dr. Hardiv Situmeang whose knowledge I tapped for much of this thesis work. This thesis, especially the case study part, would not have been possible without the support of Dr. Situmeang. I am most grateful for his round-the-clock response to my inquiries about the case study. He has guided me for the case study analysis with the highest standards that I have come to expect, resulting in the best possible outcome we both look forward to.

I would like to dedicate this thesis to my parents and my sisters. My parents, thank you for working so hard to provide me with the best possible education. Thank you for supporting all my decisions and for being together with me during all the difficulties I have been through. Thank you for your never-ending pray for me.

Diana Yuliyanti
Cambridge, MA
February 3, 2001

Table of Contents

Tables

Figures

Abbreviation

Adaro	PT. Adaro Indonesia
AF	Availability Factor
ADB	Asian Development Bank
APEC	The Asia Pacific Economic Corporation
BBN	PT Bimantara Bayu Nusa
BHP	PT. Batu Hitam Perkasa
BMMG	Consortium consisting of Mission, Mitsui, and GECC
BNIE	Consortium consisting of BBN and IEI
BOO	Build Own Operate
BOT	Build Operate Transfer
CA	Confidentiality Agreements
CCA	Coal Cooperation Agreement
COD	Commercial Operation Date
CPI	Consumer Price Index
CSA	Coal Supply Agreement
ECA	Export Credit Agencies
EIB	European Investment Bank
EPC	Engineering Procurement Construction
FSA	Fuel Supply Contract
GDP	Gross Domestic Product
GE	General Electric
GECC	General Electric Capital Corporation
GOI	Government of Indonesia
GW	Gig Watts
IA	International Arbitration
IA	Interim Agreements
IBRD	International Bank for Reconstruction and Development
IEI	Intercontinental Electric Incorporated
IFC	International Finance Corporation
IPP(s)	Independent Power Producer(s)
IRR	Internal Rate of Return
JBIC	The Japan Bank for International Cooperation
JEXIM	Export-Import Bank of Japan
MB/MS	Multi Buyers/Multi Sellers
MEC	Mission Energy Company
MIGA	Multilateral Investment Guarantee Agency
Mission	Edison Mission Energy
MITI	The Ministry of International Trade and Industry of Japan
Mission O&M Indonesia	P.T. Mission Operations and Maintenance Indonesia.
Mitsui	Mitsui and Company Limited
MME	The Indonesian Ministry of Mines and Energy
MOMI	Edison Mission Operation and Maintenance, Incorporated
NDC	Net Dependable Capacity
NPV	Net Present Value

OPIC	Overseas Private Investment Corporation
O&M	Operation and Maintenance
PEC	PT. Paiton Energy Company, the Project Company
PLN	Perusahaan Listrik Negara, the Indonesian state-owned electric utility
PPA(s)	Power Purchase Agreement(s)
PSC	Primary Supply Coal
QAC	Qualifying Alternative Coal
ROE	Return on Equity
ROI	Return on Investment
S&P	Standard and Poor's Rating Services
SEC	Securities and Exchange Commission
TBA	P.T. Tambang Batubara Bukit Asam
Toyo	Toyo Engineering Corporation
USAID	The U.S. Agency for International Development
USEXIM	Export-Import Bank of the United States

Chapter 1: Introduction

1.1. Thesis Motivation

Private, and mostly foreign, investment in the infrastructure of developing countries has grown substantially since 1990 as a result of the boom of the countries' economies in the late 1980s. Billions of dollars are being committed to finance projects in the areas of power, telecommunication, transportation, and water, with electricity becoming one of the leading sectors in attracting private investment. In fact, there is a massive need for infrastructure projects, particularly in the East Asian countries. The World Bank's 1995-2004 projection of required investment for infrastructure in this area amounts to a total of US$ 1.5 trillion, with the power sector accounting for one third of the amount[1]. This phenomenon translates into an explosive demand for project financing because traditional sources of financing such as public and corporate financing alone cannot meet such a high level of financing needs[2].

The increasing need for project financing has raised an even more interesting issue concerning the risks of investing in developing world. This concern is particularly important because of the complexity of project-financing structure involving a worldwide collaboration of sponsors, governments, financial institutions, and multilateral institutions, among other entities. Indeed, even well crafted arrangements between private investors and the host government could unexpectedly turn into conflicts when situation changes sharply from that initially anticipated. Louis T Wells, in his article on

1 The World Bank, "Infrastructure Development in East Asia and Pacific: Towards a New Public-Private Partnership", Washington D.C., 1996.

2 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

risk in infrastructure, provides various examples of arrangements that turned sour in previous decades[3]. Despite the experiences of the previous decades, private investors in recent years seem to hold the assumption that it is unlikely they will end up with such an adverse outcome because they believe they are in a better bargaining position with the host government. However, the history repeats itself as conflicted relationships between the public and private parties also occur recently[4]. There seem to be no convincing proof of why this repeated history is likely to change in the near future.

Despite the benefits such as large cash and sophisticated technology that the foreign investors bring to developing countries, which might not be available otherwise, private investment in the infrastructure of developing countries seems to create a new financial burden for the host governments. Investors tend to get high returns to compensate for the risks that they perceive as high when investing in emerging markets. The tendency to get high returns sometimes supersedes the main concern of the host government, which is to satisfy the public demands for infrastructure with as low a cost as possible. These conflicting perspectives have raised a new concern: whether the current practice of private foreign investment, which will be explored in later chapters, is

---

3 Wells, Louis T, Eric S. Gleason, "Is Foreign Infrastructure Investment Still Risky?", *Harvard Business Review*, September-October 1995, page 4-12. Wells provides a thorough analysis of foreign investments that turned into conflicts with the host government. Among other examples, in the 1960s, the Latin America holdings of American and Foreign Power, a subsidiary of General Electric (GE) that held the common stock of GE's overseas utilities, disappeared because of expropriations by the host governments. Another incident occurred in 1979 when the Indonesian government demanded that International Telephone and Telegraph Company sell its telecommunication system to the government.

4 Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy. In analyzing the reemergence of instability that characterizes earlier private investments in the infrastructure of developing countries, Wells cites recent events including Pakistan's unilateral cancellation of electric power arrangements, the renegotiation of the Dabhol power agreement in India, the dispute over the nationalization of a toll road in Bangkok, Thailand, and recent conflicts over power purchase agreements in Indonesia.

a sustainable approach to answer the necessities for infrastructure projects in developing countries.

Another paramount concern that has led to the deterioration of relationship between foreign investors and host governments is agreements that are crafted to stabilize the returns to investors regardless the economic condition of the host country. Usually, such agreements contain terms that are "inappropriately" favorable[5] to the investors, transferring most, if not all, of the commercial risks to the host government or state-owned entities. When unexpected events occur and the country's economic condition changes sharply to an adverse direction, the parties assuming the associated risks would likely be unable to honor the initially agreed terms. Louis T Wells perfectly expressed this phenomenon as "the efforts by private firms to shed commercial risks [that, in times of economic crisis, eventually] lead to political risks for the investors"[6].

A perfect illustration would be the experience of P.T. Perusahaan Listrik Negara (PLN), the Indonesian state-owned electric utility. The contract terms agreed upon in the Power Purchase Agreements (PPAs) entered into in 1994 by PLN and the Paiton Energy Company (PEC) with respect to the Paiton I - generated power are "inappropriately" favorable to PEC, providing the project sponsors with a highly secured revenue streams. The initially agreed contract terms effectively transfer *all* of the market risks and currency risks to PLN. Therefore, when the Asian monetary crisis in the mid-1997 occurred, PLN fell into a severe financial strain. The depreciation of the Indonesian Rupiah resulted in the inability of PLN to generate enough cash flow from its local-

---

5 For the origin of the terms "investor-friendly" and "inappropriately favorable" deals, see Louis T Wells, 1999. These two terms are frequently cited throughout this thesis.

6 Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

currency revenues to meet the local-currency obligations that were translated from the fixed dollar obligations under the agreed upon PPA. The corporate finance of PLN became greatly imbalanced, with the payment obligations—not only to the one relating to the Paiton I project, but also to other Independent Power Producers (IPPs)—under the PPAs agreed upon prior to the crisis accounting for the majority of PLN's financial burden. The results are apparent: PLN's default leading to disputes and contract renegotiation.

The above illustration indicates the existence of imbalanced risk sharing in some of the current contract models that has been ineffective in times of crisis, the times when the provisions should actually be in a full force. A substantial amount of risks is transferred to the public utility, assuring the investors the same net return, as they would have had in the absence of such unexpected event. These "investor-friendly" contract provisions are proved insufficient to equip the contracted parties and provide a solution when unexpected events actually materialize.

To sum up, the increasing needs for private investment in the infrastructure projects of developing countries have fueled the emergence of project financing structure involving worldwide project participants. The experience of private investors in previous and recent decades, however, has not been smooth as expected with the possibility of deterioration of relationship between the private investors and the host governments, the trend of which is unlikely to change in the near future. These undesired experiences resulted from the conflicting perspectives of the foreign investors and the host government, and the ineffective imbalanced risk-sharing provisions in recent contracts have motivated the development of a better risks-sharing framework to achieve a long term and sustainable solution when the initially anticipated economic condition changes sharply. This framework is intended to better equip the contracted parties when renegotiation efforts are inevitable.

1.2. Thesis Objectives

The thesis's main objective is to develop a better risk-sharing framework between the foreign investors and the host government or public entities to achieve a long term and sustainable solution when the initially anticipated economic condition in the host country turns adverse. The framework is developed as a modification of the current model of agreements that are "inappropriately" favorable to the foreign investors to include more appropriate contract provisions with more balanced terms and conditions. When unfavorable event occurs, the provisions should serve as a guidance to assess the associated risks and a basis to negotiate an approach for remedy.

A case study is considered the most appropriate method to arrive at a practical recommendation in satisfying the thesis's main objective. The Paiton I project, a 2x615 MW coal-fired power generation project in Indonesia, fits this purpose very well. As previously mentioned, the Paiton I project perfectly addresses issues relating to the imbalanced risks-sharing provisions that are greatly favorable to the foreign investors, putting the contracted public entity in a huge disadvantage. The Paiton I PPA model has proved to be ineffective in dealing with PLN's inability to honor the contract when the Asian crisis occurs. Further, the conflicting perspectives between the two contracted parties have prolonged the contract renegotiation process. Facing with these issues, the Paiton I project is well thought-out as an ideal case study to achieve the thesis's main objective. The analysis of the case study would lead to a proposed modification of the current PPA model as well as a proposed approach for renegotiation. Even though the renegotiation mechanism itself is beyond the scope of this thesis, an approach for a long-term commercial solution is suggested to the extent of developing a comprehensive analysis of the Paiton I electricity tariff, referred to as tariff benchmarking analysis, the analysis of which is expected to aid the contracted parties in the renegotiation process. The outcomes should accommodate the respective interests of the foreign investors, the public entity, and most importantly, the Indonesian electricity consumers.

In short, the thesis synthesizes lessons of the Indonesia's electricity sector out of the experience of the Paiton I project. Two main practical results are expected: a modification of the current PPA model, and a long-term commercial approach with respect to the negotiation of the Paiton I electricity tariff, the problem of which, at the time the thesis was final, was in await for solution. Even though the focus of this thesis is the Indonesia's electricity sector, private investments in other developing countries should take the lessons to avoid the same mistakes and be more prepared in undertaking similar deals. Further, the salient features developed out of the Paiton I experience is applicable not only to IPP practices, but also to other types of infrastructure projects that have been experiencing similar difficulties with respect to the "inappropriateness" of investor-friendly contract arrangements.

1.3. Thesis Scope

The thesis limits the analysis to a specific type of infrastructure, which is the independent power producer, with the Paiton I power generation project in Indonesia being the case study. A review of the Indonesia's electricity sector, especially its IPP program, is conducted. Most importantly, an evaluation of the contract provisions of the Paiton I PPA model provides deep insights that would point to the core problems. This evaluation, supplemented with an overview of the business environment in Indonesia, would lead to a proper development of the intended framework. In addition, even though the renegotiation process and mechanism are beyond the scope of this thesis, an approach for a long-term commercial solution is suggested to the extent of developing electricity tariff benchmarking for the Paiton I project.

Among other IPPs in Indonesia, the Paiton I project is chosen as a case study for two reasons. First, the project is the first private power producer in Indonesia and is one of the largest IPPs in Asia. Prior to this project, the country's power sector had had no experience of private investments in power generation, thereby having no template for IPP practices. Indeed, the Paiton I project, especially its PPA model, was expected to be the template for the IPPs that follow. Second, the project addresses issues relating to the imbalanced risks-sharing provisions that are inappropriately favorable to the foreign investors. By the time the thesis was final, the PPA contracted parties were still renegotiating the contract intensively. The renegotiation brought up issues relating to the conflicting perspectives between foreign investors and the host government, the impact of the 1997 Asian crisis, and inefficiency issues, the difficulties of which are often encountered in the project financing practices in developing countries.

In addition to the detailed analysis of the Paiton I project, to provide a coherent approach and a wide spectrum of the application of the recommendation, the project will be evaluated using a review of academic literature as basic references. A comparison of the project with its counterparts in other developing countries is limited to certain financial aspects.

The thesis is limited to the scope explained above. The main obstacle of the research effort was, unfortunately, the reluctance of the public and the private parties of the Paiton I project to assist in the development of the case study. They had been unwilling to share essential information especially with respect to financial information such as project cost structure and financial parameters. Confidentiality and proprietary materials were their main reasons despite the fact that the case study was, indeed, a controversial case. The case study was, therefore, developed from the publicly available information and intensive interviews with a key personnel[7] who was actively involved in the renegotiation process.

1.4. Methodology

The thesis uses the following methodologies:

1) An extensive review of literature around the themes of project financing for IPP, risks analysis, and privatization, to provide basic references for the case study analysis;

---

7 The intensive assistance of Dr. Hardiv Situmeang for the analysis and the write up of this thesis was gratefully acknowledged. Dr. Situmeang was the Director of Planning of PLN and the Chief of PLN contract renegotiation team during the early stage of PPA renegotiation process, up to January 2000. He had been actively involved in the Paiton I contract renegotiation; the different renegotiation approach between the government of Indonesia and the PLN renegotiation team was the basis of his "stepping back" from the renegotiation effort. At the time this thesis was final, Mr. Situmeang served as a senior advisor to the CEO of PLN while finalizing the write up of his book, the theme of which is the IPP renegotiation mechanism.

2) A case study analysis around the Paiton I project. Aligned with the thesis's objectives, the analysis focuses on risks profile, financial scheme and tariff structure, and contractual aspect of the project;
3) A comparative analysis of the case study with academically recommended IPP practices from the literatures; and
4) A comprehensive tariff benchmarking analysis to develop an approach to arrive at a long-term commercial solution with respect to the Paiton I tariff renegotiation.

1.5. Thesis Outline

Chapter 1 provides the introduction of the thesis, outlining the research motivation, objectives, scope, and methodology. The chapter serves as a general overview covering the whole purpose of the thesis.

Chapter 2 presents the theoretical background of project financing practices for IPPs in developing countries. This chapter basically consists of four main parts: 1) an overview of project financing, 2) project finance for IPPs, 3) the emergence of IPPs in developing world, and 4) the salient features of best practice for IPP development. The first and the second parts provide a brief introduction for readers who are not familiar with the idea of non-recourse project financing (as opposed to full-recourse corporate financing) and with the typical IPP structure. Since readers are usually familiar with these two issues, they might skip these two parts. The third part serves as a quick overview of IPP growth in developing countries and the associated problems. Reviewing this part is optional since the problems defined here are explored in details in chapter 4 as well; however, the informative explanation, supplemented with some statistical data, provides a well-thought wrap-up about the growth of IPPs in emerging markets. Reading the fourth part, however, is essential since it serves partly as academic references for the case study analysis in the chapters that follow.

Chapter 3 presents the thesis case study, which is the Paiton I power generation project in Indonesia. The chapter consists of seven subchapters, which mainly explain the entire project: project background, project description, bidding process, project participants, and project finance structure. Moreover, several sections of the Paiton I model PPA are highlighted to provide basic understanding to the mechanism of risk sharing between the power purchaser and the seller of the Paiton I – generated power. The chapter closes with the explanation of the prevailing situation covering the Indonesian economic overview, political overview, the electricity industry, and the Paiton I project status, which is the evolving relationship between PEC (the private investors) and PLN (the public entity). This chapter aims to familiarize the readers with the issues and concerns in the case study. Reading this chapter is mandatory to fully understand the case study analyses in the chapters that follow.

Chapter 4 presents the risk analysis. The chapter consists of two parts: the theoretical background of the IPP project risks, and the evaluation of the Paiton I project risks and hedging mechanisms. The first part aims to familiarize the readers with typical project risks in an IPP while the second part evaluates the Paiton I project risks and hedging mechanisms. Readers might skip the first part if they are already familiar with IPP project risks. The second part, however, is important to fully understand the analysis presented in chapter 5. Chapter 4 closes with risk matrices summarizing the project risks.

Chapter 5 presents the analysis of the Paiton I project deal. This chapter consists of two parts: the IPP key success and best practice analysis with respect to the Indonesian private power industry in general and the Paiton I project in particular, and the analysis of the Paiton I project arrangement covering the imbalanced arrangement issue in the tariff structure, the risks mitigation efforts, and the "mistakes" of IPPs in Indonesia with respect to electricity market projection and equity arrangement. Reading chapter 5 is essential since they explore the issues addressed in the thesis's main objectives and the concerns briefly outlined in subchapter 2.3. Chapter 5 closes with recommendation for practices that the author perceives as better arrangements, given the assessments in the entire chapter.

Although chapter 5 provides analyses and recommendations for certain phenomenon relating to IPPs in developing countries, many contracted parties undertaking renegotiation are, indeed, in an urgent need for a long-term commercial solution. As mentioned earlier, even though the entire renegotiation mechanism itself is beyond the scope of this chapter, the three chapters following chapter 5 provide a comprehensive tariff benchmarking analysis, with the Paiton I project still being the case study. The benchmarking analysis is expected to aid the contracted parties in the tariff renegotiation process.

Chapter 6 presents the tariff benchmarking analysis. The chapter consists of five parts: 1) the tariff benchmarking approach, 2) the definition of financial parameters used in the thesis's financial model, 3) the tariff benchmarking methodology, 4) the project cost analysis, and 5) the tariff benchmarking analysis for a 2x615 MW coal-fired power plant, of the same size to the Paiton I project. The first through the third parts are the theoretical background of the tariff benchmarking analysis while the fifth part is the case study. The benchmarking analysis is conducted in order to derive a possible range of market-based tariff for a 2x615 MW power plant of the same size to the Paiton I project, with a report on benchmark EPC cost estimate by a Canadian engineering and construction company, SNC-Lavalin Group[8], being the EPC cost for this tariff benchmarking purpose. The benchmark tariffs derived could be used either during the initial PPA negotiation or during the renegotiation process when renegotiation is eventually inevitable. The use of the benchmarking depends on the purpose of the negotiation: an ROE-based negotiation or a wholesale-utility-tariff-based negotiation. In addition, since the resulted tariffs are for a 2x615 MW power plant of the same size to the Paiton I project, these tariffs are intended to serve as a comparison to the agreed upon PPA tariff of the Paiton I power. The comparison is further explored in chapter 8.

Chapter 7 consists of two parts. The first part provides an approximation of the financial analysis specific for the Paiton I project; a financial model is developed for this purpose. The financial parameters derived from the financial model include IRR, ROE, average levelized cost, and average levelized tariff. A sensitivity analysis is also conducted, with respect to the tariff, average levelized cost, the utility's payment obligations, and the percentage of the capacity charge to the total payments. The second part provides an analysis of the trend of the increasing competition in the electricity generating business. This increasing competition is likely to result in a decrease in the private investors' expectation on ROE. The tariff benchmarking analysis in chapter 6 and

---

8 The audit was conducted in late 1999; it priced the Paiton I EPC cost at US$ 1.033 billion (with a $\pm$ 20% tolerance), sharply lower than the EPC Cost of US$ 1.772 billion cited by PEC. Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000. See also Solomon, Jay, "Indonesian Audit Uncovers Inflated Cost of Power Plant", *The Wall Street Journal*, December 26, 2000.

the trend of declining ROE in chapter 7 are used in developing an approach for commercial solution in chapter 8.

Chapter 8 outlines an approach to arrive at a long-term commercial solution with respect to the Paiton I tariff renegotiation process. The chapter proposes a renegotiation approach with respect to how to fulfill PLN's payment obligations, taking into account PLN's affordability and following the trend of the increasing competition in the electricity generating business. The approach outlined in this chapter is limited to the purpose of tariff renegotiation: 1) how to determine a reasonable market-based tariff to be renegotiated, and 2) what the contracted parties should do to arrive at this renegotiated tariff. In order to arrive at a single market-based tariff, the benchmark tariffs in chapter 5 are used. Following, the steps that the project parties should do in order to arrive at the renegotiated tariff are outlined by analyzing tariff sensitivity on factors such as coal price, debt structure, and EPC cost. The mechanisms to arrive at this tariff include coal price reduction, and debt restructuring, among others. This renegotiation approach is expected to provide a long-term commercial solution. The idea is very simple: unless the IPP's tariff is reduced to the level affordable to the public utility, and the utility itself is willing to increase its tariff to the end consumers, the renegotiation would not come to an end.

Chapter 9 provides the conclusion, briefly outlining the thesis's results and recommendations.

Chapter 2: Project Financing for IPPs

2.1. An Overview of Project Financing

Project Financing is one of the techniques to structure the financing aspects of large infrastructure projects. Although the term "project financing" has been broadly used over a wide range of project structures describing all types of projects with and without recourse, as the term evolves in recent years, project-financing experts have introduced definitions of project financing more precisely[9]. Two definitions that well represent project financing are as follows:

> A financing of a particular economic unit in which a lender is satisfied to look *initially* to the cash flows and earnings of that economic unit as the source of funds from which a loan will be repaid and to the assets of the economic units as collateral for the loan (Nevitt, 1996).

> Project financing may be defined as the raising of funds to finance an economically separable capital investment project in which the providers of the funds look *primarily* to the cash flow from the project as the source of funds to service their loans and provide the return of and a return on their equity invested in the project (Finnerty, 1996).

In simple words, project financing is basically an independent project entity, namely Project Company, which serves three primary purposes:

1) To generate cash flows and earnings for debt service and repayment;
2) To provide financial returns on equity invested in the project; and
3) To stand, together with its entire assets, as collateral for loan.

To understand the idea of project financing more fully, it is important to differentiate project financing from company financing or conventional direct financing.

---

9 Nevitt, Peter K., "Project Financing Success: Keyed to Non-Recourse Structuring", *Private Power Executive*, July-August 1996.

Company financing, namely Corporate Finance, is the financing technique where the main source of debt repayments of a project is the sponsoring company. The project is backed by the company's balance sheet, not on the project's assets alone. In other words, company financing is an "on-balance sheet" financing. Lenders look to the company's entire assets portfolio to justify whether the company will be able to generate cash flows to service debt requirements. Insights into the company's financial statements and business reputation will significantly influence the lenders' decision. If the project fails, lenders have *full recourse* to the other available assets of the company, rather than recourse only to funds related to the particular project. As long as the company owning the project remains financially strong, the lenders do not necessarily suffer[10].

Project financing is an "off-balance sheet" financing. It is a distinct legal entity whereby project assets, project-related contracts, and project cash flow are segregated to a substantial degree from the sponsoring company[11]. Because of the independent nature of a project under project financing structure, if the project fails, lenders can expect significant losses as well. Therefore, a project can obtain financing and proceed further *only* if it is technically feasible and economically viable.

There are two basic types of project financing: *non-recourse* project financing and *limited-recourse* project financing[12], as follows:

1) *Non-recourse project financing,* namely Project Finance, is the project financing structure whereby the entire project's assets and cash flows, *not* the project sponsoring companies' other available assets, are the collateral for the project

10 IFC, "Project Finance in Developing Countries," Washington D.C., 1998.

11 Finnerty, John D, "Project Financing: Asset-based Financial Engineering", John Wiley & Sons, Inc., New York, 1996.

12 IFC, "Project Finance in Developing Countries," Washington D.C., 1998.

loans. Lenders do not have any recourse to the sponsoring companies; rather, lenders rely solely on earnings generated from the project's assets to meet debt requirements. Neither the sponsoring companies nor any third parties such as governments provide loan guarantees. Therefore, the project company usually arranges some mechanisms for project protection including private insurance and guarantees.

2) *Limited-recourse project financing*, is the project financing structure that permits lenders to have recourse, not only to the individual project, but also to the project sponsoring companies' other available assets to some extent.

Figure 2.1 positions both company financing and project financing techniques on a spectrum. Corporate finance and Project finance are located on the two extreme sides of the spectrum, while limited-recourse project financing, depending on the extent of the recourse, is in between these two extremes.

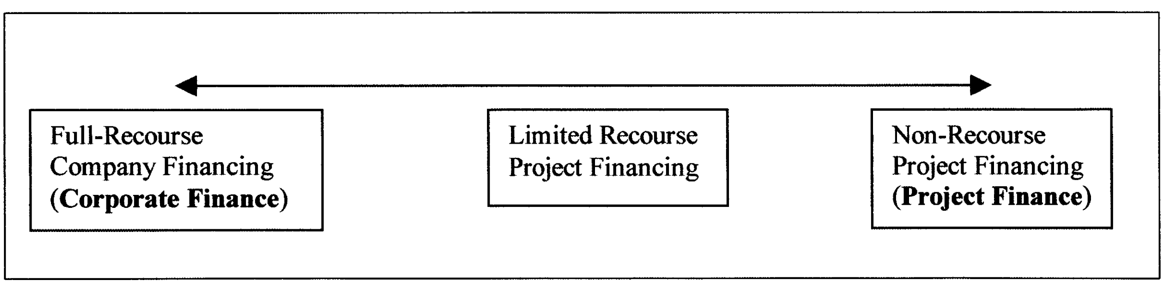


Figure 2.1. The position of the financing techniques on a spectrum

The main difference between the two financing techniques—company financing and project financing—is the arrangement of loans and equity financing, either to the sponsoring company or to the project company, as shown in Figure 2.2.

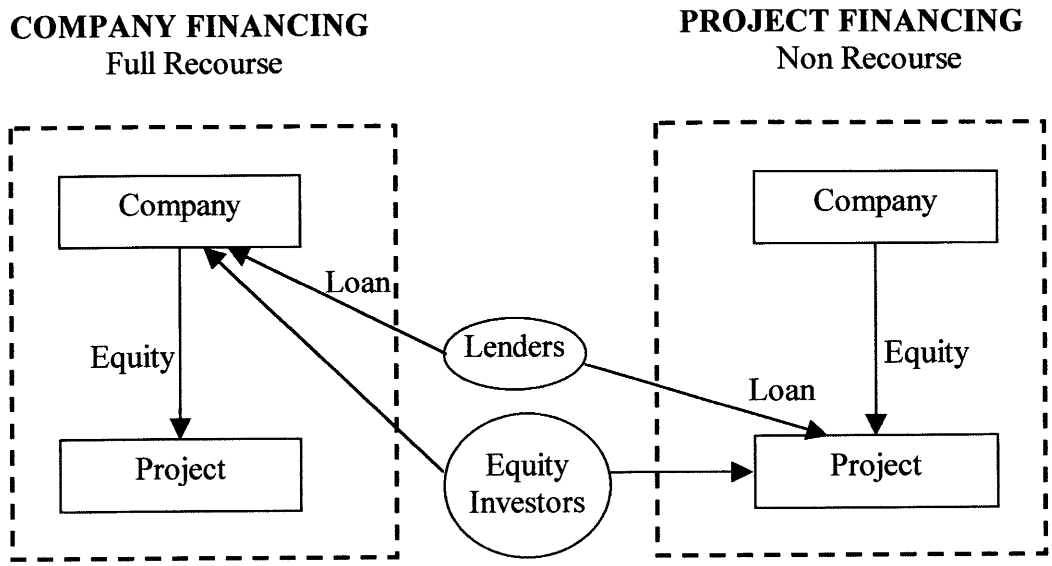


Figure 2.2: Company Financing vs Project Financing[13]

Project finance, the non-recourse type of project financing, implies that a project should be entirely self-supportive, with its cash flows being the sole source for debt requirements and equity returns; third party guarantees and undertakings are not required[14]. Unfortunately, lenders are reluctant to assume such a high level of risk especially when the uncertainty level is high. Peter K. Nevitt suggested that although lenders are willing to look *initially* to the cash flows of a project as the source of funds for loan repayments, the lenders must also feel comfortable that even in the worst case, the loan will, in fact, still be paid[15]. Lenders may want this extra comfort to be in the form of limited recourse to the sponsoring companies' assets or direct or indirect

13 Samii, Massood V., "Project Finance Notes", *Readers for Course Construction Finance*, MIT, Fall 1999.

14 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

15 Nevitt, Peter K, "Project Financing Success: Keyed to Non-Recourse Structuring", *Private Power Executive*, July-August 1996.

guarantees by third parties[16]. Therefore, limited-recourse project financing is usually preferred than non-recourse project financing.

A critical element of project financing success is the project risk profile. Since for both types of project financing, the loan repayments are *primarily* dependent on the project success, lenders pay close attention to the risk profile. Project risks should be mitigated using the possible risks hedging tools[17]. The remaining risks after the mitigation efforts should be properly distributed among the project parties in such a manner that each particular risk is borne by the parties best able to manage the risk. The objective of structuring risk profile is to lower down the risks to a level that is mutually acceptable, reducing the overall collective risks and financial burdens for those assuming the risks.

The challenge of project financing is how to structure the financing aspects of a project in such a manner that the risks and rewards are properly allocated through a combination of various guarantees and supports of the involved parties in a mutually acceptable arrangement.

2.2. Project Finance for IPPs

Independent Power Producers (IPP) are typically structured on a project finance basis, the non-recourse type of project financing. Loan guarantees to the lenders are on the project account rather than on the sponsoring companies' other available assets. The

16 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

17 For further description of risks and hedging tools in project finance, readers should review Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998, pages: 78-79. For further description of risk mitigation analysis, readers should review the World Bank discussion papers, "Submission and Evaluation of Proposals for Private Power Generation Projects in Developing Countries", Washington, D.C., 1994, pages: 63-66, and International Finance Corporation, "Project Finance in Developing Countries", Washington, D.C., 1999, pages: 38-58.

main participants typically involved in an IPP project are project sponsors, host government, lenders, EPC contractors, suppliers, and power purchasers or off takers. The challenge of structuring an IPP project is how to combine different interests of the numerous parties involved in the project. The first step to simplify the complexity is by clearly separating the different interests and defining roles and responsibilities of each project participant. Properly assigning the right responsibilities to the right participant(s) will ease the next step: the risk allocation and the risk mitigation[18]. The task would have been very simple if the roles and responsibilities of the parties remain constant; however, this is not always the case. As the project evolves, the roles and responsibilities of each party need to be redefined[19]. Figure 2.3 shows the typical structure of IPP.

---

18 Project Risks, including risk hedging tools and mechanisms for remedy, are covered in Chapter 4 of this thesis: Risks Analysis. Chapter 4 includes not only the theoretical background of IPP project risks, but also the analysis of risks involved in the Paiton I project.

19 Potash, Daniel A. "Project Participants: Roles and Responsibilities Defined". Private Power Executive. May-June 1996.

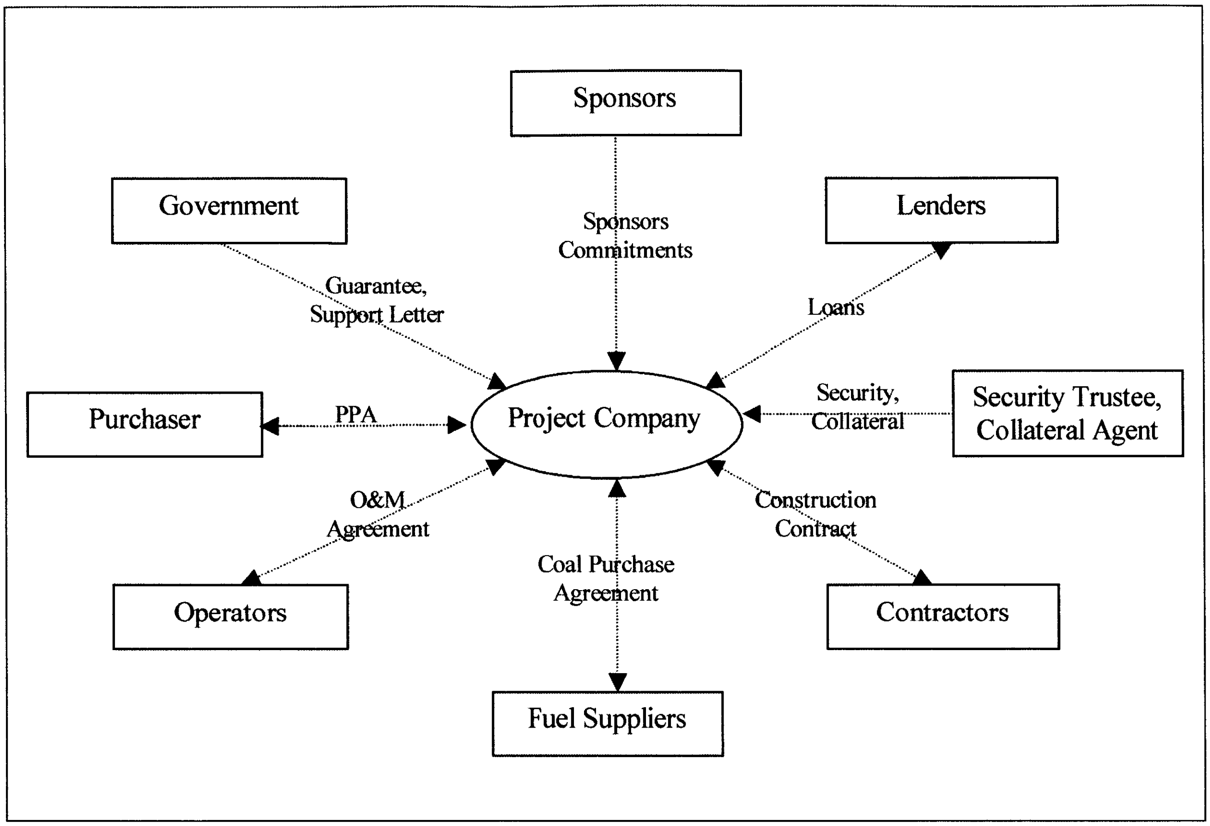


Figure 2.3: The typical structure of IPP

The critical roles and responsibilities of the key participants are summarized as follows:

1. Project Sponsors

The role of project sponsors is to establish a Project Company[20], with a distinct legal entity such as joint venture or partnership, for the purpose of developing an IPP project. The sponsors, typically consisting of several companies forming a consortium, assemble the nuts and bolts to develop the project to be a successful business enterprise. The main purpose of forming the consortium is to share the project risks. The sponsors

[20] For the definition of Project Company, readers should review subchapter 2.1. An Overview of Project Financing.

contribute equity that usually serves as up-front cash during the project development stage. This equity contribution represents their interests and commitments to the project[21], convincing lenders that the project is worth undertaking.

The sponsors may play several roles in the project[22]. Despite their initial involvement in the pre-construction stage, they may also involve in the construction stage, the operational stage, and sometimes in the purchase of the project output[23]. Therefore, a consortium usually brings together many different expertise, technologies, experiences, and resources. They are responsible for completing the project and for making available all funds necessary to achieve completion. They are responsible for making sure that after completion occurs and operation starts, the project will generate sufficient cash to meet its operating expenses, debt requirements, and equity returns. If the project fails to perform as expected because of disruption in operation, force majeure or some other accounts, depending on the cause of the disruption, the sponsors are responsible to restore the project back to normal condition[24].

In short, because of their extensive roles and responsibilities, the sponsors will develop a project if they believe it will provide an attractive return on equity. The higher the risks involved in the project, the higher their expectation for the return on equity.

---

21 A Shareholders Agreement, entered into by the sponsors, states the equity contribution and ownership interest of each sponsor and specifies each sponsor's rights and responsibilities in the Project Company; the agreement may also describe the necessary undertakings in the event of project failure (Lang, 1998).

22 Potash, Daniel A., "Project Participants: Roles and Responsibilities Defined", *Private Power Executive*, May-June 1996.

23 If the sponsors have extensive involvement in many project stages, they are likely to be more committed to the project (Potash, 1996).

24 The sponsors usually arrange hedging tools such as insurance recoveries, future deliveries, or some other means.

2. Host Government

The role of the host government is to give permission and to provide supports necessary to the project sponsors for the IPP project development[25]. Such supports could be in the form of guarantees (i.e. sovereign guarantee) and necessary supports (i.e. tax holiday, a letter of support), among others, and most importantly, a clear legal and regulatory framework of the country's privatization effort that assures a level playing field for the private sector.

The guarantees could be indirect or direct government guarantees. Indirect guarantees are the government backings of multilateral and bilateral agencies that enable the agencies to absorb risk not acceptable to private insurers or guarantors[26]. An example would be the guarantee programs offered by the World Bank Group—the International Bank for Reconstruction and Development (IBRD), International Finance Corporation (IFC), and Multilateral Investment Guarantee Agency (MIGA)—that mitigate non-commercial risks facing private sector activities in the agencies' member countries[27]. Political risks are also covered by agencies of a particular nation to promote international investment by their own nationals. Such agencies include Export Credit Agencies (ECA) such as Japan Export-Import Bank (JEXIM) and the United States Export-Import Bank (USEXIM), and other national agencies such as Overseas Private Investment Corporation (OPIC) of the United States and the Ministry of International Trade and Industry (MITI) of Japan. The arrangement is usually backed by bilateral agreement between the project

---

25 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998. The government enters into a Concession Agreement with the Project Company to grant the company the right, for a certain time period, to develop the project under a specified delivery method, for example, the build-own-operate (BOT) structure.

26 IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

27 Ibid

host government and the agencies' national government. Figure 2.4 shows the simplified arrangement for the indirect host government guarantees.

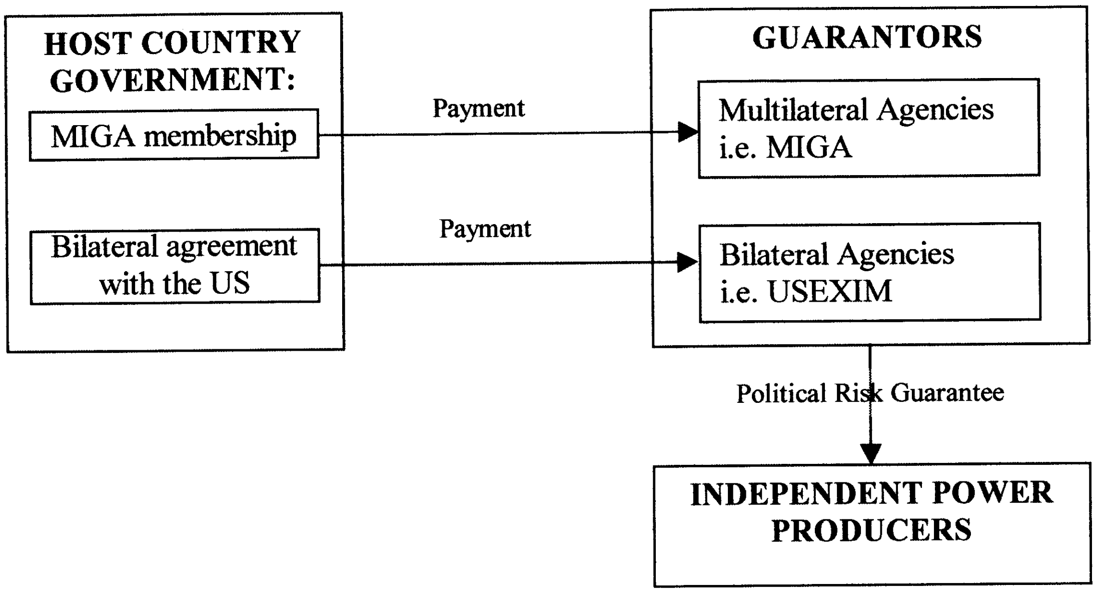


Figure 2.4: Indirect Host Government Guarantees

The direct host government guarantee is a direct financial responsibility for payment obligation if certain agreed upon conditions occur. In most developing countries, the guarantee usually covers demand risk, foreign exchange risk, and political risk including change of law risk and expropriation[28]. When IPPs enter into an agreement with state-owned entities, the sponsors usually ask for direct government guarantee on the utilities' payment obligation, which means that the government would be financially responsible when the party primarily liable fails to perform. For example, when the power purchaser is a state-owned utility, the host government may guarantee that the utility make the agreed upon PPA payment to the Project Company; in case of the

28 The coverage types of various government guarantees are explored in Chapter 4. Risks Analysis.

utility's default, the government would be responsible to make the payment. Figure 2.5 shows the mechanism of the direct government guarantee.

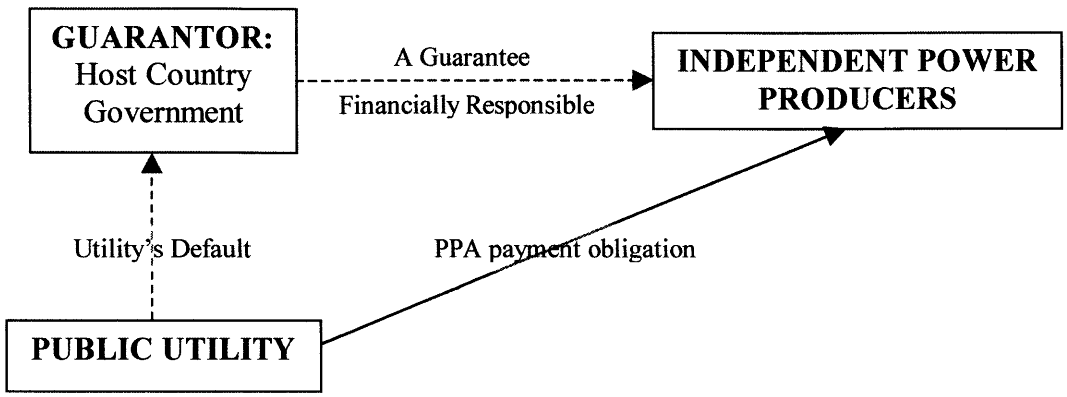


Figure 2.5: Direct Host Government Guarantee

In many cases, governments refuse to provide guarantees[29]. Instead, they issue a letter of support[30]. A quite different understanding occurs, that is, the sponsors interpret that the letter provides the same assurance as a guarantee; however, from the government's viewpoint: unlike a guarantee, under a support letter, the government would not be financially responsible in case of the utility's default. In case of dispute, the strength of this letter from the legal point of view remains unclear. Indeed, a support letter is not a guarantee, but only a letter supporting the country's privatization effort. The support letter provides a "comfort" to the private sector that the project company will

---

29 Theodore H. Moran, "Political and Regulatory Risk in Infrastructure Investment in Developing Countries: Introduction and Overview", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy. Moran points out some examples of government refusals to provide guarantees (Wells, 1999).

30 In the case of the Paiton I project, the Indonesian government did not issue a guarantee; it issued a letter of support saying that the government would "cause" PLN to "discharge" its financial obligations. This support letter is further discussed in chapter 4 of the thesis.

be run in a sound business manner; however, the letter provides no guarantees by any means, as shown in Figure 2.6.

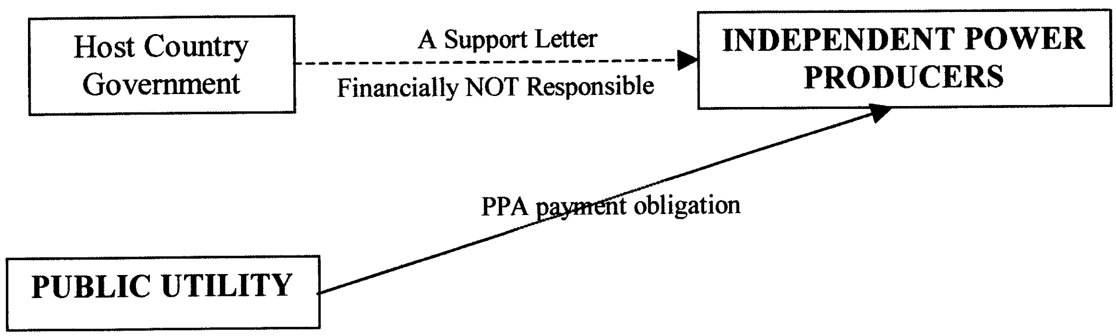


Figure 2.6: Letter of Support: the host government support

3. Lenders

The role of lenders is to provide debt financing[31] for the project. Among others, lenders can be commercial banks, multilateral funding institutions, the central bank of the host country, and governments' Export Credit Agency (ECA)[32]. Multilateral funding institutions include the International Finance Corporation (IFC) of the World Bank, the Asian Development Bank (ADB), and the European Investment Bank (EIB). The ECAs include JEXIM and USEXIM.

Since the debt repayment is dependent on the project success, lenders pay close attention to the project risk profile. There has been a tendency to delay debt financing

---

[31] Potash, Daniel A, "Project Participants: Roles and Responsibilities Defined", *Private Power Executive*, May-June 1996: Debt financing is usually confused with debt investment; therefore, it is important to differentiate these two terms. Debt investment is an investment with a fixed return and a fixed date for repayment. In this case, the sponsoring company's assets are the collateral for the loan. Debt financing is the debt borrowed by a Project Company. In debt financing, there is no recourse to the sponsors' other available assets if the loan goes bad; instead, the independent project entity stands together with its entire assets as collateral for the loan.

[32] Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

until some project risks have been proved lower and some uncertainties have been resolved[33]. Lenders usually defer the debt financing during the project's early stage, transferring the risks of pre-completion stage to the project sponsors and contractors.

4. Engineering Procurement Construction (EPC) Contractors

The role of EPC contractors is to design and construct the IPP project. They design the project, buy the equipments, arrange for the delivery to the site, construct and supervise the building of the project's facilities and system installation[34].

The project sponsors usually transfer construction risks[35] to EPC contractors. The Project Company enters into a fixed-price turnkey construction contract with the contractors, which states that the contractors agree to build the project for a fixed price and they will deliver working commercial power plants by specified dates. If the plants are delivered late or under-performed, the contractors will have to pay liquidated damages to the Project Company since delay in project completion will delay the revenue stream as well.

5. Suppliers[36]

The role of suppliers is to supply equipments and materials for the plants during the construction and operation stages. Two important suppliers in IPP projects are equipment suppliers and fuel suppliers. Equipment suppliers take orders from EPC

---

33 Potash, Daniel A, "Project Participants: Roles and Responsibilities Defined", *Private Power Executive*, May-June 1996.

34 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

35 Risks during the project construction stage are further explained in Chapter 4. Risks Analysis.

36 Potash, Daniel A, "Project Participants: Roles and Responsibilities Defined", *Private Power Executive*, May-June 1996.

Contractors, and deliver and place the equipments in the project. Such equipments include not only those to generate electricity such as turbine and generator, but also other equipments needed for operating the plant such as compressors, transformers, and coal-handling equipment. Fuel suppliers enter into a Fuel Supply Agreement with the Project Company to provide fuel for the plants under a certain pricing mechanism.

It is not uncommon that EPC contractors, equipment companies, and fuel companies together form a consortium to bid on a power project. In this way, even though the consortium assume higher risks, they are likely to be more committed to the project, and, as a result, get higher compensation.

6. Off-taker / Power Purchaser

The role of power purchaser is to purchase the IPP-generated power. The power purchaser enters into a PPA with the Project Company by which the purchaser agrees to purchase a minimum amount of the power produced by the IPP[37]. The agreement is either on a *take-or-pay* or *take-and-pay* basis. The former is an agreement whereby the purchaser agrees to make an agreed upon payment regardless the delivery of the power, but subject to the availability of the plants; even if there is no delivery, the purchaser is still obligated to make a certain level of capacity charge payment. The *take-and-pay* PPA is an arrangement whereby the payment will be made only upon the actual delivery of the power.

In most developing countries, the power purchaser is usually a state-owned electric utility entering into a *take-or-pay* PPA. The critical issues being discussed during the initial PPA negotiation process between the utility and the IPP are the level of the

37 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

take-or-pay and the pricing formula. The *take-or-pay* level represents the demand risk to be assumed by the utility while the pricing formula represents the allocation of commercial risks such as exchange rate risk and inflation risk, either to the utility or to the IPP. The payment level becomes crucial when the actual demand of electricity is far more less than that of the projection. When the demand is weak, the public utility would end up paying fixed capacity charges for the unnecessary IPPs-generated power. As previously mentioned, there has been no effective mechanism to deal with such a huge disadvantage of the utility's position. Instead, PPA provisions have been crafted in such a way that protects the revenue stream of IPPs to a great extent on the expense of the public entities, leaving the project sponsors assuming almost no risks. When the economic condition of the host country changes sharply, as has happened during the Asian crisis, the impacts of such provisions of the current PPA model become apparent.

2.3. The Emergence of IPPs in Developing Countries

Power projects were traditionally built on a full-recourse basis. Until the late 1980s, power sector in developing countries was a public sector's monopoly; funds for investment in this sector were provided only by or through government or public utility[38]. Since early 1990s, the formation of project financing as an alternative financing method

---

[38] Razavi, Hossein, "Financing Energy Projects in Emerging Economies", Pennwell Books. Oklahoma, 1996. Razavi provides an example of the construction of a new power generation plant as a public project. As a public project, the required funds would be provided from either one or the combination of the available public sources: the internal funds of the public utility, the government's budget, and the official borrowing from multilateral institutions and bilateral sources. The capital investment and borrowing, therefore, would not be on the project account. Instead, the public utility would be responsible for the debt. In other words, the project would be built as an extension of the assets of the utility. Lenders would have full recourse on all assets and revenues of the utility, not just those related to the new plant.

has emerged in the power sector as the private involvement has been increasing[39]. The power sector in developing countries has been growing rapidly due to the boom of the countries' economy in the late 1980s. The countries' public utilities were unable to keep pace with the increasing demand. The lack of financial resources has made the condition even worse. Faced with serious capacity and energy shortages that cannot be remedied from public sources, many developing countries turned to private investors. In addition, the positive results of the early experiments with private participation in Chile[40] and the United Kingdom[41] convinced many developing countries that the private sector involvement is a feasible approach.

Electricity has predominated the growth of private activities in power sector. More than 600 private electricity projects—which consist of generation, transmission, and distribution projects, and represent investment of US$ 160 billion—reached financial closure in seventy developing economies during the 1990s[42]. Most of the private participation in electricity has been through IPPs, which generally involve investors who build a power plant and sell the electricity wholesale either to an existing utility or to one or several large consumers. While IPPs now account for about half of all new generating

---

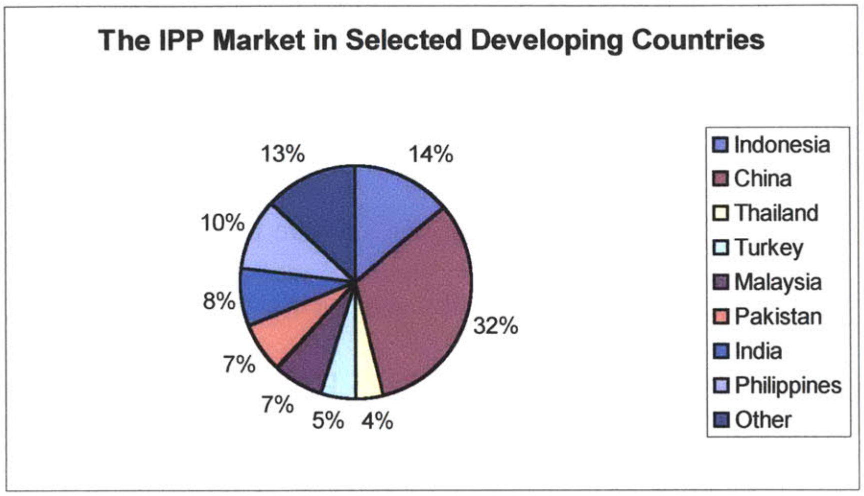
39 Izaguirre, Ada Karina, "Private Participation in the Electricity Sector—Recent Trends", *Public Policy for the Private Sector*, the World Bank Group, September 1998: the investments in electricity projects with private participation amounted only to US$3.6 billion (in 1997 US Dollars) between 1984 and 1989 (Source: the World Bank PPI Project Database).

40 Izaguirre, Ada Karina, "Private Participation in the Electricity Sector—Recent Trends", *Public Policy for the Private Sector*, The World Bank Group, September 1998: before 1990 private participation in electricity in developing countries was limited to Chile and a few isolated experiences in other countries. Chile introduced comprehensive reforms in the 1980s to create a competitive private market.

41 Besant-Jones, John E., "The England and Wales Electricity Model—Option or Warning for Developing Countries", *Public Policy for the Private Sector*, The World Bank Group, June 1996. In the late 1980s and early 1990s, the United Kingdom power supply industry underwent the most radical transformation of the industry: it went from being a state-owned, state-controlled, integrated structure to being a privately owned, autonomously regulated, unbundled structure.

42 Izaguirre, Ada Karina, "Private Participation in Energy", *Public Policy for the Private Sector*, The World Bank Group, May 2000.

capacity in the US[43], greenfield expansion—the source of IPP—in developing countries accounted for 56% of the US$ 131 billion private investments contracted in 1990-1997, most of it for generation[44]. From 1991 through 1997, contracts brought to a closure for large greenfield IPPs reached 137 projects for 67 gig watt (GW) of capacity worth US$65 billion, with IPPs mobilizing US$51 billion of private funds[45]. Figure 2.7 shows the distribution of IPP investment among selected developing countries.



Note : Data are as of end-December 1998 and cover only IPP projects of more than 100 megawatts.
Other : Argentina (3%), Chile (2%), Colombia(2%), Morocco(2%), Czech Republic (1%), LaoPDR(1%), Mexico(1%), and Peru(1%).
Source : World Bank, Energy, Mining, and Telecommunication Department, Knowledge Management Database.

Figure 2.7: The IPP market in selected developing countries, 1997[46].

In general, IPPs have made positive contributions to the developing economies. The most important one is that IPPs have helped developing countries governments to meet their large financing needs and capacity shortages; the governments, as a result, can

43 Bond, James, "Risk and Private Power—A Role for the World Bank", *Public Policy for the Private Sector*, The World Bank Group, March 1994.
44 Izaguirre, Ada Karina, "Private Participation in the Electricity Sector—Recent Trends", *Public Policy for the Private Sector*, The World Bank Group, September 1998
45 Albouy, Yves, and Reda Bousba, "The Impact of IPPs in Developing Countries—Out of the Crisis and into the Future," *Public Policy for the Private Sector*, The World Bank Group, December 1998.
46 Ibid

allocate public sources to other priorities such as health and education. Yves Albouy and Reda Bousba of the World Bank's Energy, Mining, and Telecommunications Department, agree at this point. However, they observed a drawback: when the IPP program eventually grows quickly to a large size relative to the host country's grid capacity, the negative effects become significant, as has actually happened in a few Asian countries[47]. Albouy and Bousba's observation regarding the impacts of IPPs in developing countries are summarized as follows:

1) IPPs have allowed the transfer of significant project risks—mostly construction, operating, and fuel availability risks—to the private sector. However, most IPPs are compensated for fuel price variations, and are protected against market risks by *take-or-pay* contracts; these risks are eventually passed on to the power purchaser. IPPs are also protected against political risks, often by government guarantees.
2) IPPs have generally caused the country's electricity sector exposure to foreign exchange risks to increase or at least stay the same. In few countries, the exposure is likely to be higher with IPPs than that under expansion plans by public utilities.
3) Without IPPs, the capacity shortages would have gone unmet. On the other hand, the IPPs built as a response to an overoptimistic demand has led to an excessive supply of electricity. Without the IPPs, most of the overcapacity would have not existed.

[47] Albouy, Yves, and Reda Bousba, "The Impact of IPPs in Developing Countries—Out of the Crisis and into the Future," *Public Policy for the Private Sector*, The World Bank Group, December 1998.

4) Capacity costs of IPPs have varied widely, even for similar technologies. For example, the price of gas turbines in China is 40 percent of that in Indonesia. The capacity costs of IPPs are sometimes higher than those of public utilities with World Bank financing. Further, most PPAs are on *take-or-pay* basis, a costly straightjacket that protects the project's revenue stream when demand is weak.
5) Transaction costs for IPPs have tended to be high, and elapsed time to financial close have been generally more than two years. Moreover, unclear rules for the bidding process and contract awards, accompanied by allegations of corruption, have been perceived as unfair by project sponsors losing the bid.

These observations reveal negative impacts of the IPP boom to the host country's electricity sector. Particularly in a few Asian countries, the mid-1997 Asian crisis has further triggered these impacts, placing the host government and the state-owned utilities in a huge disadvantage since they assume most, if not all, of the commercial risks under PPAs agreed upon prior to the crisis. Certain "investor friendly" provisions to stabilize returns to investors have proved to be inappropriately favorable to the investors. These provisions may initially be intended to attract private investment; however, they are proved ineffective to be fully forced in times of crises. While respect for contracts is critical for private sector development, IPPs in trouble *may* have to be restructured. Given these observations, the development of a better risk-sharing framework—by improving on the current IPP practice, with restructuring PPA being the particular emphasis—is an urgent need, not only for renegotiation purpose but also for future IPP deals.

2.4. Key Success and Best Practice for IPPs

There have been efforts to provide best practice manuals as well as guidance for IPPs by multilateral organizations such as the World Bank[48] and the Asia Pacific Economic Corporation (APEC)[49]. A number of essential principles must be incorporated into the private power development to properly satisfy the respective interests of the governments, the private investors, and the electricity consumers. Although these essential principles can be differently formulated[50], research and case study work to date as well as various literature references lead to three key success factors for IPP: Competition, Risks Mitigation, and Transparency. These three factors can be formulated around three main themes:

1) Legal and regulatory framework for private power development;
2) Procurement process; and
3) Power purchase agreement.

---

48 The World Bank discussion papers, "Submission and Evaluation of Proposals for Private Power Generation Projects in Developing Countries", Washington, D.C., 1994. The report has been prepared to help governments of developing countries address some of the constraints that have impeded development of private power generation projects. It discusses, in particular, how to prepare bidding documents and undertake effective technical and commercial evaluation of bids.

49 APEC Energy Working Group, "Manual of Best Practice Principles for Independent Power Producers", The APEC Energy Working Group Secretariat: Energy Division, August 1997.

50 Price Waterhouse LLP, "Review of Indonesian Power Sector Development Issues", Energy Project Development Fund, USAID, May 1995, recommended that the conditions for a successful IPP program include: a clear legal and regulatory framework, maintenance of a healthy power purchaser, a transparent bidding process, a competitive market for project components, discrete project facilities for each IPP project, and a new power purchase contract based upon the lessons of the Paiton I PPA model.

APEC Energy Working Group, "Manual of Best Practice Principles for Independent Power Producers", August 1997, formulated four critical success factors: transparency, predictability, reduction of risk, and encouragement of competition; and four principles of best practice for IPPs: institutional and regulatory structures, tender/bid processes and evaluation criteria, power purchase agreements and associated tariff structures, and financing and its implications.

Price Waterhouse Coopers, "Best Practice for Promoting Private Sector Investment and Competition in the Power Sector", Asian Development Bank, March 1999, formulated the best practice, according to the five stages of restructuring: establishing the structure of the power industry, preparing the market for private sector investment and competition, opening the market and carrying out privatization, and implementing the changes effectively.

2.4.1. Legal and Regulatory framework

Initially, the government owns public utilities. However, many countries have moved towards privatizing these assets[51]. Dr. Hardiv Situmeang of PLN synthesized quite different objectives of privatization in four South East Asian countries, as shown in Table 2.1, based on the different perspectives[52] and definitions[53] of privatization of each country.

---

51 Potash, Daniel A. "Project Participants: Roles and Responsibilities Defined". Private Power Executive. May-June 1996. Potash suggested two reasons behind the electricity business privatization efforts: the fresh capital available from private sources, and the "pressure" by the World Bank and other international organizations to privatize the electricity business, or at least ask the government to get out of the generating business.

52 Perspectives: Indonesia: Privatization is not only about selling public assets but is also a tool for economic reform to achieve several objectives (Master plan, 1998). Malaysia: the transfer to the private sector the activities and functions traditionally rested with the government, bringing about positive changes to the organization, management, and the performance of the public enterprises. Brunei Darussalam: A new kind of development strategy whereby growth will no longer be driven by the government; rather, by the capital market i.e. the private sector. Philippines: A tool for economic growth. (Situmeang, 2000).

53 Definitions: Indonesia: The transfer to the private manager and private owner the effective control previously rested with a state-owned company, the objective of which could be achieved when the majority of ownership has been transferred or shortly will be sold to the private sector (Master plan, 1998). Malaysia: The transfer to the private sector the activities and functions traditionally rested with the public sector. Brunei Darussalam: The transfer to the private sector the activities and functions traditionally vested in the government. Philippines: an explicit definition is not available, but the understanding is similar to that of Malaysia and Brunei Darussalam. (Situmeang, 2000).

Table 2.1: The objectives of Privatization in four South East Asian countries[54]

The Objectives of Privatization	Indonesia[1]	Malaysia	Brunei Darussalam	Phillippines
Facilitate/Improve Sustainable Economic Growth	X	X	X	X
Improve Efficiency	X	X	X	X
Improve Productivity	X	X	X	X
Increase Revenue	X	X		X
Increase Quality of Service	X	X	X	X
Relieve the financial and administrative burden of the government	X	X	X	X
Development of the Private Sector	X	X	X	X
Distribution of resources/capital	X			
Diversify Company Ownership	X	X		X
Strengthen the Capital Market	X			X
Support the Government Program: sector reform, restructuring, etc.	X	X	X	X
Improve Business Climate	X			X
Product and Technical Innovation			X	

Note: [1] Master plan for the reform of Indonesia's state-owned companies, September 1998.
X : the objectives that apply to the associated country.

Towards these privatization efforts, particularly with respect to the electricity sector, the government has the authority to create and control the legal and regulatory framework of the country's private power industry, with the best practice including the following features:

1) Create a stable framework for power sector development toward competitive market, through such mechanisms as power sector reform and restructuring.
2) Establish a clear legal and regulatory framework, which provides transparent ground rules and assures a level playing field for the private participants (Price Waterhouse LLP, 1995).

---

54 Situmeang, Hardiv, "The objectives of Privatization", The International BIMP (Brunei, Indonesia, Malaysia, and Philippines) EAGA (East Asian Gross Area) Conference on Privatization, International Convention Center Brunei, an unpublished synthesis of the conference papers, Brunei, May 3-4, 2000.

3) Establish a complete set of laws and regulations specifically relating to the private power industry including the foreign investment law, and the regulations applicable to foreign borrowings, taxation, and foreign exchange regimes; environmental and other public policy objectives should also be well incorporated.
4) Encourage competition in the electricity business through separation between regulator and public utility, and through unbundled structure of generation, transmission, and distribution function.
5) Restructure the power sector by clearly separating the sector's commercial objectives from the social objectives. Publicly owned utilities should function as commercially viable entities working under a set of commercial performance targets.
6) Simplify the approval process for IPP projects to reduce uncertainties and delays under a clear, published, and transparent approval procedures (APEC, 1997).
7) Create security over project assets that applied fairly to all project participants under enforceable legal frameworks.
8) Maintain a healthy power purchaser (Price Waterhouse LLP, 1995).
9) Implement policies to encourage the development of domestic capital markets and institutions and diversify the sources of domestic capital such as pensions and insurance funds available for equity investment in electricity projects (APEC, 1997).

2.4.2. Procurement Process

Procurement process is a starting point of the relationship between the private investors and a host government. The process includes the description of the project scope, selection and solicitation process, preparation and award of contract, and all phases of contract administration. The entire process should be well crafted to encourage competition and to assure a level playing field for the private participants. The government is responsible to assure that the appropriate procurement process is in place, with the best practice including the following features:

1) Identify the appropriate projects: the projects selected should match the power development planning and the industry and environmental policies.
2) Define the project scope and requirements. The government should at least provide the basic specifications and minimum requirements of the project. In other words, the government, *not* the private participants, is the party which is responsible for defining the project scope[55].
3) Formulate and publish objective evaluation criteria that assure a head-to-head competition among bidders. The evaluation criteria should have a comparison framework—which could be on price, on qualifications, and on combinations of

---

[55] An example of private-participants-defined project is the construction of a power plant project whereby the government provides very little information on the planned project; for example, even the required capacity and the contract period are not defined by the government. The private participants, then, prepare their bids based on their own perceived required capacity and their own assumption on contract period; these two factors would be obviously assumed differently by one participant to another. As a result, it would be difficult for the government to evaluate their proposals. Unless the evaluation criteria are the factors that vary, the proposals submitted by the participants are, indeed, crafted for a "different" project.

qualifications, among other factors—as a basis to choose the best bidder to be awarded the contract[56].

4) Formulate and publish tender/bid procedures that fairly treat the private participants. The procedures may be structured to include bidding stages such as pre-qualification of bidders on the course of financial or technical qualification, among others. When public utilities should compete with private participants, all the exclusive attributes of the utilities should be taken away to assure the fair treatment.
5) Publish in advance the full tender/bid information packages including the evaluation criteria, and apply the rules of the game during the competition.
6) Ensure transparency in the whole process: the potential competitors should be able to see and understand the process prior to making commitment to participate[57]. The overall procurement system should be reliable and predictable.
7) Provide benchmarking by an independent engineering peer to ensure cost-effective development based on the market price of the project. For example, independent engineering review must assure that the project cost offered by the bidders is not exceptionally high if compared to other similar projects.

---

[56] Competitive bid procedures should be implemented for selected projects to be awarded to the private sector, recognizing that alternative procedures, including the consideration of unsolicited bids, may be appropriate in certain circumstances (APEC, 1997). Even though for the best practice, competitive bidding would be the rule, there are certain circumstances where competitive bidding are not possible, for example, when the interested parties are too small.

[57] If prospective private participants view the bidding process as lack of competition, they may decide not to bid for the project, or in case they are already involved, they may withdraw their bids. This action, however, is sometimes practically difficult since some potential competitors may perceive an uncompetitive procurement system as an opportunity to find some other ways around the formal rules to win the project.

2.4.3. Power Purchase Agreement

As mentioned earlier, PPA is an agreement between an IPP and a power purchaser for the power purchaser to buy the IPP-generated power under an agreed upon set of pricing formula, either on a *take-or-pay* basis or on a *take-and-pay* basis. Critical aspects in PPA negotiation process include tariff structure, pricing mechanism, force majeure, and dispute resolution. The best practice features are as follows[58]:

1) Use the wholesale electricity tariff, rather than the rate of return on equity, as the basis for negotiating PPAs.
2) Formulate tariff structure that promotes competition among generators of both IPPs and utilities on cost-effective development. The structure should incorporate mechanisms that allow smooth transition to competitive electricity markets.
3) Structure a balanced risks profile under PPA. The risks should be allocated to parties that are in the best position to control and manage the risks[59]. The risks include market risks, foreign exchange rate risks, currency convertibility/availability and transferability, changes in fuel prices, costs due to change in law, and political risk.
4) Include provision for payments on termination to cover debt/equity/ return on equity.
5) Accommodate effective dispute resolution and enforcement mechanisms.

---

58 APEC Energy Working Group, "Manual of Best Practice Principles for Independent Power Producers", The APEC Energy Working Group Secretariat: Energy Division, August 1997.

59 The commercial risks that are difficult to manage, for example demand risk and exchange risk, should be negotiated properly. An imbalanced transfer of these commercial risks to be mostly assumed by the power purchaser may lead to political risks for the investors (Wells, 1999). Unlike the current PPA model, demand risk, for example, should be partly allocated to IPPs by arranging long-term contracts only for part of the capacity with the balance to be sold at spot prices (Albuoy and Bousba, 1998).

The success of the implementation of the key success and best practices for IPPs is basically dependent on the three project main parties: the project sponsors, the host government, and the power purchaser. The three key success factors—competition, risk mitigation, and transparency—should be embodied in the legal and regulatory framework, procurement process, and PPA. The goal is a stable and competitive private power development strategy that produces better service, higher quality, and lower costs to the ratepayers.

2.5. Chapter Summary

Private investments for IPPs in developing countries have grown significantly in 1990s as public utilities lacked the capacity and financial resources to keep pace with the countries' increasing electricity demand. Despite the IPPs' positive contributions to the countries, the drawbacks have become apparent when the IPP program eventually grows quickly to a large size. The negative impacts include the electricity overcapacity and the high IPP transaction costs. The most important concern, however, is the highly secured IPP deals under *take-or-pay* PPA with public electric utilities, either with or without government guarantees. While government usually provide guarantees that protect investors against political risk or the utility's default risk, the *take-or-pay* arrangement, which obligates the utilities to pay fixed capacity charges, protects the IPPs' revenue stream when demand is weak. The pricing formula transferring most of the inflation risk and currency risks to the government or the utilities have increased the country's electricity sector's exposure to the exchange risks and have placed the public entities into a severe financial strain when the economic situation changes sharply, as is the case with the Asian crisis. Therefore, the IPP deals, particularly its PPA arrangements, that are inappropriately favorable to the investors and ineffective in times of crisis, should be modified.

Despite the inappropriateness of the IPP deals, the entire IPP program of a country is actually a part of the country's effort towards privatizing the electricity business. A number of essential principles that must be incorporated into the private power development can be summarized in one sentence: the key success factors—competition, risk mitigation, and transparency—should be embodied in the legal and regulatory framework, procurement process, and PPA arrangement. These best practice features may serve the country privatizing its electricity business as a checklist for its private power development effort.

Chapter 3: The Paiton I Project[60] in Indonesia[61]

3.1. Project Background

The Indonesian power sector had been growing rapidly[62], with PT. Perusahaan Listrik Negara (PLN), the Indonesian state-owned electricity company, accounting for the major part of this growth. These rapidly expanding power needs were due to the boom of the country's economy in the late 1980s, resulting from the rapid growth of industrial and transportation sectors as well as the increasing prosperity of the population[63]. PLN's supply of electricity, however, was unable to keep pace with the increasing demand[64]. Faced with this growing demand and PLN's inability to meet the demand, the Government of Indonesia (GOI) turned to private sector.

---

60 The thesis author prepared this case under the supervision of Professor Massood V. Samii as the basis for the thesis discussion, and not to illustrate either effective or ineffective handling of infrastructure development related issues. Data presented in the case analysis might have been altered to simplify, focus, and to preserve individual confidentiality. The assistance of Dr. Hardiv Situmeang—the Planning Director of PLN (July 31, 1998 – December 31, 1999) and later, the senior advisor to the PLN CEO—in the preparation of this case is greatly appreciated. The remarkable contribution of Dr. Situmeang in the case analysis is gratefully acknowledged.

61 Indonesia is an archipelago nation comprised of five large islands, with a population of about 224 million (July 2000 est.), the world's fourth largest populous country. Indonesia's economy had demonstrated a strong and sustainable growth. In 1990s, the per capita Gross Domestic Product (GDP) was US$ 880, and the real GDP was around 7%. Following the sharp contraction and high inflation during the Asian crisis of 1997-1998, in 1999, the Indonesian economy stabilized with a modest recovery. The per capita GDP was US$ 2,800 (1999 est.); the real GDP for the whole 1999-year, however, showed 0% growth rate (The CIA World Factbook, 2000).

62 The World Bank projected that of the US$ 192 billion required infrastructure investment in Indonesia from 1995 to 2004, power plants accounts for more than 40%.

63 Technology Indonesia, Pusat Informasi Business dan Pembangunan Indonesia, P.T. Wahyu Promo Citra, "Energy: Technology and Development", 2nd Edition, September 1995, Jakarta, Indonesia.

64 The magnitude of the unmet demand was difficult to measure; however, several indicators can be a proximity. PLN statistics showed that the waiting list at the end of the 1993/94 fiscal year remained at 48% of PLN's installed capacity. Further, the Indonesian per capita electricity consumption, electricity intensity (kWh consumed per dollar of GDP) and the percentage of population with access to electricity were all the lowest in Asia (Source: ADB, Electric Utilities Data Book, 1993).

In 1990, the GOI announced a policy to encourage private investment in electric power generation to meet Indonesia's optimistic projection of 19%-24% annual increase[65] in electricity demand. Following this policy, in 1991, the Indonesian Ministry of Mines and Energy (MME) invited companies to submit proposals for the Paiton I project, the first privately financed, owned and operated power generation facility in Indonesia. In 1992, Presidential Decree 37/1992 was issued to encourage and open the way for private sector involvement in power generation; it authorizes the MME to be responsible for regulating private power industry.

In 1993, the MME developed a comprehensive policy framework to guide the longer-term reform and restructuring of the power sector[66]. Following this reform and restructuring effort, in 1994, the GOI changed the legal status of PLN from a state enterprise to a limited liability corporation, enabling PLN to establish subsidiary companies and allowing private sector participation in power generation[67]. The 1996 National Electricity Plan endorsed the concept that most of the electricity will be provided by independent power producers (IPPs), which would then sell the power to PLN under long-term power purchase agreements (PPAs). The Paiton I project is the first IPP in Indonesia.

---

65 The 19%-24% annual demand increase was the projection in the 1994 National Electricity Plan.

66 Consultants from the U.S. Agency for International Development (USAID), World Bank, and ADB were appointed to assist MME in formulating detailed proposals in terms of regulatory, legal, and institutional arrangements to secure efficient private power mechanisms.

67 US Embassy for Jakarta, Indonesia, "Indonesia: Electricity Sector Update—Focus on PLN", *Energy News*, May 1998. http://www.usembassyjakarta.org/econ/electric-pln.html

3.2. Project Description[68]

The Paiton I project is located in 140 km south east of Surabaya in East Java and is part of a power generation complex (the Paiton complex). The project consists of 2x615 MW (net) coal-fired electric generating plants. The Paiton complex is designed to accommodate eight electric power plants of which the Paiton I project is for units 7 and 8. Units 1 and 2 (2x400 MW), developed and owned by PLN, had been in operation since 1994. Units 3 and 4 (2x400 MW) and Units 5 and 6 (2x615 MW) would be privately owned.

Some facilities, eventually required by units 3 through 6, were provided within the Paiton I project's scope of work. The facilities consisted of the construction of the switchyard for units 5 and 6, initial site preparation work for units 3 through 6, and civil works, including the water intake and discharge canals that were being expanded to meet the requirements of all eight units. After construction, these facilities would be turned over to PLN for its use in connection with the Paiton complex.

3.3. Consortium Bidding Process

The Paiton I project was solicited under the build-own-operate (BOO) scheme[69], which gives the project developer the authority to build, own, and operate the plants, for a period of 30 years. Following the GOI's bid invitation for the Paiton I project, a number

---

68 CS First Boston Chase Securities, Inc., "Confidential Offering Circular for the Paiton I proposed bond offering", March 21, 1996; OPIC, "Discussion and Recommendation for Approval by the Board of Directors", *OPIC Loan Guaranty*, December 6, 1994.

69 The BOO structure is a variant of the build-operate-transfer (BOT) delivery method. Other variants of the BOT structure include the build-own-operate-transfer (BOOT) structure and the build-own-maintain-transfer (BOMT) structure. Under the BOO structure, however, the project is not transferred to the host government after the completion of the project (Lang, 1998).

of Indonesian companies were pre-qualified to bid on the project. At that time, the Indonesia's Foreign Investment Law required that any private investment group must have at least 5% Indonesian shareholding.

After being pre-qualified, PT. Batu Hitam Perkasa (BHP)[70], together with three foreign companies—Edison Mission Energy (Mission) of the US, Mitsui & Co., Ltd. (Mitsui) of Japan, and General Electric Capital Corporation (GECC) of the US—formed a consortium, known as the BMMG[71] Consortium, to bid on the project.

Despite BHP, only one other Indonesian company was pre-qualified to bid on the project, which is PT Bimantara Bayu Nusa (BBN). BBN, together with its foreign partner, Intercontinental Electric Incorporated (IEI) of the US, formed a consortium known as the BNIE [72] Consortium, to bid on the project.

In October 1991, the GOI stated that the Paiton I project would be awarded to the BNIE Consortium. However, in May 1992, the GOI announced that it had reconsidered its decision and invited the BMMG Consortium to negotiate for the project[73]. This announcement, noticing the advantages of having a single consortium build units 5 through 8 of the Paiton complex, encouraged the BMMG Consortium to include members of the BNIE Consortium to achieve a least cost approach in constructing these four units; however, the discussions about combining the two consortia failed, leading to

70 BHP is an Indonesian company having interests in cement manufacturing, petrochemicals, and energy associated contracting.
71 BMMG = BHP, Mission, Mitsui, and GECC.
72 BNIE = Bimantara Group and Intercontinental Electric
73 This reconsideration was the result of continuing debate by GOI Ministers about the appropriateness of the award to the BNIE Consortium. The ministers reportedly believed that the BMMG Consortium's bid was technologically superior and offered a lower kWh price (Driseoll, 1999).

discussions between BHP and BBN about BBN's acquiring an interest in BHP—which also failed[74].

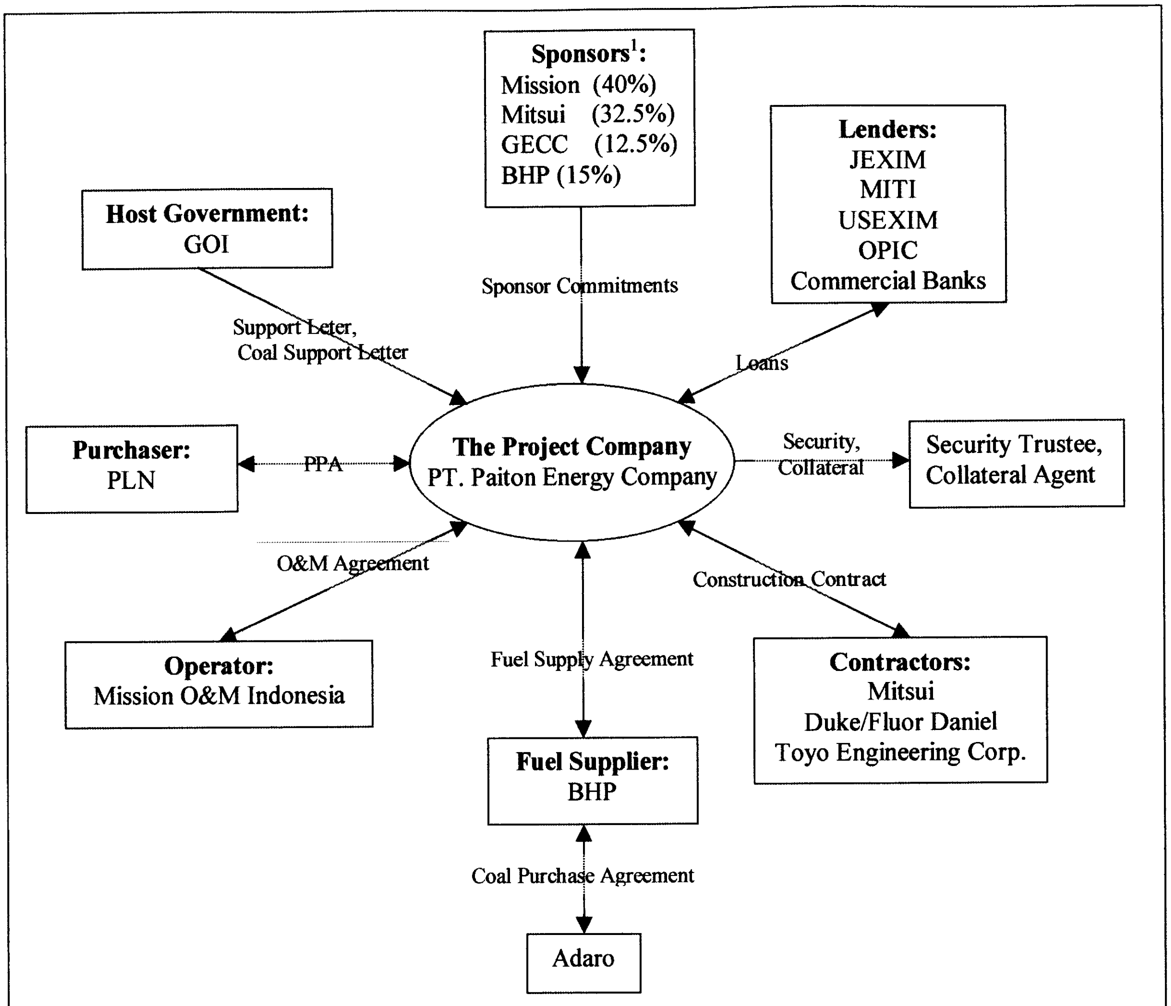
In September 1992, the GOI eventually awarded the Paiton I project to the BMMG Consortium. Formal negotiations[75] over the terms of PPA for the Paiton I-generated power took place over 18 months, and were reported to receive a high attention from the US government[76], in addition to several meetings being held by the chairman of BHP and Suharto, the Indonesian President at that time[77]. In 1994, the BMMG Consortium formed PT. Paiton Energy Company (PEC), the Project Company for the purpose of developing the Paiton I project. Figure 3.1 shows the initial contractual structure of the project participants.

74 A letter dated May 6, 1999 from Robert E. Driseoll, the Senior Vice President of the Asia Pacific Region of Edison Mission Energy, to Ralph A. Matheus, the Acting Vice President for Finance of OPIC.

75 "Paiton Energy Company—Fact Sheet (Paiton Swasta I)", source of information: OPIC. In the negotiations, the GOI was advised by a team of internationally recognized consultants including three financial advisors (Lazard Freres, S.G. Warburg, Lehman Brothers), technical advisors (Lahmeyer International), legal counsel (White & Case) and a senior international power specialist sponsored by the USAID.

76 *The Asian Wall Street Journal*, February 14, 1994, stated that "Progress [on the pricing of Paiton I] may have been helped by the January visit of three U.S. official delegations, including one led by Treasury Secretary Lloyd Bentsen, which talked to Indonesian officials about Paiton." (Wells, 1999). See also Peter Waldman and Jay Solomon, "US Deals in Indonesia Draw Flak", *The Asian Wall Street Journal*, December 24, 1998.

77 *The Asian Wall Street Journal*, February 14, 1994, reports that the chairman of BHP, who was the brother-in-law of Suharto's daughter, met several times with Suharto, the Indonesian President at that time, to expedite the negotiations for the contract (Wells, 1999).



[1] Mission, Mitsui, GECC, and BHP initially had, respectively 32.5%, 32.5%, 20%, and 15% ownership interest in PEC. On January 30, 1996, GECC transferred 7.5% of its initial holding to Mission, leaving GECC with 12.5% ownership interest.

Figure 3.1:Contractual Relationship of the Paiton I project[78]

3.4. Project Participants

1. Project Sponsors

The Paiton I project is developed by PEC, a joint venture whose sponsors are the following companies:

1) Edison Mission Energy (Mission)[79]

---

[78] Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998; CS First Boston Chase Securities, Inc., "Confidential Offering Circular for the Paiton I proposed bond offering", March 21, 1996.

2) Mitsui & Co., Ltd. (Mitsui)[80]

3) General Electric Capital Corporation (GECC)[81]

4) P.T. Batu Hitam Perkasa (BHP)[82]

PEC shareholders are BHP and subsidiaries or affiliates of Mission, Mitsui, and GECC. These subsidiaries were established specially for the purpose of the project. The subsidiaries with their ownership interests[83] in PEC are as follows:

1) Mission Indonesia B.V.[84] had 40% ownership interest.

2) Paiton Power Investment Co., Ltd.[85] had 32.5% ownership interest.

3) Capital Indonesia Power I C.V.[86] had 12.5% ownership interest[87].

4) BHP[88] had 15% ownership interest.

---

79 Edison Mission Energy (Mission), formerly named Mission Energy Company (MEC), is a wholly owned indirect subsidiary of Edison International (formerly Southern California Edison Corporation), a California corporation which is a US public utility holding company. Mission, through other subsidiaries, owns an interest in 54 power-generating facilities throughout the world. In 1996, Moody's and S&P rated Mission's outstanding senior debt Baa1 and BBB+ respectively. Mission's net income was US$ 64 million on revenues of US$ 467 million and its outstanding capitalization as of December 31, 1995 was US$ 1,028 million. (Confidential Offering Cicular, 1996).

80 Headquartered in Tokyo, Japan, Mitsui & Co., Ltd. (Mitsui) is a business conglomerate actively involved worldwide as an organizer of international business ventures designed to link sources of supply with demand. Mitsui has undertaken various infrastructure and power plant construction projects around the world. In 1996, Moody's rated Mitsui's outstanding debt A1. Mitsui's net income and outstanding capitalization as of March 31, 1995 was 21,794 million Japanese Yen and 179,326 million Japanese Yen respectively. (Confidential Offering Circular, 1996).

81 General Electric Capital Corporation (GECC) is involved in various commercial, industrial, and financial activities. GECC's outstanding senior debt is currently rated Aaa by Moody's and AAA by S&P. GECC's net earnings were US$ 1,918 million on earned income of US$ 16,923 million. Its outstanding capitalization as of December 31, 1994 was US$ 99,431 million consisting of debt and equity. (Confidential Offering Circular, 1996).

82 P.T. Batu Hitam Perkasa (BHP), a limited liability company formed under the laws of the Republic of Indonesia, is owned by P.T. Tirtamas Majutama (33.33%), P.T. Swara Bumi (33.33%), P.T. Catur Yasa (22.22%), and P.T. Wahanaputra Aluraya (11.11%). Established in 1989, BHP's primary activities were related to its role as a shareholder of and fuel supplier to PEC. (Confidential Offering Circular, 1996).

83 The ownership interests listed are those after January 30, 1996.

84 Mission Indonesia B.V. a limited liability company formed under the laws of the Netherlands, is a wholly owned indirect subsidiary of Mission.

85 Paiton Power Investment Co., Ltd., a limited liability company formed under the laws of Japan, is a wholly owned subsidiary of Mitsui.

86 Capital Indonesia Power I C.V., a limited partnership formed under the laws of the Netherlands, is an indirect, wholly owned subsidiary of GE, the parent of GECC.

87 The ownership interest of GE's subsidiary was eventually sold out to Canadian Trans. Pipe Company.

The sponsors provided equity contributions and subordinated loans[89]. They also provided the funding of contingencies and cost overruns in the amount of up to US$ 300 million[90], which is not included in the total project cost.

To facilitate BHP's 15% equity contribution, the other three sponsors extended loans to BHP to be repaid out of BHP's dividends from the project. Until loans are repaid in full, BHP is permitted to receive 35% of the dividends to which it otherwise would be entitled[91].

2. Host Government

The Paiton I project was built with no guarantees from the Indonesian government. The GOI, however, issued two kinds of support letter:

1) The PPA Support Letter

The Indonesian Minister of Finance issued a letter of support with respect to PLN's payment obligation under the PPA entered into by PEC and PLN. This letter states that the GOI will cause PLN to discharge its payment obligations under the PPA, which are due and payable and unsatisfied by PLN[92].

---

88 BHP, a limited liability company formed under the laws of the Republic of Indonesia, is a special purpose company formed by the Indonesian sponsors of the Paiton I project.

89 In this thesis, both equity contributions and subordinated debt together will be called equity contributions (or equity) only.

90 The US$ 300 million consists of US$ 175 million overrun equity and US$ 125 million contingent overrun equity. (Confidential Offering Circular, 1996)

91 A letter dated May 6, 1999 from Robert E. Driseoll, the Senior Vice President of the Asia Pacific Region of Edison Mission Energy, to Ralph A. Matheus, the Acting Vice President for Finance of OPIC.

92 Minister of Finance of the Republic of Indonesia, The Support Letter dated March 2, 1994, the second paragraph:

> "In consideration of Seller entering into the PPA, the Government of the Republic of Indonesia will cause PLN, its successors and permitted assigns, to discharge PLN's payment obligations under the PPA which are due and payable and unsatisfied by PLN".

This support letter is actually in accord with a Presidential Decree of the Republic of Indonesia Number 37 of 1992[93]. This decree states that private investment in electric power generation will *only* be undertaken with no guarantee from the GOI with respect to the capital invested and any debt repayment obligation[94].

2) The Coal Support Letter

With respect to the Coal Cooperation Agreement[95], the Indonesian Directorate of Coal issued a letter to PEC stating (i) that the GOI will not terminate the agreement with Adaro[96], due to a default under the agreement without first giving Adaro, PEC, and BHP an opportunity to cure the default; (ii) in the event that either the agreement is terminated or Adaro is replaced, any new company replacing Adaro will honor the Fuel Supply Agreement[97] and the Coal Purchase Agreement[98], and (iii) should there be a problem in the supply of coal to the project, the GOI will assist PEC and BHP in obtaining coal supply.

93 Prior to this decree, there was no specific legal authorization for PLN to purchase power from private suppliers (Gooding, 1995).

94 Dinas Peraturan dan Perundang-undangan: Divisi Humas PLN Pusat. "Keputusan Presiden Nomor 37 tahun 1992 tentang Usaha Penyediaan Tenaga Listrik oleh Swasta: Pasal 5". July 9, 1992.

95 The Coal Cooperation Agreement is an agreement entered into by P.T. Adaro Indonesia (Adaro) and PT. Tambang Batubara Bukit Asam (TBA), an Indonesian coal mining company, under which Adaro has the right to mine the coal reserves found within the Tutupan area in South Kalimantan (Confidential Circular Offering, 1996).

96 P.T. Adaro Indonesia (Adaro), under a Coal Purchase Agreement, sells coal to BHP, the coal supplier to the Paiton I plants.

97 The Fuel Supply Agreement is an agreement between PEC and BHP, which provides that BHP shall be an exclusive coal supplier to the project. (Confidential Circular Offering, 1996)

98 The Coal Purchase Agreement is an agreement between Adaro and BHP, under which Adaro has agreed to sell to BHP all of the coal BHP is required to deliver under the Fuel Supply Agreement. (Confidential Circular Offering, 1996)

3. Project Lenders

Senior debt for the project was provided by lenders consisting of the following financial institutions[99]:

1) The Export Import Bank of Japan (JEXIM)[100]

   The JEXIM credit facility consists of a JEXIM direct loan (the tranche A loan) and a co-financing by a syndicate of International commercial banks (the tranche B loan). The tranche B loan is insured for political and commercial risk by the Ministry of International Trade and Industry of Japan (MITI) and Mitsui. MITI provides political risk insurance on 97.5% of the principal amount of the tranche B loan. The commercial risk covers 95% of the principal amount of the tranche B loan (provided 75% by MITI and 20% by Mitsui)[101] in case of PLN's default to fulfill its payment obligations under the PPA.

2) The Export Import Bank of the United States (USEXIM)

   The USEXIM credit facility consists of loans funded by international syndicate of commercial lenders. The facility is guaranteed against certain political risks by USEXIM on a 100% basis of the loans' principal amount.

3) The Overseas Private Investment Corporation of the US (OPIC)

   The OPIC credit facility consists of a direct loan by OPIC, which is funded from the sale of certificates of participation issued and guaranteed by

---

[99] CS First Boston Chase Securities, Inc., "Confidential Offering Circular for the Paiton I proposed bond offering", March 21, 1996.

[100] JEXIM or Japan's Bank for International Corporation (JBIC).

[101] MITI provided only 75% insurance because the Japanese government was unsatisfied with the lack of guarantee by the GOI, which only provided a support letter; as a result, Mitsui should guarantee the remaining portion (Lang, 1998).

OPIC evidencing interests in payments due by PEC in respect of the loan. The OPIC facility is uncovered for political and commercial risk.

4) Rule 144A[102] Bond financing market.

The initial purchasers of the bonds[103] are CS First Boston Corporation, Chase Securities, Inc., BA Securities, Inc., Barclays de Zoete Wedd Securities Inc., Credit Lyonnais Securities (USA) Inc., and UBS Securities LLC. This financing is also uncovered for political and commercial risk.

5) Commercial Lenders

The commercial bank facility, which is a contingent standby facility in the amount of US$ 93,750,000, consists of a direct loan provided by a group of commercial lenders. This facility is available for funding 75% of cost overruns after the US$ 175 million overrun equity provided by project sponsors is fully utilized[104].

The ADB was actually considering a US$ 50 million loan to the project; however, they were cautious about the Indonesian first family involvement in the project[105].

4. Power Purchaser

In February 12, 1994, PEC and PLN signed a PPA for the construction, ownership, operation, management, and maintenance of the Paiton I project. The PPA

---

102 Passed in 1990 by the Securities and Exchange Commission (SEC), Rule 144A is designed to provide exemption from the Securities Act's registration requirements for resale of certain restricted securities to qualified buyers.

103 Moody's and S&P rated the Paiton I bonds Baa3 and BBB respectively.

104 Utilization of this facility is dependent on the GOI's approval to increase non-Indonesian borrowing above the current approved limit of US$ 1,820 million (the debt-financing amount).

105 Suharto's decond daughter and her brother in law have a combined indirect 2.5% interest in the project through their investment in BHP. They also have minor ownership in two of the companies involved in the coal supply chain. (Frederick, 1994).

was on a *take-or-pay* basis by which PLN would purchase the Paiton I plants' entire output for 30 years starting from the plants' commercial operation date, which was May 21, 1999. PLN was the only customer of PEC; therefore, PLN's payments under the PPA were the sole source of PEC's revenues. The operation and maintenance of the plants, the debt repayments, and the equity returns were dependent upon PLN's ability to fulfill its payment obligations. Any occurrence or circumstances that may reduce or suspend PLN's payments would adversely affect PEC's ability to pay the debt.

PLN's ability to meet its payment obligations generally depended on its financial condition. As mentioned earlier, the GOI issued a support letter to PEC, which provides that the GOI would cause PLN to discharge its PPA payment obligations. The letter, however, is not a guarantee of payment; it did not indicate any financial responsibility of the GOI in case of PLN's default.

PLN system consisted of two main divisions: the Java-Bali[106] grid and the Outer Islands[107] grid, with the Java-Bali grid accounting for 80% of PLN's total revenue[108] and being consistently profitable; the Outer Islands, however, were uneconomic. The Paiton I plants would contribute to the Java-Bali grid system via the East Java grid.

5. Contractors

The design, engineering, procurement, construction, start-up, testing, and commissioning of all of the Paiton I plant facilities were awarded to a consortium of

---

106 In Java-Bali grid, generation and transmission are managed by two units (Western Java and Eastern Java-Bali) while distribution is organized into four regions (West Java, Central Java, Jakarta, and Eastern Java-Bali).

107 The Outer Islands grid consist of hundreds of small and isolated system organized into 11 geographic regions: four on Sumatra, two on Kalimantan, two on Sulawesi, and three representing other islands or group of islands.

108 The electricity tariffs at which PLN is legally authorized to charge customers are regulated by the GOI.

contractors consisting of Mitsui, Duke/Flour Daniel International Services[109] (Duke/Fluor Daniel), and Toyo Engineering Corporation[110] (Toyo) under a fixed-price, turnkey construction contract, with a certain completion date which is May 21, 1999, the Commercial Operation Date (COD). Under the contract, the consortium was obligated to pay liquidated damages to PEC in the event of certain delays in completion or the plant's failure to meet the guaranteed performance levels.

Each consortium member undertook the following responsibilities[111]:

1) Mitsui is the consortium leader with overall commercial, financial, procurement, and shipping responsibilities.
2) Duke/Fluor Daniel is responsible for the power block area and overall plant schedule, coordination, test, start-up, and training. Its obligations are guaranteed by Fluor Corporation and Church Street Capital Corporation.
3) Toyo is responsible for the non-power block area. It also undertook the responsibilities of site general sub-contractor.

In addition, Burns and Roe Company[112] carried out the plant conceptual design on behalf of the consortium.

While the initial site preparation began in September 1994, the project construction started in April 1995 and was scheduled for completion in 49 months. The

---

109 Duke/Fluor Daniel is a Nevada general partnership. The partners are Duke Coal Project Services Pacific, Inc., a Nevada corporation, and Fluor Daniel Asia, Inc., a Californian corporation. Duke/Fluor Daniel is actively involved in the engineering, construction, operation and maintenance of electric generation facilities worldwide.

110 Toyo, a corporation under the laws of Japan, specializes in design, equipment procurement, and construction of processing plants. Toyo is engaged in various plant projects worldwide.

111 CS First Boston Chase Securities, Inc., "Confidential Offering Circular for the Paiton I proposed bond offering", March 21, 1996.

112 A company under the laws of New Jersey, USA.

project had been delivered on time; units 7 and 8 had been ready for operation since May 1999 and August 1999 respectively.

For the operation and maintenance of the plants, PEC entered into an Operation and Maintenance Agreement with P.T. Mission Operations and Maintenance Indonesia (Mission O&M Indonesia), a subsidiary of Edison Mission Operation and Maintenance, Inc. (MOMI)[113]. The obligations of Mission O&M Indonesia under the agreement are guaranteed by MOMI.

6. Suppliers

1) Equipment Suppliers

The steam generators for this project were supplied by Asea Brown Bovery– Combustion Engineering (ABB-CE) while two identical steam turbine generators were supplied by GE. Moreover, ABB-Flakt supplied the seawater scrubbing system for the project, Hitachi supplied generator step-up transformers, and Cogelex supplied the 500 kW switchyard, among other suppliers.

2) Fuel Supplier

BHP would supply[114] the plants' coal requirements pursuant to a 30-year Fuel Supply Agreement entered into with PEC. BHP would purchase the coal from PT. Adaro Indonesia[115] (Adaro) pursuant to a Coal Purchase Agreement with Adaro. Adaro has the rights to mine coal in the Tutupan area in South

[113] MOMI, wholly owned by Mission, operates and maintains projects in which Mission has an ownership interest.

[114] BHP's supply obligation include coal for start-up operation.

[115] Established in 1982 as a foreign investment company under the laws of the Republic of Indonesia, Adaro is a coal mining company.

Kalimantan pursuant to a 30-year Coal Cooperation Agreement (CCA) with PT. Tambang Batubara Bukit Asam (TBA), the state coal mining company. As mentioned earlier, with respect to CCA, the GOI issued a coal support letter.

3.5. Financing Structure

The base cost of the project totaled US$ 2.5 billion, with additional US$ 300 million sponsors-provided funding for contingencies and cost overruns, as shown in table 3.1. The base cost was financed on a *non-recourse* basis with sponsors' equity contributions and lenders' senior debt.

Table 3.1: The Project Cost Breakdown[116]

Project Cost Breakdown	US$ Million	% of Total Base Cost
EPC Construction Contract	1,772.30	70.9%
Value Added Taxes	53.70	2.1%
Interest During Construction	308.20	12.3%
Up-front Financing Fees	144.30	5.8%
MITI Fee	12.30	0.5%
Commitment Fee	29.30	1.2%
Agency Fees	3.70	0.1%
Development Expense	43.20	1.7%
Development Fee	11.80	0.5%
Owner's Engineer	15.00	0.6%
Operation and Maintenance Staffing	15.00	0.6%
Working Capital	25.30	1.0%
Insurance	30.00	1.2%
Administration Cost	26.00	1.0%
Pre-Completion Labor	6.60	0.3%
Contingency	3.30	0.1%
Total Base Project Cost	**2,500.00**	**100.0%**
Contingencies and Cost Overruns	300.00	

Similar with other power generation projects and construction projects in general, the majority of the base project cost is construction cost, which is around 70% of the total

[116] Confidential Offering Circular, 1996

cost. The second largest expense is financial cost[117], almost 20% of the total cost, while the remaining 10% includes development expense, insurance, administration cost, and working capital.

Table 3.2 shows the overall financing plan for the project. 72.80% of the total base project cost is debt financed while the remaining 27.20% is equity financed. This financing structure is comparable with other IPP projects, which have been highly leveraged, with an average debt-equity ratio being 76 to 24[118].

Table 3.2: The Breakdown of the Project Financing Plan[119]

Financing Sources	Cost US$ Million	Percentage of Total Base Cost
Senior Debt		
JEXIM Facility		
Tranche A	540.00	21.6%
Tranche B	360.00	14.4%
USEXIM Construction Facility	540.00	21.6%
OPIC Facility	200.00	8.0%
Bonds	180.00	7.2%
Total Senior Debt	**1,820.00**	**72.8%**
Subordinated Debt		
Mission	176.00	7.0%
Mitsui	143.00	5.7%
GECC	55.00	2.2%
BHP	-	0.0%
Total Subordinated Debt	374.00	15.0%
Equity		
Mission	122.40	4.9%
Mitsui	99.45	4.0%
GECC	38.25	1.5%
BHP	45.90	1.8%
Total Equity	306.00	12.2%
Total Base Project Equity	**680.00**	**27.2%**
Total Base Project Cost	**2,500.00**	**100.0%**

117 Financial cost consists of interest during construction and debt instrument fees. For the Paiton I project, debt instrument fees consist of up-front financing fees, MITI fee, and commitment fee.

118 Albouy, Yves, and Reda Bousba, "The Impact of IPPs in Developing Countries—Out of the Crisis and into the Future," *Public Policy for the Private Sector*, The World Bank Group, December 1998.

119 Confidential Offering Circular, 1996.

3.5.1. Breakdown of Debt Financing

Table 3.3 shows breakdown of debt financing while table 3.4 shows the applicable interest rates during the loans' tenor. The debt financing came from multi sources, of which the ECAs[120] contributed 79.1% of the total debt: 49.4% from JEXIM tranche A and B, and 29.7% from USEXIM. The construction contract was financed by foreign currency loans from these two sources. This was actually the first time that JEXIM had taken construction risk[121].

Table 3.3: The debt-financing breakdown

Debt Financing Sources	Principal Amount US$ Million	Percentage of Total Debt
JEXIM Facility		
Tranche A	540.00	29.7%
Tranche B	360.00	19.8%
USEXIM Facility	540.00	29.7%
OPIC Facility	200.00	11.0%
Bonds	180.00	9.9%
Total Debt Financing	**1,820.00**	**100.0%**

Table 3.4: Interest rates during the loans tenor[122]

Debt Sources	Interest Rates				Repayment Years
	PreCompletion	Years 1-4	Years 5-8	Years 9-12	
JEXIM					
Tranche A	9.44%	9.44%	9.44%	9.44%	1999-2011
Tranche B	4.88%	11.13%	11.25%	11.38%	1999-2011
USEXIM	9.38%	11.50%	11.50%	11.50%	1999-2011
OPIC	6.18%	12.29%	12.29%	12.29%	1999-2011
Bonds	10.46%	10.46%	10.46%	10.46%	2008-2014

120 JEXIM and USEXIM

121 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

122 Confidential Offering Circular, 1996

3.5.2. Breakdown of Equity Financing

Table 3.5 shows the total equity financing consisting of equity and subordinated debt, and the percentage of each sponsor's ownership interest. The percentage of ownership interest is proportional to that of equity alone; however, the percentage is not proportional to that of subordinated debt since BHP is exempted from providing subordinated debt.

Table 3.5: The equity financing breakdown.

Project Sponsors	Total Equity Financing				Ownership Interest
	Subordinated Debt		Equity		
	US$ Million	%	US$ Million	%	%
Mission	176.00	47.1%	122.40	40.0%	40.0%
Mitsui	143.00	38.2%	99.45	32.5%	32.5%
GECC	55.00	14.7%	38.25	12.5%	12.5%
BHP	-	0.0%	45.90	15.0%	15.0%
Total	374.00	100.0%	306.00	100%	100.0%

3.6. The Paiton I Model PPA[123]

The PPA specifies the rights and obligations of PLN and PEC relating to, among others, the development, financing, construction, testing, and commissioning of the Paiton I project; the operation and maintenance of the plants; the tariff structure consisting of capacity and energy payments; the allocation of risks in the event of force majeure and changes in the regulatory environment; events of default; rights of termination and the associated consequences; and dispute resolution.

A detailed analysis of the entire PPA provisions is beyond the scope of this thesis. However, several sections of PPA provide the basic understanding to the mechanism of risk sharing between PEC and PLN. Most importantly, these sections relate closely to the

123 Confidential Offering Circular, 1996

issues of the "investor friendly" provisions, the thesis' main concerns discussed earlier. In the Paiton I model PPA, these "investor friendly" issues are embodied in the provisions related to the *take-or-pay* tariff structure, terms of payment, force majeure, and tariff adjustments. These provisions and the agreed dispute resolution are explained in this chapter while the detailed analyses are provided in later chapters.

3.6.1. Tariff Structure

The electricity tariff comprises four components consisting of two capacity components (components A and B) and two energy components (components C and D). Under the PPA, PLN is obligated to make the capacity payments irrespective of dispatch levels, but subject to the availability of the plants. This obligation represents the *take-or-pay* mechanism of the Paiton I model PPA. Regardless the delivery of power[124], as long as the plants are able to produce the electricity available to PLN, PLN is obligated to pay fixed capacity charges. The energy payments, on the other hand, are payable based on the actual amount of power delivered to PLN.

1. Capacity Component A

Component A provides for debt service requirements, Indonesian taxes, and the return on equity to sponsors. The capacity charge rates of component A are as follows:

1) Step 1 (Year 1-6) : Rp. 1,092,596 per kW-year
2) Step 2 (Year 7-12) : Rp. 1,065,816 per kW-year
3) Step 3 (Year 13-30) : Rp. 553,439 per kW-year

---

124 but subject to the plant availability

Component A is protected in US Dollars term against exchange rate fluctuation by indexation factors linked to the Rupiah/US Dollar exchange rate; there is, however, no inflationary increase to this component. The actual value of this component is dependent on the plant availability according to an annual availability schedule agreed upon in the PPA. The average annual contracted availability over the 30-year term of the PPA is 83%. If actual availability is less than the contracted level, the component will be proportionally reduced. However, if actual availability exceeds the contracted level, a bonus payment of 50% of the incremental value of the component will be given to PEC.

2. Capacity Component B

Component B is set to recover the estimated fixed operation and maintenance costs that are not dependent on the amount of the electricity generated, such us insurance, O&M management, and certain labor costs. The capacity charge rates of component B consist of a local element (Rp. 38,830 per kWh in 1998) and a foreign element (Rp. 38,830 per kWh in 1998). In other words, the foreign element is approximately 50% of the total value of component B. The local and foreign elements are protected against inflation rate risk by indexation factors linked to changes, after 1998, in the Indonesian consumer price index and in the US consumer price index respectively. The foreign element is protected against exchange rate fluctuation by indexation factors linked to the Rupiah/US Dollar exchange rate. The total value of component B is adjusted for actual availability compared to contracted availability in the same way as that for component A.

3. Energy Component C

Component C is the fuel component, which is calculated, based on the price of Primary Supply Coal[125] (PSC) to be renegotiated annually. The price utilized in the PPA for calculation during 1997 was Rp 71.126 per kg, which would be adjusted on the first business day of 1997 to the extent the Rupiah/US$ exchange rate on that day differs from the PPA agreed base exchange rate of 2,038 Rupiah per US Dollar. After 1997, the coal price should be re-determined annually. The portion attributable to foreign currency costs, estimated at 60% of the coal price, is protected against exchange rate fluctuation by indexation factors linked to the Rupiah/US Dollar exchange rate. The total value of component C would be adjusted for the variance in actual specific heat rate compared to the agreed value of specific heat rate at contract capacity, which is 2,447 kcal/kWh. In the case of a coal supply force majeure event, the coal price and specific heat rate with respect to the Qualifying Alternate Coal[126] (QAC) will apply.

4. Energy Component D

Component D is to recover the variable operation and maintenance costs of the plants such as spare parts, chemicals, and other consumables. The variable O&M charge rates of component D consist of a local element (Rp. 4.356 per kWh in 1998) and a foreign element (Rp. 1.452 per kWh in 1998). In other words, the foreign element is approximately 25% of the total value of component D. The local and foreign elements

[125] Primary Supply Coal means all coal acquired from BHP pursuant to the Fual Supply Agreement, provided that in the case of BHP's failure to supply such coal, then Primary Supply Coal shall be the coal supplied under a modified coal supply plan, which is conditional of PLN's approval pursuant to the PPA.

[126] Qualifying Alternate Coal means coal which has quality and chemistry characteristics within ranges set forth in the PPA available for delivery to the plants in case the Primary Supply Coal, for certain reasons, is not available.

are protected against inflation by indexation factors linked to changes, after 1998, in the Consumer Price Index (CPI) of Indonesia and the US. The foreign element is protected against exchange rate fluctuation by indexation factors linked to the Rupiah/US Dollar exchange rate.

3.6.2. Terms of Payment

The tariff payments are denominated and made monthly in Rupiah. As previously mentioned, certain portion, if not all, of each tariff component is protected against currency exchange rate movement. With respect to this portion, the amount of Rupiah to be paid by PLN is determined based on the rate at which PEC is able to enter into foreign exchange contracts to convert this Rupiah amount into US Dollars. PEC's expense to settle the contracts is also reimbursed by PLN. In the case that PEC, after a specified period of time subject to certain condition set forth in the PPA, is unable to enter into such foreign exchange contracts, PLN ultimately becomes obligated to pay the agreed portion in US Dollars. As a result, this mechanism fully protects the foreign currency portion of PEC's tariff components from both exchange rate fluctuation risk and foreign exchange availability risk, transferring all these risks to PLN.

3.6.3. Force Majeure

Events of force majeure are conditions that are out of the reasonable control of the affected party. Under the PPA, these events include acts of war, insurrection, violent demonstration, acts of god, employee strikes or lockouts, governmental action, and a coal supply force majeure event, among others. While the occurrence of force majeure events affecting PEC may reduce payments to PEC, such events do not relieve PLN from meeting its payment obligations under the PPA. In the case of the occurrence of certain force majeure events that are not normally insured results in a material delay in completion and causes material damage to the plants, PEC and PLN should enter into good faith negotiations regarding tariff adjustment.

In the case that force majeure events affect PLN's ability to receive electricity from the plants or such events are resulted from governmental action affecting PEC's ability to deliver electricity to PLN, PLN will remain obligated to make capacity payments to the extent that PEC would have been able to deliver without such occurrence.

In the case of coal supply force majeure event, PLN is remain obligated to make capacity charges to the extent that PEC is required to limit output as a result of using QAC, or PEC is unable to obtain QAC because of PLN's unapproval, or PLN fails to deliver coal pursuant to its obligation under the PPA. If a disruption in the supply of Primary Supply Coal is the result of a Coal Supply Force Majeure Event, not resulting from a default by any party to any coal-related contracts, the price of QAC would be fully passed to PLN.

3.6.4. Tariff Adjustments

Under the PPA, tariff components should be adjusted following the occurrence of a triggering event resulting in material cost or saving to PEC. Such adjustments provide PEC with the same net, after-tax economic return, as if such costs had not been incurred and savings realized. Triggering event means: 1) a change in the interpretation or application of Indonesian law resulting in environmental requirements different from those initially agreed in the PPA, 2) other changes in Indonesian law (including changes relating to taxes, duties or levies), 3) any governmental actions which delay the equipment and supplies import, or 4) PLN's unexcused delay or default in performing its PPA obligations resulting in delay in project completion.

3.6.5. Dispute Resolution

Under the PPA, disputes between PLN and PEC, if cannot be settled by mutual discussions, would then be referred to a single expert (to be appointed by the International Chamber of Commerce's International Center for Expertise in the event PEC and PLN cannot agree to an expert).

Disputes that cannot be settled by mutual discussions, and referral to an expert is not required or elected by the parties, would be resolved by arbitration in Stockholm, Sweden under the UNCITRAL Rules of International Arbitration. In the arbitration, each party would appoint an arbitrator who would then jointly appoint the third arbitrator. The international arbitration decision would be final, binding, and un-appeal-able.

3.7. The Current Situation[127]

3.7.1. Economic Overview[128]

The Asian monetary crisis of 1997-1998 brought severe impacts to the Indonesian economy. The exchange rate of the Indonesian Rupiah to the US Dollars depreciated

[127] As of January 2001, the final write-up of the thesis
[128] CIA, "The World Factbook 2000: Indonesia".

sharply and was continuously volatile. To illustrate, the exchange rate prior to the crisis was hovering around Rp. 2,500 per US Dollar, while that during and after the crisis fluctuated in the range of 8,000 to 10,000 Rupiah per US Dollar. In response to the fall of the Rupiah, interest rates increased as high as 70%. Furthermore, in 1998, the real GDP growth was estimated to have declined by 13.7%, the sharpest decline of any major East Asian economy, while the inflation spiked up to over 70%.

In the wake of the crisis, the Indonesian economy stabilized in 1999. The real GDP showed some growth in the second half of 1999, although for the overall year it experienced a negative growth of –1.1%. The interest rates fell rapidly to the range of 10% to 15%. The high inflation was reduced to 2% by the GOI's implementing tight monetary policy. Even though the GOI forecasted economic growth[129] of 3.8% for fiscal year 2000/2001, the continuing uncertainties with respect to overall long-term economic growth would make it difficult for Indonesia to attract private investment in the near future.

3.7.2. Political Overview[130]

The instability of the Indonesian politics had further complicated the Indonesian adverse economic condition. In 1998, Soeharto, the Indonesian President who had been in power for more than three decades, stepped down following a reform towards democratic and decentralized government. His vice president, Habibie, took over the position and was in power only for a year, the transition period to an elected government. Following, Abdurrahman Wahid, the elected president in 1999, had been a legitimate

129 Since the 1970s, the average of Indonesian annual economic growth had been 7%.
130 CIA, "The World Factbook 2000: Indonesia".

president during the wake of the crisis, not to mention that, similar with the previous two governances, his governance was confronted by critics and challenges from opposition. The allegation of cronyism and corruption in the bureaucracies is one of the critical issues to be resolved.

In addition, Indonesia experienced political turbulence following the religious ethnic conflicts, the alleged human right violations by the military, and the growing pressures for independence in certain regions such as Aceh[131] and Irian Jaya[132]. Following the 30 August 1999 referendum in which most of the people of East Timor chose to be independent, the independent status of East Timor was formally established. In short, the GOI was confronted by the spread of violence as well as separatist movement, the challenges to be resolved if the country is to realize stability in economics and politics.

3.7.3. The Electricity Industry

The Indonesian economic downturn significantly reduced demand for exported products and internal consumption. A large number of industries slowed down and stopped their operations, resulting in a considerable decline in electricity demand. The optimistic scenario of a 19%-24% annual increase in electricity demand projected earlier in the 1994 National Electricity Plan turned out to be only the average of 14%[133]. Table 3.6 shows the projected and the actual demand during 1994 to1999 fiscal year.

---

131 Aceh is an oil ans gas rich province in north Sumatra, which is located in the strategically important Strait of Malacca.

132 Irian Jaya is a copper and gold rich province in eastern Indonesia, the country border between Indonesia and the Papua New Guinea.

133 Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim, "Mengapa Listrik Swasta Jadi Masalah? (Why do private power producers create problems?)", *Tempo*, 24 September 2000, page: 117.

Table 3.6: The projected and the actual demand in electricity, 1994-1999[134]

Year	Projection (MW)	% increase	Actual (MW)	% increase
1994/95	7,427		7,092	
1995/96	8,823	19%	8,110	14%
1996/97	10,717	21%	9,228	14%
1997/98	12,084	13%	10,016	9%
1998/99	13,348	10%	9,982	0%
1999/00	14,671	10%	11,356	14%
2000/01	16,037	9%	?	?

Because of the Rupiah depreciation and the demand decline, the US Dollar term and the magnitude of PLN's revenues (subsidized tariffs), which are earned in Rupiah, dropped significantly. However, the *take-or-pay* nature of the PPAs would keep PLN to remain obligated for making payments to IPPs, the payments of which accounted for the majority of PLN's financial burden. While the exchange rate that actually materialized during and after the Asian crisis was hovering around 8,000 to 10,000 Rupiah per US Dollar, most of the PPAs were signed with the agreed base exchange rate being around Rp.2,500 per US Dollar. With these large payment obligations and lost of revenues, PLN faced an option of shutting down some of its own power plants to accommodate the otherwise wasted IPPs-generated power[135]. The severe financial constraints and the dilemmatic problem to shut down its own plants led PLN to renegotiate the PPAs, namely the IPP Contracts Rationalization program.

The renegotiation program was intended to discuss the PPAs on mutually acceptable solutions in accord with the following considerations[136]: 1) the economic and social realities, and public acceptance, of the outcomes impacting on PLN and the GOI; 2) an electricity and demand balance consistent with good utility industry practices and

---

[134] P.T. PLN (Persero), Transmission and Java Bali Control Center, March 30, 2000.

[135] Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000.

[136] PT PLN (Persero), "Intention of PT. PLN (Persero) to Commence IPP Contracts Rationalization", *Press Release*, Jakarta, December 22, 1998.

system requirements; 3) legal rights and obligation of all parties; 4) Future private investment and business climate in Indonesia. (PLN Press Release, 1998)

The renegotiation, which was formally started in February 1999, had obviously been not as smooth as expected. For example, deals with two geothermal-based IPPs, the 60 MW (of 95 MW total) Dieng project and the 4x55 MW Patuha project[137], ended up in International Arbitration (IA), which then required PLN to pay the IPPs US$ 572 million[138] in damages for PLN's failure to honor its obligations[139]. Similarly, Florida Power and Lights Co., the majority owner of the Karaha Bodas geothermal power plant in West Java sued PLN for suspending its project[140]. Surprisingly, despite the agreed upon dispute resolution stating that the decision of the international arbitration is final, binding, and unappealable, the Central Jakarta District Court annulled the arbitration ruling[141] following PLN's filing the lawsuit[142]. Indeed, even if the arbitration decision were to be followed, PLN cannot afford the obligated payments. As a result, as demonstrated by these cases, the agreed upon international arbitration mechanism had failed to provide a mutually acceptable solution for both private and public parties.

---

137 According to MidAmerican Energy Holdings Co. (formerly known as CalEnergy Company)of the US, the majority owner of the Dieng project and the Patuha project, when the disputes were filed, the Patuha project had began construction of an 80 MW power generation unit at its Patuha plant and had developed proven geothermal resources of at least 170 MW (the Jakarta Post, May 1999)

138 US$ 391.7 million for Himpurna California Energy, the project company of the Dieng project, and US$ 180.5 million for Patuha Power Ltd., the project company of the Patuha project.

139 The Jakarta Post, "PLN ordered to pay U.S. company $572m in damages", May 06, 1999.

140 In 1997, the GOI announced that of the 27 signed PPAs, only 10 were permitted to proceed. Those 10 are Pare-pare, Salak (4,5,6), Sengkang, Paiton I, Paiton II, Dieng (1,2,3), Wayang Windu, Amurang, Sibolga A, Tanjung Jati B. (Source: PLN).

141 of the Dieng and Patuha project

142 The Jakarta Post, "Court annuls arbitration ruling against PLN", July 23, 1999.

3.7.4. The Paiton I Project Status

Regarding the unfavorable condition especially with respect to the Asian crisis, although the Paiton I plants had been completely built and ready for operation, PLN had not allowed the plants to start the operation, and PLN had made only a small partial payment of PEC's initial invoices. In line with the renegotiation program, in March 1999, PLN invited Paiton I to renegotiate. Through a letter dated April 22, 1999, PEC stated that it had agreed to sign the Confidentiality Agreement (CA) as a requirement to negotiate; however, in August 1999, PEC objected to sign the CA. Instead, PEC sent a notice of dispute to PLN in August 18, 1999. PLN viewed the issuance of this notice as a breach of an agreement in July 26, 1999 meeting whereby PEC agreed not to issue any dispute notice under certain requirements, which had been fulfilled by PLN. In September 1, 1999, PEC cancelled the dispute notice following the discussion of requirement for having a Standstill Agreement. Since the requirements were viewed by PLN as burdensome and not in accord with PLN's public accountability, the discussion stalled; as a result, in September 27, 1999, PEC re-issued a dispute notice again. (PLN Press Release, 1999).

In several meetings during October 1-4, 1999, the 30-day discussions under the dispute notice were postponed from October 5 to October 8, 1999. A meeting in October 6, 1999 was not formally held following PEC's refusal to agree on CA, which had been previously enforced during the October 1-4 discussions. In accord with the renegotiation intentions mentioned earlier, several main concerns that have been discussed include the following[143]:

1) PLN's public accountability under the prevailing social and economic condition of Indonesia.
2) The actual supply and demand of electricity indicating that the Paiton I-generated power was, at that time, unnecessary.
3) The Paiton I project cost that is perceived as relatively high if compared to other IPPs in the country[144], resulting in a high PPA payment obligations of PLN to PEC. In other words, the Paiton I project was considered too expensive for the country.

Despite the discussions, there had been allegations that the high project cost was the result of cronyism and corruption practices during the Suharto regime. For example, Badan Pengawasan Keuangan dan Pembangunan (BPKP), the state-owned supervisory board on monetary and development, indicated that the mark-up on the Paiton I project reached US$602 million, which is 41% of the Paiton I US$ 2.5 billion total project cost[145]. Indeed, there had ever been critics by members of parliament on the price of the Paiton I[146], the matters of which, after a long time of silent, eventually rose again. While the Paiton I project with the capacity of 2x615 MW cost a total of US$ 2.5 billion, the total cost of the 3x660 MW Guangzou project in China is US$ 1.9 billion, and the total

143 These three concerns were synthesized from the author's review of various press releases as well as other publicly available documents.
144 The Paiton I project would produce significantly more expensive power than PLN does. Thomas, Eapen, "A Beautiful Place to Develop", *Infrastructure Finance*, April/May 1995.
145 Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim. "Dapatkah PLN Lolos dari Jepitan Paiton?", *Tempo*, 24 September 2000. p. 117.
146 The Jakarta Post, "PLN Criticized over Pricing of Private Electricity", November 29, 1994; The Jakarta Post, "PLN Under Fire for Cooperation", February 14, 1995.

cost of the 2x609 MW Sual project in Pengasinan, Philippines is US$ 1.4 billion[147]. A 2100 MW power plant, the biggest power plant project in Malaysia, located in Pulau Lekir was expected to be fully operational by September 2003 with the estimated total cost of US$ 1.84 billion[148].

Apart from all the allegations, the discussions between PEC and PLN were unable to reach agreements on the concerns mentioned earlier. Therefore, in October 7, 1999, PLN[149] filed a lawsuit (to the Central Jakarta District Court) contesting the validity of the Paiton I PPA. In the suit, PLN argued that the contracted electricity price was above international standards as a result of bribery to politically well-connected people in Indonesia. An audit, conducted in late 1999 by a Canadian engineering and construction company SNC-Lavalin Group, priced the Paiton I EPC cost at US$ 1.033 billion (with a $\pm$ 20% tolerance), sharply lower than the EPC Cost of US$ 1.772 billion cited by PEC[150]. This audit was to be a key evidence in PLN's lawsuit against PEC; however, before PLN was able to present its case in court, President Wahid demanded PLN to withdraw the

---

147 Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim. "Dapatkah PLN Lolos dari Jepitan Paiton?", *Tempo*, 24 September 2000, page: 117.

148 Asian Power, "Malaysia Market Report: Restructure, Reform, and Reward", *Asian Power*, March/April 2000.

149 Reasoning that the material of the lawsuit is questioning the validity of the PPA rather than resolving any problems <u>related to the content</u> of the PPA, PLN argued that bringing the case to the Indonesian national court, instead of International Arbitration, was the right approach since the international arbitration is a dispute resolution for any problems <u>related to the content</u> of PPA, which is NOT the case in this matter.

150 Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000. See also Solomon, Jay, "Indonesian Audit Uncovers Inflated Cost of Power Plant", *The Wall Street Journal*, December 26, 2000.

case[151]. On January 20, 2000, the lawsuit was withdrawn; since then, the dispute resolution was to be pursued out of the court[152].

On February 21, 2000, PEC and PLN executed an Interim Agreement (IA) pursuant to which the PPA would be administered pending a long-term restructuring of the power purchase agreement[153]. The IA provided fixed monthly payments to PEC by PLN, the first of which was received on March 24, 2000, and the standstill of any further legal proceedings by either party during the IA's term, which run through December 31, 2000 and may be extended by mutual agreement[154].

Dr. Hartojo Wignjowijoto[155], the President Director of the Asian Pacific Economic Consultancy Indonesia, viewed that the Interim Agreement did not provide a long term and sustainable approach; instead, it only deferred the payment obligation of PLN[156]. In his argument, he presented his two perceptions. His first perception is that the main missions of foreign investors and international financial institutions in private electricity business is to gain as much profit as possible by developing two aspects: 1) political pressures through the gigantic power of the US after the cold war, and 2) increase leverage during contract negotiation by utilizing financial, legal, and technical consultants, as well as insurance scheme, among others. His second perception was that

---

151 Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000. See also Solomon, Jay, "Indonesian Audit Uncovers Inflated Cost of Power Plant", *The Wall Street Journal*, December 26, 2000.

152 President Director of PLN, Adhi Satriya, and Director of Planning of PLN, Hardiv Situmeang stepped down because of their disagreement with Wahid's approach to resolve the Paiton I problems out of court settlement.

153 Edison International, "Edison International Announces Interim Agreement on Paiton Power Plant", March 2, 2000. http://www.prnewswire.com

154 Ibid

155 Hartojo Wignjowijoto holds a PhD in Economics from Harvard University. He served as a chairman and a senior economist of the Asian Pacific Economic Consultancy Indonesia.

156 Wignjowijoto, Hartojo, "The Roles of Foreign Investors and International Financial Institutions in Electricity Sector," Session 1: The Roles of International Financial Institutions in Public Investments, Jakarta, *Seminar: Private Power Projects, Indonesian Corruption Watch in cooperation with PLN's Labor Organization*, October 12, 2000.

the regulations in Indonesia had been crafted to catalyze discretionary behaviors[157], rather than legal-based behaviors, of governmental actions. Based on these two perceptions, he viewed the IA of the Paiton I as a tool providing PEC with necessary time to strengthen its position and increase its leverage while gathering further support from the US as well as Indonesian institutions[158].

Apart from all the allegations, even though the Paiton I project had all the characteristics of a textbook finance case[159], the arrangements have been proved inefficient and rigid as to be unable to provide long-term solution in the event the initially anticipated situation changes sharply, the condition of which is likely to happen in developing world.

3.8. Chapter Summary

The Paiton I project is an example of private foreign investments that turn sour in times of crisis. Indeed, it is a perfect example of a well-crafted arrangement that provides favorable terms and conditions to foreign investors for the purpose of providing the investors with a stable financial return regardless the economic situation of the host country. When the economic situation materializes to be sharply adverse, as perfectly illustrated by the Asian crisis, a lot (emphasis added) of agreements need to be renegotiated. This phenomenon shows that the current practices have been somewhat flawed as to be too rigid and inflexible.

---

157 Discretionary behaviors depend on the level of intelligence as well as honesty of decision makers.

158 According to Wignjowijoto, the honesty of the Indonesian high level government officials—including the Minister of Finance, the Minister of Mines and Energy, and the President Director of PLN—with respect to the private electricity business had been questioned.

159 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

With respect to IPP projects, the risk sharing arrangement embodied in PPA contracts should be appropriately allocated. PPA contracts should not be imbalanced as to transfer to public parties most of the risks with a great deal of uncertainties. The analysis of the Paiton I project would lead to a proposed modification of the current PPA model. Even though the renegotiation mechanism itself is beyond the scope of this thesis, a proposed renegotiation approach to achieve a long term commercial solution—for project of similar problems—is developed to a certain extent. The later chapters would try to provide the answers, hopefully, to the level of our expectations.

Chapter 4: Project Risks Analysis

4.1. IPP Project Risks: Theoretical Background[160]

The key to successful project finance is risks management. Project risks should be properly assessed, allocated, and mitigated. The first step is to identify project risks (and the risk sources, if possible) that may exist in a particular project; then, the roles and responsibilities[161] of each project participant should be determined to figure out which party is in the best position to manage each type of risk. The next step is to allocate and mitigate the risks among parties via contractual agreements and hedging tools. The remaining risks left after the mitigation stage should be distributed to the project participants with mutually acceptable arrangements. Risks that cannot be allocated can still be ameliorated by the selection of proper credit enhancement and monitoring methods[162].

Project risks can be grouped into two broad categories, commercial risks and non-commercial risks or policy risks[163], as follows:

1) *Commercial risks* consist of project-specific risks and broader economic environment risks. Project-specific risks are risks related to the development, construction, operation, and maintenance aspects of the project, including identifying a market for the project output, while economic environment risks are

---

160 Synthesized from Ruster, Jeff, "Mitigating Commercial Risks in Project Finance", *Public Policy for the Private Sector*, The World Bank Group, February 1996; International Finance Corporation, "Project Finance in Developing Countries", Washington, D.C., 1999, pages: 38-58; Lang, Larry H.P.,"Project Finance in Asia", Netherlands, 1998, pages: 78-79.

161 Subchapter 2.2 discussed the roles and responsibilities of project participants typically involved in an IPP project , while subchapter 3.4 discussed those of the Paiton I project.

162 IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

163 Ibid

risks related to interest rate changes, inflation, currency risk, energy price risk, and all other risks beyond the control of the project sponsors that have a direct impact on the project.

2) *Non-commercial risks* consist of political risks including project-specific policy risks, and other uncontrollable events not included in political risks. While project-specific policy risks are risks arising from the actions of host government or public entities that materially affects the project (i.e. expropriation, regulatory changes, and failure of the government or public entities to perform contractual obligations), political risks are the project-specific policy risks and other uncontrolled political insecurities such as acts of war and civil disturbance. The other uncontrollable events such as acts of god and natural calamities, and political risks, both categories are usually referred in contracts as force majeure risks.

Another common approach to identify project risks is by grouping the risks based on the project phases. Beidleman, Fletcher, and Vesbosky group risks in general project finance into four categories, as follows[164]:

1) Development phase risks: technology risk, credit risk, and bid risk;
2) Construction phase risks: completion risk, cost overrun risk, performance risk, and political risk;
3) Operating phase risks: performance risk, cost overrun risk, liability risk, equity resale risk, and off-take risk;

[164] For detail description of risks associated in general project finance, see Beidleman, Carl L., Donna Fletcher, and David Vesbosky, "On Allocating Risk: The Essence of Project Finance", *Sloan Management Review*, MIT Sloan School of Management, Cambridge, Spring 1-9.

4) On-going risks: foreign exchange risk, interest rate risk, and inflation risk.

Either approach to grouping project risks, many project finance experts have discussed these risks in great detail including the description of the appropriate hedging tools to mitigate the risks and the mechanisms to ameliorate the remaining risks. The thesis, however, discusses only the critical risks typically encountered in an IPP project and the possible hedging mechanism, some of which are also familiar in general project finance. Appendix 1 of this chapter provides matrix for project risks and possible hedging tools for an IPP project.

4.1.1. Development, Design, Construction and Operational Risks

In the development stage, sponsors assess the project scope, seek approval from governments and authorities, and make attempts to attract financing. In this stage, the project sponsors are exposed to a high degree of risks since only their up-front capital is used to finance the initial undertakings of the prospective project. Risks in this phase arise usually because of unclear processes that may result in delays in project approvals and may even lead sponsors to abandon an otherwise sound project[165]. In this stage, the primary concerns were bidding risk, financing risk, and approval risk. Bidding risk is the possibility that the consortium might not win the project. Financing risk is the possibility that the project might not be able to attract financing from lenders. Approval risk is the possibility of opposition from both official and unofficial sources of the host country. Mechanisms used to mitigate these risks are dependent on the sophistication of sponsors in crafting their proposal. For example, to attract financing, sponsors might allow a

165 IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

relatively high interest rate for loan and high equity return for risks that they perceive as high when investing in developing world.

In the design stage, the main concerns are design risk and technology risk. Even if the consortium wins the project, there is still a possibility that the project might not be launched successfully because of unacceptable design (design risk) or unfamiliarity in technology (technology risk). Sponsors hedge these risks by contracting the project to contractors that have strong expertise and experience in undertaking similar projects. The contractors hedge technology risk by using well-proven technology.

In the construction stage, the primary concerns are completion and cost overrun risks. Completion risk is the risk of unable to complete the project on time while cost overrun risk is the risk that the actual construction cost becomes unexpectedly higher than the estimated cost. Delay in completion may lead to increases in interest costs and construction costs, resulting in construction cost overruns. Also of major concern is plant performance risk, which is the risk of plant's failure to meet specification at completion. In an IPP project, sponsors hedge these construction-related risks by entering into a fixed-price, certain-date turnkey construction contract with contractors that have strong expertise, experience, and reputation in constructing similar projects. The contract usually includes provisions for liquidated damages that specify penalties if the contractor fails to perform, and bonuses for better than expected performance. Project companies also hedge the cost overrun risk by making available standby financing[166] to ensure that any unexpected costs would not jeopardize the project.

In the operational stage the main concerns are cost overrun risk and plant performance risk. Cost overrun risk is the risk that the actual operating cost is

166 Standby financing may be provided by sponsors and/or lenders

unexpectedly higher than the estimated cost while the performance risk is the risk of the plant's failure to generate the amount of power agreed upon in the purchase agreement. This failure may result in lower revenue as well as liquidated damages obligation.

During both construction and operational stages, the project faces force majeure risk, which is the risk of project disruption because of uncontrolled events including acts of war, public disorders, explosion, and natural calamities, among others. To hedge force majeure risk—and also other on-going risks and unexpected events—, project company seeks insurance, which can come from national agencies (such as OPIC of the US and MITI of Japan), multilateral institutions (such as MIGA of the World Bank), or from private insurance agencies.

4.1.2. Market Risks

Market risks (or usually referred to as the off-take risk) are the risk that the actual revenue may not meet projected revenue. Market risks include demand risk and price risk[167]. Demand risk is the possibility that the actual demand of the project output, which is electricity, materializes to be far less than the projected demand, on which the calculation of the revenue and profitability were initially based on. Price risk is the possibility that the actual price of the project output—such as electricity—and the project input—such as fuel and other supplies—vary significantly from projection as a result of changes in demand for the project input/output as well as vulnerability of the world market price.

---

167 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

Market risks can be hedged by using such mechanisms as power purchase agreements, other off-take agreements, and call and put options. A long-term PPA can well mitigate these risks. However, if an IPP enters into a PPA only with a single power purchaser, for example a public electric utility, the reliance to a single purchaser is risky considering the risk of the purchaser's default. Similar to a PPA, an off-take agreement obligates the off-taker, which is often a sponsor, to purchase all or part of the project output; such agreements could be to buy up to a certain amount per year at the prevailing market price, buy enough to ensure debt payment, to provide foreign exchange for debt service, or to reduce foreign exchange risk[168]. Other market risk hedging tools are call and put options. A call option gives the project company the option to buy the plant input, for example fuel, at a fixed price in the future while a put option gives the company the option to sell its output, the generated power, at a fixed price in the future. Another commonly used mechanism is the fuel price pass through embodied in the PPA tariff structure, transferring the risk of fuel price fluctuation to the power purchaser[169].

4.1.3. Economic Risks

Economic risks include currency risks, interest rate risk, and inflation risk. Currency risks include currency convertibility/availability risk and exchange rate risk. Exchange rate risk is the risk of exchange rate fluctuation affecting the magnitude of local currency-denominated revenue with respect to the dollar-denominated payment obligation. Convertibility/availability risk is the risk that the local currency cannot be converted to the foreign currency, either because of unavailability of the currency

168 IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

169 In the Paiton I model PPA, the fuel price is renegotiated yearly; the fuel price fluctuation risk is transferred to PLN.

(availability risk) or because of government policy controlling the matter. Currency risks can be mitigated by a number of mechanisms[170]: mix local currency and foreign currency loans, index output prices to the exchange rate[171], swap currency, obtain contingency sponsor support, establishing an escrow account, and obtain government guarantee of foreign exchange availability.

Interest rate risk is the risk of unexpected increases in the interest rate during the maturity period of the project loans. This risk can be mitigated using several mechanisms[172]: negotiate a fixed interest rate, borrow at a floating rate to take the advantage of a later expected fall in interest rates, and swap interest rates.

Inflation risk is the risk of unexpected increases in inflation rate. The most effective tool to hedge inflation risk is to sign long-term supply and output contracts with price schedules[173]. Another commonly used mechanism is indexation factors linked to changes in country's CPI.

4.1.4. Political Risks

Political risks are risks related to any government actions, either project-specific or not, that could interfere the project, resulting in a loss or reduced profitability. Such actions can be expropriation of project assets, changes in regulations, failure to perform contract obligations, acts of war, and civil disturbance.

---

170 See IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

171 The hedging approach of indexing output prices to the exchange rate had been vulnerable if the exchange rate changes dramatically, as demonstrated by the Asian Crisis. The government or other contracting parties such as public utility was unwilling to honor the agreed upon indexing since it meant passing the currency risk to customers in the form of electricity tariff increases.

172 See IFC, "Project Finance in Developing Countries", Washington, D.C., 1999.

173 Lang, Larry H.P., "Project Finance in Asia", Netherlands, 1998.

Political risks, and other non-commercial risks, can be managed through insurance and guarantees, which can come from national agencies (such as OPIC of the US, MITI of Japan, and ECAs), multilateral institutions (such as MIGA), or from private insurance agencies[174]. The insurance policies usually include other unexpected events such as fire, acts of god, and natural calamities, the risks of which, together with political risks, are referred as force majeure risks. Even though insurance and guarantees are available in private market, the government backing of multilateral and bilateral agencies enables them to assume risk not acceptable to private insurers or guarantors; this kind of insurance and guarantees are referred as indirect government guarantees[175]. Whatever the source is, political risk guarantee is usually limited in its coverage, with the most commonly available policies being to insure against inconvertibility of earnings, civil disturbances, and expropriation[176].

Therefore, the investors usually ask for government direct guarantees, which is the government's financial responsibility under certain unexpected conditions. Such guarantees include government assurances of contractual obligations with financial responsibilities in the case of the responsible entities' default. For example, when foreign investors enter into purchase agreements with a public entity, the government would be responsible to make the agreed upon payments in case of the purchaser's payment default.

---

174 For thorough explanation on insurers and guarantors, see Razavi, Hossein, "Financing Energy Projects in Emerging Economies", Pennwell Books, Tulsa, Oklahoma, 1996.

175 Indirect government guarantees are explained subchapter 2.2. Roles and responsibilities of IPP project participants: host government. Indirect government guarantees also include government treaties and international treaties, which are agreements between the host government and the investors' government(s) to assure political securities for the investors with respect to their investments in the associated countries.

176 Wells, 1999

Despite involving international institutions mentioned above, attracting local participants into the project may also help mitigating political risk. Such participation can be in the form of sharing equity with local investors, borrowing from local lenders, or entering into purchasing agreement for with local suppliers[177]. Local interest in the project is believed to significantly reduce political risk.

4.2. The Paiton I Project Risks

Following the explanation of the previous section about risks typically involved in an IPP project, the following sections analyze the risks and hedging tools specifically involved in the Paiton I project. Appendix 2 of this chapter provides the risk assessment matrix and the hedging tools and/or mechanisms for remedy used in the Paiton I project, while appendix 3 provides the detailed of those risks and hedging tools of the Paiton I project.

4.2.1. Development, Design, Construction, and Operational Risks

1. Development Stage

Bidding risk, financing risk, and approval risk were assumed by project sponsors. Bidding risk was moderate. Since only two consortia were participating in the competition, there was a fifty-fifty chance that a consortium could win the project. This risk, however, increased with the bidding process lacking competition and transparency[178].

177 Razavi, Hossein, "Financing Energy Projects in Emerging Economies", Pennwell Books, Tulsa, Oklahoma, 1996.

178 Subchapter 5.1.2 provides thorough evaluation of the Paiton I bidding process.

Financing risk was somewhat greater for two reasons. First, even though equity contributions from the sponsors were assured, debt financing was complicated by country risk since the project was the first private IPP in the country without a sovereign guarantee from the GOI. Second, the involvement of the first family might discourage prospective lenders, which is the case with ADB[179], since the project might be put into hold in case of government change.

Approval risk was high since the Paiton I project was the first IPP project in Indonesia. The legal and regulatory framework was still in some respect incomplete[180] while the approval process was long and complicated[181]. A number of ministries—other than PLN and MME—had a strong interest in power projects, each of which had a numerous layers of bureaucracies that have to be passed through before any binding resolutions can be reached[182]. Indeed, President Suharto's intervention was required before any agreement could be reached[183]. Despite the fact that one of BHP's roles was to fulfill the GOI's requirement of at least 5% local shareholding, BHP[184] was expected to reduce the approval risk; in other words, the sponsors utilized BHP's local network to reduce the risk. In addition, the risk might also be reduced by the high support from the

179 ADB was actually considering a US$ 50 million loan to the project; however, they were cautious about the Indonesian first family involvement in the project. (Frederick, 1994).

180 Gooding, Gregory, Debevoise & Plimpton, "Indonesia", Power in Asia, September 1995. A review of the Paiton I project by the Frankfurt-based engineering firm Lahmeyer International stated that "The government of Indonesia initiated development of Paiton prior to developing either of these [policy and regulatory] frameworks" (Thomas, Eapen, "A Beautiful Place to Develop", *Infrastructure Finance*, April/May 1995).

181 Gilbert, Edward P.,"Getting Around in Indonesia", *Infrastructure Finance*, April/May 1995.

182 Ibid

183 Ibid

184 The chairman of BHP was the brother in law of Suharto's daughter. He conducted several meetings with Suharto to expedite the negotiations for the contract (ASWJ, February 14, 1994)

US government throughout the negotiation process[185]; the US government was involved in stressing the importance of the project[186].

2. Design Stage

Both the design risk and the technology risk were low. The project company, PEC, mitigated the risks by transferring the risks to the contractor consortium consisting of Mitsui, Duke/Fluor Daniel, and Toyo. As previously mentioned, these contractors have a strong experience and expertise in electric generating facilities worldwide. In addition to providing design warranty[187], the contractors allocated segments of these risks to suppliers, which also have a strong expertise, experience, and reputation. Furthermore, both the design and technology used in this project are not new; both have been well proven worldwide.

---

185 *The Asian Wall Street Journal*, February 14, 1994, stated that "Progress [on the pricing of Paiton I] may have been helped by the January visit of three U.S. official delegations, including one led by Treasury Secretary Lloyd Bentsen, which talked to Indonesian officials about Paiton." (Wells, 1999). See also Peter Waldman and Jay Solomon, "US Deals in Indonesia Draw Flak", *The Asian Wall Street Journal*, December 24, 1998.

186 The US Embassy in Indonesia gave extensive supports, especially to Mission, the US sponsor, through meetings arranged with high-level GOI officers. Ambassador Barry, the US Ambassador at that time, advocated continuously with various Ministers and Ministries. When negotiation appeared to be stalled, the Embassy arranged for a visit of the Indonesian Paiton Power Purchasing Negotiation Team to the US to meet with officials from the Departments of Commerce, Energy, and State, and USEXIM. In addition, Secretary Brown sent letters to decision makers, and made a phone call in support of the project to help pushing for final agreement (http://www.ita.doc.gov/td/advocacy/Mission.html).

187 The contractor warrants that the portion of the work constituting the design and engineering of the facilities will be free from defects and deficiencies, will be suitable for the purpose intended, will be in accordance with standards of care and diligence, will conform to the construction contract and generally accepted utility industry codes and standards (Confidential Circular Offering, 1996)

3. Construction Stage

Site availability risk was low. PLN, with the consent of the GOI, occupied the Paiton I site, and granted PEC the right to use the site[188]. PLN would also supply power and other utilities during construction at applicable tariff rates[189].

PEC allocated completion risk to the contractors by entering into a turnkey construction contract with a certain completion date[190]. The contractors, in turn, allocated segments of completion risks to the subcontractors and suppliers. The completion risk was considered moderate because even though the contractors and suppliers had a good reputation in constructing and servicing power plants worldwide, there was still certain risk of hidden conditions that may cause delay. The contractors were also entitled to an extension of the schedule of work in the case of changes requested by PEC, other PEC's delay or failure to perform its non-payment obligations, and force majeure events.

PEC hedge completion risk by having liquidated damages provisions embodied in the construction contract, obligating the contractors to make certain payments to PEC for certain delays in completion not excused by force majeure. However, if the contractors successfully completed the Net Dependable Capacity (NDC) Tests prior to the required completion date, a bonus in the amount of US$ 325,000 per day[191] would be payable by PEC to the contractors. However, if the contractors failed to complete the NDC test prior to the required completion date, the contractors should make liquidated damages in the

---

188 Confidential Offering Circular, 1996

189 Ibid

190 The plants should be ready for commissioning by May 21, 1999, the COD.

191 For each day from and including the date on which the contractors completed the Net Dependable Capacity Tests to but not including the required commission date. (Confidential Offering Circular, 1996)

amount of US$ 575,000 per day for each day the NDC test for both units were completed late[192].

Similar to completion risk, cost overrun risk was considered moderate as well. PEC hedged this risk by having the turnkey contract arranged on a fixed price basis[193]. In addition to insurance coverage[194], sponsors provided stand-by financing in the amount of US$ 300 million[195] for use in case of unexpected circumstances. A group of commercial lenders also provided a contingent standby facility in the amount of US$ 93,750,000[196]. The contractors were also entitled to an increase in the fixed sum in the case of changes requested by PEC, other PEC's delay or failure to perform its non-payment obligations, and force majeure events.

Another concern was plant performance risk prior to COD. This risk was considered low because the project used established design and technology. In addition to plant general warranties provided by PEC[197], PEC imposed liquidated damages payable by contractors for lower than expected performance[198].

---

192 Confidential Offering Circular, 1996

193 PEC agreed to pay a fixed price of US$ 1,772,300,000.

194 PEC was obligated to obtain and maintain insurance policies that cover against physical loss of or damage to permanent and temporary works under construction, including materials and equipments. Additional insurance coverage includes cargo insurance, legal liability insurance, and automobile liability insurance (Confidential Circular Offering, 1996).

195 The US$ 300 million consists of US$ 175 million overrun equity and US$ 125 million contingent overrun equity. (Confidential Offering Circular, 1996)

196 This facility is available for funding 75% of cost overruns after the US$ 175 million overrun equity provided by project sponsors is fully utilized.

197 The contractors warrant the work not included in the design warranty and the equipment and materials used in the work, except that the equipment and materials must be new according to the quality specified in the construction contract unless otherwise provided by PEC.

198 If the contractors failed to demonstrate that the facilities were in compliance with the requisite emissions limits with respect to SO_2 air emissions, the contractors agreed to pay PEC liquidated damages in the amount of US$ 750,000 for each MW by which the net electrical output must be reduced to comply with the emission limits (Confidential Offering Circular, 1996).

The contractors agreed to pay PEC liquidated damages in the amount of US$ 5 million for each MW by which the net electrical output of a Unit falls below 615 MW and US$ 130,000 for each kilo joule per kWh that the heat rate exceeds 10,088 kilojoules per kWh (Confidential Offering Circular, 1996).

4. Operational Stage

Cost overrun risk was considered moderate. PEC mitigated this risk by entering into operation and maintenance agreement with a fixed lump sum fee of US$ 15,000,000 (payable in monthly installments) during the pre-commercial phase[199], and an annual base fee of US$ 3,250,000 (payable in monthly installments) after the COD.

Plant performance risk was moderate. PEC imposed bonuses and/or penalties to the operator for higher and/or lower than expected performance respectively with respect to the target annual availability factor[200]. Furthermore, the operator was entitled to a compensation adjustment in the event that a change in law or other events occur—thereby increasing or decreasing the operation and maintenance cost to the operator—and PEC was entitled to an adjustment in tariff pursuant to the PPA.

Another concern was also the operator's performance, which is the possibility that the operator might not meet quality standards because of lack of technical and/or managerial skills. Having Mission O&M Indonesia, which had experience in operation and maintenance of similar plants worldwide, as the plant operator, would minimize this risk. Moreover, the obligations of the operator, Mission O&M Indonesia, were guaranteed by its parent company, MOMI.

Coal supply risk was minimal since the coal was provided from reliable coal reserves in Tutupan area in South Kalimantan. As mentioned earlier, BHP would supply

---

[199] After the commission date of unit 7 but prior to COD, PEC would pay the operator a fee of US$ 135,417 per month.

[200] The bonus payments for performance in excess of the target availability factor would be equal to 20% of the bonus payment received by PEC under the PPA, payable on an annual basis. If the annual availability factor is less than the target availability factor, the operator is responsible for a penalty in the amount fo 10% of the shortfall in revenues derived from capacity component A pursuant to the PPA (Confidential Offering Circular, 1996).

the coal pursuant to the Fuel Supply Agreement[201] entered into with PEC, and BHP would purchase the coal from Adaro, the coal mining company, pursuant to the Coal Purchase Agreement[202]. Adaro has the right to mine coal in the Tutupan area pursuant to the Coal Cooperation Agreement entered into with TBA. As previously mentioned, with respect to CCA, the GOI issued a coal support letter.

4.2.2. Market Risks

Demand and price risks of the project output were considered moderate. With respect to demand risk, while PEC might have relied on the Indonesia's optimistic projection of 19%-24% annual increase[203] in electricity demand, the actual increase materialized to be far more less than the projection, with the average of 14%. With respect to price risk, PEC might have relied on the possible increase of PLN's electricity tariffs to the consumers. These tariffs were regulated and subsidized by the GOI. Unfortunately, PLN was unable to measure and track the level of financial support actually provided by the GOI; besides, extensive cross-subsidies were embedded in the tariff structure[204]. Therefore, relying on tariff increase projection is very risky.

PEC transferred demand and price risks to PLN using the *take-or-pay* PPA that obligated PLN to buy the plant's entire output for the 30-year contract period. The *take-or-pay* mechanism set forth in the PPA obligated PLN to pay fixed capacity payments consisting of component A and component B, irrespective of dispatch but subject to the

---

201 Under the term of FSA, BHP would supply coal of 750,000 tons to 1.3 million tons quarterly, and 3 million tons to 4.5 million tons annually.

202 Adaro agreed to dedicate 130 million tons of coal, which satisfies the coal characteristics in the FSA.

203 The 19%-24% annual demand increase was the projection in the 1994 National Electricity Plan.

204 Price Waterhouse LLP, "Review of Indonesian Power Sector Development Issues", Energy Project Development Fund, USAID, May 1995.

availability of the plants. Component A would cover debt service requirements, Indonesian taxes, and the return on equity to sponsors while component B would cover the fixed operation and maintenance costs that are independent of the amount of the electricity generated. Under this arrangement, therefore, the revenues stream payable to PEC were assured regardless demand condition and vulnerability of the electricity market price. Most importantly, from the capacity payments, PEC would be able to cover its basic responsibilities with respect to lenders, project sponsors, and operation and maintenance of the plants. However, PEC's reliance to a single customer is risky since in case of the customer's default, PEC's revenue streams would entirely put in a halt unless alternative customer(s) could be identified.

Fuel price risk was considered moderate. PEC accommodated the fuel price fluctuation by renegotiating the price with the fuel supplier on an annual basis. However, PEC transferred this fuel price fluctuation risk to PLN through the pricing mechanism set forth in the energy component C of the PPA tariff structure, passing this fluctuation risk to PLN on a 100% basis.

4.2.3. Economic Risks

During the project inception, the currency exchange rate risk might be considered moderate to low since the exchange rate of the Indonesian Rupiah to the US Dollar had demonstrated a strong position; this position was projected to be steady in the near future. However, since the Asian crisis, the Rupiah depreciated sharply and was continuously volatile[205]. PEC transferred the exchange rate risk to PLN by indexation factors being linked to the Rupiah/US Dollars exchange rate and embodied in the tariff structure. The tariff components that are protected against the exchange rate risk are the portions attributable to the US Dollar cost, as follows:

1) The entire component A,
2) The foreign element of component B (approximately 50% of the total value of component B),
3) The foreign element of component C (approximately 60% of the coal price), and;
4) The foreign element of component D (which is approximately 25% of the total value of component D).

In other words, the foreign currency portion of the tariff components was protected against the exchange rate risk on a 100% basis.

Currency convertibility risk was low because since 1983, the GOI had had no currency controls and no limitations on holding or remittance abroad of foreign currency by Indonesian persons or companies[206]. Most importantly, the Presidential Approval Notification Letter (the "SPPP"), which served as the provisional license until a power plant is commissioned, granted the project company the right to convert Rupiah into foreign currency and to remit foreign currency to the foreign investors' home countries; this right should protect investors if the government imposes exchange controls in the future[207].

[205] To illustrate, the exchange rate prior to the crisis was hovering around Rp. 2,500 per US Dollar, while that during and after the crisis fluctuated in the range of 8,000 to 10,000 Rupiah per US Dollar.
[206] Gooding, 1995
[207] Ibid

Currency availability risk was considered moderate to high since there was a possibility that the foreign currency needed might not be available. During the Asian crisis, there were certain times when foreign currency availability was very limited. To mitigate the currency availability risk, PEC would enter into foreign exchange contracts. As mentioned earlier, PEC's expenses to settle the contracts is also reimbursed by PLN. In the case that PEC—after a specified period of time and subject to certain condition set forth in the PPA—is unable to enter into such foreign exchange contracts, PLN ultimately becomes obligated to pay the agreed portion in US Dollars. In other words, PEC transferred the availability risk to PLN.

Except for the USEXIM operation loan and the JEXIM tranche A loan, all of the debt facilities were variable rate based loans. To mitigate the impact of changes in interest rates on the floating rate debt, PEC entered into interest rate swap agreements.

Inflation risk was moderate to high. PEC transferred the inflation risk to PLN by indexation factors being linked to changes, after 1998, in the CPI of Indonesia and the US. The tariff components that are protected against the inflation risk are the component B and component D that covered fixed and variable O&M cost respectively.

4.2.4. Political Risk

Change of law risk was moderate. Legal and regulatory regime to support Indonesia private power were in certain respects incomplete; despite changes in law specific to private power, there was possibility of law changes in other aspects (i.e. environmental law) that may significantly affect the project. PEC was entitled to tariff adjustments in the events of changes in law that materially reduces or increases PEC's costs. The adjustments would provide PEC the same net, after-tax economic return, as it would have had in the absence of such events.

Country risk is risks related to political instability of the host country, either within or out of the government's control, that materially affects the project. Such risks include acts of war, civil disturbance, and violent demonstration, among others. Country risk was considered moderate to high. The risk was included into force majeure events provisions under the PPA. Such events do not relieve PLN from meeting its payment obligations under the PPA. In the case that the occurrence of certain force majeure events that are not normally insured results in a material delay in completion and causes material damage to the plants, PEC and PLN should enter into good faith negotiations regarding tariff adjustment.

Expropriation risk was low; expropriation action was unlikely to happen since the GOI had taken no expropriation in the recent past. Even if the Paiton I project sponsors were aware of nationalization case in Indonesia such as the nationalization of Indosat, an ITT[208]-owned communications company in Indonesia in the late 1970s[209], the sponsors seem to hold the assumptions that they have better bargaining position than the other private investors. PEC mitigated the expropriation risk by having a strong local partner, BHP, as well as attracting international lenders including OPIC, USEXIM and JEXIM, among other lenders. The involvement of local partner as well as international institutions is believed to reduce expropriation risk. Finally, the Indonesian Foreign

[208] ITT = International Telephone and Telegraph
[209] Wells, 1999

Investment Law grants foreign investors the right to compensation in the event of nationalization[210].

The risk of purchaser's default was high. PLN's ability to meet its payment obligations generally depended on its financial strength. As a public utility, PLN was expected to meet both social and commercial objectives. A report stated that these ambiguous objectives have led to a lack of accountability for commercially oriented operations since inefficiencies were always be perceived as exigencies to fulfill PLN's social mission[211]. In other words, PLN's financial strength was questionable and likely to be in an unhealthy condition. Even though the GOI issued a support letter to PEC, which provided that the GOI would cause PLN to discharge its PPA payment obligation, the letter was not a guarantee of payment and it did not indicate any financial responsibility of the GOI in case of PLN's default; in case of disputes, the strength of the letter from legal viewpoint remains unclear. Indeed, the risk of PLN's failure to perform its payment obligations is high and certainly has a potential of creating problems.

Overall, force majeure risks, which include the above political risks as well as other uncontrollable events such as acts of god and natural calamities, were assumed by PLN under certain terms of PPA contracts. While the occurrence of force majeure events affecting PEC may reduce payments to PEC, such events do not relieve PLN from meeting its payment obligations under the PPA. In the case that the occurrence of certain force majeure events that are not normally insured results in a material delay in completion and causes material damage to the plants, PEC and PLN should enter into good faith negotiations regarding tariff adjustment. In the case that force majeure events

210 Gooding, 1995
211 Price Waterhouse LLP, 1995

affect PLN's ability to receive electricity from the plants or such events are resulted from governmental action affecting PEC's ability to deliver electricity to PLN, PLN would remain obligated to make capacity payments to the extent that PEC would have been able to deliver without such occurrence. In sum, in most, if not all, of the cases, PLN would remain obligated either under the tariff adjustment resulted from negotiations or the capacity payments under the PPA.

According to the best available information, even though PEC maintained insurance policies[212] that cover against physical loss or damages to the maximum foreseeable loss to the plants and special facilities, the thesis author was not aware of the existence of any force majeure insurance arrangement that specifically protects PEC (and the Paiton I project as a whole) against force majeure risks. Given the fact that the Paiton I project is the first private IPP in Indonesia without a sovereign guarantee, it is risky to exclude force majeure insurance arrangement.

Some lenders, however, arranged certain insurance to protect their loans against political and commercial insurance. For example, JEXIM tranche B loan was insured for political and commercial risk by MITI and Mitsui[213] and the USEXIM credit facility that consisted of loans funded by international syndicate of commercial lenders was guaranteed against certain political risks by USEXIM on a 100% basis of the loans' principal amount.

---

212 PEC was obligated to obtain and maintain insurance policies that cover against physical loss of or damage to permanent and temporary works under construction, including materials and equipments. Additional insurance coverage includes cargo insurance, legal liability insurance, and automobile liability insurance (Confidential Circular Offering, 1996).

213 MITI provides political risk insurance on 97.5% of the principal amount of the tranche B loan. The commercial risk covers 95% of the principal amount of the tranche B loan (provided 75% by MITI and 20% by Mitsui) in case of PLN's default to fulfill its payment obligations under the PPA.

4.3. Chapter Summary

The Paiton I project is a well-crafted textbook project arrangement. Almost all risks were mitigated, providing the project company with high securities over the project assets, especially the project's revenue stream. The major risks of an IPP, which include market risks, currency risks, and force majeure risks, were mitigated by transferring all of these risks to the state-owned utility. Such arrangements are vulnerable given the fact that the utility itself did not have a strong financial health to accommodate such a high level of risks. Indeed, the Paiton I project is risky without the GOI's guarantee and, as far as the author is concerned, without force majeure risk insurance. When the crisis occurred, the arrangements of the project company's transferring risks to the financially unhealthy state-owned utility, proved to be ineffective arrangements, which eventually led to another kind of instability. Chapter 5 further analyzes the ineffectiveness of such arrangements.

Appendix 1: Project Risks and Possible Hedging Tools for Independent Power Producers

Project Phase	Project Risks	Definition	Reasons	Hedging Tools/ Mechanism for Remedy	Participants providing Hedge
A. Development, Design, Construction, Operation and Maintenance Risks					
Development	Bid Risk	the risk of unable to win the project	unclear scope unclear evaluation criteria	feasibility study, clarification of RFP well-crafted proposal	sponsors
	Financing Risk	the risk of unable to attract financing	high uncertainties	viability analysis well-crafted proposal attractive financial return	sponsors
	Approval Risk	the risk of difficulties in getting permits, licenses, and approval for the project	conditions on approval official/unofficial sources lengthy approval process	feasibility study good working relationship with government clarification of procedures	sponsors
Design	Design Risk	the risk of unable to launch the project succesfully due to unacceptable design	design uncertainty	experienced EPC contractors design warranty	sponsors EPC contractors
	Technology Risk	the risk of unable to launch the project succesfully due to unacceptable technology	technology uncertainty	experienced EPC contractors use well-proven technology	sponsors EPC contractors
Construction	Site Availability	the risk of unavailability of the project site	official/unofficial sources	land use agreement	authorities on the site
	Contractor's performance	the risk of inability of the contractors to construct the project successfully	lack of experience within contractors' control out of contractor's control	experienced EPC contractors penalties/bonuses insurance	sponsors EPC contractors insurance agency
	Delay in Completion	the risk of unable to complete the project on time	within contractors' control owner's change order hidden ground conditions	certain date construction contract penalties/bonuses equitable adjustment on schedule stand-by financing	EPC contractors project owner lenders/sponsors
	Cost Overrun	the risk that the actual construction cost is unexpectedly higher than the estimated cost	within contractors' control insured events uninsured events hidden ground conditions	fixed-sum turnkey contract penalties/bonuses insurance stand-by financing stand-by financing	EPC contractors insurance agency lenders/sponsors lenders/sponsors
	Supply	the risk of unavailability of supply items including building material, raw material and other supply items such as power, coal, and other utilities	within contractors' control	supply agreement fuel supply agreement power supply agreement	suppliers
	Plant Performance	the risk of the plant's failure to meet specifications at completion.	equipments' failure within contractors' control	plant performance tests plant general warranties penalties/bonuses insurance	EPC contractors insurance agency
	Contractor's Default	the risk of contractors' failure to continue performing their obligations under the contract	abandonement of the work insolvency, bankruptcy	irrevocable letter of credit parent companies' guarantee	EPC contractors EPC contractors' parent companies
	Force Majeure	the risk of project disruption because of uncontrolled events including acts of war, public disorders, explotion or natural calamities, etc.	insured force majeure events uninsured force majeure events remediable events non-remediable events	force-majeure insurance stand-by financing project restoration negotiation, contract termination	insurance agency lenders/sponsors sponsors/EPC contractors project parties
Operation Maintenance Repair	Operator's performance	the risk of inability of the operator to perform the operation and maintenance obligations successfully	lack of experience out of operator's control within operator's control	experienced O&M Operator insurance penalties/bonuses training program	sponsors insurance agency O&M Operator equipment suppliers, technical advisors
	Cost Overrun	the risk that the actual operating cost is unexpectedly higher than the estimated cost	within operator's control changes in regulation uninsured events insured events	penalties/bonuses tariff adjustment operator's compensation adjustment stand-by financing insurance	O&M Operator power purchaser / sponsors sponsors lenders/sponsors insurance agency
	Fuel Supply	the risk of unavailability of fuel for the operation of the plant	within supplier's control out of supplier's control	long-term fuel supply contract obtain other sources of fuel	fuel supplier other fuel suppliers
	Plant Performance	the risk of the plant's failure to generate the amount of power agreed upon in the purchase agreement	equipments failure within operator's control out of operator's control	plant general warranties monitoring and maintenance penalties/bonuses insurance	equipment suppliers O&M Operator insurance agency
	Transportion of project output	the risk that the electricity generated cannot be transported/transmitted to the market		long-term transportation contract other means of transportation arrangement	tranportation company sponsors
	Operator's default	the risk of operator's failure to continue performing obligations under the contract	abandonement of the work insolvency, bankruptcy	contract termination parent companies' guarantee	sponsors O&M Operator's parent companies

Appendix 1: Project Risks and Possible Hedging Tools for Independent Power Producers (Continued)

Risk Matrix	Project Risks	Definition	Reasons	Hedging Tools/ Mechanism for Remedy	Participants providing Hedge
	Force Majeure	the risk of disruption of the plant operation because of uncontrolled events including acts of war, public disorders, explotion or natural calamities, etc	insured force majeure events uninsured force majeure events remediable events non-remediable events	force-majeure insurance tariff adjustment operator's compensation adjustment project restoration negotiation, contract termination	insurance agency power purchaser / sponsors sponsors sponsors/O&M Operator project parties
B. Market Risks					
	Electricity Demand	the risk that the actual demand of the project output is less than the projected demand	demand vulnerability	take or/and pay power purchase agreement other off-take agreements	power purchaser or off taker sponsors/multibuyers
	Electricity Price	the risk of electricity price fluctuation	market price vulnerability	a put option power purchase agreement	sponsors/power purchaser power purchaser
	Fuel Price	the risk of fuel price fluctuation	market price vulnerability	tariff adjustment, fuel price pass through long-term fuel supply agreement	sponsors / power purchaser fuel supplier
C. Economic Risks					
	Currency Exchange Rate Risk	the risk of depreciation or appreciation of the local currency to the foreign currency exchange rate		mix local and foreign currency loans index output prices to exchange rate match currency of project loans to project revenue swap currency establishing an escrow account	sponsors, lenders sponsors, purchasers sponsors, lenders financial institutions financial institutions
	Foreign Exchange Availability and Covertibility	the risk of non availability and non convertibility of foreign currency	changes in regulation	obtain government guarantee of availability of foreign exchange mix local and foreign currency loans obtain contingency sponsor support establishing an escrow account	government sponsors, lenders sponsors financial institutions
	Interest Rate	the risk of unexpected increase or decrease in the interest rates during the maturity period of the project loans		negotiate a fixed interest rate borrow at a floating rate to take advantage of later rate fall swap interest rates	sponsors, lenders sponsors, lenders financial institutions
	Inflation Rate	the risk of unexpected increase or decrease in inflation rate		long-term supply contract output prices indexed to inflation	suppliers sponsors, power purchasers
D. Political Risks					
	Law and Regulatory	the risk of unexpected changes in law and regulatory that materially affects the project	changes in law and regulation	good working relationship with government government guarantee	sponsors government
	Country Risk	the risk that unexpected events occur because of imperfections of the country's business environment	country's business environments	feasibility study political risk insurance direct government guarantee indirect government guarantee government treaties	sponsors public or private insurance agency government government, multilateral and bilateral agencies host government and sponsors' government
	Purchaser's Default	the risk that the power purchaser is unable to fulfill its payment obligation under certain power purchase agreement	not creditworthy purchaser uncontrolled events	sell to creditworthy purchaser government guarantee tariff adjustment good faith negotiation contract termination	sponsors government sponsors / purchasers sponsors / purchasers sponsors
	Expropriation	the risk that the government for some reasons takes over the possession of the project	government action	participation of local sponsors and suppliers borrowing from local lenders political risk insurance involve multilateral development bank or other international agency in financing government treaties	sponsors, suppliers sponsors, local lenders public and private insurance agency sponsors, international lenders host government and sponsors' government

Appendix 2: Risk Matrix for the Paiton I Project

Project Phase	Categories of Risk	Evaluation	Project Participants Assuming the Risks							Hedging Tools	Mechanisms/Remedy
			Project Company PEC	Lenders	Government GOI	EPC Contractors	Operator Mission O&M	Fuel Supplier BHP	Power Purchaser PLN		
A. Development, Design, Construction, Operation and Maintenance											
Development	Bid Risk	Moderate	X		R					well-crafted proposal	feasibility study local sponsor's network
	Financing Risk	High	X							well-crafted proposal	viability analysis attractive financial return
	Approval Risk	High	X		R					good working relationship US govt's support in the negotiation	local sponsor's network
Design	Design Risk	Low				X				experienced EPC Contractors design warranty	feasibility study
	Technology Risk	Low				X				experienced EPC Contractors	use well-proven technology
Construction	Site Availability	Low			R				X	land use agreement	PLN grants PEC the site use
	Contractors' Performance	Low				X				experienced EPC Contractors performance warranties insurance	construction contract
	Delay in Completion	Moderate				X				certain-date construction contract	penalties/bonuses equitable adjustment on schedule PPA contract termination by PLN
	Cost Overrun	Moderate				X				fixed-price construction contract equity standby financing insurance	equitable adjustment on price
	Supply of Power and Other Utilities	Low							X		applicable tariff payable to PLN
	Supply of Coal prior to COD	Low						X		reliable coal reserves government coal support letter qualifying alternate coal	long-term fuel supply agreement coal-supply plan obtain coal from other sources
	Plant Performance	Moderate				X				plant performance tests plant general warranties insurance	penalties/bonuses
	Contractor's Default	Low	X			X				irrevocable letter of credit parent companies' guarantee	contract termination
	Force Majeure		X		R	X					project restoration, equitable adjustment contract termination
Operation Maintenance Repair	Operator's Performance	Low					X			experienced O&M Operator insurance	O&M contract training program
	Cost Overrun	Moderate					X		X	pre-commercial: fixed-lump sum fee commercial: fixed monthly fee good utility practice insurance	penalties/bonuses operator's compensation adjustment tariff adjustment
	Supply of Coal	Low						X		reliable coal reserves government coal support letter	long-term fuel supply agreement coal supply plan
	Plant Performance	Moderate					X			good utility practice plant general warranties insurance	penalties/bonuses maintenance and monitoring
	Operator's Default	Low	X				X			parent companies' guarantee	contract termination
	Force Majeure		X		R		X		X	PLN's PPA payment obligation	project restoration, tariff adjustment renegotiation, contract termination

Appendix 2: Risk Matrix for the Paiton I Project (Continued)

Project Phase	Categories of Risk	Evaluation	Project Participants Assuming the Risks							Hedging Tools	Mechanisms
			Project Company PEC	Lenders	Government GOI	EPC Contractors	Operator Mission O&M	Fuel Supplier BHP	Power Purchaser PLN		
B. Market Risks											
	Electricity Demand	Moderate							X	fixed capacity payment obligation (components A and B)	take-or-pay PPA
	Electricity Price	Moderate							X	fixed capacity payment obligation (components A and B)	take-or-pay PPA
	Fuel Price Increase	Moderate							X	fuel price pass through	tariff adjustment (component C) annual price renegotiation
C. Economic Risks											
	Currency Exchange Risk	High							X	price indexed to exchange rate	tariff adjustment
	Foreign Currency Availability and Convertibility	High			R				X	foreign exchange contracts	foreign exchange contracts and the remaining risks will be on PLN's expense
	Interest Rate	High	X							fixed interest rates on loans swap interest rate agreements	
	Inflation Rate	High							X	price indexed to inflation rate	tariff adjustment
D. Political Risks											
	Law and Regulatory	High			R				X		tariff adjustments
	Country Risk	High	X		R				X	PLN's PPA payment obligation	project restoration, tariff adjustment renegotiation, contract termination
	Purchaser's Default	High	X	X						provisions in the PPA government support letter	good faith negotiation dispute resolution: arbitration
	Expropriation	Low	X	X	R					participation of local sponsor involvement of ECAs and other international financial institutions	compensation

Notes
X = The main project participant(s) who assume the associated risks
R = The party who is responsible for Legal and Regulatory Framework: the Government of Indonesia

Appendix 3: Project Risks and Hedging Tools for the Paiton I Project

	Project Risks	Evaluation	Remarks	Reasons	Hedging Tools/Mechanism	Participants providing Hedge
A. Development, Design, Construction, and Operation Risks						
Development	Bid Risk	Moderate	Lack of competition and transparency US Government's high support in the negotiation	unclear scope unclear evaluation criteria unclear bidding procedure	feasibility study well-crafted proposal local sponsor's network	PEC
	Financing Risk	High	ADB's concern of the first family involvement	high uncertainties	viability analysis well-crafted proposal attractive financial return	PEC
	Approval Risk	High	The first private power project: no prior experience in laws and regulatory enforcements Laws and regulations for private power projects are not fully developed	conditions on approval lengthy approval process	good working relationship with government local sponsor's network	PEC
Design	Design Risk	Low	The EPC contractors have a lot of experience in designing similar power plants worldwide		experienced EPC contractors design warranty	PEC EPC contractors
	Technology Risk	Low	The technology used have been well-proven worldwide for example: GE's technology		well-proven technology	EPC contractors
Construction	Site Availability	Low	PLN occupies the land with the consent of GOI PLN grants PEC the right to use the site		land use agreement	PLN
	Contractor's Performance	Low	The EPC contractors have a lot of experience in constructing similar power plants worldwide		experienced EPC contractors performance warranties insurance	PEC EPC contractors insurance agency
	Delay in Completion	Moderate	commercial operation date: May 21, 1999 $325,000 bonus per day for early completion payable from PEC to EPC Contractors $575,000 penalty per day for late completion payable from the contractors to PEC	within contractors' control owner's change order	certain date construction contract penalties/bonuses payable to EPC contractors equitable adjustment on schedule PPA contract termination by PLN	EPC contractors PEC PLN
	Cost Overrun	Moderate	stand-by financing: $300 million of contingent overrun equity by sponsors $93.75 million of standby facility by commercial lenders	within contractors' control owner's change order insured events uninsured events hidden ground conditions	fixed-price construction contract equitable adjustment on price insurance stand-by financing stand-by financing	EPC contractors PLN insurance agency PEC PEC
	Supply of Power and Other Utilities	Low	PLN is responsible for the provision of power and other utilities during construction at applicable tariff rate		tariff payable to PLN	PLN
	Supply of Coal	Low	BHP acts as coal supplier under fuel supply agreement	within supplier's control supplier's failure	long-term fuel supply agreement government coal support letter obtain coal from other sources	BHP
	Plant Performance	Moderate	SO2 air emission limits, minimum net electrical output, maximum net heat rate, net dependable capacity (NDC) Equipment and Materials Design and Engineering	within contractors' control out of contractors' control	emission test, performance guarantee test, NDC test, and reliability test; each test imposed liquidated damages payable to PEC up to a certain limits plant general warranties insurance	EPC contractors insurance agency
	Contractor's Default	Low	suspension/abandonment of the work, failure to perform obligations, insolvency/bankruptcy etc.		irrevocable letter of credit parent companies' guarantee	EPC contractors EPC contractors' parent companies
	Force Majeure		acts of war, public disorders, explosion or natural calamities, certain strikes, certain actions by the GOI, certain termination of the PPA.	remediable events non-remediable events	equitable adjustment on price and schedule contract termination	PEC
Operation Maintenance Repair	Operator's Performance	Low	The O&M Operator has a lot of experience in doing operation, maintenance, and repair of similar power plants worldwide		experienced O&M Operator insurance training program	PEC insurance agency O&M Operator
	Cost Overrun	Moderate		within operator's control out of operator's control change in law or other events	pre-commercial: a fixed lump-sum fee commercial: a fixed monthly fee penalties/bonuses insurance tariff adjustment operator's compensation adjustment	O&M Operator insurance agency PLN
	Supply of Coal	Low	BHP acts as coal supplier under fuel supply agreement BHP purchased the coal from Adaro under coal purchase agreement; Adaro had the mining right in the Tutupan Area under coal cooperation agreement with TBA	within supplier's control supplier's failure	long-term fuel supply agreement government coal support letter obtain coal from other sources	BHP

Appendix 3: Project Risks and Hedging Tools for the Paiton I Project (Continued)

	Project Risks			Reasons	Hedging Tools	Participants providing Hedge
	Plant Performance	Moderate	bonus payment equal to 20% of PEC's bonus from PLN for performance in excess of the target availability factor penalty is equal to 10% of the shortfall in revenues derived from capacity component A	within operator's control	penalties/bonuses maintenance and monitoring plant general warranties insurance	O&M Operator O&M Operator insurance agency
	Operator's Default	Low	suspension/abandonment of the work, failure to perform obligations, insolvency/bankruptcy etc.		parent companies' guarantee contract termination	O&M Operator's parent companies
	Force Majeure		acts of war, insurrection, violent demonstrations, acts of god, employee strikes or lockouts, failures to act without justifiable cause by any instrumentality of the Republic of Indonesia	remediable events non-remediable events up to certain limits	equitable adjustment on price and schedule tariff adjustment project restoration contract termination	PEC PLN O&M Operator
B. Market Risks						
	Electricity Demand	Moderate		demand vulnerability	take or pay Power Purchase Agreement (fixed capacity payment obligation)	PLN
	Electricity Price	Moderate		market price vulnerability	take-or-pay PPA	PLN
	Fuel Price Increase	Moderate		fuel price vulnerability	tariff adjustment: fuel price pass through (component C) annual price renegotiation	PLN PLN/BHP
C. Economic Risks						
	Currency Exchange Rate	High			prices indexed to exchange rate (tariff adjustment)	PLN
	Foreign Exchange Availability and Covertibility	High			foreign exchange contracts	PLN
	Interest Rate	High			fixed interest rates on loans interest rate swap agreements	PEC, lenders
	Inflation Rate	High			index output prices to inflation (tariff adjustment)	PLN
D. Political Risks						
	Law and Regulatory	High		changes in law and regulation	tariff adjustment	PLN
	Country Risk	High		country's business environments	feasibility study local sponsor's network	PEC, lenders
	Purchaser's Default	High		PLN's default	PPA, government support letter renegotiation, international arbitration	PEC, lenders
	Expropriation	Low		government action	participation of local sponsors and suppliers involvement of ECAs and other international financial institutions	PEC, lenders

Chapter 5: Analysis on The Paiton I Project Deal

5.1. IPP Best Practice Analysis on the Paiton I Deal

Following the explanation in subchapter 2.4 about key success and best practice for IPPs, the following sections provide the analysis of the Indonesian IPP program related to the Paiton I project. The analysis covers the themes in subchapter 2.4: 1) the legal and regulatory framework, 2) procurement process, and 3) power purchase agreement.

5.1.1. The Indonesian Legal and Regulatory Framework

At the time the GOI initiated the development of the Paiton I project, the Indonesian legal and regulatory framework for private power were not developed. A review of the Paiton I project by Lahmeyer International, a Frankfurt-based engineering firm, for the Directorate General for Electricity and Energy Development in December 1993, prior to the completion of negotiations between the GOI and the BMMG consortium, stated that "the GOI initiated development of Paiton prior to establishing either of these [policy and regulatory] frameworks".

Based on the the best practice features for legal and regulatory framework for private power outlined in subchapter 2.4.1, the Indonesian frameworks can be evaluated as follows:

1) The GOI did not have a clearly stated long-term framework for its private power program. The GOI initiated the development of private power producers to

answer the power shortage in the early 1990s. At that point, the GOI viewed the process of defining comprehensive legal and regulatory frameworks for long-term private participation in the power sector as unnecessary when the power capacity was desperately needed by the country.

2) The GOI did not provide legal and regulatory frameworks in adequate detail. Even though the GOI somehow issued regulations specific to private power such as the Presidential Decree Number 37 of 1992[214] and the Minister of Mines and Energy (MME) Decree Number 2 of 1993[215], these regulations constitute more of an outline than a detailed regulatory regime[216].

3) The set of laws and regulations established to support the Indonesian private power was incomplete. Prior to initiating the Paiton I project, the GOI had not published a complete list of the permits, licenses, and the GOI consents that were required to develop a power project.

4) The approval process to develop a private power plant was long and complicated. The developers had to pass through numerous layers of bureaucracies before any agreements can be reached.

5) The social and commercial objectives of the power sector were not clearly separated. PLN as a public entity was expected to perform these two objectives

---

214 Several important features of the Presidential Decree 37/1992 are that the decree: 1) provides that the development of private power projects is to supply electricity directly to PLN "where PLN cannot satisfy the demand for electricity", 2) states that BOO delivery method is the government's preference for the private power projects, 3) authorizes the Ministry of Mines and Energy to be responsible for regulating private power industry, 4) obligates private power producers to be responsible for their own fuel supply, prohibiting transferring the responsibility to PLN, 5) mandates that top priority should be given to domestic fuel suppliers. (Gooding, 1995).

215 Several important features of the MME Decree 2/1993 are that the decree: 1) outlines the negotiation procedures and evaluation criteria for both solicited and unsolicited private power projects, 2) provides that imported fuel supplies can be used only with the approval of the Minister of Trade, upon the advice of the Ministry of Mines and Energy, 3) Establishes the licensing system applicable to private power producers (Gooding, 1995)

216 Gooding, 1995.

simultaneously. The result was that while PLN could not function as a commercially viable entity working under a set of commercial targets, inefficiencies became an excuse for fulfilling its social objectives.

6) The GOI did not maintain a healthy power purchaser. PLN's financial condition was not strong enough to accommodate IPPs on a *take-or-pay* basis. The financial strength was vulnerable because of PLN's lack of control over its costs and assets[217] as well as the PLN's two conflicting objectives mentioned above. Moreover, the effect of the GOI's financial support was difficult to assess because of PLN's inability to measure and track the level of financial support actually provided by the GOI[218].

7) Security over project assets that applied fairly to all project participants was not available. For example, the GOI did not clearly specify its preferred allocation of sovereign risks including the risk of PLN's default; instead of providing a guarantee, the GOI issued the letter of support whose status is unclear in case of disputes. If the GOI's intention was not to provide a guarantee, instead of issuing such an ambiguous support letter, the GOI should have clearly stated its unwillingness to provide the guarantee. While the GOI's letter of support was not a guarantee, the efforts by PEC to provide high level of security to the project by transferring major risks to PLN turned out to be unfair for PLN.

8) There were no policies encouraging the development of domestic capital markets and institutions and diversifying the sources of domestic capital for equity investment in electricity projects.

---

217 Price Waterhouse LLP, 1995.

218 Ibid

Overall, during the inception of the Paiton I project, the legal and regulatory framework specific to private power projects were not fully developed, thereby creating uncertainties to the private participants. Because of these uncertainties, the PPA was crafted in such a way that provides high level of securities to the project sponsors, including the *take-or-pay* PPA mechanism.

5.1.2. The Paiton I Project Procurement Process

The procurement process for the Paiton I project did not considerably follow the best practice features in the procurement process outlined in section 2.4.2. The major inefficiencies of the Paiton I project procurement process can be synthesized as follows:

1) The GOI had not yet prepared comprehensive bid documents when the bids for the Paiton I project were solicited in 1990[219]. Instead, the GOI issued a Terms of Reference, which was also incomplete; it did not cover important issues such as risk allocation, environmental standards, and tariff and payment mechanisms. Drafts of PPA were issued only five days before the bid submission date. The lack of the GOI's preparation also contributed to the long process of bid solicitation.
2) The Paiton I project was supposed to be a solicited project; however, the bidding process reflected the process for an unsolicited one since the project scope was not a government-defined scope, but the participant-defined scope. Even though the GOI provides the basic requirements for the project—i.e. the project was for two units coal-fired power plants, located in the Paiton complex, etc—they lacked

219 Lahmeyer International, "Final Report: Lessons learned from Paiton One", *Recommendations for Improving Indonesia's Private Power Program*, Volume 1, November 1993.

in specifying the minimum requirements for the project. Therefore, the private participants crafted their bidding documents based on their own definition of project scope, which was obviously different from one consortium to the other consortium. The lack of a government-defined scope, as a result, provided no standard criteria for the government to base the proposal evaluation.

3) The evaluation criteria, if there actually were, did not assure a head to head competition among bidders. There was no apple-to-apple comparison framework on financial and technical qualifications because the GOI themselves lacked the minimum requirements for the project. Since the GOI had no standard framework that can serve as a base line to evaluate the proposals, the GOI simply put the proposals (of the only two consortiums participating in the bidding process) side by side and tried to assess which proposal was better than the other. However, conducting such assessment on a fair basis was certainly very difficult, if not impossible. Indeed, the government did not have comparison standards since the proposals were actually crafted for projects that were entirely different from one bidder to another bidder according to their own perceived set of project scope.

4) There were no pre-qualification process—whereby the prospective bidders submit information concerning their technical capabilities and financial strength. Lahmeyer International reported that no such pre-qualification was done in the case of Paiton[220].

5) The bidding process was not transparent. Even though the process might have been announced publicly, the details were negotiated in secrecy. The fact that

---

220 Lahmeyer International, "Final Report: Lessons learned from Paiton One", *Recommendations for Improving Indonesia's Private Power Program*, Volume 1, November 1993.

during the negotiation process, the chairman of BHP[221] intensively held several meetings with Soeharto to discuss about the project provides the evidence of this lack of transparency. Indeed, the procurement was not an open tender procedure, the problem of which caused Dennis de Tray from the World Bank to send a warning letter to the Minister of Mines and Energy at the end of 1997[222]. Moreover, the GOI's changing decisions by initially awarding the project to the BNIE consortium but eventually awarding it to the BMMG consortium is an evidence that the overall procurement system itself was not reliable and predictable.

6) No benchmarking by an independent engineering peer to ensure cost-effective development. Despite the facts that competition was minimal and there was no objective and rigorous bid evaluation, the procurement system did not ensure a cost-effective development. For bid evaluation purpose, the GOI did not set up a benchmarking mechanism by independent engineers to, at least, ensure that the project cost offered by bidders reflects the market price and is not exceptionally high if compared to other projects with similar size and capacity.

Overall, the procurement system conducted for the Paiton I project did not encourage competition, transparency, and cost-effective development. Such system would unlikely be sustainable unless the GOI would like to fear potential investors in the future.

---

[221] As previously mentioned, the chairman of BHP was closely related to the Suharto family.

[222] Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim, "Perjalanan Proyek Paiton I?"(The Chronology of the Paiton I Project), *Tempo*, 24 September 2000, page: 120.

5.1.3. The Paiton I Model Power Purchase Agreement

The Paiton I model PPA somehow did not fully reflect the best practice features outlined in subchapter 2.4.3 of the thesis, with the following analysis:

1) The PPA did not use the wholesale electricity tariff—that is, the PLN's tariff to the electricity consumers—as a basis to set up the tariff payable from PLN to PEC for the Paiton I-generated power. Instead, the PPA used the project cost, the debt service requirements, and the rate of return on equity as a basis to negotiate the PPA tariff structure.
2) The Paiton I model PPA tariff structure did not promote competition for cost-effective development towards competitive electricity markets. Instead, the structure provides a high security for the project's revenue streams even under its reliance on the purchaser's ability to *take-or-pay* payments.
3) The risks profile indicated an imbalanced risk sharing, with PLN being in the position to assume currency risks, market risks, and force majeure risks. Indeed, PLN's ability to manage the risks was in question and it is a doubtful proposition that says that PLN was in the position to control the currency risks, market risks, and force majeure risks.
4) Dispute resolution was clearly outlined in the Paiton I model PPA, with the International Arbitration being the final dispute resolution. Despite the fact that the International Arbitration is perceived as a neutral party between the contracted parties, the arbitration's decisions imposing payment obligations to the public utility were ineffective to be implemented especially in times of crisis since the utility simply did not have the cash to make the payment.

In short, the Paiton I model PPA provide high level of security to the project sponsors by transferring some of the major risks to PLN. This arrangement was greatly favorable to the sponsors. However, in times of crisis, this arrangement has proved ineffective, as has happened during the Asian crisis. Even if PEC were to seek solution through the International Arbitration, the effectiveness of the arbitration's decisions obligating PLN to pay certain amount in damages—as was the case with the Dieng project and the Patuha project mentioned earlier in subchapter 3.7.3—is in question since PLN simply did not have the cash to make the payment. Therefore, while such investor-friendly arrangements are viewed as inappropriate to a certain extent, the dispute resolution also could not provide a mutually acceptable solution.

5.2. The Analysis of the Paiton I Project Arrangement

This subchapter analyzes the Paiton I project deal with respect to the *take-or-pay* PPA tariff structure, the risks mitigation efforts, and the "mistakes" of IPPs in Indonesia. These arrangements were proved ineffective when the Asian crisis occurred. This section serves as a detailed explanation of the analysis covered in section 5.1.3 and provides an answer to the concerns outlined in section 2.3.

5.2.1. The Analysis of the Paiton I PPA Tariff Structure

The thesis author developed a financial model to calculate the PPA tariff components for the 30-year contract period[223]. This analysis takes into account any publicly available financial information of the Paiton I project and the author's

223 The financial analysis is further explored in chapter 7

reasonable assumptions[224]. Several findings can be synthesized out of the tariff projections, as follows:

1) The Level of the *take-or-pay* is high.

The fixed capacity charges (component A and component B) that PLN must pay irrespective of dispatch levels amounts to an average of 71% of the projected total payment[225], under the coal price US$ 34.9 per tons (= Rp. 71.126 per kg, the coal price allowance in 1997, with the base exchange rate Rp. 2,038 per US$). The average US dollar term of these capacity payments for the first six years is US$ 573 million. This amount closely confirmed PLN's press release stating the PLN's *take-or-pay* payment obligations of approximately US$ 598 million per year[226]. A 71% fixed capacity payment regardless the delivery of power is considered high. When demand is weak, as was the case during the Asian crisis, such amount would be wasted for power that was actually unnecessary. PLN was "forced" to utilize the power, thereby reducing the operation of its own plants to accommodate the otherwise-wasted power from the Paiton I plants.

2) The Demand Projection is over optimistic.

The Availability Factor (AF) agreed upon in the PPA is 83%. This high percentage reflects an optimistic projection of the electricity demand, which means the power is so desperately needed that the plants should be in operation

224 Assumptions include percentage of annual increase in exchange rate movement prior and after the Asian crisis, the inflation rate projection of Indonesia and the US, the actual exchange rate projection, the discount rate, the fuel cost is estimated the same for the whole contract year.

225 A complete analysis is explored in the appendix 2 of chapter 7

226 Adnan Buyung Nasution & Partners, "PLN filed a lawsuit against Paiton Energy", *Press Release*, October 7, 1999.

for the whole year except during the repair and maintenance period. An 83% was over optimistic given the demand that actually materialized to be far from the projection. To illustrate, PLN's own power plants usually have approximately 60% to 75% availability factor[227].

A high AF should lead to a lower tariff rate because of the economy of scale that should have been realized. The higher the AF, the lower the electricity price should be. However, this was not the case with the Paiton I project since the Paiton I plants' tariff rate with the 83% AF was relatively high if compared to the tariff rate of the PLN's power plants with the 60% AF. It was reported that PLN's power plants were much cheaper and more efficient[228].

5.2.2. The Analysis of the Risk Mitigation Efforts

Certain types of risks mitigation efforts of the Paiton I project had been proved ineffective when the initially anticipated conditions change. Those ineffective efforts are as follows:

1) The imbalanced commercial risks arrangements embodied in the Paiton I model PPA that had been greatly ineffective in times of crisis,
2) The politically well-connected local participant that was initially intended to reduce political risks, but eventually increased the political risks itself when the government changed.
3) The international arbitration's decisions that fail to provide a mutually acceptable solution to be implemented in times of crisis.

227 An exclusive interview with Dr. Situmeang.

228 Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000.

Louis T. Wells, in his paper on managing non-commercial risks for private investment in infrastructure, viewed the problems, of which this thesis refers as imbalanced risks arrangements, as "the efforts by private firms to shed commercial risks [that eventually] lead to political risks for the investor"[229].

1. The Imbalanced Commercial Risks Arrangement of the Paiton I PPA

The major concerns of the private, especially foreign, investment in infrastructure are market risks and economic risks. As previously mentioned, under the Paiton I PPA tariff pricing mechanisms, all the market risks, which include the electricity demand and price risks and the fuel price risk, are transferred to PLN. The demand and price risks were hedged by the *take-or-pay* mechanism, and the fuel price fluctuation risk was hedged by the fuel price pass through mechanism. The economic risks, which include exchange rate risk, currency convertibility/availability risk, and inflation rate risk, were also transferred to PLN. The exchange rate risk and the inflation risk were transferred by indexation factors being linked to the Rupiah/US Dollar exchange rate and the countries' CPI respectively, and the convertibility/availability risks were hedged by using the foreign exchange contracts by which PLN became ultimately responsible, under certain PPA terms, if such contracts were not available. In short, with respect to the types of risks mentioned above, the project sponsors assume no risk[230].

---

[229] Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

[230] Only the foreign element of the tariff components was protected against exchange risk since the local element obviously did not need such protection. Moreover, only component B and D were protected against inflation rate risk; component A and C actually did not need inflation protection. Component A did not need inflation protection since component A was intended to cover the capital costs, which had been spent prior to the COD, and there would be no further expense with respect to component A. Component C

Such PPA arrangements place PEC in a very secured position while PLN would be in a disadvantage position when the risks actually became very significant. Indeed, PLN is not the party who can control such risks: PLN was unable to control currency risks while PLN's ability to control electricity demand was also doubtful. Unfortunately, PLN was not sophisticated enough to provide hedging mechanisms to handle such a high level of risks. As a result, PLN would likely need to pass the risks to its consumers by increasing the electricity tariff rates. This effort would be very difficult in times of crisis, not only because the purchase power of the consumers are weak during that time, but also because such tariff increase would eventually lead into a political friction.

2. The politically well-connected local participant

PEC might have believed that the involvement of local participants, especially with the inclusion of high-level politically well-connected people, would greatly reduce political risks. The local participants were expected not only to help in obtaining and negotiating the initial deals but also to defend the project in case any governmental actions threaten the project (i.e. nationalization) or reduce profitability. Indeed, the involvement of BHP as a local shareholder as well as a local fuel supplier had effectively helped PEC in obtaining the initial deals. Since all issues relating to infrastructure development were set by presidential decree and there was no system in place to make decision without the president's approval, the president's decision is critical for the

---

also did not need protection against inflation risk since the fuel price would be renegotiated annually and therefore, the fuel price risk would be automatically transferred to PLN.

project approval[231]. Through its politically well-connected chairman, BHP was reported to hold several meetings with President Suharto[232] to expedite the negotiations.

BHP functioned very well during the initial stage of the project development. Unfortunately, when the government changed in 1998, the drawback of having a politically well-connected participant materialized. Critics on the price of the Paiton I[233] that became silent during the Suharto regime raised again when Suharto was not in power, with allegations that the high project cost of the Paiton I project being the result of cronyism and corruption practices during the regime.

Louis T. Wells concluded that partners chosen for their political connections can turn out to be liabilities when governments change[234]. In addition, Wells argues that the evidence that local partners do decrease political risk is a bit shaky[235]. He cited a study that showed that the chances of nationalization are higher for foreign projects with joint venture partners than for the projects where the foreign investors held all the equity[236].

In short, with respect to the Paiton I project, the politically well-connected local participant, which might be chosen for their political connections and was initially intended to reduce political risks, actually increased the political risks itself when the government changed.

---

231 The Paiton I project would produce significantly more expensive power than PLN does. Thomas, Eapen, "A Beautiful Place to Develop", *Infrastructure Finance*, April/May 1995.

232 *The Asian Wall Street Journal*, February 14, 1994.

233 The Jakarta Post, "PLN Criticized over Pricing of Private Electricity", November 29, 1994; The Jakarta Post, "PLN Under Fire for Cooperation", February 14, 1995.

234 Wells, 1999.

235 Ibid

236 David G. Bradley, "Managing Against Expropriation," Harvard Business Review, July/August 1977, pages 75-83. Problems that partners can cause with subsequent governments are dealt with in Stephen J. Kobrin, "Foreign Enterprise and Forced Divestment in the LDCs," International Organization, Winter 1980 (Vol. 34, No. 1), pages 65-88. (Wells, 1999)

3. The International Arbitration's decision

Even though International Arbitration was the agreed upon dispute resolution under the PPA, the efforts of foreign investors to solve disputes in the International Arbitration with respect to the public utility's default to perform obligations do not always lead to best solution. The host government (and/or the public utility) often find that the International Arbitration's decisions charging the public utility certain payments in damages payable to the foreign investors to be unacceptable and very difficult to enforce since the utility simply did not have the cash to make such payments. This condition is perfectly illustrated by the experience mentioned earlier of the MidAmerican Energy Holdings Co. with respect to the Dieng and Patuha project.[237] So, it might not be a coincidence that PEC agreed to pursue settlement out of international arbitration when the renegotiation is inevitable.

Louis T. Wells assessed that the ineffectiveness of the International Arbitration's decisions is because the value of arbitration in settling disputes has been so far limited to interpretation of the letter of contracts[238]. In other words, International Arbitration limits itself to the rigidity of the contracts agreed upon between parties, but it does not allow for change. When the condition changes sharply and the initially agreed contract terms turn out to be imbalanced and unable to satisfy the contracted party(s), the International Arbitration would play a very useful if it allows changes that could be applied under the prevailing economic conditions. Furthermore, the International Arbitration would play a

[237] According to MidAmerican Energy Holdings Co. (formerly known as CalEnergy Company)of the US, the majority owner of the Dieng project and the Patuha project, when the disputes were filed, the Patuha project had began construction of an 80 MW power generation unit at its Patuha plant and had developed proven geothermal resources of at least 170 MW (the Jakarta Post, May 1999)

[238] Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

very useful role if it were available to handle conflicts over the appropriateness of the contract terms[239]. Indeed, under the condition out of the Asian crisis, renegotiations are inevitable; therefore, it would have been better if there is a mechanism that smooth changes in contract terms instead of forcing the initial terms that are inappropriate under such difficult condition.

5.2.3. The "Mistakes" of IPPs in Indonesia

Apparently, IPPs in Indonesia seem to make "mistakes" during the inception of their projects. Such mistakes are with respect to the electricity market projection (the projection of demand and tariff) and the IPPs equity arrangement.

1. Electricity Market Projection

1) Electricity demand is projected as a target, not a natural growth

At the time of the inception of the Paiton I project, the demand forecasting was over optimistic within the range of 19% to 24% annual increase[240]. However, the actual trend turned out to be the average of 14% annual increase, even before the occurrence of the mid-1997 Asian crisis[241]. Despite the fact that the natural growth of electricity demand had actually materialized to be far from the optimistic scenario, IPPs following the Paiton I project seemed to stick their reference to the initial projection, not the one that actually materialized.

---

239 Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

240 The 1994 National Electricity Plan

241 As shown in table 3.6, the actual demand increases were 14% in both fiscal year 1995/1996 and 1996/1997.

Furthermore, IPPs might not have taken into account the boom of IPPs in Indonesia that might eventually lead to a possibility of electricity overcapacity in the near future, resulting in their plants might not be as necessary as initially perceived.

2) Electricity tariff projection is a sole reference for the IPPs to assess the viability of their tariffs to PLN

The IPPs refer solely to the projection of increase in PLN tariff to the consumers. A World Bank study predicted a significant increase of the PLN tariff; this increase was expected to exceed the Paiton I tariff after approximately the first 8 years of operation[242]. If the increase would not actually materialize, the Paiton I tariff would significantly exceed the PLN tariff; as a result, PLN would not be able to afford the Paiton I tariff.

To illustrate, the average PLN's electricity tariff to the consumers was Rp. 223 per kWh; with the exchange rate Rp. 7,000 per 1 US$, the tariff was approximately US$ 3.2 cents/kWh[243]. However, the electricity tariffs that PLN is obligated to pay under the PPA is estimated to be approximately US$ 8.5 cents/kWh for the first 6 years, US$ 8.3 cents/kWh for year 7 to 12, and US$ 5.5 cents/kWh for year 13 to 30[244]. PLN should increase its tariff significantly; without an increase, PLN would not be able to afford the Paiton I power. However, such increase would eventually lead into a political friction.

The reliance solely on the tariff projection is not sufficient. The IPPs should also take into account the electricity purchase power of the various areas

242 World Bank Published Data

243 PLN Press Release, "Latar Belakang: Background", 1999.

244 Ibid.

within the country. Even though some areas lacked of electricity, at the same time, they cannot afford to buy it. To illustrate, the Java-Bali region experienced electricity overcapacity while the other regions lacked the capacity and also lacked the ability to pay for the electricity.

2. The Characteristics of the Equity Arrangement

1) The "debt-like" Equity Arrangement[245]

Louis T. Wells noticed that one of the most distinguished characteristics of recent greenfield infrastructure investments is that the economic of many arrangements look more like loans than like equity. According to Wells, the usual equity arrangement outside infrastructure is strongly influenced by profits derived as a function of market demand for the product or service, the resulting price that can be charged, and the costs incurred by the investor in producing the product or service. Furthermore, the amount of foreign exchange demanded by the investors would vary with the profit and with the exchange rate. Therefore, for a project whose output is sold locally, a local recession such as the Asian crisis, would usually lead to a fall in demand, and therefore, a fall in profits and dividends, and less demand for foreign currency exchange[246]. In short, in times of crisis, the usual equity investors serving local market with local-currency-denominated revenues would demand less foreign currency exchange.

---

245 For the origin of the concept, see Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

246 The fall in demand for foreign currency exchange is even sharper since as the local currency depreciated, the local currency-denominated profits would buy less foreign currency (Wells, 1999).

Unlike the usual equity arrangement, the equity arrangements for investments in infrastructure are more "debt-like" than "equity-like". Like loans, the "debt-like" equity arrangement is denominated in foreign currency and is unlikely to vary with economic conditions. Demand risk and/or foreign currency risk are shifted away from the investors. As a result, in times of crisis, there will be a little or no decrease in revenues, which are denominated in dollars. The amount of foreign currency to be remitted abroad by the investors is fixed by the agreements. Louis T. Wells confirmed that:

> This is much like an arrangement under which the government simply borrows in foreign currency to build the project; it would owe the lender a fixed (say) dollar amount, regardless of the exchange rate and demand for the output of the project (Wells, 1999).

Similarly, the equity arrangement of the Paiton I project was a "debt-like" arrangement under the *take-or-pay* PPA obligating PLN to make fixed payments regardless the country's economic condition and the demand condition for the project output. As explored in previous sections, the impact of such arrangement had been severe especially for the public utility.

2) The "loan-financed" Equity Arrangement of the Local Participant[247]

To facilitate the equity contribution of the Paiton I local partner (BHP), the other three sponsors extended loans to BHP to be repaid out of BHP's dividends from the project. Facilitating equity contribution by extending loan is a common practice for power generation projects. Although BHP did not bring any other expertise despite its coal supply expertise and local networks, BHP's shares

247 Wells, 1999

in PEC was important for, at least, fulfilling the GOI's requirement as to the minimum 5% of local ownership in the consortium.

The US Foreign Corrupt Practices states that it is illegal for US companies to make direct (and certain indirect) payments to high-level public officials. However, when the local participant—which was expected to help obtaining the deals—includes a high level politically well-connected people, such arrangements became vulnerable as to be alleged as "indirect payments" to smooth the project deals. One might argue that this kind of arrangement is not "corruption" since the recipient is not a government officer and the well-connected recipient would eventually "pays" back the shares out of dividends from the projects. However, the fact that the influential people eventually receive "free" shares is referred as no more than a delayed gift, the benefits of which would accrue at some future date, after the shares have generated enough dividends to pay off the "loan"[248]. Indeed, it is difficult to ascertain whether such delayed gifts are received or the future paybacks actually accrue since even though the transaction is not secret, the details were usually negotiated in secrecy.

In the case of the Paiton I project, such "loan-financed" equity arrangement of BHP was suspected as a corruption practice. The US$ 2.5 billion total project cost of the Paiton I project—which is perceived as high if compared to other projects of similar size—have further fueled the allegations that the equity-financing which consists of 27% of the total amount was actually unnecessary; in other words, considering the fact that other projects of similar size were much cheaper, one might argue that the US$ 1.82 billion debt-financing

248 Wells, 1999

alone was considered enough to build the project. Apart from this factor, however, the "loan-financed" type of equity arrangement, which was suspected as a corruption practice, is widely believed to be one of the reasons behind PLN's lawsuit to validate the contracts claiming that they were obtained through corruption.

5.3. Recommendation

The analysis of the Paiton I project arrangement have led to several recommendations, as follows:

5.3.1. The PPA Tariff Structure

1) Allow the private entity to assume part of the market risks

With respect to the market risks, demand risks should be partly allocated to IPPs. The mechanism could probably be by reducing the high level of *take-or-pay* to a certain level. Unlike the Paiton I PPA whose fixed capacity charges amount to an average of approximately 70% of the total payment, such arrangements could have been reduced into only 50%, for example. Another example could be that the public utility is only responsible for part of the capacity charge, and the remaining would be sold under the prevailing market price rate, an arrangement that sounds to be very effective under a competitive electricity generating business. This way, when economic condition of the host country changes sharply, affecting the demand of the project output, the burden will not be solely in the public utility, but also the investors.

2) Reduce the Availability Factor (AF)

The AF should be reduced to commensurate with the actual demand projection. To avoid being mistaken as a result of an over optimistic demand projection, however, the availability factor could be reduced to a level comparable with other power projects in the country. In the case of the Paiton I project, the availability factor may be reduced to around 60% to 75%.

5.3.2. The Risk Mitigation Efforts

1) Encourage a balanced risk sharing

The risks arrangement embodied in the PPA should become more balanced by allowing the private investors to assume certain level of risks. Such major concerns as the market risks, the currency exchange risks, and the force majeure risks should be well distributed equally among the contracted parties, instead of putting the entire burden either to the government or the public utility alone. The parties can arrange certain mechanisms to hedge the risks. If compared to the public entity, the private sectors seem to be more sophisticated in hedging such risks[249].

1) Prepare an appropriate arrangement with local participants

Arrangements with local participants should be better prepared. The hidden political risks beyond a sound local participant should be well understood. Instead of arranging for the local participant to have "free" shares in the project company, it would have probably reduced the risks if the local participant also

[249] Wells, 1999

contributed shares from the initial stage of the project. This way, the local participant would be perceived as being fully involved in the project, thereby, together with other project participants, assuming the risks and being more committed to the project when the relations with the host government eventually turn sour. In addition, local participant arrangements could also be diversified by involving not only the politically well-connected people but also other companies with regular arrangement.

2) The role of the International Arbitration

When the relationship with the host government deteriorated and renegotiation is inevitable, as mentioned earlier, the international arbitration would play a very useful role if it allows for changes and helps the risks reallocation efforts that could be applied under the prevailing economic conditions when such changes cannot be avoided[250]. Instead of limiting its role to interpreting the letter of contracts, the international arbitration would play a very useful role if it were available to handle conflicts over the appropriateness of the contract terms[251]. In other words, instead of freezing the relationship between the host government and the foreign investors under certain contract terms and conditions for long period, which is usually around 20 to 30 years, the contract itself would play a useful role if it allows certain changes under certain prevailing conditions.

The contract may also allow profit and risks sharing under certain conditions. For example, if the market turns out to be a windfall for the private

---

250 Wells, 1999

251 Ibid

entity, the government would be entitled to a certain tax increase. Another example would be if economic condition changes sharply, the availability factor of a power plant under a *take-or-pay* arrangement should be reduced accordingly. In addition, contracts may need to be set to allow renegotiations after certain period to update the initially agreed conditions that may be proved not valid anymore under the prevailing conditions.

5.3.3. The "Mistakes" of IPPs in Indonesia

1. Electricity Market Projection

1) IPPs should rely on the natural growth of the electricity demand, and should also take into account the purchasing power of the regions that desperately need electricity.
2) Use the wholesale electricity tariff of the public utility, instead of the return on equity, as a basis to set up the electricity tariff for the IPP-generated power.

2. The Equity Arrangement

1) Under the "debt-like" equity arrangement, risks should be properly allocated so that the public entity would not assume such a high level of risk as to be politically untenable. Even when the "debt-like" equity arrangement is secured by a government guarantee, the guarantee should be specified in details to avoid misunderstanding or misinterpretation of the guarantee intention.
2) Under the "loan-financed" equity arrangement, it is important to make sure that the local participants, despite their political connections, have certain expertise

that make them capable to be included in the project company. The fact that the "loan-financed" shares could eventually be suspected as corruption practices lead to an assumption that it may be better if the local participants share the risks from the beginning of the project through their equity contribution. Otherwise, if loan-financed equity arrangement cannot be avoided, it should be well announced publicly to avoid controversy.

5.4. Chapter Summary

The Paiton I project deal has been analyzed to the extent that covers the PPA tariff structure, the risks mitigation efforts, and the interpretation of IPPs with respect to demand and price projection and the equity arrangements. The issues and recommendation explored in this chapter are expected to provide the answers for the concerns about the prevailing negative impacts of IPPs in developing countries. However, even though the phenomenon can be explored and the recommendation can be synthesized, the IPPs under renegotiation is in desperate need of solution. For example, when the thesis was final, the Paiton I project had been renegotiating for almost two years with no significant results. Therefore, this thesis does not stop at this point: a possible approach for commercial solution for the Paiton I tariff negotiation would be explored in the three chapters that follow.

Chapter 6: Tariff Benchmarking

6.1. Tariff Benchmarking: Approach

The core problem in the case of the Paiton I project is that while PLN's tariff to consumers was low, PEC's tariff to PLN was high as a result of a high project cost; therefore, PLN could not afford PEC's tariff. Facing this problem, an approach to arrive at a tariff of IPPs-generated power that would minimize the overall cost of power supply while satisfying the consumers' demand within a utility's tariff constraint is developed in this chapter. In other words, the purpose of this chapter is to develop tariff benchmarking for project with the same capacity as the 2x615 MW Paiton I project.

Figure 6.1 shows the simple value chain of electricity generated by private power plants until it reaches the end users. With reference to figure 5.1, Ta is the IPPs' tariff to the utility while Tb is the utility's tariff to the consumers.

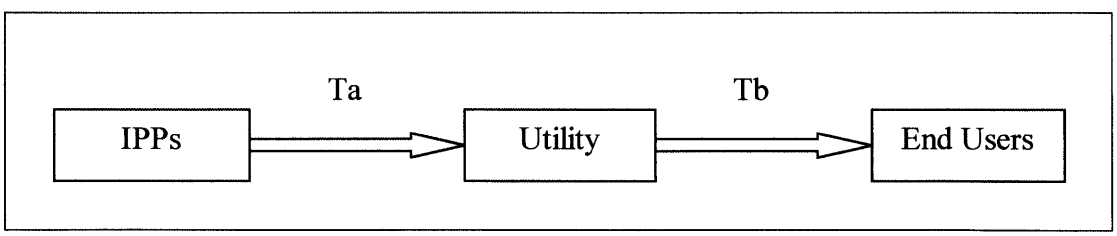


Figure 6.1: The Value Chain of the IPP-s generated Power

There are two approaches to arrive at Ta, the IPPs' tariff to the utility, as follows:

1) The ROE[252]-based Analysis

[252] ROE = Return on Equity

In this analysis, the IPPs would arrive at Ta by considering the total project cost, given a certain rate of ROE, in addition to the fuel cost, and the fixed and the variable O&M cost. In this case, the IPPs do not take Tb into account.

2) The Wholesale Tariff-based Analysis

In this analysis, the IPPs would arrive at Ta by taking Tb into account, in addition to the project cost, the fuel cost, and the fixed and variable O&M cost. In other words, Tb is a variable of Ta; and this calculation does not base on a certain rate of ROE.

As mentioned earlier in section 2.4.3, APEC Energy Working Group suggested that one of the best practice feature for IPPs is to use the wholesale electricity tariff, rather than the rate of return on equity, as the basis for negotiating PPAs[253]. Therefore, according to APEC, the wholesale tariff-based analysis is an appropriate approach to arrive at an IPP tariff.

While other books may refer the two approaches mentioned above as least-cost analysis, the thesis calls the approaches as "tariff benchmarking" since in this thesis, the IPP's tariff to the utility would actually be benchmarked against the utility's tariff to the end consumers.

6.2. Financial Parameters

Financial parameters are being used to measure the viability of a project. Prior to developing a financial model for the tariff benchmarking, it is important to review the

[253] APEC Energy Working Group, "Manual of Best Practice Principles for Independent Power Producers", The APEC Energy Working Group Secretariat: Energy Division, August 1997.

definition of financial parameters to be derived from the financial models developed in this thesis, as follows:

1) **Net Present Value (NPV):** The NPV of a project is the discounted value of the net cash flows before financing less the initial investments[254]. NPV indicates the attractiveness of an investment: the project is desirable if its NPV is positive.

2) **Internal Rate of Return (IRR) on Project:** The IRR of a project is the discount rate that makes the NPV zero. The IRR measures the return on the whole project. The project is desirable if the IRR exceeds the cost of capital (discount rate), which is about 13% in the US, and relatively higher in Asian countries[255].

3) **Return on Equity (ROE):** The ROE of a project is the internal rate of return for the leveraged projected cash flows to be generated by the project[256]. ROE is calculated as the net cash flows after senior debt service divided by total equity investment.

4) **Return on Investment (ROI):** The ROI of a project is the rate of return for the un-leveraged projected cash flows to be generated by the project[257]. ROI is calculated as the net cash flows before financing divided by total investment.

5) **Average Levelized Cost** for power generation: Average levelized cost is calculated as the present value of all costs involved in the project divided by the present value of the net electricity generated throughout the project contract term.

6) **Average Levelized Tariff** for power generation: Average levelized tariff is calculated as the present value of all revenues generated by the project divided by

---

254 Lang, 1998
255 Ibid
256 Ibid
257 Ibid

the present value of the net electricity generated throughout the project contract term.

6.3. Tariff Benchmarking: Methodology

As a tool for tariff benchmarking analysis, a financial model for a power generation plant is developed. The purpose of this model is to calculate the average levelized cost of developing the plant, with the calculation being as follow[258]:

Average levelized cost = (Present Value of cost stream)/(Present Value of output stream)

It is important to remember that the average levelized cost is *not* a tariff, but it provides a simple measure of the average costs of the power generation. Costs involved in a power generation are as follows:

1) Capacity Cost which consists of Capital Cost (component A) and Fixed O&M Cost (component B)
2) Energy Cost which consists of components Fuel Cost (component C) and Variable O&M Cost (component D)

The Fixed and Variable O&M Costs are usually set as fixed values throughout the contract year, and may vary with the exchange rate movement and inflation rate depending on the pricing mechanism agreed upon in the contract. On the other hand, the Fuel Cost is usually renegotiated annually to follow coal price movement[259], and the Capital Cost depends significantly on the project EPC cost and the project cost structure. The majority of the tariff is usually comprised by the Capital Cost and the Fuel Cost; therefore, it is important to understand the sensitivity of the tariff under various

258 Razavi, 1996
259 This assumption follows the arrangement in the Paiton I model PPA

combination of Capital Cost and Fuel Cost. EPC cost, as mentioned earlier in chapter III, comprises the majority of the total project cost. Furthermore, project cost structure (the percentage of the project cost breakdown) is essential, not only to determine the percentage of EPC Cost involved, but also to determine the significance of other factors—such as development cost and debt-financing cost—that contribute to the total project cost. Most importantly, cost structure can be compared to other projects of similar size to figure out project characteristics that may differ[260].

The project average levelized cost would then be benchmarked against the utility's tariff. Figure 6.2 shows the framework of the benchmarking analysis.

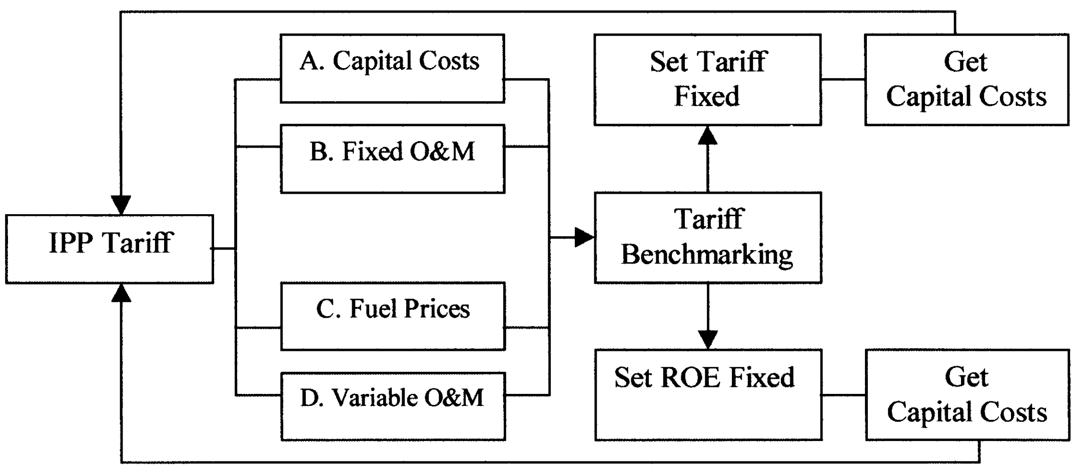


Figure 6.2: The Framework of Tariff Benchmarking Analysis

Given a set of Fixed and Variable O&M Costs and Fuel Cost assumptions, the average levelized costs of Fuel and O&M can be derived. The tariff benchmarking process would then take either one of the following two processes depending on the basis of the initial negotiation between the IPP and the public utility, as follows:

---

260 For example, projects in developed country may need less development cost than those in developing countries.

1) The Wholesale Utility's Tariff

When the utility's tariff is the basis for negotiation by which there will be no increase for this tariff, the utility's tariff would be set fixed as the maximum tariff that could be charged by the IPP. The difference between the utility's tariff and the average levelized costs for Fuel and O&M would serve as an average levelized tariff for the Capital Cost component. This tariff component would serve as a maximum value at which the project ROE would be determined. This tariff component, together with the average levelized costs of Fuel and O&M, would form the IPP tariff.

2) The ROE

When the ROE is the basis for negotiation, the ROE would be set fixed to derive the average levelized tariff for the Capital Cost component (component A). This tariff, together with the average levelized costs of Fuel and O&M, would form the IPP tariff. The difference between the utility's tariff and the IPP tariff would be the basis to adjust the utility's tariff. In this case, if the IPP's tariff is higher than the utility's tariff, then the utility's tariff need to be increased.

In sum, the tariff benchmarking would utilize the average levelized cost for a power plant to be benchmarked against the utility's tariff. As previously indicated, the Capital Cost component of an IPP electricity tariff depends significantly on the project EPC cost and the project cost structure. Therefore, prior to developing tariff benchmarking for a project, it is important to first develop an EPC unit cost analysis (US$/kW) and a cost structure analysis.

As a case study, this thesis develops a tariff benchmarking analysis for a coal-fired power generation project with a capacity of 2x615 MW, the same capacity as the Paiton I project. While the EPC unit cost (US$/kW) can be used to determine the approximate total project cost of a 2x615 MW power plant under a certain cost structure, the cost structure can also be used to determine the dollar amount of the other cost items such as the development cost and the debt-financing cost.

6.4. Project Cost Analysis

This section consists of two parts: the total unit cost (US$/kW) analysis and the cost structure analysis. The purpose of the first part is to obtain the possible range of total project unit cost (US$/kW) for a power plant with the capacity of 2x615 MW, the same capacity as the Paiton I project. Following, the second part analyzed a certain cost structure composition by which the possible range of EPC unit cost (US$/kW) can be obtained. The range of EPC unit cost would be used in the tariff benchmarking calculation to see the sensitivity of the tariff under various EPC unit costs possible and also various fuel costs, which would be explained in later section.

6.4.1. The Total Unit Cost Analysis

A statistical analysis of the total project unit cost (US$/kW) of IPPs around the world is developed. The data[261] used in this analysis is gathered from 46 coal-fired power generation projects that started construction between 1995-2000, excluding the

[261] To preserve confidentiality, the name of the 46 projects, the unit cost of each individual project, and the source of information have not been disclosed. Rather, the thesis reveals only the result of the statistical analysis, in the form of a normal distribution curve of the total project unit costs.

Paiton I project. It is reasonable to fit a normal distribution curve to the unit costs data[262], as shown in figure 6.3.

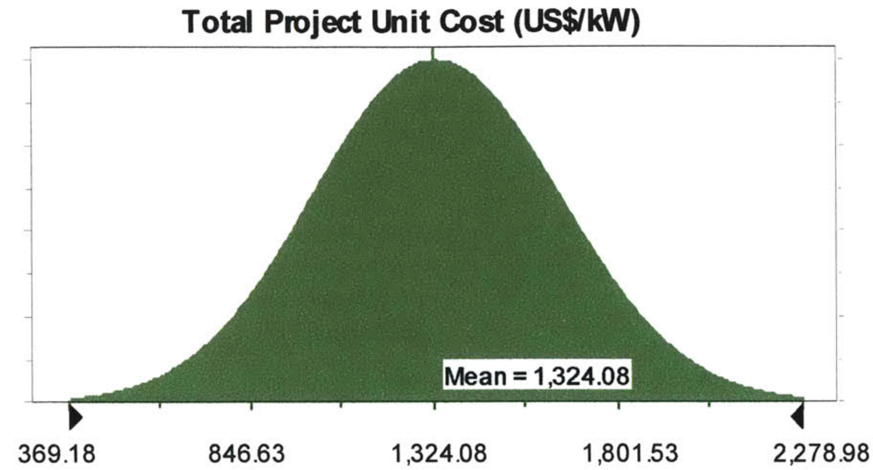


Figure 6.3: Normal Distribution Curve of the Total Project Unit Cost Data (US$/kW)

The statistical parameters derived from this curve include Mean US$ 1,324.08 per kW, and Standard Deviation 318.30. The Paiton I total project unit cost is US$ 2,032.5 per kW, which is in the 98.7 percentile[263]. Other parameters include the unit costs in the 25 percentile[264] and the 75-percentile[265], which are US$ 1,109.39 per kW and US$ 1,538.77 per kW respectively. It is reasonable to assume that the possible total unit cost lies within the 25-percentile and 75-percentile range; however, for simplicity, let us take

---

262 To figure out which type of distribution curve best fits the data, curve fitting tests were conducted, with the result being as follows: 1) Plotting the unit cost data as cumulative distribution suggests that fitting a uniform or linear cumulative probability distribution to this data may not be quite right since there are inflections around a straight line in the plot, and 2) Plotting the unit cost data as normal fractiles suggests that it is reasonable to fit a normal distribution to the data. The inflection appeared in the straight line fit (the uniform cumulative distribution fit) has disappeared.

263 This means that there are only 1.3 projects in a hundred projects that may exceed the value of the Paiton I project unit cost.

264 This means that only 75% of a hundred projects may exceed the 25-percentile value.

265 This means that only 25% of a hundred projects may exceed the 75-percentile value.

the mean value, US$ 1,324.08 per kW, to be a single total project unit cost derived from this statistical analysis.

6.4.2. The Project Cost Structure Analysis

Table 6.1 shows the rearrangement of the Paiton I project cost breakdown structure in table 3.1 to be compared with typical cost structures of other projects with similar capacities and similar business environments. The comparison is demonstrated in table 6.2. The cost structure of the 2x615 MW Paiton I project is compared to the cost structure of two coal-fired power plants with the capacity of 2x660 MW (Project A) and 2x600 MW (Project B)[266]. The cost structure of Project B is actually derived from an international competitive bidding.

Table 6.1: The Paiton I Project Cost Structure

Project Cost Breakdown	The Paiton I Project	
	Cost US$ Million	% of Total Project Cost
EPC Cost (special facility included)	**1,772,300**	**70.9%**
Development Cost	**190,000**	**7.6%**
Development Fee	11,800	
Development Expense	43,200	
Insurance	30,000	
Administration Cost	26,000	
Owner's Engineer	15,000	
Pre-Completion Labor	6,600	
Agency Fees	3,700	
Value added Taxes	53,700	
Initial Working Capital	**40,300**	**1.6%**
Working Capital	25,300	
O&M Staffing	15,000	
Contingency	**3,300**	**0.1%**
Financial Cost	**494,100**	**19.8%**
Interest During Construction	308,200	
MITI Fee	12,300	
Commitment Fee	29,300	
Up front financing fees	144,300	
Total Project Cost	**2,500,000**	**100.0%**

[266] To preserve confidentiality, the name of the projects, the actual cost of the projects, and the source of information have not been disclosed. Rather, the thesis reveals only the cost structure in the form of the cost percentage of the total project cost to be compared with the cost structure of the Paiton I project.

Table 6.2: The comparison of the Paiton I project with two other projects of similar capacities

Project Cost Breakdown	Project A 2x660 MW	The Paiton I 2x615 MW	Project B 2x600 MW	Average
EPC Cost (Special Facility Incl.)	59.53%	70.89%	70.02%	**66.81%**
Development Cost	17.97%	7.60%	4.99%	**10.19%**
Initial Working Capital	1.35%	1.61%	4.99%	**2.65%**
Contingency	9.76%	0.13%	4.99%	**4.96%**
Financial Cost	11.39%	19.76%	15.00%	**15.38%**
Total Project Cost	100.00%	100.00%	100.00%	**100.00%**

Figure 6.4 shows the percentage of the elements of the total project cost averaged from the three projects in table .2. The two largest components are the EPC cost and the financing cost, which are 66.8% and 15.4% of the total project cost respectively. The remaining costs are development cost, contingency, and initial working capital cost.

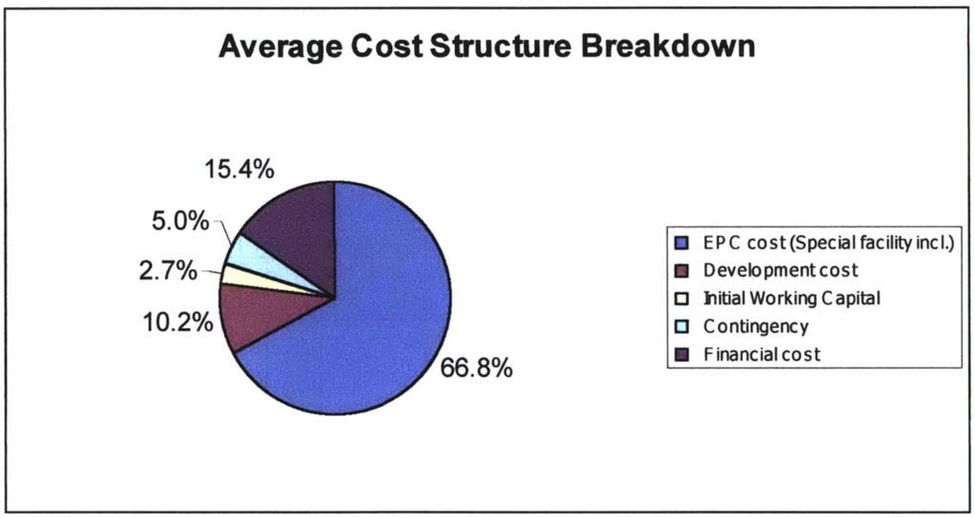


Figure 6.4: The Average Cost Structure

The average of these three project cost structures will be used as the base project cost structure for further calculation in this thesis. Even though this averaging method is considered as a rough approximation, the result shows a similarity in trend by which the largest cost is the EPC cost, followed by financial cost and development cost respectively. This averaging method is used because of the unavailability of cost structure data from considerable number of coal-fired power plants with similar capacities. A more fine approach could be a statistical analysis of an adequate amount of samples of historical project cost structure data of coal-fired power plants with similar capacities. Similarity in capacity is important because of the economy of scale that the projects may realize. A further research in this area is highly encouraged.

6.4.3. The EPC Costs for a 2x615 MW Power Plant

Up to this point, we have been incorporated results derived from the following analyses:

1) The cost auditor report[267] for the 2x615 MW Paiton I project, resulting in an EPC benchmark cost of US$ 1,033 million.
2) The statistical analysis, resulting in a total project unit cost of US$ 1,324.08 per kW.
3) The cost structure analysis, resulting in a cost structure approximation by which 66.81% of the total project cost is the EPC cost.

Based on these three results, the range of the possible EPC unit cost for a 2x615 MW can be determined, as shown in table 6.3. From 2) and 3), the EPC unit cost—the 66.81% of US$ 1,324.08 per kW—would be US$ 884.67 per kW. From 1), the EPC unit cost—the value of US$ 1.033 billion divided by 1,230,000 kW—would be US$ 839.84 per kW.

[267] An audit, conducted in late 1999 by a Canadian engineering and construction company SNC-Lavalin Group, priced the Paiton I EPC cost at US$ 1.033 billion (with a $\pm$ 20% tolerance)

Table 6.3: The range of EPC unit cost (US$) for a 2x615 MW

EPC Unit Cost US$/kW	Total Project Unit Cost US$/kW	Capacity kW	Total EPC Cost US$	Total Project Cost US$
839.84	1,256.98	1,230,000	1,033,000,000	1,546,084,082
884.67	1,324.08	1,230,000	1,088,144,446	1,628,618,400

In short, it is reasonable to conclude that EPC unit cost for a 2x615 MW falls approximately in the range between US$ 839.84 per kW and US$ 884.67 per kW.

6.5. Tariff Benchmarking

This section provides the tariff benchmarking analysis for a 2x615 MW power plant. A financial model is developed for this purpose; figure 6.5 shows the project cost structure breakdown for this model. The thesis author develops the model based on certain financial parameters and technical parameters. The technical parameters closely follow those of the Paiton I power project mentioned earlier[268], as follows:

a) Availability Factor = 83%,

b) Net plant heat rate = 2447 kcal/kWh,

c) HHV coal = 5215 kg/kcal,

d) Contract terms = 30 years

e) Fixed O&M = 0.3220 c/kWh[269]

f) Variable O&M = 0.1552 cents/kWh[270]

On the other hand, with respect to financial parameters, the debt equity ratio is equal to that of the Paiton I project, which is 72.8% : 27.3%, while the debt-financing scheme varies according to the relative composition of commercial loan and soft loan.

268 in Chapter 3

269 The average levelized fixed O&M cost, with 14% discount rate.

270 The average levelized variable O&M Cost, with 14% discount rate.

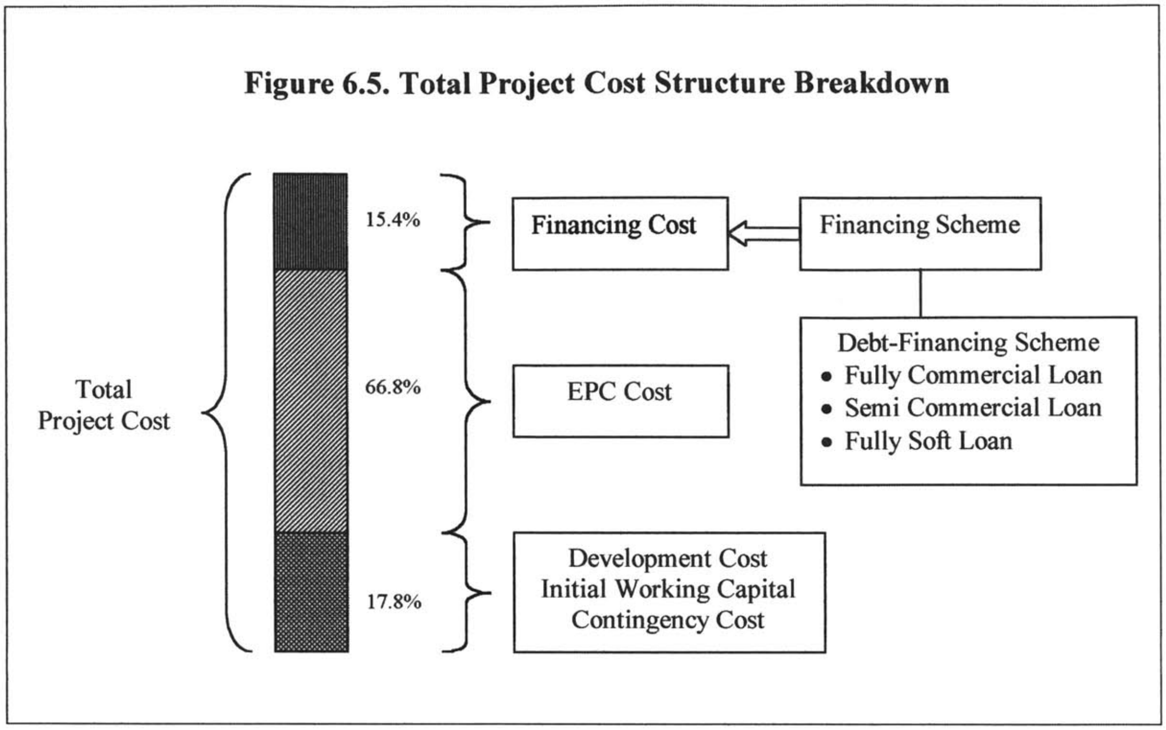


Figure 6.5: The Components of Total Project Cost

Appendices 1-7 of this chapter show the result of the analysis. Each appendix indicates the financial and technical parameters being used. The tariff components follow those of the Paiton I project: the Capital cost (component A), the Fixed O&M cost (component B), the Fuel cost (component C), and the Variable O&M cost (component D). The sensitivity of the tariff is tested against the following variables:

1) The possible range of EPC Unit Costs: US$ 839.84 per kW and US$ 884.67 per kW
2) The Coal Prices: US$ 21.0 per tons, US$ 23.0 per tons[271], US$ 30.0 per tons[272], US$ 34.9[273] per tons, US$ 39.7 per tons[274].

---

[271] US$ 23 per tons is the average of US$ 22 per tons, the Banjarmasin spot price in December 1998, and US$ 24 per tons, the coal in the Asian market in 1999 (PLN Press Release, "Background", 1999).

[272] US$ 30 per tons is included to serve as a middle number.

3) The Debt-Financing Scheme scenario[275]:

    a) 100% Soft Loan (fully soft loan)

    b) 25% Commercial Loan and 75% Soft Loan (majority soft loan)

    c) 50% Commercial Loan and 50% Soft Loan (semi commercial loan)

    d) 75% Commercial Loan and 25% Soft Loan (majority commercial loan)

    e) 100% Commercial Loan[276] (fully commercial loan)

The loan used in the calculation is estimated to carry interest rates of 11% and 5% for the commercial loan and soft loan respectively.

While readers can view the results of the tariff benchmarking in the appendices, the following section provides an example of the tariff benchmarking analysis using the 100% soft loan scheme in the appendix 1 and appendix 2 for the ROE-based negotiation and for the Wholesale utility's tariff-based negotiation respectively.

6.5.1. The ROE-based analysis[277]

As shown in appendix 1—tariff benchmarking with fully soft loan scheme whereby the ROE is set fixed—when the ROE is set fixed, the tariff derived would experience the following trend:

---

273 US$ 34.9 per tons is equal to Rp. 71.126 per kg, the coal price allowance in 1997, under the exchange rate Rp. 2.038 per US$ agreed upon in the Paiton I PPA.

274 US$ 39.7 per tons is the coal price in 1998 under the FSA negotiated with BHP (PLN Press Release, "Background", 1999)

275 As shown in Figure 5.5, debt-financing scheme may significantly affect the financial cost.

276 The lenders follow those of the Paiton I project.

277 When the IRR is the basis for negotiation by which there could be certain increase in the utility's tariff, the IRR would be set fixed to derive the average levelized tariff for the capital cost component. This tariff, together with the average levelized costs of fuel and O&M, would eventually form the IPP tariff. The difference between the utility's tariff and the IPP tariff would be the basis to adjust the utility's tariff.

1) Tariff Sensitivity on Coal Price

The tariff increases as the coal price increases. The higher the fuel cost, the higher the IPP needs to charge the utility, if the arrangement is that the utility would assume the fuel price fluctuation risk. To illustrate, in appendix 1, under the EPC cost US$ 839.84 per kW and ROE 17%, the tariffs are US$ 4.0287 cents/kWh and US$ 4.8477 cents/kWh for the coal prices US$ 21 per tons and US$ 39.7 per tons respectively, as shown in figure 6.6.

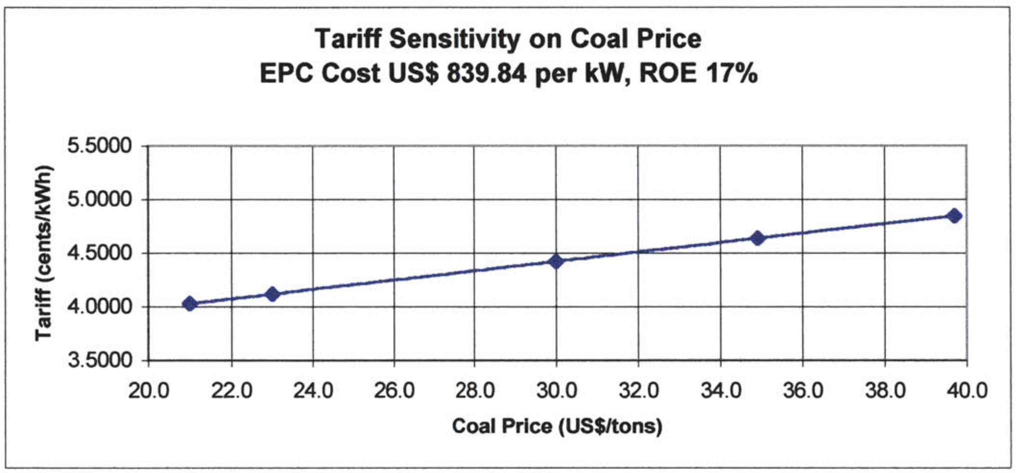


Figure 6.6: Tariff Sensitivity on Coal Price for EPC Cost US$ 839.84 per kW and ROE 17%

2) Tariff Sensitivity on ROE

The tariff increases as the ROE increases. The higher the ROE to compensate the project sponsors' equity investments, the higher the Capital Cost component (component A); as a result, the tariff that the IPP needs to charge the utility would be higher. To illustrate, in appendix 1, under the EPC Cost US$ 839.84 per kW and coal price US$ 21 per tons, the tariffs are US$ 3.8971 cents/kWh and US$ 4.0287 cents/kWh for ROEs 14% and 17% respectively, as shown in figure 6.7.

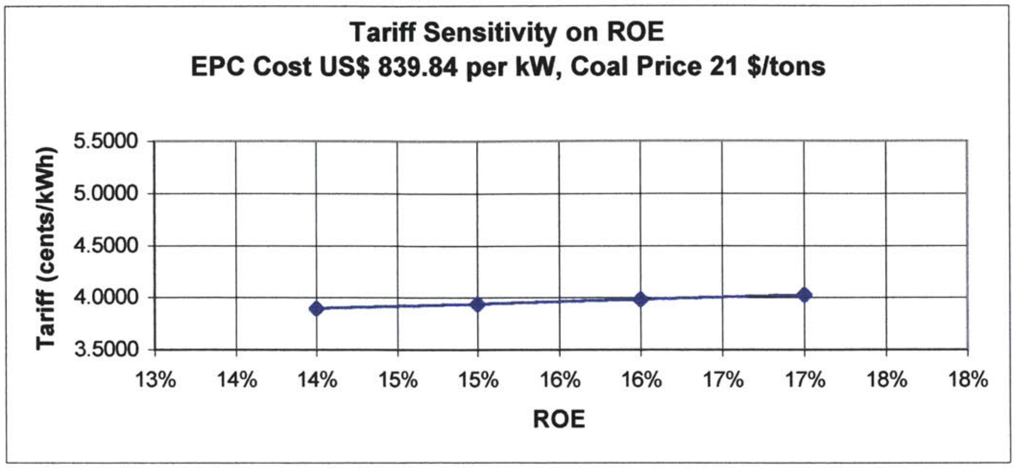


Figure 6.7: Tariff Sensitivity on ROE for EPC Cost 839.84 $/kW and Coal Price 21 $/tons

3) Tariff Sensitivity on EPC Unit Cost

The tariff increases as the EPC unit cost increases. The more expensive the IPP project is, the higher the Capital Cost component that the IPP needs to charge. To illustrate, in appendix 1, under ROE 17% and the coal price US$ 21 per tons, the tariffs are US$ 4.0287 cents/kWh and US$ 4.1693 cents/kWh for EPC Unit cost US$ 839.84 per kW and US$ 884.67 per kW respectively, as shown in figure 6.8.

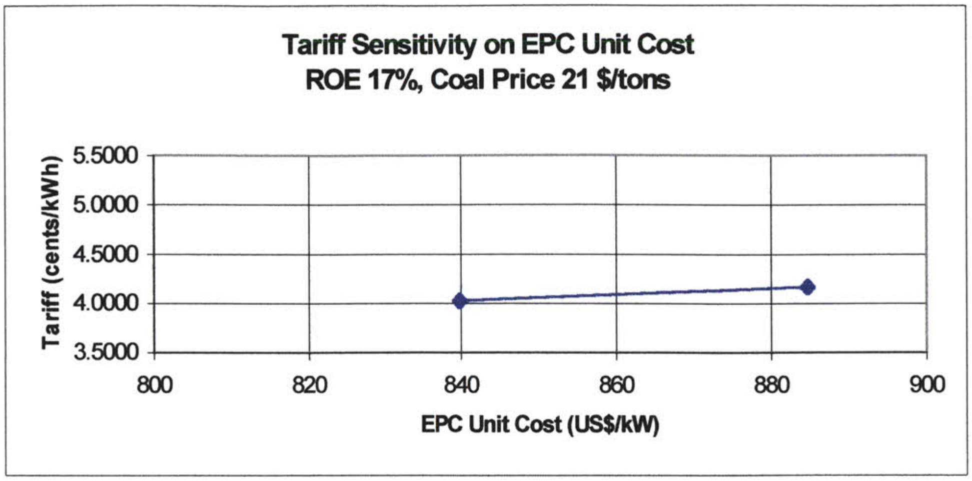


Figure 6.8: Tariff Sensitivity on EPC Unit Cost for ROE 17% and Coal Price 21 $/tons

4) Tariff Sensitivity on Debt-Financing Scheme

The tariff increases as the magnitude of commercial loan increases. The higher the magnitude of commercial loan, the higher the interest expenses; as a result, the Capital Cost component would be higher as well. To illustrate, under the EPC Cost US$ 839.84 per kW, coal price US$ 21 per tons, and ROE 17%, the tariffs are US$ 4.0287 cents/kWh for 0% commercial loan, US$ 4.2309 cents/kWh for 25% commercial loan, US$ 4.2351 for 50% commercial loan, US$ 4.3179 cents/kWh for 75% commercial loan, and US$ 4.4693 for 100% commercial loan, as shown in figure 6.9.

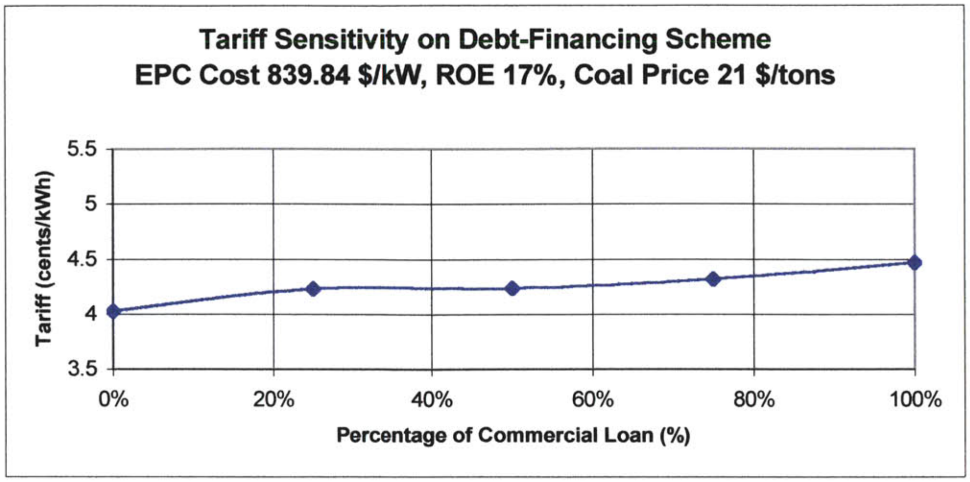


Figure 6.9: Tariff Sensitivity on Debt-Financing Scheme

Despite these trends, these results can be used by a state-owned utility to figure out the level of tariff increase that allows an IPP to have a certain percentage of ROE. To illustrate, if the current utility's tariff is US$ 3.2 cents/kWh[278] and the utility allows an IPP developing a power project (with EPC Cost US$ 839.84 per kW under a fully commercial debt-financing scheme and a coal price of US$ 21 per tons) to have 14% ROE, the utility should increase its tariff to US$ 4.3378 cents/kWh to afford the IPP's tariff to the utility. If the coal price materializes to be higher, for example to US$ 39.7 per tons, and the IPP under the PPA would pass through this increase to the utility, then the utility eventually would pass this coal price increase to consumers by increasing its tariff to approximately US$ 5.1568 cents/kWh. This dynamics is demonstrated in figure 6.10 that shows tariffs under combination of various ROEs and Coal Price, under an EPC Unit Cost of US$ 839.84 per kW and fully soft loan-financing scheme (Appendix 1). Figure 6.11 shows the same combination under a semi commercial debt-financing scheme while figure 6.12 shows that under a fully commercial loan scheme.

[278] This tariff is a subsidized tariff; the amount includes the transmission and distribution costs.

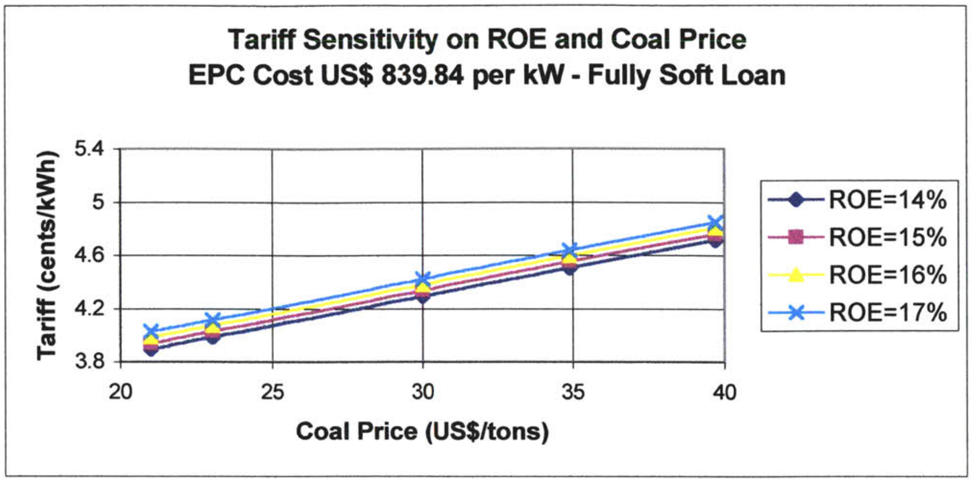


Figure 6.10: Tariff Sensitivity for EPC Cost US$ 839.84 per kW and fully soft loan-financing scheme

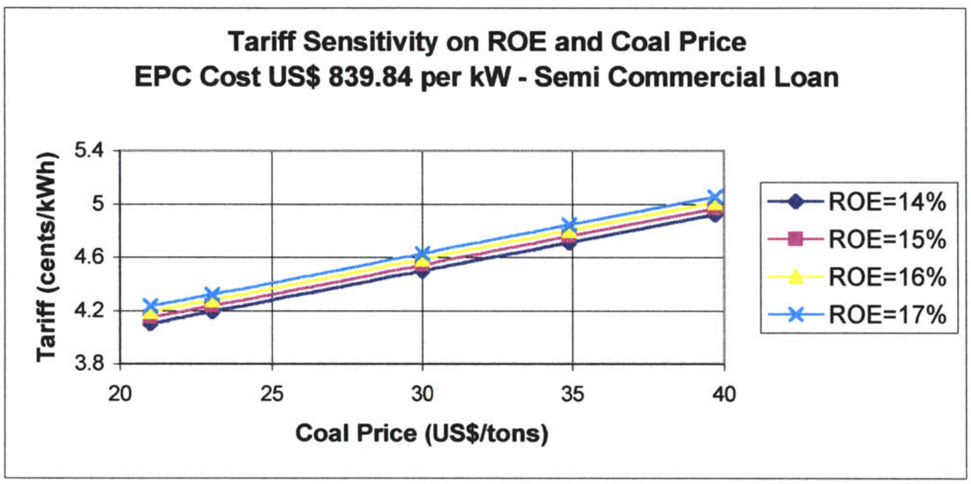


Figure 6.11: Tariff Sensitivity for EPC Cost US$ 839.84 per kW and semi commercial loan scheme

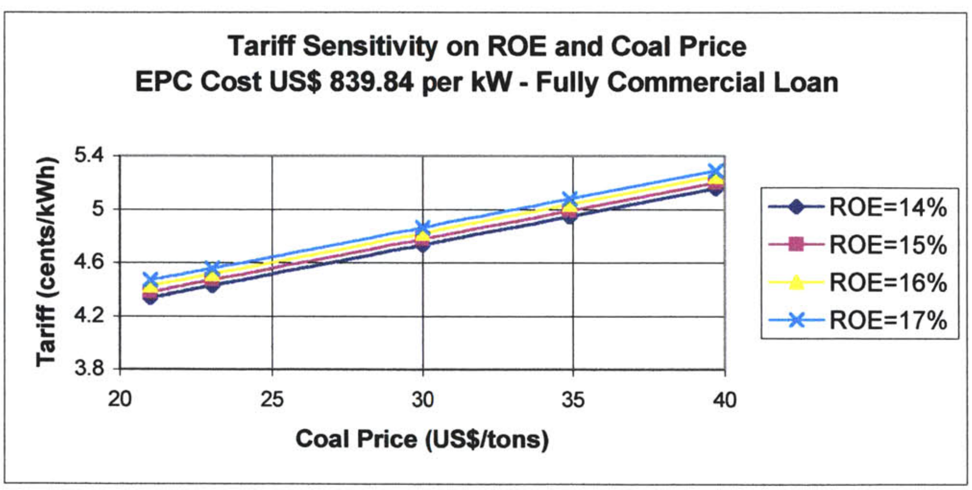


Figure 6.12: Tariff Sensitivity for EPC Cost US$ 839.84 per kW and fully commercial loan scheme

6.5.2. The Utility's Tariff-based Analysis[279]

As shown in appendix 2—tariff benchmarking with fully soft loan scheme whereby the tariff is set fixed—when the tariff is set fixed, the ROE derived would experience the following trend:

1) ROE Sensitivity on Coal Price

The ROE decreases as the coal price increases. Under a fixed tariff, the higher the fuel cost, the lower the Capital Cost component, thereby resulting in a lower ROE that the IPP could realize. To illustrate, in appendix 2, under the EPC cost US$ 839.84 per kW and Tariff US$ 4.1 cents/kWh, the ROE are 18.63% and –0.05% for the coal prices US$ 21 per tons and US$ 39.7 per tons respectively, as shown in figure 6.13.

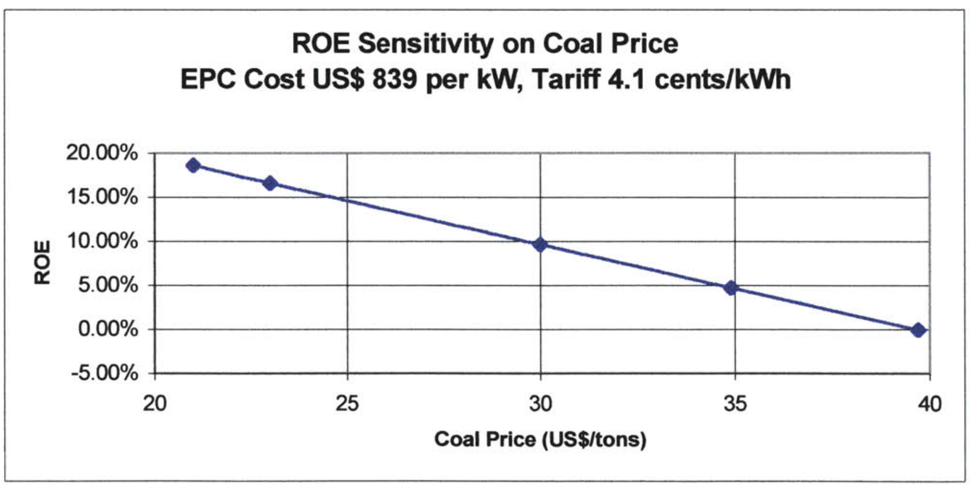


Figure 6.13: Tariff Sensitivity on Coal Price for EPC Cost US$ 839.84 per kW and Tariff 4.1 c/kWh

[279] When the utility's tariff is the basis for negotiation by which there will be no increase for this tariff, the utility's tariff would be set fixed as the maximum tariff that could be charged by the IPP. The difference between the utility's tariff and the average levelized costs of fuel and O&M would serve as an average levelized tariff for the capital cost component. This tariff component would serve as a maximum value at which the project IRR would be determined. This component, together with the average levelized costs of fuel and O&M, would eventually form the IPP tariff.

2) ROE Sensitivity on Tariff

The ROE increases as the tariff increases. The higher the tariff, the higher the Capital Cost component (component A); as a result, the ROE that the IPP could realize would be higher. To illustrate, in appendix 2, under the EPC Cost US$ 839.84 per kW and coal price US$ 21 per tons, the ROE are 11.79% and 18.63% for tariffs US$ 3.8 cents/kWh and US$ 4.1 cents/kWh respectively, as shown in figure 6.14.

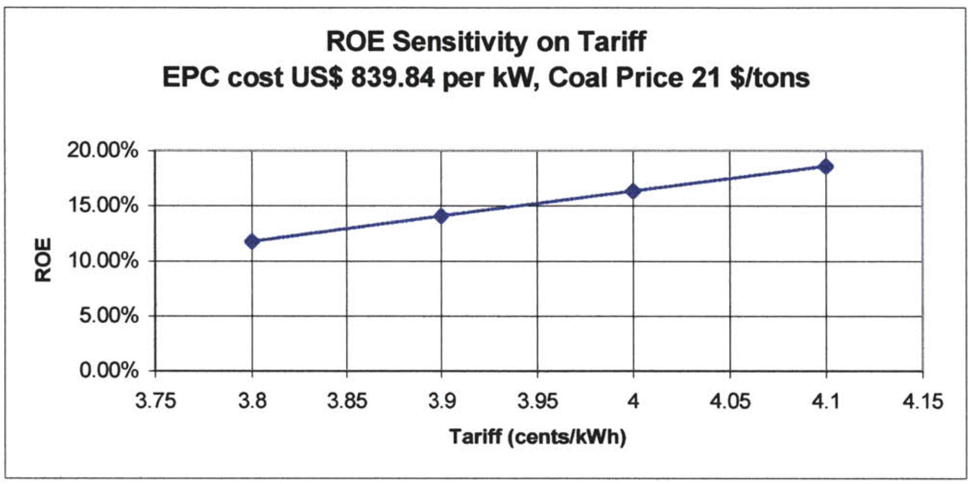


Figure 6.14: ROE Sensitivity on Tariff for EPC Cost 839.84 $/kW and Coal Price 21 $/tons

3) ROE Sensitivity on EPC Unit Cost

The ROE decreases as the EPC unit cost increases. The more expensive the IPP project is, the lower the ROE that the IPP could realize. To illustrate, in appendix 2, under tariff 4.1 cents/kWh and the coal price US$ 21 per tons, the ROEs are 18.63% and 15.50% for EPC Unit cost US$ 839.84 per kW and US$ 884.67 per kW respectively, as shown in figure 6.15.

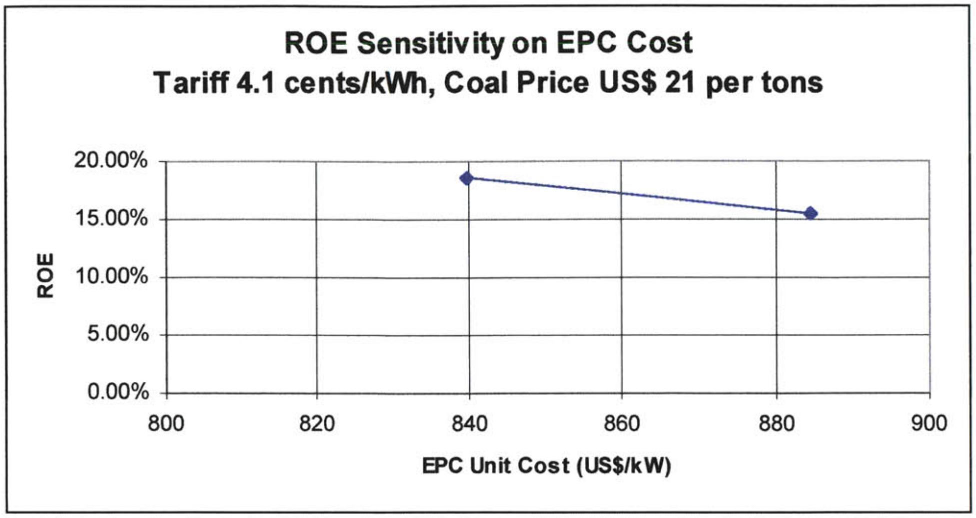


Figure 6.15: ROE Sensitivity on EPC Unit Cost for Tariff 4.1 cents/kWh and Coal Price 21 $/tons

4) ROE Sensitivity on Debt-Financing Scheme

The ROE decreases as the magnitude of commercial loan increases. The higher the magnitude of commercial loan, the higher the interest expenses; as a result, under a fixed tariff, the ROE that the IPP could realize would be lower. To illustrate, under the EPC Cost US$ 839.84 per kW, coal price US$ 21 per tons, and Tariff 4.1 cents/kWh, the ROEs are 18.63% for 0% commercial loan, 14.01% for 25% commercial loan, 13.92% for 50% commercial loan, 12.94% for 75% commercial loan, and 8.58% for 100% commercial loan, as shown in figure 6.16.

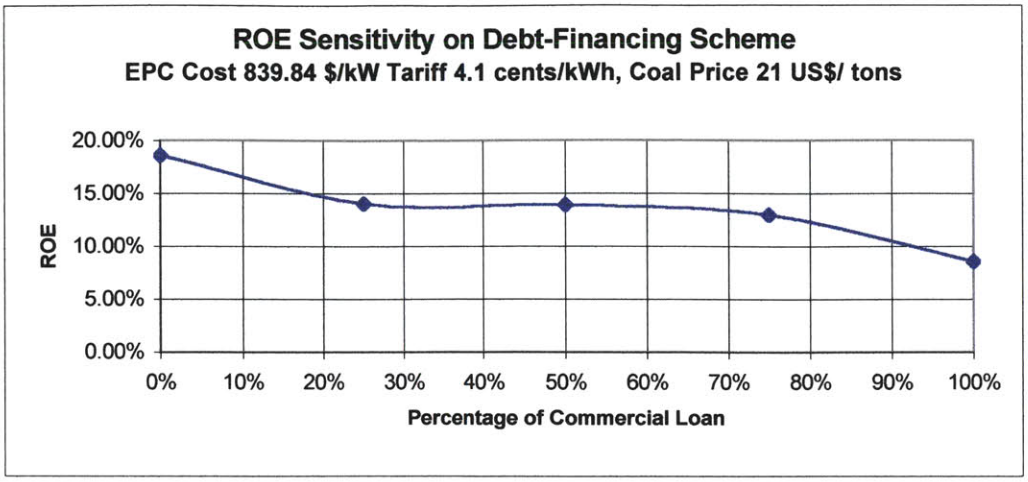


Figure 6.16: ROE Sensitivity on Debt-Financing Scheme

Despite these trends, these results can be used by a state-owned utility to figure out the ROE that an IPP may realize if a fixed tariff were to be set or negotiated with the IPP. To illustrate, in appendix 2, if the utility wants the IPP to lower down the IPP's tariff to US$ 4.1 cents/kWh, the IPP should give up certain percentage of its ROE, realizing only approximately 18.63%. In addition, to realize this 18.63%, the IPP should also negotiate a lower coal price to approximately US$ 21 per tons; high expense in fuel cost would significantly reduce ROE. Figure 6.17 shows ROEs under combination of various tariffs and Coal Price, under an EPC Unit Cost of US$ 839.84 per kW and fully soft loan-financing scheme (Appendix 2). Figure 6.18 shows the same combination under a semi commercial debt-financing scheme while figure 6.19 shows that under a fully commercial loan scheme.

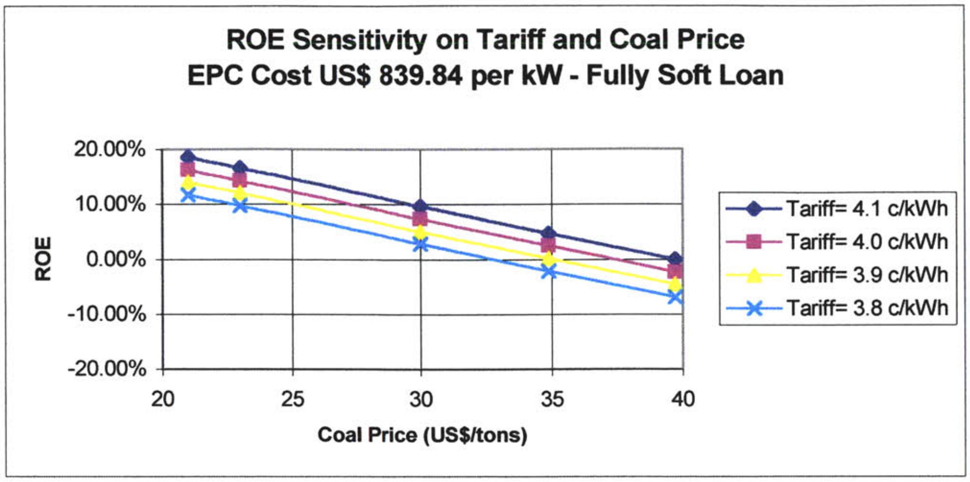


Figure 6.17: ROE Sensitivity for EPC Cost US$ 839.84 per kW and fully soft loan scheme

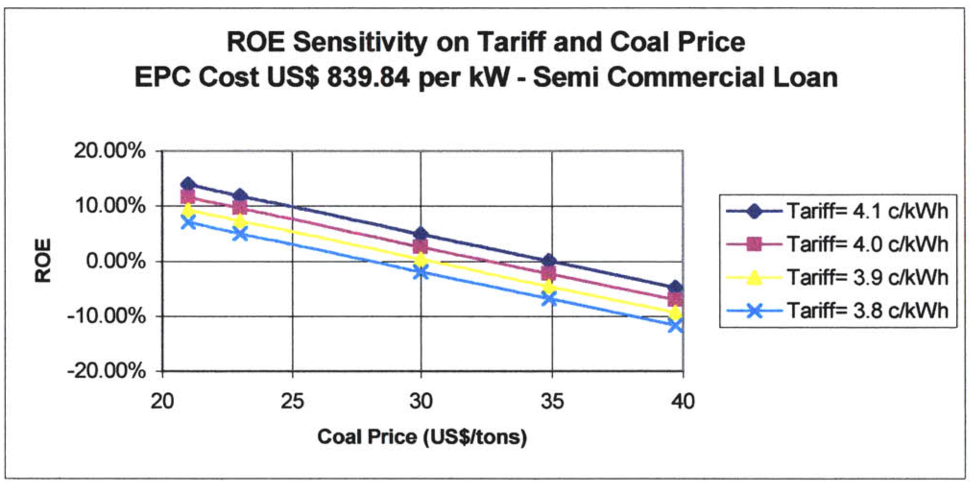


Figure 6.18: ROE Sensitivity for EPC Cost US$ 839.84 per kW and semi commercial loan scheme

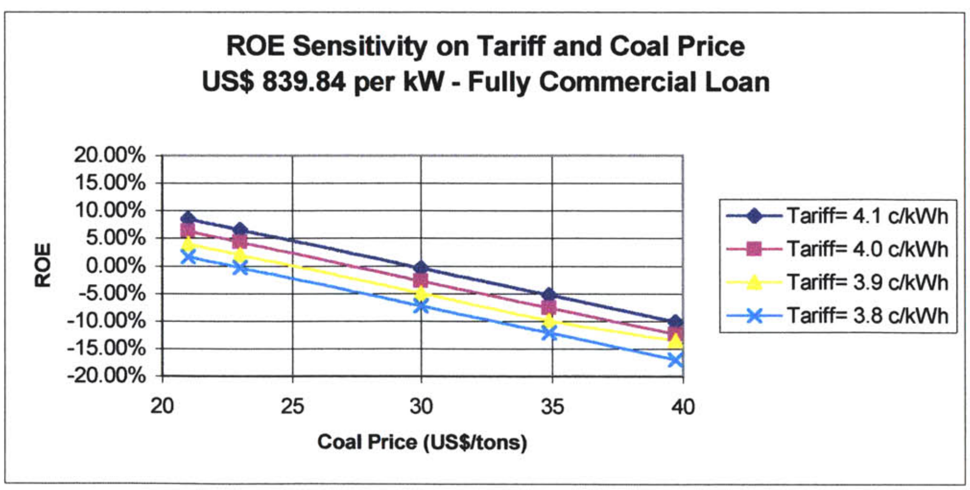


Figure 6.19:Figure 5.19. ROE Sensitivity for EPC Cost US$ 839.84/kW and fully commercial loan

In sum, tariff-benchmarking analysis may be conducted with various scenarios depending on the purpose of negotiation. This analysis can be used to assess whether a tariff offered by an IPP to a utility is reasonable or whether an increase in the utility's tariff to the consumers (and how high the increase should be) is needed to allow the private entity to assume a certain ROE. In addition, this benchmarking analysis can be used both during the initial contract negotiation between a utility and an IPP and during contract renegotiation process if under certain conditions the agreed upon tariffs need to be adjusted. This benchmarking analysis can also aid in figuring the most appropriate combination of certain parameters (ROE, coal price, EPC unit cost, debt-financing scheme, etc.) and which parameters should be adjusted to arrive at a desirable solution regarding an increase or decrease in the utility's tariff to consumers and/or in the IPP's tariff to the utility.

6.6. Chapter Summary

This chapter provides the tariff benchmarking analysis for a power plant of 2x615 MW capacity. The methodology of the analysis is outlined, supplemented with examples of benchmarking process under various scenarios. This analysis should aid the contracted parties, the power seller and purchaser, in the initial negotiation and/or in the renegotiation to figure out the most appropriate combination of parameters under certain constraints. The tariff benchmarking developed in this chapter would be used to identify the critical parameters of an IPP tariff. For this purpose, the Paiton I project is still the case study. The following chapters would provide the financial analysis for the Paiton I project and an approach to arrive at a commercial solution for renegotiation purpose.

Appendix 1: TARIFF BENCHMARKING: ROE SET FIXED (FULLY SOFT LOAN)

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan

% of Total Loan	Lender	Repayment	Interest
0%	Commercial Loan	12 years	11%
100%	Soft Loan	12 years	5%

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh

Variables

1. ROE Set Fixed
2. EPC Cost (US$/kW)
3. Coal Price ($/tons)

Notes:
ALC = Average Levelized Cost

ROE Set Fixed 17%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	17.00%	**2.6347**	0.3220	0.9197	0.1522	**4.0287**	3.3839	17.00%	**2.7754**	0.3220	0.9197	0.1522	**4.1693**
23.0	3.3707	17.00%	**2.6347**	0.3220	1.0073	0.1522	**4.1163**	3.4715	17.00%	**2.7754**	0.3220	1.0073	0.1522	**4.2569**
30.0	3.6772	17.00%	**2.6347**	0.3220	1.3139	0.1522	**4.4229**	3.7781	17.00%	**2.7754**	0.3220	1.3139	0.1522	**4.5635**
34.9	3.8918	17.00%	**2.6347**	0.3220	1.5285	0.1522	**4.6375**	3.9927	17.00%	**2.7754**	0.3220	1.5285	0.1522	**4.7781**
39.7	4.1021	17.00%	**2.6347**	0.3220	1.7388	0.1522	**4.8477**	4.2029	17.00%	**2.7754**	0.3220	1.7388	0.1522	**4.9883**

ROE Set Fixed 16%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	16.00%	**2.5908**	0.3220	0.9197	0.1522	**3.9848**	3.3839	16.00%	**2.7292**	0.3220	0.9197	0.1522	**4.1231**
23.0	3.3707	16.00%	**2.5908**	0.3220	1.0073	0.1522	**4.0724**	3.4715	16.00%	**2.7292**	0.3220	1.0073	0.1522	**4.2107**
30.0	3.6772	16.00%	**2.5908**	0.3220	1.3139	0.1522	**4.3790**	3.7781	16.00%	**2.7292**	0.3220	1.3139	0.1522	**4.5173**
34.9	3.8918	16.00%	**2.5908**	0.3220	1.5285	0.1522	**4.5936**	3.9927	16.00%	**2.7292**	0.3220	1.5285	0.1522	**4.7319**
39.7	4.1021	16.00%	**2.5908**	0.3220	1.7388	0.1522	**4.8038**	4.2029	16.00%	**2.7292**	0.3220	1.7388	0.1522	**4.9421**

ROE Set Fixed 15%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	15.00%	**2.5470**	0.3220	0.9197	0.1522	**3.9410**	3.3839	15.00%	**2.6830**	0.3220	0.9197	0.1522	**4.0769**
23.0	3.3707	15.00%	**2.5470**	0.3220	1.0073	0.1522	**4.0286**	3.4715	15.00%	**2.6830**	0.3220	1.0073	0.1522	**4.1645**
30.0	3.6772	15.00%	**2.5470**	0.3220	1.3139	0.1522	**4.3351**	3.7781	15.00%	**2.6830**	0.3220	1.3139	0.1522	**4.4711**
34.9	3.8918	15.00%	**2.5470**	0.3220	1.5285	0.1522	**4.5497**	3.9927	15.00%	**2.6830**	0.3220	1.5285	0.1522	**4.6857**
39.7	4.1021	15.00%	**2.5470**	0.3220	1.7388	0.1522	**4.7600**	4.2029	15.00%	**2.6830**	0.3220	1.7388	0.1522	**4.8959**

ROE Set Fixed 14%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	14.00%	**2.5031**	0.3220	0.9197	0.1522	**3.8971**	3.3839	14.00%	**2.6368**	0.3220	0.9197	0.1522	**4.0307**
23.0	3.3707	14.00%	**2.5031**	0.3220	1.0073	0.1522	**3.9847**	3.4715	14.00%	**2.6368**	0.3220	1.0073	0.1522	**4.1183**
30.0	3.6772	14.00%	**2.5031**	0.3220	1.3139	0.1522	**4.2913**	3.7781	14.00%	**2.6368**	0.3220	1.3139	0.1522	**4.4249**
34.9	3.8918	14.00%	**2.5031**	0.3220	1.5285	0.1522	**4.5059**	3.9927	14.00%	**2.6368**	0.3220	1.5285	0.1522	**4.6395**
39.7	4.1021	14.00%	**2.5031**	0.3220	1.7388	0.1522	**4.7161**	4.2029	14.00%	**2.6368**	0.3220	1.7388	0.1522	**4.8497**

Appendix 2: TARIFF BENCHMARKING: TARIFF SET FIXED (FULLY SOFT LOAN)

Financial Parameters				Technical Parameters			Variables
1. Debt Equity Ratio 73%/27%				1. Net Dependable Capacity	2x615	MW	1. Tariff Set Fixed (c/kWh)
2. Loan				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**	3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
0%	**Commercial Loan**	12 years	11%	4. HHV Coal	5215	kg/kcal	
100%	**Soft Loan**	12 years	5%	5. Contract Terms	30	years	Notes:
3. Discount Rate	14%			6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
				7. Variable O&M	0.1522	c/kWh	

Tariff Set Fixed 4.1

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	**18.63%**	2.7060	0.3220	0.9197	0.1522	4.1	3.3839	**15.50%**	2.7060	0.3220	0.9197	0.1522	4.1
23.0	3.3707	**16.63%**	2.6184	0.3220	1.0073	0.1522	4.1	3.4715	**13.60%**	2.6184	0.3220	1.0073	0.1522	4.1
30.0	3.6772	**9.64%**	2.3118	0.3220	1.3139	0.1522	4.1	3.7781	**6.97%**	2.3118	0.3220	1.3139	0.1522	4.1
34.9	3.8918	**4.74%**	2.0972	0.3220	1.5285	0.1522	4.1	3.9927	**2.32%**	2.0972	0.3220	1.5285	0.1522	4.1
39.7	4.1021	**-0.05%**	1.8870	0.3220	1.7388	0.1522	4.1	4.2029	**-2.23%**	1.8870	0.3220	1.7388	0.1522	4.1

Tariff Set Fixed 4.0 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	**16.35%**	2.6060	0.3220	0.9197	0.1522	4.0	3.3839	**13.33%**	2.6060	0.3220	0.9197	0.1522	4.0
23.0	3.3707	**14.35%**	2.5184	0.3220	1.0073	0.1522	4.0	3.4715	**11.44%**	2.5184	0.3220	1.0073	0.1522	4.0
30.0	3.6772	**7.36%**	2.2118	0.3220	1.3139	0.1522	4.0	3.7781	**4.80%**	2.2118	0.3220	1.3139	0.1522	4.0
34.9	3.8918	**2.46%**	1.9972	0.3220	1.5285	0.1522	4.0	3.9927	**0.16%**	1.9972	0.3220	1.5285	0.1522	4.0
39.7	4.1021	**-2.33%**	1.7870	0.3220	1.7388	0.1522	4.0	4.2029	**-4.39%**	1.7870	0.3220	1.7388	0.1522	4.0

Tariff Set Fixed 3.9 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	**14.07%**	2.5060	0.3220	0.9197	0.1522	3.9	3.3839	**11.17%**	2.5060	0.3220	0.9197	0.1522	3.9
23.0	3.3707	**12.07%**	2.4184	0.3220	1.0073	0.1522	3.9	3.4715	**9.27%**	2.4184	0.3220	1.0073	0.1522	3.9
30.0	3.6772	**5.08%**	2.1118	0.3220	1.3139	0.1522	3.9	3.7781	**2.64%**	2.1118	0.3220	1.3139	0.1522	3.9
34.9	3.8918	**0.18%**	1.8972	0.3220	1.5285	0.1522	3.9	3.9927	**-2.01%**	1.8972	0.3220	1.5285	0.1522	3.9
39.7	4.1021	**-4.61%**	1.6870	0.3220	1.7388	0.1522	3.9	4.2029	**-6.56%**	1.6870	0.3220	1.7388	0.1522	3.9

Tariff Set Fixed 3.8 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.2831	**11.79%**	2.4060	0.3220	0.9197	0.1522	3.8	3.3839	**9.01%**	2.4060	0.3220	0.9197	0.1522	3.8
23.0	3.3707	**9.79%**	2.3184	0.3220	1.0073	0.1522	3.8	3.4715	**7.11%**	2.3184	0.3220	1.0073	0.1522	3.8
30.0	3.6772	**2.80%**	2.0118	0.3220	1.3139	0.1522	3.8	3.7781	**0.47%**	2.0118	0.3220	1.3139	0.1522	3.8
34.9	3.8918	**-2.10%**	1.7972	0.3220	1.5285	0.1522	3.8	3.9927	**-4.17%**	1.7972	0.3220	1.5285	0.1522	3.8
39.7	4.1021	**-6.89%**	1.5870	0.3220	1.7388	0.1522	3.8	4.2029	**-8.72%**	1.5870	0.3220	1.7388	0.1522	3.8

Appendix 3: TARIFF BENCHMARKING: ROE SET FIXED (MAJORITY SOFT LOAN)

Financial Parameters					Technical Parameters			Variables
1. Debt Equity Ratio 73%/27%					1. Net Dependable Capacity	2x615	MW	1. ROE Set Fixed
2. Loan					2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**		3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
25%	Commercial Loan	12 years	11%		4. HHV Coal	5215	kg/kcal	
75%	Soft Loan	12 years	5%		5. Contract Terms	30	years	Notes:
3. Discount Rate	14%				6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
					7. Variable O&M	0.1522	c/kWh	

ROE Set Fixed 17%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	17.00%	**2.8369**	0.3220	0.9197	0.1522	**4.2309**	3.5969	17.00%	**2.9884**	0.3220	0.9197	0.1522	**4.3824**
23.0	3.5729	17.00%	**2.8369**	0.3220	1.0073	0.1522	**4.3185**	3.6845	17.00%	**2.9884**	0.3220	1.0073	0.1522	**4.4699**
30.0	3.8795	17.00%	**2.8369**	0.3220	1.3139	0.1522	**4.6251**	3.9911	17.00%	**2.9884**	0.3220	1.3139	0.1522	**4.7765**
34.9	4.0941	17.00%	**2.8369**	0.3220	1.5285	0.1522	**4.8397**	4.2057	17.00%	**2.9884**	0.3220	1.5285	0.1522	**4.9911**
39.7	4.3043	17.00%	**2.8369**	0.3220	1.7388	0.1522	**5.0499**	4.4159	17.00%	**2.9884**	0.3220	1.7388	0.1522	**5.2014**

ROE Set Fixed 16%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	16.00%	**2.7931**	0.3220	0.9197	0.1522	**4.1870**	3.5969	16.00%	**2.9422**	0.3220	0.9197	0.1522	**4.3362**
23.0	3.5729	16.00%	**2.7931**	0.3220	1.0073	0.1522	**4.2746**	3.6845	16.00%	**2.9422**	0.3220	1.0073	0.1522	**4.4237**
30.0	3.8795	16.00%	**2.7931**	0.3220	1.3139	0.1522	**4.5812**	3.9911	16.00%	**2.9422**	0.3220	1.3139	0.1522	**4.7303**
34.9	4.0941	16.00%	**2.7931**	0.3220	1.5285	0.1522	**4.7958**	4.2057	16.00%	**2.9422**	0.3220	1.5285	0.1522	**4.9449**
39.7	4.3043	16.00%	**2.7931**	0.3220	1.7388	0.1522	**5.0061**	4.4159	16.00%	**2.9422**	0.3220	1.7388	0.1522	**5.1552**

ROE Set Fixed 15%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	15.00%	**2.7492**	0.3220	0.9197	0.1522	**4.1432**	3.5969	15.00%	**2.8960**	0.3220	0.9197	0.1522	**4.2900**
23.0	3.5729	15.00%	**2.7492**	0.3220	1.0073	0.1522	**4.2308**	3.6845	15.00%	**2.8960**	0.3220	1.0073	0.1522	**4.3775**
30.0	3.8795	15.00%	**2.7492**	0.3220	1.3139	0.1522	**4.5374**	3.9911	15.00%	**2.8960**	0.3220	1.3139	0.1522	**4.6841**
34.9	4.0941	15.00%	**2.7492**	0.3220	1.5285	0.1522	**4.7520**	4.2057	15.00%	**2.8960**	0.3220	1.5285	0.1522	**4.8987**
39.7	4.3043	15.00%	**2.7492**	0.3220	1.7388	0.1522	**4.9622**	4.4159	15.00%	**2.8960**	0.3220	1.7388	0.1522	**5.1090**

ROE Set Fixed 14%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	14.00%	**2.7054**	0.3220	0.9197	0.1522	**4.0993**	3.5969	14.00%	**2.8498**	0.3220	0.9197	0.1522	**4.2437**
23.0	3.5729	14.00%	**2.7054**	0.3220	1.0073	0.1522	**4.1869**	3.6845	14.00%	**2.8498**	0.3220	1.0073	0.1522	**4.3313**
30.0	3.8795	14.00%	**2.7054**	0.3220	1.3139	0.1522	**4.4935**	3.9911	14.00%	**2.8498**	0.3220	1.3139	0.1522	**4.6379**
34.9	4.0941	14.00%	**2.7054**	0.3220	1.5285	0.1522	**4.7081**	4.2057	14.00%	**2.8498**	0.3220	1.5285	0.1522	**4.8525**
39.7	4.3043	14.00%	**2.7054**	0.3220	1.7388	0.1522	**4.9183**	4.4159	14.00%	**2.8498**	0.3220	1.7388	0.1522	**5.0628**

Appendix 4: TARIFF BENCHMARKING: TARIFF SET FIXED (MAJORITY SOFT LOAN)

Financial Parameters					**Technical Parameters**			**Variables**
1. Debt Equity Ratio	73%/27%				1. Net Dependable Capacity	2x615	MW	1. Tariff Set Fixed (c/kWh)
2. Loan					2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**		**Repayment**	**Interest**	3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
25%	**Commercial Loan**		12 years	11%	4. HHV Coal	5215	kg/kcal	
75%	**Soft Loan**		12 years	5%	5. Contract Terms	30	years	Notes:
3. Discount Rate	14%				6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
					7. Variable O&M	0.1522	c/kWh	

Tariff Set Fixed 4.1

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	**14.01%**	2.7060	0.3220	0.9197	0.1522	4.1	3.5969	**10.89%**	2.7060	0.3220	0.9197	0.1522	4.1
23.0	3.5729	**12.02%**	2.6184	0.3220	1.0073	0.1522	4.1	3.6845	**8.99%**	2.6184	0.3220	1.0073	0.1522	4.1
30.0	3.8795	**5.03%**	2.3118	0.3220	1.3139	0.1522	4.1	3.9911	**2.36%**	2.3118	0.3220	1.3139	0.1522	4.1
34.9	4.0941	**0.13%**	2.0972	0.3220	1.5285	0.1522	4.1	4.2057	**-2.29%**	2.0972	0.3220	1.5285	0.1522	4.1
39.7	4.3043	**-4.66%**	1.8870	0.3220	1.7388	0.1522	4.1	4.4159	**-6.84%**	1.8870	0.3220	1.7388	0.1522	4.1

Tariff Set Fixed 4.0 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	**11.73%**	2.6060	0.3220	0.9197	0.1522	4.0	3.5969	**8.72%**	2.6060	0.3220	0.9197	0.1522	4.0
23.0	3.5729	**9.74%**	2.5184	0.3220	1.0073	0.1522	4.0	3.6845	**6.83%**	2.5184	0.3220	1.0073	0.1522	4.0
30.0	3.8795	**2.75%**	2.2118	0.3220	1.3139	0.1522	4.0	3.9911	**0.19%**	2.2118	0.3220	1.3139	0.1522	4.0
34.9	4.0941	**-2.15%**	1.9972	0.3220	1.5285	0.1522	4.0	4.2057	**-4.45%**	1.9972	0.3220	1.5285	0.1522	4.0
39.7	4.3043	**-6.94%**	1.7870	0.3220	1.7388	0.1522	4.0	4.4159	**-9.00%**	1.7870	0.3220	1.7388	0.1522	4.0

Tariff Set Fixed 3.9 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	**9.45%**	2.5060	0.3220	0.9197	0.1522	3.9	3.5969	**6.56%**	2.5060	0.3220	0.9197	0.1522	3.9
23.0	3.5729	**7.46%**	2.4184	0.3220	1.0073	0.1522	3.9	3.6845	**4.66%**	2.4184	0.3220	1.0073	0.1522	3.9
30.0	3.8795	**0.47%**	2.1118	0.3220	1.3139	0.1522	3.9	3.9911	**-1.97%**	2.1118	0.3220	1.3139	0.1522	3.9
34.9	4.0941	**-4.43%**	1.8972	0.3220	1.5285	0.1522	3.9	4.2057	**-6.62%**	1.8972	0.3220	1.5285	0.1522	3.9
39.7	4.3043	**-9.22%**	1.6870	0.3220	1.7388	0.1522	3.9	4.4159	**-11.17%**	1.6870	0.3220	1.7388	0.1522	3.9

Tariff Set Fixed 3.8 cents/kWh

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4853	**7.17%**	2.4060	0.3220	0.9197	0.1522	3.8	3.5969	**4.39%**	2.4060	0.3220	0.9197	0.1522	3.8
23.0	3.5729	**5.18%**	2.3184	0.3220	1.0073	0.1522	3.8	3.6845	**2.50%**	2.3184	0.3220	1.0073	0.1522	3.8
30.0	3.8795	**-1.81%**	2.0118	0.3220	1.3139	0.1522	3.8	3.9911	**-4.14%**	2.0118	0.3220	1.3139	0.1522	3.8
34.9	4.0941	**-6.71%**	1.7972	0.3220	1.5285	0.1522	3.8	4.2057	**-8.78%**	1.7972	0.3220	1.5285	0.1522	3.8
39.7	4.3043	**-11.50%**	1.5870	0.3220	1.7388	0.1522	3.8	4.4159	**-13.33%**	1.5870	0.3220	1.7388	0.1522	3.8

Appendix 5: TARIFF BENCHMARKING: ROE SET FIXED (SEMI COMMERCIAL LOAN)

Financial Parameters					Technical Parameters			Variables
1. Debt Equity Ratio	73%/27%				1. Net Dependable Capacity	2x615	MW	1. ROE Set Fixed
2. Loan	Follow Original Terms of Paiton I				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**		**Repayment**	**Interest**	3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
50%	Commercial Loan		12 years	11%	4. HHV Coal	5215	kg/kcal	
50%	Soft Loan		12 years	5%	5. Contract Terms	30	years	Notes:
3. Discount Rate	14%				6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
					7. Variable O&M	0.1522	c/kWh	

ROE Set Fixed 17%

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	17.00%	**2.8412**	0.3220	0.9197	0.1522	**4.2351**	3.6014	17.00%	**2.9928**	0.3220	0.9197	0.1522	**4.3868**
23.0	3.5771	17.00%	**2.8412**	0.3220	1.0073	0.1522	**4.3227**	3.6890	17.00%	**2.9928**	0.3220	1.0073	0.1522	**4.4744**
30.0	3.8837	17.00%	**2.8412**	0.3220	1.3139	0.1522	**4.6293**	3.9956	17.00%	**2.9928**	0.3220	1.3139	0.1522	**4.7810**
34.9	4.0983	17.00%	**2.8412**	0.3220	1.5285	0.1522	**4.8439**	4.2102	17.00%	**2.9928**	0.3220	1.5285	0.1522	**4.9956**
39.7	4.3085	17.00%	**2.8412**	0.3220	1.7388	0.1522	**5.0542**	4.4204	17.00%	**2.9928**	0.3220	1.7388	0.1522	**5.2058**

ROE Set Fixed 16%

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	16.00%	**2.7973**	0.3220	0.9197	0.1522	**4.1913**	3.6014	16.00%	**2.9466**	0.3220	0.9197	0.1522	**4.3406**
23.0	3.5771	16.00%	**2.7973**	0.3220	1.0073	0.1522	**4.2789**	3.6890	16.00%	**2.9466**	0.3220	1.0073	0.1522	**4.4282**
30.0	3.8837	16.00%	**2.7973**	0.3220	1.3139	0.1522	**4.5855**	3.9956	16.00%	**2.9466**	0.3220	1.3139	0.1522	**4.7348**
34.9	4.0983	16.00%	**2.7973**	0.3220	1.5285	0.1522	**4.8001**	4.2102	16.00%	**2.9466**	0.3220	1.5285	0.1522	**4.9494**
39.7	4.3085	16.00%	**2.7973**	0.3220	1.7388	0.1522	**5.0103**	4.4204	16.00%	**2.9466**	0.3220	1.7388	0.1522	**5.1596**

ROE Set Fixed 15%

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	15.00%	**2.7534**	0.3220	0.9197	0.1522	**4.1474**	3.6014	15.00%	**2.9004**	0.3220	0.9197	0.1522	**4.2944**
23.0	3.5771	15.00%	**2.7534**	0.3220	1.0073	0.1522	**4.2350**	3.6890	15.00%	**2.9004**	0.3220	1.0073	0.1522	**4.3820**
30.0	3.8837	15.00%	**2.7534**	0.3220	1.3139	0.1522	**4.5416**	3.9956	15.00%	**2.9004**	0.3220	1.3139	0.1522	**4.6886**
34.9	4.0983	15.00%	**2.7534**	0.3220	1.5285	0.1522	**4.7562**	4.2102	15.00%	**2.9004**	0.3220	1.5285	0.1522	**4.9032**
39.7	4.3085	15.00%	**2.7534**	0.3220	1.7388	0.1522	**4.9664**	4.4204	15.00%	**2.9004**	0.3220	1.7388	0.1522	**5.1134**

ROE Set Fixed 14%

Coal Price	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
($/tons)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	14.00%	**2.7096**	0.3220	0.9197	0.1522	**4.1036**	3.6014	14.00%	**2.8542**	0.3220	0.9197	0.1522	**4.2482**
23.0	3.5771	14.00%	**2.7096**	0.3220	1.0073	0.1522	**4.1912**	3.6890	14.00%	**2.8542**	0.3220	1.0073	0.1522	**4.3358**
30.0	3.8837	14.00%	**2.7096**	0.3220	1.3139	0.1522	**4.4977**	3.9956	14.00%	**2.8542**	0.3220	1.3139	0.1522	**4.6424**
34.9	4.0983	14.00%	**2.7096**	0.3220	1.5285	0.1522	**4.7123**	4.2102	14.00%	**2.8542**	0.3220	1.5285	0.1522	**4.8570**
39.7	4.3085	14.00%	**2.7096**	0.3220	1.7388	0.1522	**4.9226**	4.4204	14.00%	**2.8542**	0.3220	1.7388	0.1522	**5.0672**

Appendix 6: TARIFF BENCHMARKING: TARIFF SET FIXED (SEMI COMMERCIAL LOAN)

Financial Parameters				Technical Parameters			Variables
1. Debt Equity Ratio 73%/27%				1. Net Dependable Capacity	2x615	MW	1. Tariff Set Fixed (c/kWh)
2. Loan				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**	3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
50%	**Commercial Loan**	12 years	11%	4. HHV Coal	5215	kg/kcal	
50%	**Soft Loan**	12 years	5%	5. Contract Terms	30	years	Notes:
3. Discount Rate	14%			6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
				7. Variable O&M	0.1522	c/kWh	

Tariff Set Fixed **4.1**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	**13.92%**	2.7060	0.3220	0.9197	0.1522	4.1	3.6014	**10.79%**	2.7060	0.3220	0.9197	0.1522	4.1
23.0	3.5771	**11.92%**	2.6184	0.3220	1.0073	0.1522	4.1	3.6890	**8.90%**	2.6184	0.3220	1.0073	0.1522	4.1
30.0	3.8837	**4.93%**	2.3118	0.3220	1.3139	0.1522	4.1	3.9956	**2.26%**	2.3118	0.3220	1.3139	0.1522	4.1
34.9	4.0983	**0.04%**	2.0972	0.3220	1.5285	0.1522	4.1	4.2102	**-2.39%**	2.0972	0.3220	1.5285	0.1522	4.1
39.7	4.3085	**-4.75%**	1.8870	0.3220	1.7388	0.1522	4.1	4.4204	**-6.94%**	1.8870	0.3220	1.7388	0.1522	4.1

Tariff Set Fixed **4.0 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	**11.64%**	2.6060	0.3220	0.9197	0.1522	4.0	3.6014	**8.63%**	2.6060	0.3220	0.9197	0.1522	4.0
23.0	3.5771	**9.64%**	2.5184	0.3220	1.0073	0.1522	4.0	3.6890	**6.73%**	2.5184	0.3220	1.0073	0.1522	4.0
30.0	3.8837	**2.65%**	2.2118	0.3220	1.3139	0.1522	4.0	3.9956	**0.09%**	2.2118	0.3220	1.3139	0.1522	4.0
34.9	4.0983	**-2.24%**	1.9972	0.3220	1.5285	0.1522	4.0	4.2102	**-4.55%**	1.9972	0.3220	1.5285	0.1522	4.0
39.7	4.3085	**-7.03%**	1.7870	0.3220	1.7388	0.1522	4.0	4.4204	**-9.10%**	1.7870	0.3220	1.7388	0.1522	4.0

Tariff Set Fixed **3.9 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	**9.36%**	2.5060	0.3220	0.9197	0.1522	3.9	3.6014	**6.46%**	2.5060	0.3220	0.9197	0.1522	3.9
23.0	3.5771	**7.36%**	2.4184	0.3220	1.0073	0.1522	3.9	3.6890	**4.57%**	2.4184	0.3220	1.0073	0.1522	3.9
30.0	3.8837	**0.37%**	2.1118	0.3220	1.3139	0.1522	3.9	3.9956	**-2.07%**	2.1118	0.3220	1.3139	0.1522	3.9
34.9	4.0983	**-4.52%**	1.8972	0.3220	1.5285	0.1522	3.9	4.2102	**-6.71%**	1.8972	0.3220	1.5285	0.1522	3.9
39.7	4.3085	**-9.31%**	1.6870	0.3220	1.7388	0.1522	3.9	4.4204	**-11.26%**	1.6870	0.3220	1.7388	0.1522	3.9

Tariff Set Fixed **3.8 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.4895	**7.08%**	2.4060	0.3220	0.9197	0.1522	3.8	3.6014	**4.30%**	2.4060	0.3220	0.9197	0.1522	3.8
23.0	3.5771	**5.08%**	2.3184	0.3220	1.0073	0.1522	3.8	3.6890	**2.40%**	2.3184	0.3220	1.0073	0.1522	3.8
30.0	3.8837	**-1.91%**	2.0118	0.3220	1.3139	0.1522	3.8	3.9956	**-4.23%**	2.0118	0.3220	1.3139	0.1522	3.8
34.9	4.0983	**-6.80%**	1.7972	0.3220	1.5285	0.1522	3.8	4.2102	**-8.88%**	1.7972	0.3220	1.5285	0.1522	3.8
39.7	4.3085	**-11.59%**	1.5870	0.3220	1.7388	0.1522	3.8	4.4204	**-13.43%**	1.5870	0.3220	1.7388	0.1522	3.8

Appendix 7: TARIFF BENCHMARKING: ROE SET FIXED (MAJORITY COMMERCIAL LOAN)

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan Follow Original Terms of Paiton I

% of Total Loan	Lender	Repayment	Interest
75%	Commercial Loan	12 years	11%
25%	Soft Loan	12 years	5%

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh

Variables

1. ROE Set Fixed
2. EPC Cost (US$/kW)
3. Coal Price ($/tons)

Notes:
ALC = Average Levelized Cost

ROE Set Fixed 17%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5723	17.00%	**2.9240**	0.3220	0.9197	0.1522	**4.3179**	3.6886	17.00%	**3.0800**	0.3220	0.9197	0.1522	**4.4740**
23.0	3.6599	17.00%	**2.9240**	0.3220	1.0073	0.1522	**4.4055**	3.7762	17.00%	**3.0800**	0.3220	1.0073	0.1522	**4.5616**
30.0	3.9665	17.00%	**2.9240**	0.3220	1.3139	0.1522	**4.7121**	4.0828	17.00%	**3.0800**	0.3220	1.3139	0.1522	**4.8682**
34.9	4.1811	17.00%	**2.9240**	0.3220	1.5285	0.1522	**4.9267**	4.2974	17.00%	**3.0800**	0.3220	1.5285	0.1522	**5.0828**
39.7	4.3913	17.00%	**2.9240**	0.3220	1.7388	0.1522	**5.1369**	4.5076	17.00%	**3.0800**	0.3220	1.7388	0.1522	**5.2930**

ROE Set Fixed 16%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5723	16.00%	**2.8801**	0.3220	0.9197	0.1522	**4.2741**	3.6886	16.00%	**3.0338**	0.3220	0.9197	0.1522	**4.4278**
23.0	3.6599	16.00%	**2.8801**	0.3220	1.0073	0.1522	**4.3617**	3.7762	16.00%	**3.0338**	0.3220	1.0073	0.1522	**4.5154**
30.0	3.9665	16.00%	**2.8801**	0.3220	1.3139	0.1522	**4.6682**	4.0828	16.00%	**3.0338**	0.3220	1.3139	0.1522	**4.8220**
34.9	4.1811	16.00%	**2.8801**	0.3220	1.5285	0.1522	**4.8829**	4.2974	16.00%	**3.0338**	0.3220	1.5285	0.1522	**5.0366**
39.7	4.3913	16.00%	**2.8801**	0.3220	1.7388	0.1522	**5.0931**	4.5076	16.00%	**3.0338**	0.3220	1.7388	0.1522	**5.2468**

ROE Set Fixed 15%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5723	15.00%	**2.8362**	0.3220	0.9197	0.1522	**4.2302**	3.6886	15.00%	**2.9876**	0.3220	0.9197	0.1522	**4.3816**
23.0	3.6599	15.00%	**2.8362**	0.3220	1.0073	0.1522	**4.3178**	3.7762	15.00%	**2.9876**	0.3220	1.0073	0.1522	**4.4692**
30.0	3.9665	15.00%	**2.8362**	0.3220	1.3139	0.1522	**4.6244**	4.0828	15.00%	**2.9876**	0.3220	1.3139	0.1522	**4.7758**
34.9	4.1811	15.00%	**2.8362**	0.3220	1.5285	0.1522	**4.8390**	4.2974	15.00%	**2.9876**	0.3220	1.5285	0.1522	**4.9904**
39.7	4.3913	15.00%	**2.8362**	0.3220	1.7388	0.1522	**5.0492**	4.5076	15.00%	**2.9876**	0.3220	1.7388	0.1522	**5.2006**

ROE Set Fixed 14%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5723	14.00%	**2.7924**	0.3220	0.9197	0.1522	**4.1864**	3.6886	14.00%	**2.9414**	0.3220	0.9197	0.1522	**4.3354**
23.0	3.6599	14.00%	**2.7924**	0.3220	1.0073	0.1522	**4.2739**	3.7762	14.00%	**2.9414**	0.3220	1.0073	0.1522	**4.4230**
30.0	3.9665	14.00%	**2.7924**	0.3220	1.3139	0.1522	**4.5805**	4.0828	14.00%	**2.9414**	0.3220	1.3139	0.1522	**4.7296**
34.9	4.1811	14.00%	**2.7924**	0.3220	1.5285	0.1522	**4.7951**	4.2974	14.00%	**2.9414**	0.3220	1.5285	0.1522	**4.9442**
39.7	4.3913	14.00%	**2.7924**	0.3220	1.7388	0.1522	**5.0054**	4.5076	14.00%	**2.9414**	0.3220	1.7388	0.1522	**5.1544**

Appendix 8: TARIFF BENCHMARKING: TARIFF SET FIXED (MAJORITY COMMERCIAL LOAN)

Financial Parameters				Technical Parameters			Variables
1. Debt Equity Ratio	73%/27%			1. Net Dependable Capacity	2x615	MW	1. Tariff Set Fixed (c/kWh)
2. Loan				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**	3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
75%	**Commercial Loan**	12 years	11%	4. HHV Coal	5215	kg/kcal	
25%	**Soft Loan**	12 years	5%	5. Contract Terms	30	years	Notes:
3. Discount Rate	14%			6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
				7. Variable O&M	0.1522	c/kWh	

Tariff Set Fixed **4.1**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5324	**12.94%**	2.7060	0.3220	0.9197	0.1522	4.1	3.6886	**8.90%**	2.7060	0.3220	0.9197	0.1522	4.1
23.0	3.6200	**10.94%**	2.6184	0.3220	1.0073	0.1522	4.1	3.7762	**7.01%**	2.6184	0.3220	1.0073	0.1522	4.1
30.0	3.9265	**3.95%**	2.3118	0.3220	1.3139	0.1522	4.1	4.0828	**0.37%**	2.3118	0.3220	1.3139	0.1522	4.1
34.9	4.1412	**-0.94%**	2.0972	0.3220	1.5285	0.1522	4.1	4.2974	**-4.27%**	2.0972	0.3220	1.5285	0.1522	4.1
39.7	4.3514	**-5.73%**	1.8870	0.3220	1.7388	0.1522	4.1	4.5076	**-8.82%**	1.8870	0.3220	1.7388	0.1522	4.1

Tariff Set Fixed **4.0 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5324	**10.66%**	2.6060	0.3220	0.9197	0.1522	4.0	3.6886	**6.74%**	2.6060	0.3220	0.9197	0.1522	4.0
23.0	3.6200	**8.66%**	2.5184	0.3220	1.0073	0.1522	4.0	3.7762	**4.84%**	2.5184	0.3220	1.0073	0.1522	4.0
30.0	3.9265	**1.67%**	2.2118	0.3220	1.3139	0.1522	4.0	4.0828	**-1.79%**	2.2118	0.3220	1.3139	0.1522	4.0
34.9	4.1412	**-3.22%**	1.9972	0.3220	1.5285	0.1522	4.0	4.2974	**-6.44%**	1.9972	0.3220	1.5285	0.1522	4.0
39.7	4.3514	**-8.01%**	1.7870	0.3220	1.7388	0.1522	4.0	4.5076	**-10.99%**	1.7870	0.3220	1.7388	0.1522	4.0

Tariff Set Fixed **3.9 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5324	**8.38%**	2.5060	0.3220	0.9197	0.1522	3.9	3.6886	**4.58%**	2.5060	0.3220	0.9197	0.1522	3.9
23.0	3.6200	**6.38%**	2.4184	0.3220	1.0073	0.1522	3.9	3.7762	**2.68%**	2.4184	0.3220	1.0073	0.1522	3.9
30.0	3.9265	**-0.61%**	2.1118	0.3220	1.3139	0.1522	3.9	4.0828	**-3.96%**	2.1118	0.3220	1.3139	0.1522	3.9
34.9	4.1412	**-5.50%**	1.8972	0.3220	1.5285	0.1522	3.9	4.2974	**-8.60%**	1.8972	0.3220	1.5285	0.1522	3.9
39.7	4.3514	**-10.29%**	1.6870	0.3220	1.7388	0.1522	3.9	4.5076	**-13.15%**	1.6870	0.3220	1.7388	0.1522	3.9

Tariff Set Fixed **3.8 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.5324	**6.10%**	2.4060	0.3220	0.9197	0.1522	3.8	3.6886	**2.41%**	2.4060	0.3220	0.9197	0.1522	3.8
23.0	3.6200	**4.10%**	2.3184	0.3220	1.0073	0.1522	3.8	3.7762	**0.51%**	2.3184	0.3220	1.0073	0.1522	3.8
30.0	3.9265	**-2.89%**	2.0118	0.3220	1.3139	0.1522	3.8	4.0828	**-6.12%**	2.0118	0.3220	1.3139	0.1522	3.8
34.9	4.1412	**-7.78%**	1.7972	0.3220	1.5285	0.1522	3.8	4.2974	**-10.77%**	1.7972	0.3220	1.5285	0.1522	3.8
39.7	4.3514	**-12.57%**	1.5870	0.3220	1.7388	0.1522	3.8	4.5076	**-15.32%**	1.5870	0.3220	1.7388	0.1522	3.8

Appendix 9: TARIFF BENCHMARKING: ROE SET FIXED (FULLY COMMERCIAL LOAN)

Financial Parameters					Technical Parameters			Variables
1. Debt Equity Ratio	73%/27%				1. Net Dependable Capacity	2x615	MW	1. ROE Set Fixed
2. Loan	Follow Original Terms of Paiton I				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**		3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
100%	Commercial Loan	12 years	11%		4. HHV Coal	5215	kg/kcal	
0%	Soft Loan	12 years			5. Contract Terms	30	years	Notes:
3. Discount Rate	14%				6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
					7. Variable O&M	0.1522	c/kWh	

ROE Set Fixed 17%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	17.00%	**3.0754**	0.3220	0.9197	0.1522	**4.4693**	3.8481	17.00%	**3.2395**	0.3220	0.9197	0.1522	**4.6335**
23.0	3.8113	17.00%	**3.0754**	0.3220	1.0073	0.1522	**4.5569**	3.9357	17.00%	**3.2395**	0.3220	1.0073	0.1522	**4.7211**
30.0	4.1179	17.00%	**3.0754**	0.3220	1.3139	0.1522	**4.8635**	4.2423	17.00%	**3.2395**	0.3220	1.3139	0.1522	**5.0277**
34.9	4.3325	17.00%	**3.0754**	0.3220	1.5285	0.1522	**5.0781**	4.4569	17.00%	**3.2395**	0.3220	1.5285	0.1522	**5.2423**
39.7	4.5427	17.00%	**3.0754**	0.3220	1.7388	0.1522	**5.2883**	4.6671	17.00%	**3.2395**	0.3220	1.7388	0.1522	**5.4525**

ROE Set Fixed 16%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	16.00%	**3.0315**	0.3220	0.9197	0.1522	**4.4255**	3.8481	16.00%	**3.1933**	0.3220	0.9197	0.1522	**4.5873**
23.0	3.8113	16.00%	**3.0315**	0.3220	1.0073	0.1522	**4.5131**	3.9357	16.00%	**3.1933**	0.3220	1.0073	0.1522	**4.6749**
30.0	4.1179	16.00%	**3.0315**	0.3220	1.3139	0.1522	**4.8197**	4.2423	16.00%	**3.1933**	0.3220	1.3139	0.1522	**4.9815**
34.9	4.3325	16.00%	**3.0315**	0.3220	1.5285	0.1522	**5.0343**	4.4569	16.00%	**3.1933**	0.3220	1.5285	0.1522	**5.1961**
39.7	4.5427	16.00%	**3.0315**	0.3220	1.7388	0.1522	**5.2445**	4.6671	16.00%	**3.1933**	0.3220	1.7388	0.1522	**5.4063**

ROE Set Fixed 15%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	15.00%	**2.9876**	0.3220	0.9197	0.1522	**4.3816**	3.8481	15.00%	**3.1471**	0.3220	0.9197	0.1522	**4.5411**
23.0	3.8113	15.00%	**2.9876**	0.3220	1.0073	0.1522	**4.4692**	3.9357	15.00%	**3.1471**	0.3220	1.0073	0.1522	**4.6287**
30.0	4.1179	15.00%	**2.9876**	0.3220	1.3139	0.1522	**4.7758**	4.2423	15.00%	**3.1471**	0.3220	1.3139	0.1522	**4.9353**
34.9	4.3325	15.00%	**2.9876**	0.3220	1.5285	0.1522	**4.9904**	4.4569	15.00%	**3.1471**	0.3220	1.5285	0.1522	**5.1499**
39.7	4.5427	15.00%	**2.9876**	0.3220	1.7388	0.1522	**5.2006**	4.6671	15.00%	**3.1471**	0.3220	1.7388	0.1522	**5.3601**

ROE Set Fixed 14%

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	14.00%	**2.9438**	0.3220	0.9197	0.1522	**4.3378**	3.8481	14.00%	**3.1009**	0.3220	0.9197	0.1522	**4.4949**
23.0	3.8113	14.00%	**2.9438**	0.3220	1.0073	0.1522	**4.4253**	3.9357	14.00%	**3.1009**	0.3220	1.0073	0.1522	**4.5825**
30.0	4.1179	14.00%	**2.9438**	0.3220	1.3139	0.1522	**4.7319**	4.2423	14.00%	**3.1009**	0.3220	1.3139	0.1522	**4.8891**
34.9	4.3325	14.00%	**2.9438**	0.3220	1.5285	0.1522	**4.9465**	4.4569	14.00%	**3.1009**	0.3220	1.5285	0.1522	**5.1037**
39.7	4.5427	14.00%	**2.9438**	0.3220	1.7388	0.1522	**5.1568**	4.6671	14.00%	**3.1009**	0.3220	1.7388	0.1522	**5.3139**

Appendix 10: TARIFF BENCHMARKING: TARIFF SET FIXED (FULLY COMMERCIAL LOAN)

Financial Parameters					Technical Parameters			Variables
1. Debt Equity Ratio	73%/27%				1. Net Dependable Capacity	2x615	MW	1. Tariff Set Fixed (c/kWh)
2. Loan	Follow the Original Terms of the Paiton I				2. Availability Factor	83%		2. EPC Cost (US$/kW)
% of Total Loan	**Lender**	**Repayment**	**Interest**		3. Net Plant Heat Rate	2447	kcal/kWh	3. Coal Price ($/tons)
100%	**Commercial Loan**	12 years		11%	4. HHV Coal	5215	kg/kcal	
0%	**Soft Loan**	12 years			5. Contract Terms	30	years	Notes:
3. Discount Rate	14%				6. Fixed O&M	0.3220	c/kWh	ALC = Average Levelized Cost
					7. Variable O&M	0.1522	c/kWh	

Tariff Set Fixed **4.1**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	**8.58%**	2.7060	0.3220	0.9197	0.1522	4.1	3.8481	**5.45%**	2.7060	0.3220	0.9197	0.1522	4.1
23.0	3.8113	**6.58%**	2.6184	0.3220	1.0073	0.1522	4.1	3.9357	**3.56%**	2.6184	0.3220	1.0073	0.1522	4.1
30.0	4.1179	**-0.41%**	2.3118	0.3220	1.3139	0.1522	4.1	4.2423	**-3.08%**	2.3118	0.3220	1.3139	0.1522	4.1
34.9	4.3325	**-5.30%**	2.0972	0.3220	1.5285	0.1522	4.1	4.4569	**-7.73%**	2.0972	0.3220	1.5285	0.1522	4.1
39.7	4.5427	**-10.09%**	1.8870	0.3220	1.7388	0.1522	4.1	4.6671	**-12.27%**	1.8870	0.3220	1.7388	0.1522	4.1

Tariff Set Fixed **4.0 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	**6.30%**	2.6060	0.3220	0.9197	0.1522	4.0	3.8481	**3.29%**	2.6060	0.3220	0.9197	0.1522	4.0
23.0	3.8113	**4.30%**	2.5184	0.3220	1.0073	0.1522	4.0	3.9357	**1.39%**	2.5184	0.3220	1.0073	0.1522	4.0
30.0	4.1179	**-2.69%**	2.2118	0.3220	1.3139	0.1522	4.0	4.2423	**-5.24%**	2.2118	0.3220	1.3139	0.1522	4.0
34.9	4.3325	**-7.58%**	1.9972	0.3220	1.5285	0.1522	4.0	4.4569	**-9.89%**	1.9972	0.3220	1.5285	0.1522	4.0
39.7	4.5427	**-12.37%**	1.7870	0.3220	1.7388	0.1522	4.0	4.6671	**-14.44%**	1.7870	0.3220	1.7388	0.1522	4.0

Tariff Set Fixed **3.9 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	**4.02%**	2.5060	0.3220	0.9197	0.1522	3.9	3.8481	**1.12%**	2.5060	0.3220	0.9197	0.1522	3.9
23.0	3.8113	**2.02%**	2.4184	0.3220	1.0073	0.1522	3.9	3.9357	**-0.77%**	2.4184	0.3220	1.0073	0.1522	3.9
30.0	4.1179	**-4.97%**	2.1118	0.3220	1.3139	0.1522	3.9	4.2423	**-7.41%**	2.1118	0.3220	1.3139	0.1522	3.9
34.9	4.3325	**-9.86%**	1.8972	0.3220	1.5285	0.1522	3.9	4.4569	**-12.05%**	1.8972	0.3220	1.5285	0.1522	3.9
39.7	4.5427	**-13.47%**	1.6870	0.3220	1.7388	0.1522	3.9	4.6671	**-16.60%**	1.6870	0.3220	1.7388	0.1522	3.9

Tariff Set Fixed **3.8 cents/kWh**

Coal Price ($/tons)	EPC cost US$ 839.84 per kW							EPC Cost US$ 884.67						
	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)	ALC (c/kWh)	ROE	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.7237	**1.74%**	2.4060	0.3220	0.9197	0.1522	3.8	3.8481	**-1.04%**	2.4060	0.3220	0.9197	0.1522	3.8
23.0	3.8113	**-0.26%**	2.3184	0.3220	1.0073	0.1522	3.8	3.9357	**-2.94%**	2.3184	0.3220	1.0073	0.1522	3.8
30.0	4.1179	**-7.25%**	2.0118	0.3220	1.3139	0.1522	3.8	4.2423	**-9.57%**	2.0118	0.3220	1.3139	0.1522	3.8
34.9	4.3325	**-12.14%**	1.7972	0.3220	1.5285	0.1522	3.8	4.4569	**-14.22%**	1.7972	0.3220	1.5285	0.1522	3.8
39.7	4.5427	**-16.93%**	1.5870	0.3220	1.7388	0.1522	3.8	4.6671	**-18.77%**	1.5870	0.3220	1.7388	0.1522	3.8

Chapter 7: Financial Analysis for the Paiton I[280]

7.1. Financial Parameter Analysis

The author developed an approximation of the cash flow analysis for the Paiton I project, as shown in Appendix 1. This analysis takes into account any publicly available financial information of the Paiton I project and the author's reasonable assumptions[281]. Even though the cash flow projection was developed to best reflect the cash flow of the Paiton I project, the results of the analysis might deviate and are not intended to reveal the original cash flow by any means.

The financial parameters derived from the cash flow analysis are as follows:

1) IRR on Project = 14.69%

As mentioned earlier, a project is attractive if the IRR exceeds the cost of capital, which has been 13% in the US and even higher in Asian countries[282]. Hossein Razavi states that private investors usually want an IRR of approximately 15% while Lang indicates that the normal practice for infrastructure projects in Asia is 18%[283]. Therefore, the approximation of 14.69% IRR for the Paiton I project is considered the normal practice.

---

280 The thesis author prepared this case under the supervision of Professor Massood V. Samii as the basis for the thesis discussion, and not to illustrate either effective or ineffective handling of infrastructure development related issues. Data presented in the case analysis might have been altered to simplify, focus, and to preserve individual confidentiality. The assistance of Dr. Hardiv Situmeang—the Planning Director of PLN (July 31, 1998 – December 31, 1999) and later, the senior advisor to the PLN CEO—in the preparation of this case is greatly appreciated. The remarkable contribution of Mr. Situmeang in the case analysis is gratefully acknowledged.

281 Assumptions include percentage of annual increase in exchange rate movement prior and after the Asian crisis, the inflation rate projection of Indonesia and the US, the actual exchange rate projection, the discount rate, the fuel cost is estimated the same for the whole contract year.

282 Lang, 1998

283 Ibid

2) ROE = 24.76%

Razavi provides an approximation formula to derive ROE based on the IRR, the debt equity ratio, and the average interest rate on the debt, as follows:

Project IRR = (% of equity)(ROE) + (% of debt)(Average interest rate on debt)

Since the IRR of the Paiton I is approximately 14.69%, the debt equity ratio is 72.8%:27.2%, and the average interest rate on debt is approximately 11%, the ROE would be approximately 24.57%, almost the same as the one derived from the cash flow analysis.

According to Lang, a 30% ROE for infrastructure projects in Asia are deemed acceptable by most players[284]. Furthermore, Hossein Razavi states that private investors usually want at least 25% to 35% ROE[285]. Therefore, the approximation of 24.76% ROE for the Paiton I project is considered the normal practice.

3) Average Levelized Cost = 5.6596 cents/kWh[286]

The average levelized cost consists of the following components:

a) Component A = 3.6568 cents/kWh

b) Component B = 0.3220 cents/kWh

c) Component C = 1.5285 cents/kWh[287]

d) Component D = 0.1522 cents/kWh

---

284 Lang, 1998

285 Razavi, Hossein, "Financing Energy Projects in Emerging Economies", Pennwell Books, Tulsa, Oklahoma, 1996.

286 Under the coal price US$ 34.9 per tons

287 Under the coal price US$ 34.9 per tons

4) Average Levelized Tariff = 7.2447 cents/kWh[288]

Despite the average levelized tariff, the total tariff[289] are:

a) Years 1-6 = 8.1706 cents/kWh

b) Years 7-12 = 8.1241 cents/kWh

c) Years 13-30 = 5.4889 cents/kWh

As previously mentioned in chapter III, the average PLN's electricity tariff to the consumers was approximately US$ 3.2 cents/kWh[290].

5) Sensitivity Analysis

Appendix 2 shows the sensitivity analysis of the tariff, average levelized cost, total charge, capacity charge, and percentage of the capacity charge to the total charge, with respect to the coal price. As previously mentioned in chapter 5, the fixed capacity charges (component A and component B) that PLN must pay irrespective of dispatch levels amounts to an average of 71% of the total payment, under the coal price US$ 34.9 per tons. The average dollar term of these capacity payments for the first 6 years is US$ 573 million. This capacity payment shows the *take-or-pay* level of the Paiton I PPA.

7.2. Analysis on ROE trend

Based on the successes of the early players, private power projects in developing countries are expected to provide ROE in the range of mid-20s or higher[291]. As

[288] Under the coal price US$ 34.9 per tons

[289] Tariff is derived from the present value of total costs (discounted to COD) during the associated years divided by the present value of net energy output (discounted to COD) during those years. The result is slightly different from those derived by PLN, which are US$ 8.5 cents/kWh for the first 6 years, US$ 8.3 cents/kWh for year 7 to 12, and US$ 5.5 cents/kWh for year 13 to 30 (PLN Press Release, 1999).

[290] The tariff was Rp. 223 per kWh with the exchange rate Rp. 7,000 per 1 US$ (PLN Press Release, "Latar Belakang: Background", 1999)

mentioned earlier, Lang and Razavi advocated a 30% and a 25% to 35% ROE respectively. However, Jacob J. Worenklein argues that in general the expectations have not been realized, for the following reasons[292]:

1) Only small numbers of projects have actually moved forward.
2) Greater numbers of project developers are competing for these projects.
3) Unrealistic nature of these expectations. With greater supply of capital and less demand for capital, the price of capital (the ROE) should be lowered.

The Paiton I model PPA protect the project company from market risks, currency risks, and political force majeure risks. In other words, the equity and debt for the Paiton I project are highly secured. Its capital markets tranche were re-financed at an early stage of construction at approximately 9.5% interest rate. The question becomes apparent: what is then the appropriate ROE if the debt return is 9.5%?[293]. Although there are significant risks especially during the development and the construction stages, after these stages, the risks proved to be simultaneously lower because of high protections under the *take-or-pay* PPA, providing certainty in the revenue stream. Therefore, it is logical that the project investors should consider a lower than the mid-20s range ROE to compensate for the risks that they perceived as high, but had been highly secured.

In addition, the private power market is becoming more competitive with the inclusion of merchant plants. As the market is getting more competitive, various countries will move towards new facilities financed on a merchant basis, even without any guarantees from government or public utility. To illustrate, figure 7.1 shows the

---

291 Worenklein, Jacob J., "Project Finance: Adapts to Changing Power Market", *Private Power Executive*, May-June 1996.

292 Ibid

293 Worenklein, Jacob J., "Project Finance: Adapts to Changing Power Market", *Private Power Executive*, May-June 1996.

lifetime ROE for a combined-cycle plant from the US examples. When the market is oligopoly[294], the private investors demand a high ROE and therefore sell the electricity at a higher tariff rate. This phenomenon is the initial case in most developing countries. As the market is becoming more competitive, the private investors should agree to expect a lower ROE and therefore sell the electricity at a lower price.

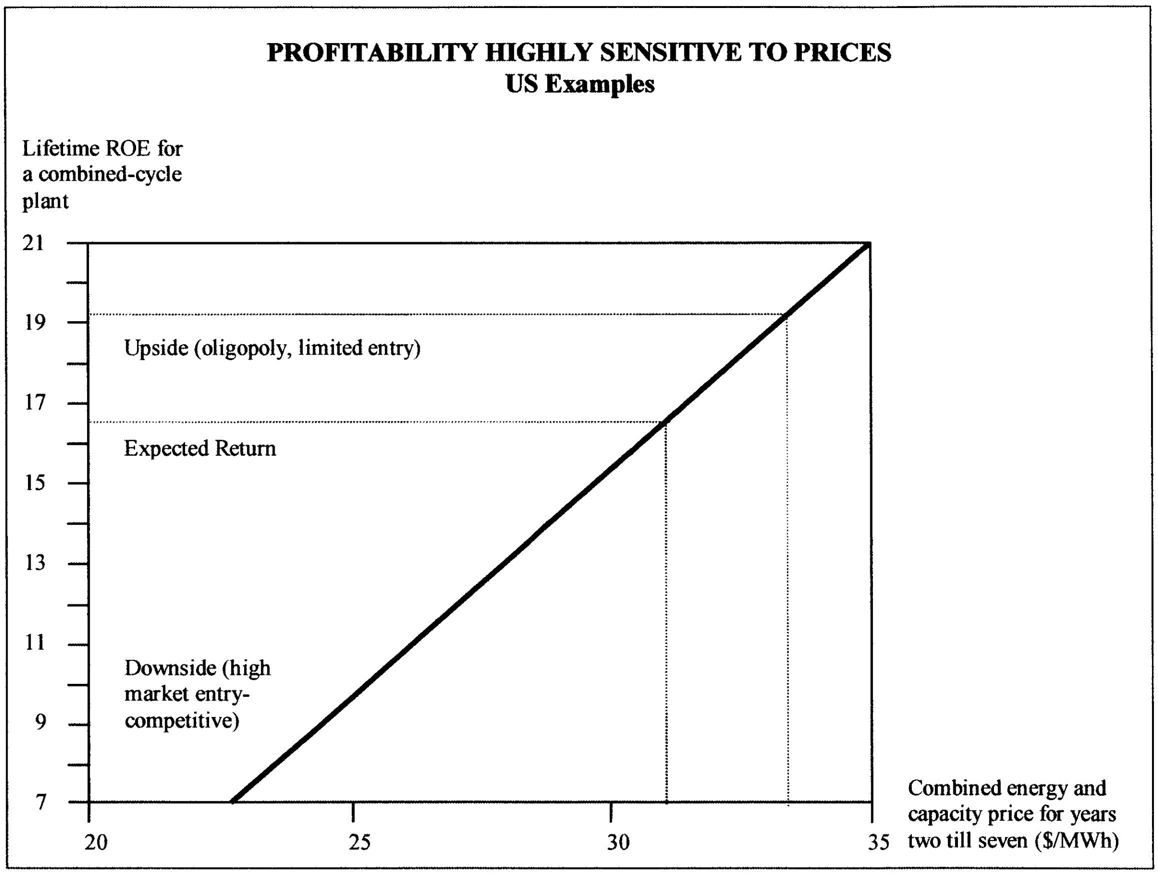


Figure 7.1: Profitability Highly Sensitive to Prices: US Examples[295]

The Indonesia's electricity sector had been analyzing the possibility for a competitive electricity business. In 2007, the sector was expected to start restructuring the business towards a competitive industry under the merchant plants scheme, namely

---

[294] Oligopoly is a market condition in which sellers are so few that the actions of any one of them will materially affect price and then the costs that competitors must pay (The American Heritage Dictionary).

[295] The Boston Consulting Group, "Deconstruction for the New Millennium: Building the Competitive Utility Company", *2000 Asian Utility CEO Conference*, Singapore, March 9-10, 2000.

the Multiple Buyers/Multiple Sellers (MB/MS) scheme[296]. Under this MB/MS scheme, the industry would be highly competitive; the producers are allowed to sell power to several purchasers at the same time while the purchasers would purchase power from purchasers with the lowest bid. Since the market is not an oligopoly anymore, the producers that offer the least electricity tariff are likely to attract more buyers. The highly competitive nature of the industry under this bidding scheme would demand lower tariff. The producers would likely to undertake a cost-effective development and expect a lower ROE[297]. As a result, under this MB/MS scheme, there would be more projects demanding lower ROE. The question would be to what level the ROE can be lowered. In some situations in Chile, and elsewhere, there have been bids for power projects with surprising single-digit returns[298]. In addition, figure 7.1 shows that in the high market entry competitive, the expected ROE could fall to approximately 16.5%, and the extreme downside could be 7%.

Worenklein addresses the entire phenomenon of the increasing competition in the electricity business, as follows:

> … we will see more projects, more demand for capital, but not materially higher rates of return in view of the large supply of capital poised to invest and the perception that the level of project risk does not warrant returns higher than those currently being obtained in most countries. (Worenklein, 1996).

296 Interview with Dr. Situmeang

297 With a low ROE, the producers' tariff would approach the average levelized cost, the cost to generate the power.

298 Worenklein, Jacob J., "Project Finance: Adapts to Changing Power Market", *Private Power Executive*, May-June 1996.

7.3. Chapter Summary

This chapter provides an approximation of the financial analysis for the Paiton I project. The IRR and ROE derived from the analysis reflect the normal practice for infrastructure projects in developing countries. However, there has been a tendency that the high expectation of ROE for power projects would decrease as the competition in the electricity generating business increases with the inclusion of merchant plants (multi-buyers and multi-sellers) scheme.

The only problem was that the Paiton I's tariff to PLN significantly exceeded PLN's subsidized tariff to the end consumers, despite the appropriateness issues addressed in chapter 4. When the thesis was final, the contracted parties had been renegotiating the PPA for almost two years with no significant results. The next chapter would propose a commercial approach to arrive at a competitive tariff by taking into account the tariff benchmarking analysis outlined in chapter 6 as well as the tendency of decreasing ROE expectation because of the increasing competition in the electricity generating business.

Appendix 1: Cash Flow Analysis for the Paiton I Power Generation Project

(all numbers in $1,000 unless indicated otherwise)

Date	29-Dec-00
File Name	Paiton-01

GENERAL ASSUMPTION

Pre-Construction Start Date		1993		
Construction Start Date		1995	Jul-95	
Construction months including Start Up			48	months
Commercial Operations		1999	Jul-99	
Project Life (years)			30	
Operating Availability	PPA Attachment A		83%	
Start-Up Availability	PPA Attachment A		83%	
Total Annual Hours	normal years		8,760	hours
Total Annual Hours	leap years		8,784	hours

CONSTRUCTION COST ASSUMPTION

Project Cost Breakdown (in US$ 1000)	% of Total Cost	Cost Breakdown	Original Paiton
Construction Cost			
EPC Cost (including Special Facility)	70.89%	1,772,300	**1,772,300**
Contingency	0.13%	3,300	**3,300**
Development Cost	7.60%	190,000	**190,000**
Development Fee			11,800
Development Expense			43,200
Insurance			30,000
Administration Cost			26,000
Owner's Engineer			15,000
Pre-Completion Labor			6,600
Agency Fees			3,700
Value Added Taxes			53,700
Initial Working Capital	1.61%	40,300	**40,300**
Working Capital			25,300
O&M Staffing			15,000
Financial Cost			**494,100**
Debt Instrument Fee: MITI Fee	7.44%	185,900	12,300
Commitment Fee			29,300
Up-front Financing Fees			144,300
Interest During Construction	12.33%	308,200	308,200
Total Project Cost	100.00%	2,500,000	**2,500,000**

PROJECT COST ASSUMPTION

EPC Unit Cost	1440.89	$/kW
Capacity	1,230	MW
Discount Rate	14.00%	
Coal Price in 1997	34.9	$/tonnes

RESULTS

PARAMETERS		Paiton-01
1. IRR on Project		14.69%
2. ROE		24.76%
3. Tariff (A+B+C+D)	(cents/kWh)	
Years 1-6		8.1706
Years 7-12		8.1241
Years 13-30		5.4889
4. Average Levelized Tariff		7.2447
5. Average Levelized Cost		5.6596
6. Total Payment (A+B+C+D)	(cents/kWh)	
Years 1-6		731,873,851
Years 7-12		727,404,680
Years 13-30		498,492,919
7. Capacity Charge Payment (A+B)	(US$/year)	
Years 1-6		573,391,787
Years 7-12		565,869,046
Years 13-30		326,819,022
8. Capacity Charge Tariff (A+B)	(cents/kWh)	
Years 1-6		6.4022
Years 7-12		6.3207
Years 13-30		3.5985

FINANCING STRUCTURE

Financing Amount (in US$ 1,000)		Principal	Repayment Years	Repayment Years
US Exim Loan	$	540,000	1999-2011	12
J Exim - Tranche A: Loan	$	540,000	1999-2011	12
J Exim - Tranche B: Co-financing	$	360,000	1999-2011	12
OPIC Loan	$	200,000	1999-2011	12
Bonds	$	180,000	2008-2014	6
	$	1,820,000	72.8%	
Equity	$	680,000	27.2%	
Total Sources	$	2,500,000	100.0%	

Interest Rates	Pre-Comp	Years 1-4	Years 5-8	Years 9-12
US Exim Loan	9.38%	11.50%	11.50%	11.50%
J Exim - Tranche A	9.44%	9.44%	9.44%	9.44%
J Exim - Tranche B	4.88%	11.13%	11.25%	11.38%
OPIC Loan	6.18%	12.29%	12.29%	12.29%
Bonds	10.46%	10.46%	10.46%	10.46%

OTHER FINANCIAL ASSUMPTIONS

The PPA Agreed Base Exchange Rate (RD_b)		2,038		12-Feb-94
Annual Increase in Exchange Rate prior to Asian Crisis (up to 1997)		3.5%		
Exchange Rate (RD_m)	1999	9,000		1999
Projected Annual Exchange Rate movement after the Asian Crisis (after 1997)				
Years 1-10		2%	increase	
Years 11-20		-4%	decrease	
Years 21-30		0%	steady	
Tax		0%		
Inflation - Indonesia				
Years 1-10		8%		
Years 11-20		6%		
Years 21-30		4%		
Inflation - the US				
Years 1-30		3%		
Plants Life		35	years	

OPERATING COST ASSUMPTION				
Component A				
Capital Cost Recovery Charge Rate	CCR			
Years 1-6	CCR_1		1,092,596	Rp per kW-year
Years 7-12	CCR_2		1,065,816	Rp per kW-year
Years 13-30	CCR_3		553,439	Rp per kW-year
Component B				
Fixed O&M non-Indonesian	$FOMR_F$		38,830	Rp per kW-year
Fixed O&M Indonesian	$FOMR_L$		38,830	Rp per kW-year
Component C				
Weighted Average Specific Heat Rate	SHR_W		2,447	kilocalorie/kWh
Specific Heat Rate at Full Load	SHR_{CC}		2,447	kilocalorie/kWh
Higher Heating Value of Coal	HHV		5,215	kcal/kg
Price Allowance in 1997	P_{1997}		71.126	Rp/kg
Adjusted Price Allowance in 1997	P		78.86	Rp/kg
Coal Price in 1997			34.90	$/tonnes
The exchange rate immediately preceding the cris		1997	2,260	Rp/$
Fraction of P attributable to foreign currency costs	DP_P		0.6	
Component D				
Variable O&M non-Indonesian	$VOMR_F$		1.452	Rp per kWh
Variable O&M Indonesian	$VOMR_L$		4.356	Rp per kWh

REVENUE CALCULATION	(in US$)						COD
Year	1993	1994	1995	1996	1997	1998	1999
Year Index	-5	-4	-3	-2	-1	0	1
DCR_1 - Discount Factor to adjust for the US Inflation							1.000
DCR_2 - Discount Factor to adjust for Indonesian Inflation							1.000
Contract Capacity - CC (kW): PPA Attachment A						615,000	1,230,000
Availability Factor - AF (%): PPA Attachment A						83.00%	83.00%
Total Annual Hours (hours)						8,760	8,760
The US Consumer Price Index (CPI)							
Indonesian Consumer Price Index (ICPI)							
Currency Exchange Rate (Rp/$)		2,038	2,109	2,183	2,260	10,000	9,000
CCR (Rp per kW-year)							1,092,596
Pm (Rp/kg)		71.126			78.86	349.00	314.10
P($/tonnes)		34.90			34.90	34.90	34.90
Component A (Rupiah term)							4,925,849,513,052
Component A (Dollar term)							547,316,613
Dollar portion (Dollar term)							547,316,613
Rupiah portion (Dollar term)							0
Component B (Rupiah term)							214,702,353,183
Component B (Dollar term)							23,855,817
Dollar portion (Dollar term)							19,451,201
Rupiah portion (Dollar term)							4,404,616
Component C (Rupiah term)						732,255,087,752	1,318,059,157,953
Component C (Dollar term)						73,225,509	146,451,018
Dollar portion (Dollar term)						0	0
Rupiah portion (Dollar term)						73,225,509	146,451,018
Component D (Rupiah term)							96,300,638,041
Component D (Dollar term)							10,700,071
Dollar portion (Dollar term)							6,371,618
Rupiah portion (Dollar term)							4,328,453
Total Components A+B+C+D (Dollar Term)						73,225,509	728,323,518
Total Dollar Portion (Dollar term)						-	573,139,431
Total Rupiah Portion (Dollar term)						73,225,509	155,184,087
% Dollar						0%	79%
% Rupiah						100%	21%
Capacity Charge Components A+B (Dollar Term)							571,172,430
Dollar portion (Dollar term)							566,767,813
Rupiah portion (Dollar term)							4,404,616
% Dollar							99%
% Rupiah							1%
TOTAL REVENUE (Components A, B, C, D)						**73,225,509**	**728,323,518**
Tariff (cents/kWh)						1.6376	8.1440
Capacity Charge (Components A+B) (cents/kWh)						0.0000	6.3868

REVENUE CALCULATION (Continued) (in US$)

2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2	3	4	5	6	7	8	9	10	11	12
1.030	1.061	1.093	1.126	1.159	1.194	1.230	1.267	1.305	1.344	1.384
1.080	1.166	1.260	1.360	1.469	1.587	1.714	1.851	1.999	1.791	1.898
1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760
9,180	9,364	9,551	9,742	9,937	10,135	10,338	10,545	10,756	10,326	9,913
1,092,596	1,092,596	1,092,596	1,092,596	1,092,596	1,065,816	1,065,816	1,065,816	1,065,816	1,065,816	1,065,816
320.38	326.79	333.33	339.99	346.79	353.73	360.80	368.02	375.38	360.36	345.95
34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
5,024,366,503,313	5,124,853,833,379	5,227,350,910,047	5,331,897,928,248	5,438,535,886,813	5,411,339,723,039	5,519,566,517,500	5,629,957,847,850	5,742,557,004,807	5,512,854,724,615	5,292,340,535,630
547,316,613	547,316,613	547,316,613	547,316,613	547,316,613	533,901,646	533,901,646	533,901,646	533,901,646	533,901,646	533,901,646
547,316,613	547,316,613	547,316,613	547,316,613	547,316,613	533,901,646	533,901,646	533,901,646	533,901,646	533,901,646	533,901,646
0	0	0	0	0	0	0	0	0	0	0
226,731,753,735	239,463,078,875	252,939,304,938	267,206,179,582	282,312,409,748	298,309,862,959	315,253,782,925	333,203,020,513	352,220,281,216	340,911,280,042	342,147,702,193
24,698,448	25,573,826	26,483,373	27,428,579	28,411,005	29,432,291	30,494,154	31,598,397	32,746,908	33,016,124	34,516,528
20,034,737	20,635,779	21,254,852	21,892,498	22,549,273	23,225,751	23,922,523	24,640,199	25,379,405	26,140,787	26,925,011
4,663,711	4,938,047	5,228,521	5,536,081	5,861,733	6,206,540	6,571,631	6,958,198	7,367,503	6,875,336	7,591,517
1,348,103,684,513	1,371,308,747,935	1,398,734,922,893	1,426,709,621,351	1,459,230,783,131	1,484,348,690,054	1,514,035,663,855	1,544,316,377,132	1,579,518,328,523	1,512,194,596,488	1,451,706,812,628
146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018
0	0	0	0	0	0	0	0	0	0	0
146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018
102,599,084,266	108,733,021,358	115,570,800,158	122,861,441,599	130,994,318,186	138,929,446,612	147,776,737,377	157,217,097,915	167,750,504,018	158,181,702,007	161,377,291,884
11,176,371	11,612,310	12,100,550	12,611,665	13,182,843	13,707,264	14,294,283	14,909,253	15,596,235	15,319,372	16,280,056
6,580,747	6,759,650	6,962,439	7,171,312	7,406,689	7,608,045	7,836,287	8,071,375	8,336,293	8,562,922	8,819,810
4,595,624	4,852,660	5,138,110	5,440,352	5,776,155	6,099,218	6,457,996	6,837,878	7,259,942	6,756,450	7,460,247
730,043,685	730,953,766	732,351,553	733,807,873	735,762,714	723,492,218	725,141,100	726,860,313	729,097,043	728,688,159	731,149,248
573,932,096	574,712,041	575,533,904	576,380,423	577,272,574	564,735,442	565,660,456	566,613,220	567,617,344	568,605,355	569,646,467
156,111,588	156,241,725	156,817,649	157,427,450	158,490,140	158,756,776	159,480,644	160,247,093	161,479,698	160,082,804	161,502,781
79%	79%	79%	79%	78%	78%	78%	78%	78%	78%	78%
21%	21%	21%	21%	22%	22%	22%	22%	22%	22%	22%
572,015,061	572,890,439	573,799,985	574,745,191	575,727,618	563,333,937	564,395,800	565,500,043	566,648,554	566,917,770	568,418,174
567,351,349	567,952,391	568,571,465	569,209,110	569,865,885	557,127,397	557,824,169	558,541,845	559,281,051	560,042,433	560,826,657
4,663,711	4,938,047	5,228,521	5,536,081	5,861,733	6,206,540	6,571,631	6,958,198	7,367,503	6,875,336	7,591,517
99%	99%	99%	99%	99%	99%	99%	99%	99%	99%	99%
1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
730,043,685	**730,953,766**	**732,351,553**	**733,807,873**	**735,762,714**	**723,492,218**	**725,141,100**	**726,860,313**	**729,097,043**	**728,688,159**	**731,149,248**
8.1409	8.1734	8.1890	8.2053	8.2047	8.0900	8.1084	8.1276	8.1304	8.1481	8.1756
6.3787	6.4060	6.4161	6.4267	6.4201	6.2991	6.3110	6.3233	6.3189	6.3392	6.3560

REVENUE CALCULATION (Continued) (in US$)

2011 13	2012 14	2013 15	2014 16	2015 17	2016 18	2017 19	2018 20	2019 21	2020 22	2021 23
1.426	1.469	1.513	1.558	1.605	1.653	1.702	1.754	1.806	1.860	1.916
2.012	2.133	2.261	2.397	2.540	2.693	2.854	3.026	2.191	2.279	2.370
1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760
9,516	9,135	8,770	8,419	8,082	7,759	7,449	7,151	7,151	7,151	7,151
553,439	553,439	553,439	553,439	553,439	553,439	553,439	553,439	553,439	553,439	553,439
332.11	318.83	306.07	293.83	282.08	270.79	259.96	249.56	249.56	249.56	249.56
34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
2,638,192,847,124	2,532,665,133,239	2,431,358,527,910	2,334,104,186,794	2,240,740,019,322	2,151,110,418,549	2,065,066,001,807	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735
277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464
277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464
0	0	0	0	0	0	0	0	0	0	0
343,673,554,124	345,503,790,886	347,654,291,830	350,141,915,768	352,984,559,438	356,201,219,487	359,812,058,169	363,838,472,999	338,075,510,036	349,086,370,447	360,462,300,476
36,115,062	37,820,201	39,641,253	41,588,442	43,673,000	45,907,272	48,304,830	50,880,601	47,277,807	48,817,609	50,408,464
27,732,761	28,564,744	29,421,686	30,304,337	31,213,467	32,149,871	33,114,367	34,107,798	35,131,032	36,184,963	37,270,512
8,382,300	9,255,457	10,219,567	11,284,105	12,459,533	13,757,401	15,190,463	16,772,803	12,146,775	12,632,646	13,137,952
1,393,638,540,123	1,341,558,458,788	1,284,377,278,577	1,233,002,187,434	1,183,682,099,937	1,139,448,062,011	1,090,881,423,302	1,047,246,166,370	1,047,246,166,370	1,050,115,333,949	1,047,246,166,370
146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018
0	0	0	0	0	0	0	0	0	0	0
146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253	146,451,018
164,835,124,650	169,031,981,210	172,598,203,949	176,936,111,106	181,601,694,125	187,125,129,508	191,992,653,167	197,759,337,357	167,648,230,429	174,006,680,983	179,624,909,053
17,321,760	18,502,904	19,680,497	21,015,756	22,468,662	24,116,717	25,775,047	27,655,443	23,444,587	24,333,778	25,119,453
9,084,404	9,382,572	9,637,644	9,926,774	10,224,577	10,560,167	10,847,254	11,172,671	11,507,851	11,885,561	12,208,679
8,237,356	9,120,332	10,042,852	11,088,983	12,244,085	13,556,550	14,927,793	16,482,771	11,936,736	12,448,217	12,910,773
477,123,302	480,410,822	483,008,231	486,290,680	489,828,143	494,111,706	497,766,358	502,222,525	494,408,876	497,239,104	499,214,398
314,052,629	315,182,779	316,294,794	317,466,574	318,673,508	319,945,502	321,197,084	322,515,933	323,874,347	325,305,988	326,714,655
163,070,674	165,228,042	166,713,437	168,824,105	171,154,635	174,166,204	176,569,274	179,706,592	170,534,529	171,933,116	172,499,743
66%	66%	65%	65%	65%	65%	65%	64%	66%	65%	65%
34%	34%	35%	35%	35%	35%	35%	36%	34%	35%	35%
313,350,525	315,055,664	316,876,717	318,823,906	320,908,463	323,142,735	325,540,294	328,116,065	324,513,271	326,053,073	327,643,928
304,968,225	305,800,208	306,657,150	307,539,801	308,448,931	309,385,335	310,349,831	311,343,262	312,366,496	313,420,427	314,505,976
8,382,300	9,255,457	10,219,567	11,284,105	12,459,533	13,757,401	15,190,463	16,772,803	12,146,775	12,632,646	13,137,952
97%	97%	97%	96%	96%	96%	95%	95%	96%	96%	96%
3%	3%	3%	4%	4%	4%	5%	5%	4%	4%	4%
477,123,302	**480,410,822**	**483,008,231**	**486,290,680**	**489,828,143**	**494,111,706**	**497,766,358**	**502,222,525**	**494,408,876**	**497,239,104**	**499,214,398**
5.3351	5.3572	5.4009	5.4376	5.4772	5.5100	5.5659	5.6158	5.5284	5.5448	5.5821
3.5038	3.5133	3.5433	3.5650	3.5883	3.6035	3.6401	3.6689	3.6287	3.6359	3.6637

REVENUE CALCULATION (Continued) (in US$)

2022 24	2023 25	2024 26	2025 27	2026 28	2027 29	2028 30
1.974	2.033	2.094	2.157	2.221	2.288	2.357
2.465	2.563	2.666	2.772	2.883	2.999	3.119
1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000	1,230,000
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,760	8,760	8,784	8,760	8,760	8,760	8,784
7,151	7,151	7,151	7,151	7,151	7,151	7,151
553,439	553,439	553,439	553,439	553,439	553,439	553,439
249.56	249.56	249.56	249.56	249.56	249.56	249.56
34.90	34.90	34.90	34.90	34.90	34.90	34.90
1,982,463,361,735	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735	1,982,463,361,735
277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464
277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464	277,235,464
0	0	0	0	0	0	0
372,215,641,962	384,359,162,591	396,906,070,894	409,870,031,783	423,265,182,649	437,106,150,038	451,408,066,925
52,052,097	53,750,295	55,504,904	57,317,835	59,191,066	61,126,641	63,126,677
38,388,627	39,540,286	40,726,495	41,948,290	43,206,738	44,502,940	45,838,029
13,663,470	14,210,009	14,778,409	15,369,546	15,984,328	16,623,701	17,288,649
1,047,246,166,370	1,047,246,166,370	1,050,115,333,949	1,047,246,166,370	1,047,246,166,370	1,047,246,166,370	1,050,115,333,949
146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253
0	0	0	0	0	0	0
146,451,018	146,451,018	146,852,253	146,451,018	146,451,018	146,451,018	146,852,253
185,936,883,641	192,475,146,558	199,793,848,452	206,263,907,700	213,531,870,309	221,061,073,612	229,488,099,567
26,002,144	26,916,481	27,939,957	28,844,755	29,861,136	30,914,049	32,092,517
12,574,940	12,952,188	13,377,304	13,740,976	14,153,206	14,577,802	15,056,273
13,427,204	13,964,293	14,562,653	15,103,779	15,707,930	16,336,247	17,036,244
501,740,723	504,353,257	507,532,578	509,849,072	512,738,683	515,727,171	519,306,911
328,199,031	329,727,938	331,339,262	332,924,730	334,595,408	336,316,206	338,129,765
173,541,692	174,625,319	176,193,315	176,924,342	178,143,275	179,410,965	181,177,146
65%	65%	65%	65%	65%	65%	65%
35%	35%	35%	35%	35%	35%	35%
329,287,561	330,985,759	332,740,368	334,553,299	336,426,529	338,362,105	340,362,141
315,624,091	316,775,750	317,961,958	319,183,753	320,442,202	321,738,404	323,073,492
13,663,470	14,210,009	14,778,409	15,369,546	15,984,328	16,623,701	17,288,649
96%	96%	96%	95%	95%	95%	95%
4%	4%	4%	5%	5%	5%	5%
501,740,723	**504,353,257**	**507,532,578**	**509,849,072**	**512,738,683**	**515,727,171**	**519,306,911**
5.6104	5.6396	5.6596	5.7010	5.7334	5.7668	5.7909
3.6820	3.7010	3.7105	3.7409	3.7619	3.7835	3.7955

CASH FLOW CALCULATION

(in US$ 1,000)

Year / Year Index	CHECK TOTAL	1993 / -5	1994 / -4	1995 / -3	1996 / -2	1997 / -1	1998 / 0	COD 1999 / 1
Plant Performance								
Contract Capacity (MW)		0	0	0	0	0	615	1,230
Availability Factor (%)		0	0	0	0	0	83.00%	83.00%
Net Electricity Generated (MWh)		0	0	0	0	0	4,471,542	8,943,084
Total Coal Volume (tonnes/year)		0	0	0	0	0	2,098	4,196
Prices								
Coal Price ($/tonnes)							34.90	34.90
Cash Inflows								
Electricity Sales		0	0	0	0	0	73,226	728,324
Total Operating Inflows		0	0	0	0	0	73,226	728,324
Cash Outflows								
Fixed O&M		0	0	0	0	0	0	23,856
Variable O&M		0	0	0	0	0	0	10,700
Coal Payment		0	0	0	0	0	73,226	146,451
Depreciation								71,429
Total Operating Outflows		0	-	-	-	-	73,226	252,435
Net Cashflow from Operations		0	-	-	-	-	(0)	547,317
EPC Construction Cost	1,772,300			248,122	1,027,934	265,845	230,399	
Contingency	3,300		3,300					
Development Cost	190,000	22,420	167,580					
Initial Working Capital	40,300					20,150	20,150	
Financial Cost	185,900		185,900					
Interest During Construction	308,200	-	-	25,105	44,330	111,238	127,527	
Taxation	0	-	-	-	-	-	-	-
Net Cashflow Before Financing	**2,500,000**	(22,420)	(356,780)	(273,227)	(1,072,264)	(397,233)	(378,076)	547,317
Financing								
Drawdown								
1. US Exim Loan	540,000		267,585	204,920	67,495			
2. J Exim - Tranche A: Loan	540,000				540,000			
3. J Exim - Tranche B: Co-financing	360,000				196,703	163,297		
4. OPIC Loan	200,000					134,628	65,372	
5. Bonds	180,000						180,000	-
Interest Expense								
Interest 1								(62,100)
Interest 2								(50,976)
Interest 3								(40,068)
Interest 4								(24,576)
Interest 5								(18,828)
Repayment								
Repayment 1	$540,000							
Repayment 2	$540,000							
Repayment 3	$360,000							
Repayment 4	$200,000							
Repayment 5	$180,000							
Senior Debt Service		-	267,585	204,920	804,198	297,925	245,372	(196,548)
Net Cash Flow After Senior Debt Service		(22,420)	(89,195)	(68,307)	(268,066)	(99,308)	(132,704)	350,769
Equity	**680,000**	22,420	89,195	68,307	268,066	99,308	132,704	
Total Financing		22,420	356,780	273,227	1,072,264	397,233	378,076	(196,548)
Net Cash After Financing		-	-	-	-	-	-	350,769
Net Cash Available for Distribution		-	-	-	-	-	-	350,769
Distribution		-	-	-	-	-	-	350,769
Closing Cash Balance		-	-	-	-	-	-	-

CASH FLOW CALCULATION (Continued) (in US$ 1,000)

2000 2	2001 3	2002 4	2003 5	2004 6	2005 7	2006 8	2007 9	2008 10	2009 11	2010 12
1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,967,586	8,943,084	8,943,084	8,943,084	8,967,586	8,943,084	8,943,084	8,943,084	8,967,586	8,943,084	8,943,084
4,208	4,196	4,196	4,196	4,208	4,196	4,196	4,196	4,208	4,196	4,196
34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
730,044	730,954	732,352	733,808	735,763	723,492	725,141	726,860	729,097	728,688	731,149
730,044	730,954	732,352	733,808	735,763	723,492	725,141	726,860	729,097	728,688	731,149
24,698	25,574	26,483	27,429	28,411	29,432	30,494	31,598	32,747	33,016	34,517
11,176	11,612	12,101	12,612	13,183	13,707	14,294	14,909	15,596	15,319	16,280
146,852	146,451	146,451	146,451	146,852	146,451	146,451	146,451	146,852	146,451	146,451
71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429
254,156	255,066	256,464	257,920	259,875	261,019	262,668	264,387	266,624	266,215	268,676
547,317	547,317	547,317	547,317	547,317	533,902	533,902	533,902	533,902	533,902	533,902
-	-	-	-	-	-	-	-	-	-	-
547,317	547,317	547,317	547,317	547,317	533,902	533,902	533,902	533,902	533,902	533,902
(62,100)	(56,925)	(51,750)	(46,575)	(41,400)	(36,225)	(31,050)	(25,875)	(20,700)	(15,525)	(10,350)
(50,976)	(46,728)	(42,480)	(38,232)	(33,984)	(29,736)	(25,488)	(21,240)	(16,992)	(12,744)	(8,496)
(40,068)	(36,729)	(33,390)	(30,375)	(27,000)	(23,625)	(20,250)	(17,070)	(13,656)	(10,242)	(6,828)
(24,576)	(22,528)	(20,480)	(18,432)	(16,384)	(14,336)	(12,288)	(10,240)	(8,192)	(6,144)	(4,096)
(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(18,828)	(15,690)
($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)
($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)	($45,000)
($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)	($30,000)
($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)	($16,667)
									($30,000)	($30,000)
(333,215)	(318,405)	(303,595)	(289,109)	(274,263)	(259,417)	(244,571)	(229,920)	(215,035)	(230,150)	(212,127)
214,102	228,912	243,722	258,208	273,054	274,485	289,331	303,982	318,867	303,752	321,775
(333,215)	(318,405)	(303,595)	(289,109)	(274,263)	(259,417)	(244,571)	(229,920)	(215,035)	(230,150)	(212,127)
214,102	228,912	243,722	258,208	273,054	274,485	289,331	303,982	318,867	303,752	321,775
214,102	228,912	243,722	258,208	273,054	274,485	289,331	303,982	318,867	303,752	321,775
214,102	228,912	243,722	258,208	273,054	274,485	289,331	303,982	318,867	303,752	321,775
-	-	-	-	-	-	-	-	-	-	-

CASH FLOW CALCULATION (Continued) (in US$ 1,000)

2011 13	2012 14	2013 15	2014 16	2015 17	2016 18	2017 19	2018 20	2019 21	2020 22	2021 23
1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,943,084	8,967,586	8,943,084	8,943,084	8,943,084	8,967,586	8,943,084	8,943,084	8,943,084	8,967,586	8,943,084
4,196	4,208	4,196	4,196	4,196	4,208	4,196	4,196	4,196	4,208	4,196
34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90	34.90
477,123	480,411	483,008	486,291	489,828	494,112	497,766	502,223	494,409	497,239	499,214
477,123	480,411	483,008	486,291	489,828	494,112	497,766	502,223	494,409	497,239	499,214
36,115	37,820	39,641	41,588	43,673	45,907	48,305	50,881	47,278	48,818	50,408
17,322	18,503	19,680	21,016	22,469	24,117	25,775	27,655	23,445	24,334	25,119
146,451	146,852	146,451	146,451	146,451	146,852	146,451	146,451	146,451	146,852	146,451
71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429	71,429
271,316	274,604	277,201	280,484	284,021	288,305	291,959	296,416	288,602	291,432	293,408
277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235
-	-	-	-	-	-	-	-	-	-	-
277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235	277,235
(5,175)	(0)	(0)	(0)	(0)						
(4,248)	(0)	(0)	(0)	(0)						
(3,414)	(0)	(0)	(0)	(0)						
(2,048)	0	0	0	0						
(12,552)	(9,414)	(6,276)	(3,138)	-						
($45,000)										
($45,000)										
($30,000)										
($16,667)										
($30,000)	($30,000)	($30,000)	($30,000)							
(194,104)	(39,414)	(36,276)	(33,138)	(0)	-	-	-	-	-	-
83,132	237,821	240,959	244,097	277,235	277,235	277,235	277,235	277,235	277,235	277,235
	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)
(194,104)	(79,414)	(76,276)	(73,138)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)
83,132	197,821	200,959	204,097	237,235	237,235	237,235	237,235	237,235	237,235	237,235
83,132	197,821	200,959	204,097	237,235	237,235	237,235	237,235	237,235	237,235	237,235
83,132	197,821	200,959	204,097	237,235	237,235	237,235	237,235	237,235	237,235	237,235
-	-	-	-	-	-	-	-	-	-	-

CASH FLOW CALCULATION (Continued) (in US$ 1,000)

2022 24	2023 25	2024 26	2025 27	2026 28	2027 29	2028 30
1,230	1,230	1,230	1,230	1,230	1,230	1,230
83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
8,943,084	8,943,084	8,967,586	8,943,084	8,943,084	8,943,084	8,967,586
4,196	4,196	4,208	4,196	4,196	4,196	4,208
34.90	34.90	34.90	34.90	34.90	34.90	34.90
501,741	504,353	507,533	509,849	512,739	515,727	519,307
501,741	504,353	507,533	509,849	512,739	515,727	519,307
52,052	53,750	55,505	57,318	59,191	61,127	63,127
26,002	26,916	27,940	28,845	29,861	30,914	32,093
146,451	146,451	146,852	146,451	146,451	146,451	146,852
71,429	71,429	71,429	71,429	71,429	71,429	71,429
295,934	298,546	301,726	304,042	306,932	309,920	313,500
277,235	277,235	277,235	277,235	277,235	277,235	277,235
-	-	-	-	-	-	-
277,235	277,235	277,235	277,235	277,235	277,235	277,235
-	-	-	-	-	-	-
277,235	277,235	277,235	277,235	277,235	277,235	277,235
($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)	($40,000)
(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)	(40,000)
237,235	237,235	237,235	237,235	237,235	237,235	237,235
237,235	237,235	237,235	237,235	237,235	237,235	237,235
237,235	237,235	237,235	237,235	237,235	237,235	237,235
-	-	-	-	-	-	-

Appendix 2: Sensitivity Analysis on Coal Price

Coal Price (US$/tons)	Tariff (c/kWh)			Average Levelized Tariff (c/kWh)
	Years 1-6	Years 7-12	Years 13-30	
21.0	7.5184	7.4719	4.8367	6.5925
23.0	7.6123	7.5657	4.9306	6.6863
30.0	7.9407	7.8942	5.2590	7.0148
34.9	8.1706	8.1241	5.4889	7.2447
39.7	8.3959	8.3493	5.7142	7.4700

Coal Price (US$/tons)	Total Charge (Component A, B, C, D)		
	Years 1-6	Years 7-12	Years 13-30
21.0	673,491,955	669,049,417	440,119,900
23.0	681,892,227	677,445,858	448,518,895
30.0	711,293,183	706,833,401	477,915,380
34.9	731,873,851	727,404,680	498,492,919
39.7	752,034,507	747,556,138	518,650,508

Coal Price (US$/tons)	Capacity Charge (Component A and B) in US$		
	Years 1-6	Years 7-12	Years 13-30
21.0	573,391,787	565,869,046	326,819,022
23.0	573,391,787	565,869,046	326,819,022
30.0	573,391,787	565,869,046	326,819,022
34.9	573,391,787	565,869,046	326,819,022
39.7	573,391,787	565,869,046	326,819,022

Coal Price (US$/tons)	Percentage Capacity Charge of the Total Charge			
	Years 1-6	Years 7-12	Years 13-30	Weighted Average
21.0	85.14%	84.58%	74.26%	78.50%
23.0	84.09%	83.53%	72.87%	77.25%
30.0	80.61%	80.06%	68.38%	73.17%
34.9	78.35%	77.79%	65.56%	70.56%
39.7	76.25%	75.70%	63.01%	68.20%

Coal Price (US$/tons)	Average Levelized Cost				
	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total (c/kWh)
21.0	3.6568	0.3220	0.9197	0.1522	5.0508
23.0	3.6568	0.3220	1.0073	0.1522	5.1384
30.0	3.6568	0.3220	1.3139	0.1522	5.4450
34.9	3.6568	0.3220	1.5285	0.1522	5.6596
39.7	3.6568	0.3220	1.7388	0.1522	5.8698

Chapter 8: A Proposed Approach for Remedy[299]

8.1. Problems

As previously mentioned in chapter 6, the core problem in the private power development in Indonesia was that the IPPs' tariff to PLN was relatively high if compared to the PLN's tariff to the end consumers. Table 8.1 shows the disparity of the electricity tariffs of some private IPPs in Indonesia. While the bulk tariffs are widely spread, PLN's tariff to the consumers is far more less, around US$ 3.2 cents/kWh. As a result, PLN could not afford the IPPs' tariff.

Table 8.1: The bulk electricity tariffs from the IPPs to PLN (Source: PLN, July 1999)[300]

Power Generation	Capacity (MW)	Tariff (US cents/kWh)
Steam Coal Power Plants		
Paiton I	1,230	8.47
Paiton II	1,220	6.59
Tanjung Jati B	1,320	5.73
Amurang	110	6.70
Sibolga A	200	6.55
Geothermal Power Plant		
Dieng 1,2,3	95	7.65
Salak 4,5,6	165	8.46
Wayang Windu	220	8.40

This chapter would propose an approach to arrive at a reasonable renegotiated tariff. For this purpose, the Paiton I still serves as the case study. This approach would

[299] The thesis author prepared this case under the supervision of Professor Massood V. Samii as the basis for the thesis discussion, and not to illustrate either effective or ineffective handling of infrastructure development related issues. Data presented in the case analysis might have been altered to simplify, focus, and to preserve individual confidentiality. The assistance of Dr. Hardiv Situmeang—the Planning Director of PLN (July 31, 1998 – December 31, 1999) and later, the senior advisor to the PLN CEO—in the preparation of this case is greatly appreciated. The remarkable contribution of Dr. Situmeang in the case analysis is gratefully acknowledged.

[300] Husein, Ahmad, Andi Setia Gunawan, and Wuri Hardiastuti, "Impian Adhi Pupus di Tengah Jalan", *Gamma*, January 2, 2000.

take into account PLN's affordability and would follow the trend of the increasing competition in the electricity generating business, thereby demanding a lower ROE. The tariff benchmarking analysis outlined in chapter 6 would be used for the Paiton I tariff benchmarking analysis.

8.2. Proposed Approach for Remedy

Figure 8.1 shows the graphical representation of a proposed framework for renegotiation of PLN's payment obligations. X_0 is the current PLN's tariff to the customers, which is US$ 3.2 cents/kWh and will be increased annually, as shown by the blue line in figure 8.1. Still with respect to figure 8.1, the letter "A" in this figure represents the annual tariff increase, which could be 20% annual increases, for example, while X_1, represented by the horizontal black line, is the renegotiated tariff. The renegotiated tariff is a tariff that is perceived as reasonably represents the market price; this tariff should be renegotiated between PLN and PEC.

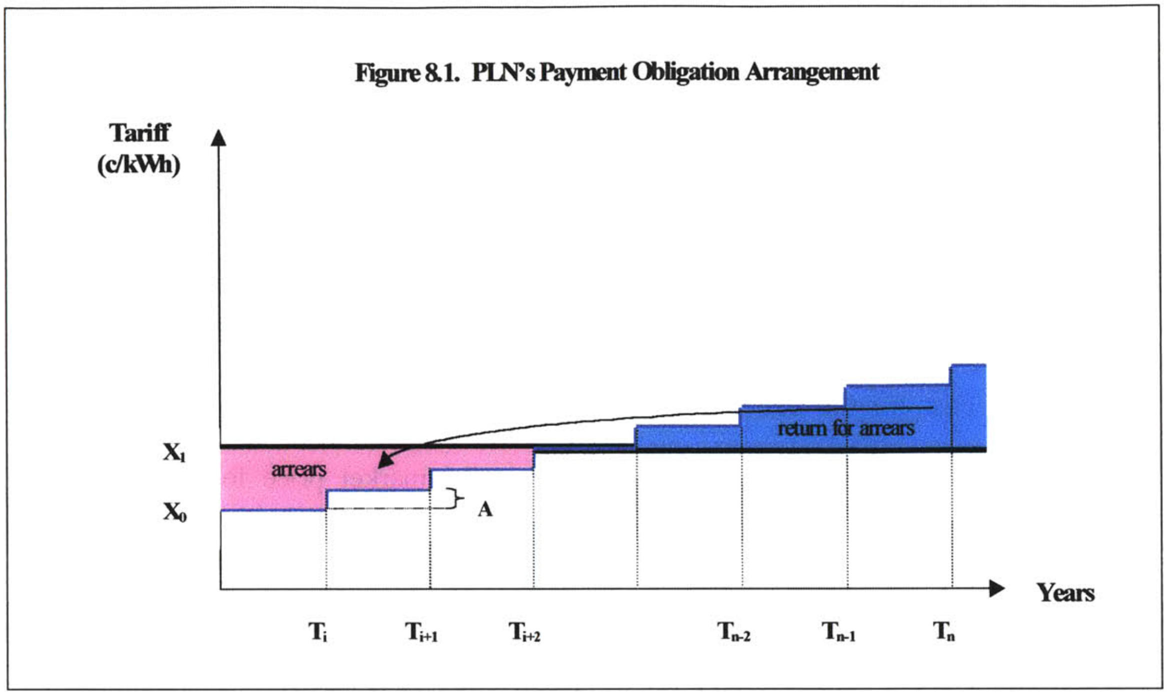


Figure 8.1: The framework of how to fulfill PLN's payment obligation

With this approach, PLN would delay the payment for the first few years while it increases the tariff by 20% each year to exceed the renegotiated tariff. After a certain point, when the tariff is higher than the renegotiated tariff, the difference can be used to pay back the arrears and the delayed payment during the previous period until all the previous arrears are paid back in full.

With respect to the approach shown in figure 8.1, there are two matters that should be resolved, as follows:

1) What is the value of the reasonable tariff that should be renegotiated between PLN and PEC? In other words, how to determine X_1?
2) Since the current PEC's tariff is relatively high, what should PEC do if PEC were to agree on X_1?

8.2.1. How to determine X_1?

To answer this question, this thesis would take the following assumptions:

1) Since the Paiton I project was obtained through a bidding process whose competition is questionable, it is reasonable to assume that the US$ 2.5 billion project cost for the 2x615 MW power plants might not assure a cost-effective development; therefore, it might not reflect the market price for projects with similar size.
2) The US$ 1.772 billion EPC cost (US$ 1440.89 per kW), which comprises 71% of the total project cost, is likely to be attributable to the high project cost of the Paiton I project.
3) An audit mentioned earlier, conducted in late 1999 by a Canadian engineering and construction company SNC-Lavalin Group, priced the Paiton I EPC cost at US$ 1.033 billion (with a ± 20% tolerance)[301], which is equal to an EPC unit cost of US$ 839.84 per kW. This audit strengthens the assumption that the EPC cost cited by PEC might not reflect a market-based price.
4) For the purpose of the case study, let us assume that the US$ 1.033 billion EPC cost for the Paiton I project by SNC-Lavalin Group is the EPC cost benchmark that reflects a market-based price[302].
5) With respect to ROE, instead of using the 24.76% ROE derived from the financial analysis in chapter 7, let us use an assumption of 17% ROE as an upper bound

---

301 Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000. See also Solomon, Jay, "Indonesian Audit Uncovers Inflated Cost of Power Plant", *The Wall Street Journal*, December 26, 2000.

302 This assumption is made to simplify and focus the case study.

and 14% as a lower bound. This assumption takes into account the *take-or-pay* PPA mechanism that provides a relatively high level of protections to the project company. In addition, because the Indonesian electricity generating business was expected to start the MB/MS scheme in 2007 whereby the business would be highly competitive, as mentioned earlier, it would be reasonable to assume that the private investors would reduce their ROE expectations of mid-20s or higher. The ROE would be lowered to around 15% to 20% or probably to a single-digit ROE, as illustrated by the experience of Chile[303]. Therefore, an assumption of 14% to 17% ROE is perceived as reasonable for the purpose of the case study, despite the fact that the Paiton I project is the first IPP in Indonesia.

Based on these assumptions, a tariff benchmarking analysis with ROEs set fixed is developed for the market-based EPC cost, which is US$ 839.84 per kW. The benchmarking uses ROEs ranging from 14% to 17% to derive the associated tariffs, with the technical and financial parameters closely following those of the Paiton I project. The results are presented in appendix 10 of chapter 6 and appendix 1 of this chapter.

---

303 Worenklein, Jacob J., "Project Finance: Adapts to Changing Power Market", *Private Power Executive*, May-June 1996. It is true that we have recently seen in some situations in Chile, and elsewhere, bids for power projects with surprising single-digit returns (Worenklein, 1996)

Figure 8.2 shows the graphical representation of the sensitivity of the tariffs with the EPC cost US$ 839.84 per kW and the project cost structure follows that developed in the subchapter 6.4.2 (appendix 10 of chapter 6). For the upper bound, the 17% ROE, the maximum tariff would be US$ 5.2883 cents/kWh (the tariff when the coal price is US$ 39.7 per tons), while the minimum tariff would be US$ 4.4693 cents/kWh (the tariff when the coal price is US$ 21.0 per tons). For the lower bound, the 14% ROE, the maximum tariff and the minimum tariff would be US$ 5.1568 cents/kWh and US$ 4.3378 cents/kWh respectively.

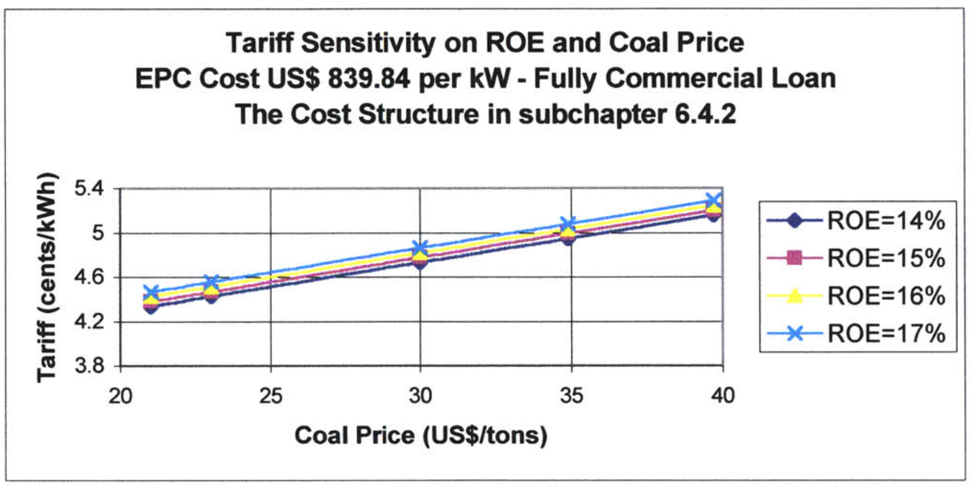


Figure 8.2: Tariff Sensitivity for EPC Cost US$ 839.84 per kW

Figure 8.3 shows the graphical representation of the sensitivity of the tariffs with the EPC cost US$ 839.84 per kW and the project cost structure follows that of the Paiton I project. For the upper bound, the 17% ROE, the maximum tariff would be US$ 5.0471 cents/kWh (the tariff when the coal price is US$ 39.7 per tons), while the minimum tariff would be US$ 4.2281 cents/kWh (the tariff when the coal price is US$ 21.0 per tons).

For the lower bound, the 14% ROE, the maximum tariff and the minimum tariff would be US$ 4.9231 cents/kWh and US$ 4.1041 cents/kWh respectively.

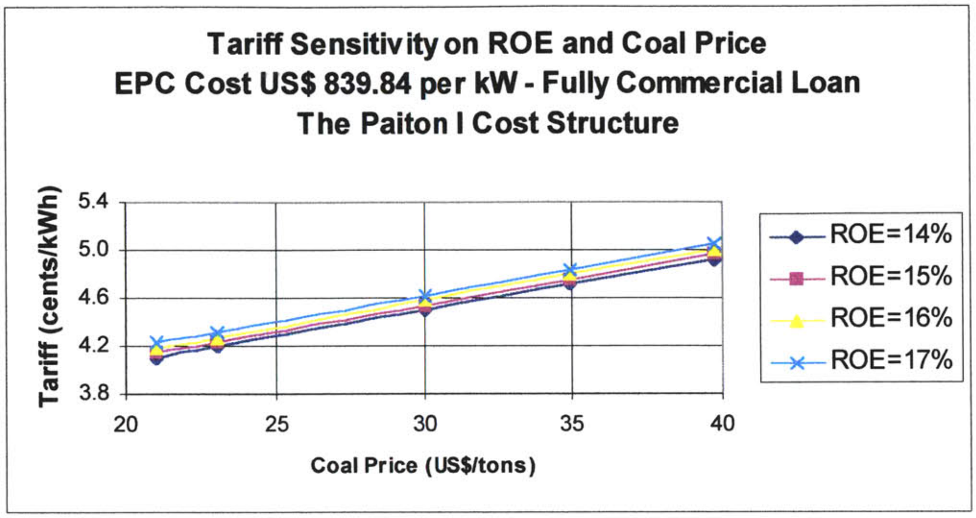


Figure 8.3: Tariff Sensitivity for EPC Cost US$ 839.84 per kW with the Paiton I cost structure

To determine the most appropriate renegotiated tariff, the results with the Paiton I cost structure represented in figure 8.3 (appendix 1) would be used. Deciding on a single tariff depends on the renegotiation process between PLN and PEC. If PLN allows PEC to realize 17% ROE, and PEC agrees on reducing its ROE from 25% to 17%, then the renegotiated tariff, X_1, would be in the range from US$ 4.2281 cents/kWh to US$ 5.0471 depending on the agreed coal price. However, if PLN allows PEC only to realize 14% ROE, and PEC agrees on reducing its ROE from 25% to 14%, then the renegotiated tariff, X_1, would be in the range from US$ 4.1041 cents/kWh to US$ 4.9231 cents/kWh depending on the agreed coal price. Indeed, reducing ROE is probably a tough effort for the private sponsors.

Let us assume that PLN allows PEC to realize only 14% ROE and the parties agree on the coal price of US$ 21 per tons; therefore, the renegotiated tariff, X_1, would be

US$ 4.1041 cents/kWh. This assumption is made to see the bottom line of the tariff that is possible. The 14% ROE is a bottom line since the calculation used a 14% discount rate assumption: having a 14% ROE means that the sponsors obtain no profits. The coal price of US$ 21 per tons is assumed as the bottom line of the coal price that can be negotiated.

After arriving at the possible renegotiated tariff of US$ 4.1041 cents/kWh, the next question is: what PEC should do to arrive at this tariff?

8.2.2. How to arrive at X_1?

The author developed a tariff sensitivity analysis using the Paiton I project cost structure with the total project cost of US$ 2.5 billion. This analysis is to figure out which of the Paiton I original arrangements should be restructured to yield a tariff of US$ 4.1041 cents/kWh. Appendix 2 to 7 of this chapter shows the results of the sensitivity analysis. These results are explained in the following sections.

1. Coal Price

Figure 8.4 shows the tariff sensitivity under various ROEs if the coal price is reduced (appendix 2).

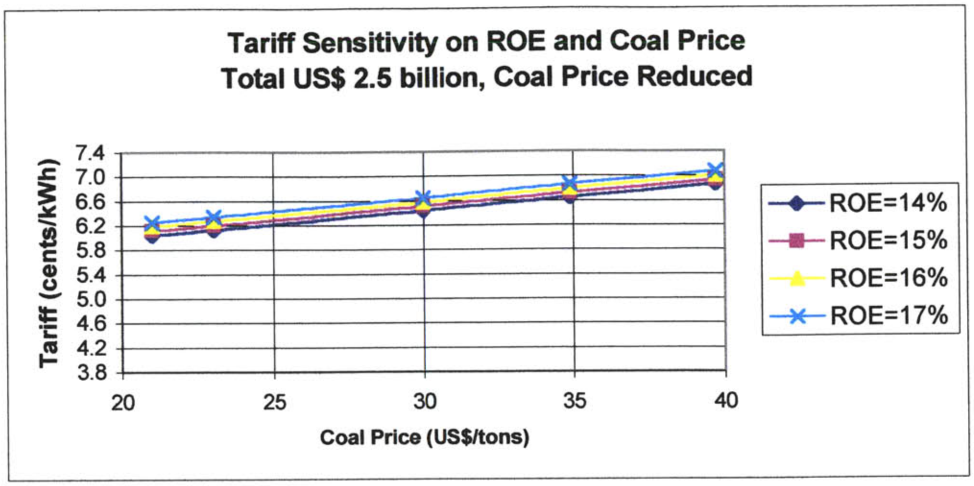


Figure 8.4: Coal Price Reduced

As shown in this figure, if only the coal price is reduced, the minimum tariff derived is US$ 6.0437 cents/kWh, which is the tariff when ROE 14% and the coal price is US$ 21 per tons. This value is still far from the renegotiated tariff of US$ 4.1041 cents/kWh. Therefore, despite the coal price reduction, other arrangement should be restructured.

2. Interest on Loans

Figure 8.5 shows the tariff sensitivity under various ROEs if the coal price is reduced, and the interests on loans are reduced to 6%, from the original interests of around 11% (appendix 3).

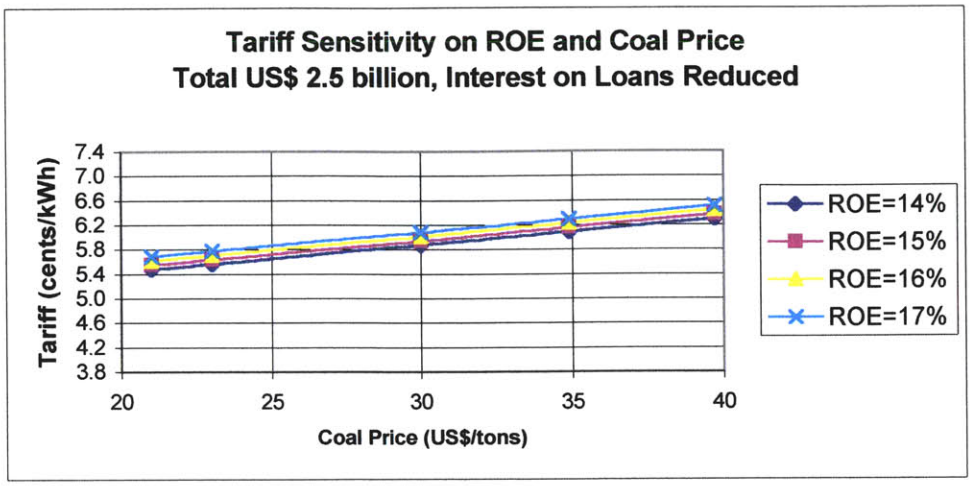


Figure 8.5: Coal Price and Interest on Loans Reduced

As shown in this figure, when the coal price is reduced, and the interests on loans are reduced to 6%, the minimum tariff derived is US$ 5.4774 cents/kWh, which is the tariff when ROE 14% and the coal price is US$ 21 per tons. This value is still far from the renegotiated US$ 4.1041 cents/kWh. Therefore, despite the reduction on coal price and loan interests, other arrangement should be restructured.

3. Debt Repayment Periods I

Figure 8.6 shows the tariff sensitivity under various ROEs if the coal price is reduced, the interests on loans after COD are reduced to 6%, and the debt repayment periods are stretched out to 20 years (from the original 12 years) for the US and Japan lenders and 14 years (from the original 6 years) for the bonds (appendix 4).

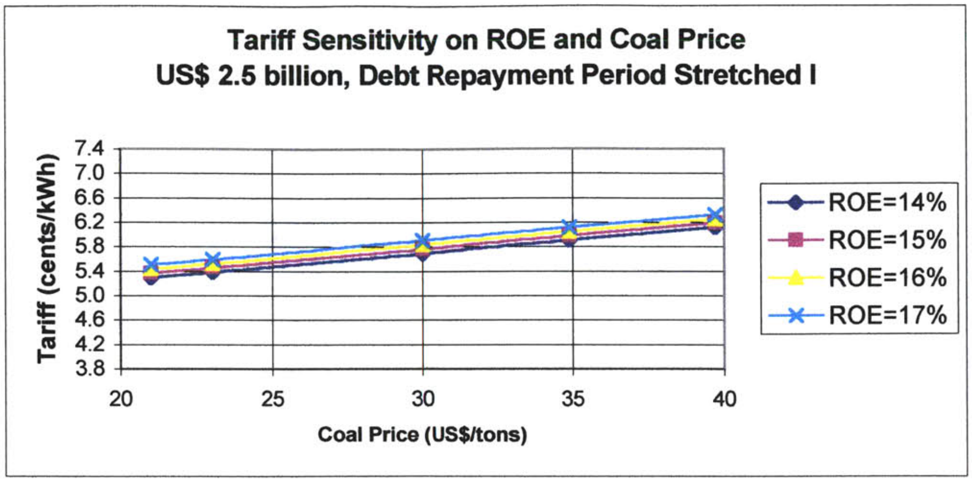


Figure 8.6: Coal Price and Interest on Loans reduced, and Debt Repayment Periods stretched out

As shown in this figure, under this arrangement, the minimum tariff derived is US$ 5.2963 cents/kWh, which is the tariff when ROE 14% and the coal price is US$ 21 per tons. This value is still far from the renegotiated US$ 4.1041 cents/kWh. Therefore, despite renegotiation of the coal price, the interest on loans, and the debt repayment periods, other arrangement should also be restructured.

4. Debt Repayment Periods II

Figure 8.7 shows the tariff sensitivity under various ROEs if the coal price is reduced, the interests on loans after COD are reduced to 6%, and the debt repayment periods are stretched out to 29 years (from the original 12 years) for the US and Japan lenders and 20 years (from the original 6 years) for the bonds (appendix 5). As shown in this figure, under this arrangement, the minimum tariff derived is US$ 5.1816 cents/kWh, which is the tariff when ROE 14% and the coal price is US$ 21 per tons. This value is still far from the renegotiated US$ 4.1041 cents/kWh. Therefore, other arrangements should also be restructured.

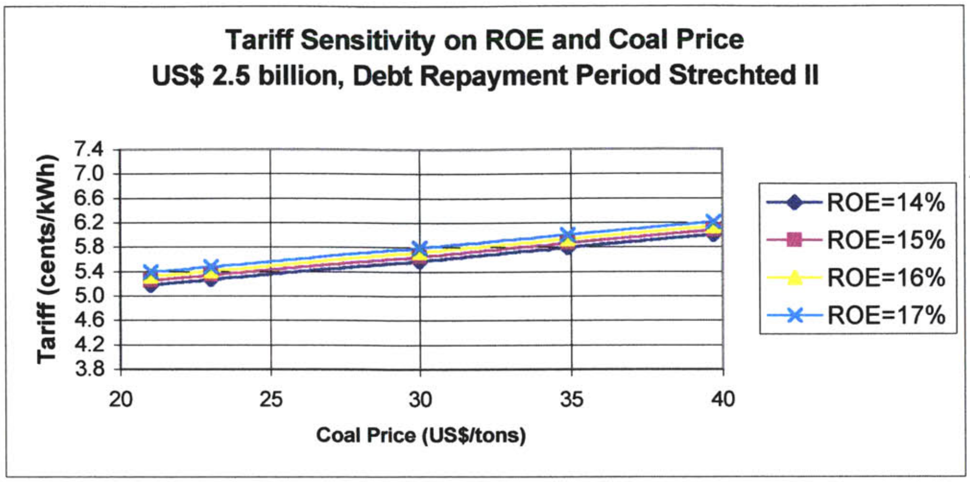


Figure 8.7: Coal Price and Interest on Loans reduced, and Debt Repayment Periods stretched out

5. Equity Right Off

Figure 8.8 shows the tariff sensitivity under various ROEs if the coal price is reduced, the interests on loans after COD are reduced to 6%, and the debt repayment periods are stretched out to 20 years for the US and Japan lenders and 14 years for the bonds, and the equity contributions are right off (appendix 6).

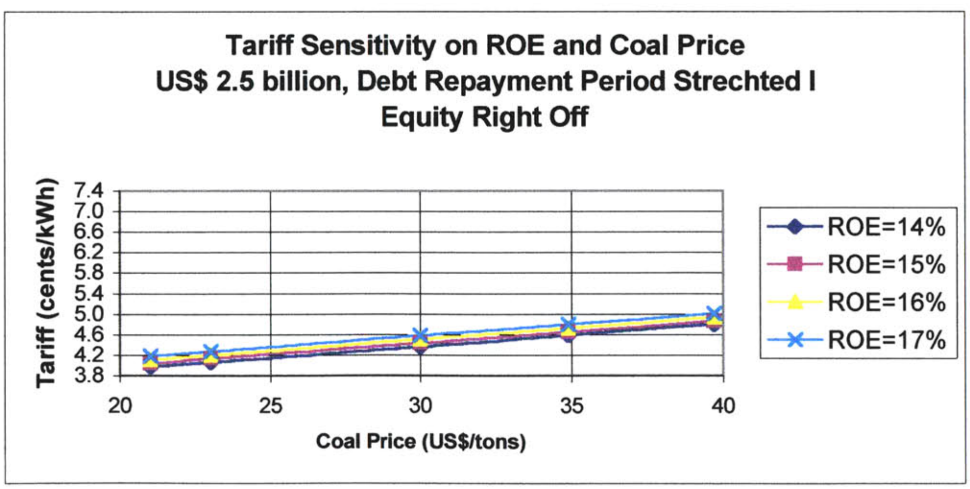


Figure 8.8: Equity Right Off

As shown in this figure, under this arrangement, the minimum tariff derived is US$ 3.9717 cents/kWh, which is the tariff when ROE is 14% and the coal price is US$ 21 per tons, and the maximum tariff is US$ 5.0035 cents/kWh, which is the tariff when ROE 17% and the coal price is US$ 39.7 per tons. The renegotiated US$ 4.1041 cents/kWh is within this tariff range. For example, under this arrangement, when ROE 16% and the coal price is US$ 21 per tons, the tariff would US$ 4.1136 cents/kWh.

In sum, to arrive at the renegotiated tariff of US$ 4.1041 cents/kWh, the following project original arrangements should be restructured, as follows:

1) Coal Price Renegotiation: the coal price should be reduced
2) Debt Restructuring Renegotiation:
    a. The interest on loans after COD should be reduced to approximately 6%
    b. The loan repayment periods should be stretched out to approximately 20 years for the US and the Japan lenders and to approximately 14 years for the bonds.
3) Equity right off: under the equity-right-off arrangement, the equity expenses of the project sponsors during the project development and construction stages are deemed void.

Renegotiation on coal price reduction, debt restructuring arrangement, and equity right off is tough efforts. Lenders are usually reluctant to reduce the interest rates and to stretch out the repayment periods. Similarly, project sponsors are reluctant to reduce their ROEs and deem void their equity contributions. Indeed, renegotiating the current PEC's average levelized tariff of US$ 7.2447 cents/kWh to US$ 4.1041, if possible, requires a hard renegotiation effort.

Such an approach for renegotiation purpose is still not impossible, however hard it is. This approach seems reasonable: the renegotiated tariff uses the assumed market-based project cost and the ROE follows the trend of the increasing competition in the electricity generating business. In addition, while PEC is expected to reduce its tariff to the level of the renegotiated tariff, PLN is also expected to increase its tariff to exceed this renegotiated tariff. In addition, even though the IPP renegotiation process towards the MB/MS scheme is beyond the scope of this thesis, PEC's tariff reduction would at least have the following long-term advantages:

1) PLN can afford the tariff, thereby fulfilling its payment obligations,
2) PEC's tariff is competitive when the MB/MS Scheme starts, in case another arrangements are required whereby PEC should "re-compete" with other IPPs.

8.3. Chapter Summary

The results derived from this chapter are for the purpose of suggesting an approach for remedy to be negotiated between PLN and PEC. This approach might not be a perfect approach given the author's limitation of access to information; however, this approach is expected to serve as an input that may generate a more creative approach as to the most appropriate solution. Based on the results of this chapter, to arrive at a market-based renegotiated tariff, which is approximately US$ 4.1 cents/kWh, PEC should undertake hard renegotiation: coal price reduction, debt restructuring, and equity right off. Unless the tariff is reduced to the level affordable to PLN, the renegotiation process between PEC and PLN would not come to the end.

Appendix 1: Tariff Sensitivity on Coal Price and ROE

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

EPC Cost : 839.84 US$/kW

Project Cost Structure Follows the Paiton I Project

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	Original	12
29.7%	J Exim - Tranche A: Loan	Original	12
19.8%	J Exim - Tranche B: Co-financing	Original	12
11.0%	OPIC Loan	Original	12
9.9%	Bonds	Original	6

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	839.84	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,061 million, Equity: US$396 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	17.00%	466,222,970	2.8341	0.3220	0.9197	0.1522	4.2281
23.0	5.1384	17.00%	466,222,970	2.8341	0.3220	1.0073	0.1522	4.3157
30.0	5.4450	17.00%	466,222,970	2.8341	0.3220	1.3139	0.1522	4.6223
34.9	5.6596	17.00%	466,222,970	2.8341	0.3220	1.5285	0.1522	4.8369
39.7	5.8698	17.00%	466,222,970	2.8341	0.3220	1.7388	0.1522	5.0471

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,061 million, Equity: US$396 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	16.00%	459,424,984	2.7928	0.3220	0.9197	0.1522	4.1868
23.0	5.1384	16.00%	459,424,984	2.7928	0.3220	1.0073	0.1522	4.2744
30.0	5.4450	16.00%	459,424,984	2.7928	0.3220	1.3139	0.1522	4.5810
34.9	5.6596	16.00%	459,424,984	2.7928	0.3220	1.5285	0.1522	4.7956
39.7	5.8698	16.00%	459,424,984	2.7928	0.3220	1.7388	0.1522	5.0058

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,061 million, Equity: US$396 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	15.00%	452,617,409	2.7515	0.3220	0.9197	0.1522	4.1454
23.0	5.1384	15.00%	452,617,409	2.7515	0.3220	1.0073	0.1522	4.2330
30.0	5.4450	15.00%	452,617,409	2.7515	0.3220	1.3139	0.1522	4.5396
34.9	5.6596	15.00%	452,617,409	2.7515	0.3220	1.5285	0.1522	4.7542
39.7	5.8698	15.00%	452,617,409	2.7515	0.3220	1.7388	0.1522	4.9645

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,061 million, Equity: US$396 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	14.00%	445,819,423	2.7101	0.3220	0.9197	0.1522	4.1041
23.0	5.1384	14.00%	445,819,423	2.7101	0.3220	1.0073	0.1522	4.1917
30.0	5.4450	14.00%	445,819,423	2.7101	0.3220	1.3139	0.1522	4.4983
34.9	5.6596	14.00%	445,819,423	2.7101	0.3220	1.5285	0.1522	4.7129
39.7	5.8698	14.00%	445,819,423	2.7101	0.3220	1.7388	0.1522	4.9231

Appendix 2: Tariff Sensitivity on Coal Price and ROE

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	Original	12
29.7%	J Exim - Tranche A: Loan	Original	12
19.8%	J Exim - Tranche B: Co-financing	Original	12
11.0%	OPIC Loan	Original	12
9.9%	Bonds	Original	6

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	17.00%	466,222,970	4.8625	0.3220	0.9197	0.1522	6.2565
23.0	5.1384	17.00%	466,222,970	4.8625	0.3220	1.0073	0.1522	6.3440
30.0	5.4450	17.00%	466,222,970	4.8625	0.3220	1.3139	0.1522	6.6506
34.9	5.6596	17.00%	466,222,970	4.8625	0.3220	1.5285	0.1522	6.8652
39.7	5.8698	17.00%	466,222,970	4.8625	0.3220	1.7388	0.1522	7.0755

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	16.00%	459,424,984	4.7916	0.3220	0.9197	0.1522	6.1855
23.0	5.1384	16.00%	459,424,984	4.7916	0.3220	1.0073	0.1522	6.2731
30.0	5.4450	16.00%	459,424,984	4.7916	0.3220	1.3139	0.1522	6.5797
34.9	5.6596	16.00%	459,424,984	4.7916	0.3220	1.5285	0.1522	6.7943
39.7	5.8698	16.00%	459,424,984	4.7916	0.3220	1.7388	0.1522	7.0045

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	15.00%	452,617,409	4.7206	0.3220	0.9197	0.1522	6.1146
23.0	5.1384	15.00%	452,617,409	4.7206	0.3220	1.0073	0.1522	6.2022
30.0	5.4450	15.00%	452,617,409	4.7206	0.3220	1.3139	0.1522	6.5088
34.9	5.6596	15.00%	452,617,409	4.7206	0.3220	1.5285	0.1522	6.7234
39.7	5.8698	15.00%	452,617,409	4.7206	0.3220	1.7388	0.1522	6.9336

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	5.0508	14.00%	445,819,423	4.6497	0.3220	0.9197	0.1522	6.0437
23.0	5.1384	14.00%	445,819,423	4.6497	0.3220	1.0073	0.1522	6.1313
30.0	5.4450	14.00%	445,819,423	4.6497	0.3220	1.3139	0.1522	6.4379
34.9	5.6596	14.00%	445,819,423	4.6497	0.3220	1.5285	0.1522	6.6525
39.7	5.8698	14.00%	445,819,423	4.6497	0.3220	1.7388	0.1522	6.8627

Appendix 3: Tariff Sensitivity on Coal Price, Interest on Loans, and ROE

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	6%	12
29.7%	J Exim - Tranche A: Loan	6%	12
19.8%	J Exim - Tranche B: Co-financing	6%	12
11.0%	OPIC Loan	6%	12
9.9%	Bonds	6%	6

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.4845	17.00%	411,925,372	**4.2962**	0.3220	**0.9197**	0.1522	**5.6901**
23.0	4.5721	17.00%	411,925,372	**4.2962**	0.3220	**1.0073**	0.1522	**5.7777**
30.0	4.8787	17.00%	411,925,372	**4.2962**	0.3220	**1.3139**	0.1522	**6.0843**
34.9	5.0933	17.00%	411,925,372	**4.2962**	0.3220	**1.5285**	0.1522	**6.2989**
39.7	5.3035	17.00%	411,925,372	**4.2962**	0.3220	**1.7388**	0.1522	**6.5092**

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.4845	16.00%	405,117,798	**4.2252**	0.3220	**0.9197**	0.1522	**5.6192**
23.0	4.5721	16.00%	405,117,798	**4.2252**	0.3220	**1.0073**	0.1522	**5.7068**
30.0	4.8787	16.00%	405,117,798	**4.2252**	0.3220	**1.3139**	0.1522	**6.0134**
34.9	5.0933	16.00%	405,117,798	**4.2252**	0.3220	**1.5285**	0.1522	**6.2280**
39.7	5.3035	16.00%	405,117,798	**4.2252**	0.3220	**1.7388**	0.1522	**6.4382**

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.4845	15.00%	398,319,812	**4.1543**	0.3220	**0.9197**	0.1522	**5.5483**
23.0	4.5721	15.00%	398,319,812	**4.1543**	0.3220	**1.0073**	0.1522	**5.6359**
30.0	4.8787	15.00%	398,319,812	**4.1543**	0.3220	**1.3139**	0.1522	**5.9425**
34.9	5.0933	15.00%	398,319,812	**4.1543**	0.3220	**1.5285**	0.1522	**6.1571**
39.7	5.3035	15.00%	398,319,812	**4.1543**	0.3220	**1.7388**	0.1522	**6.3673**

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.4845	14.00%	391,521,825	**4.0834**	0.3220	**0.9197**	0.1522	**5.4774**
23.0	4.5721	14.00%	391,521,825	**4.0834**	0.3220	**1.0073**	0.1522	**5.5650**
30.0	4.8787	14.00%	391,521,825	**4.0834**	0.3220	**1.3139**	0.1522	**5.8716**
34.9	5.0933	14.00%	391,521,825	**4.0834**	0.3220	**1.5285**	0.1522	**6.0862**
39.7	5.3035	14.00%	391,521,825	**4.0834**	0.3220	**1.7388**	0.1522	**6.2964**

Appendix 4: Tariff Sensitivity on Coal Price, Interest on Loans, Loan Repayment Period, and ROE

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	6%	20
29.7%	J Exim - Tranche A: Loan	6%	20
19.8%	J Exim - Tranche B: Co-financing	6%	20
11.0%	OPIC Loan	6%	20
9.9%	Bonds	6%	14

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
	Debt: US$ 1,820 million, Equity: US$ 680 million							
21.0	4.3034	17.00%	394,551,675	4.1150	0.3220	0.9197	0.1522	5.5090
23.0	4.3910	17.00%	394,551,675	4.1150	0.3220	1.0073	0.1522	5.5966
30.0	4.6975	17.00%	394,551,675	4.1150	0.3220	1.3139	0.1522	5.9032
34.9	4.9121	17.00%	394,551,675	4.1150	0.3220	1.5285	0.1522	6.1178
39.7	5.1224	17.00%	394,551,675	4.1150	0.3220	1.7388	0.1522	6.3280

ROE 16%

Coal Price ($/tons)	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
	Debt: US$ 1,820 million, Equity: US$ 680 million							
21.0	4.3034	16.00%	387,753,689	4.0441	0.3220	0.9197	0.1522	5.4381
23.0	4.3910	16.00%	387,753,689	4.0441	0.3220	1.0073	0.1522	5.5257
30.0	4.6975	16.00%	387,753,689	4.0441	0.3220	1.3139	0.1522	5.8323
34.9	4.9121	16.00%	387,753,689	4.0441	0.3220	1.5285	0.1522	6.0469
39.7	5.1224	16.00%	387,753,689	4.0441	0.3220	1.7388	0.1522	6.2571

ROE 15%

Coal Price ($/tons)	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
	Debt: US$ 1,820 million, Equity: US$ 680 million							
21.0	4.3034	15.00%	380,955,703	3.9732	0.3220	0.9197	0.1522	5.3672
23.0	4.3910	15.00%	380,955,703	3.9732	0.3220	1.0073	0.1522	5.4548
30.0	4.6975	15.00%	380,955,703	3.9732	0.3220	1.3139	0.1522	5.7614
34.9	4.9121	15.00%	380,955,703	3.9732	0.3220	1.5285	0.1522	5.9760
39.7	5.1224	15.00%	380,955,703	3.9732	0.3220	1.7388	0.1522	6.1862

ROE 14%

Coal Price ($/tons)	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
	Debt: US$ 1,820 million, Equity: US$ 680 million							
21.0	4.3034	14.00%	374,157,716	3.9023	0.3220	0.9197	0.1522	5.2963
23.0	4.3910	14.00%	374,157,716	3.9023	0.3220	1.0073	0.1522	5.3838
30.0	4.6975	14.00%	374,157,716	3.9023	0.3220	1.3139	0.1522	5.6904
34.9	4.9121	14.00%	374,157,716	3.9023	0.3220	1.5285	0.1522	5.9050
39.7	5.1224	14.00%	374,157,716	3.9023	0.3220	1.7388	0.1522	6.1153

Appendix 5: Tariff Sensitivity on Coal Price, Interest on Loans, Loan Repayment Period, and ROE

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	6%	29
29.7%	J Exim - Tranche A: Loan	6%	29
19.8%	J Exim - Tranche B: Co-financing	6%	29
11.0%	OPIC Loan	6%	29
9.9%	Bonds	6%	20

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	17.00%	383,908,848	**4.0004**	0.3220	**0.9197**	0.1522	**5.3944**
23.0	4.2763	17.00%	383,908,848	**4.0004**	0.3220	**1.0073**	0.1522	**5.4819**
30.0	4.5829	17.00%	383,908,848	**4.0004**	0.3220	**1.3139**	0.1522	**5.7885**
34.9	4.7975	17.00%	383,908,848	**4.0004**	0.3220	**1.5285**	0.1522	**6.0031**
39.7	5.0077	17.00%	383,908,848	**4.0004**	0.3220	**1.7388**	0.1522	**6.2134**

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	16.00%	376,765,688	**3.9295**	0.3220	**0.9197**	0.1522	**5.3234**
23.0	4.2763	16.00%	376,765,688	**3.9295**	0.3220	**1.0073**	0.1522	**5.4110**
30.0	4.5829	16.00%	376,765,688	**3.9295**	0.3220	**1.3139**	0.1522	**5.7176**
34.9	4.7975	16.00%	376,765,688	**3.9295**	0.3220	**1.5285**	0.1522	**5.9322**
39.7	5.0077	16.00%	376,765,688	**3.9295**	0.3220	**1.7388**	0.1522	**6.1424**

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	15.00%	369,958,114	**3.8585**	0.3220	**0.9197**	0.1522	**5.2525**
23.0	4.2763	15.00%	369,958,114	**3.8585**	0.3220	**1.0073**	0.1522	**5.3401**
30.0	4.5829	15.00%	369,958,114	**3.8585**	0.3220	**1.3139**	0.1522	**5.6467**
34.9	4.7975	15.00%	369,958,114	**3.8585**	0.3220	**1.5285**	0.1522	**5.8613**
39.7	5.0077	15.00%	369,958,114	**3.8585**	0.3220	**1.7388**	0.1522	**6.0715**

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	14.00%	363,160,128	**3.7876**	0.3220	**0.9197**	0.1522	**5.1816**
23.0	4.2763	14.00%	363,160,128	**3.7876**	0.3220	**1.0073**	0.1522	**5.2692**
30.0	4.5829	14.00%	363,160,128	**3.7876**	0.3220	**1.3139**	0.1522	**5.5758**
34.9	4.7975	14.00%	363,160,128	**3.7876**	0.3220	**1.5285**	0.1522	**5.7904**
39.7	5.0077	14.00%	363,160,128	**3.7876**	0.3220	**1.7388**	0.1522	**6.0006**

Appendix 6: Tariff Sensitivity on Coal Price, Interest on Loans, Loan Repayment Period, and ROE

Equity Right Off

Financial Parameters

1. Debt Equity Ratio 73%/27%
2. Loan 100% Commercial Loan

% of Total Loan	Lender	Interest	Repayment
29.7%	US Exim Loan	6%	20
29.7%	J Exim - Tranche A: Loan	6%	20
19.8%	J Exim - Tranche B: Co-financing	6%	20
11.0%	OPIC Loan	6%	20
9.9%	Bonds	6%	14

3. Discount Rate 14%

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.3034	17.00%	267,556,853	2.7905	0.3220	0.9197	0.1522	4.1845
23.0	4.3910	17.00%	267,556,853	2.7905	0.3220	1.0073	0.1522	4.2721
30.0	4.6975	17.00%	267,556,853	2.7905	0.3220	1.3139	0.1522	4.5787
34.9	4.9121	17.00%	267,556,853	2.7905	0.3220	1.5285	0.1522	4.7933
39.7	5.1224	17.00%	267,556,853	2.7905	0.3220	1.7388	0.1522	5.0035

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.3034	16.00%	260,758,867	2.7196	0.3220	0.9197	0.1522	4.1136
23.0	4.3910	16.00%	260,758,867	2.7196	0.3220	1.0073	0.1522	4.2012
30.0	4.6975	16.00%	260,758,867	2.7196	0.3220	1.3139	0.1522	4.5078
34.9	4.9121	16.00%	260,758,867	2.7196	0.3220	1.5285	0.1522	4.7224
39.7	5.1224	16.00%	260,758,867	2.7196	0.3220	1.7388	0.1522	4.9326

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.3034	15.00%	253,960,880	2.6487	0.3220	0.9197	0.1522	4.0427
23.0	4.3910	15.00%	253,960,880	2.6487	0.3220	1.0073	0.1522	4.1303
30.0	4.6975	15.00%	253,960,880	2.6487	0.3220	1.3139	0.1522	4.4368
34.9	4.9121	15.00%	253,960,880	2.6487	0.3220	1.5285	0.1522	4.6515
39.7	5.1224	15.00%	253,960,880	2.6487	0.3220	1.7388	0.1522	4.8617

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.3034	14.00%	247,162,894	2.5778	0.3220	0.9197	0.1522	3.9717
23.0	4.3910	14.00%	247,162,894	2.5778	0.3220	1.0073	0.1522	4.0593
30.0	4.6975	14.00%	247,162,894	2.5778	0.3220	1.3139	0.1522	4.3659
34.9	4.9121	14.00%	247,162,894	2.5778	0.3220	1.5285	0.1522	4.5805
39.7	5.1224	14.00%	247,162,894	2.5778	0.3220	1.7388	0.1522	4.7908

Appendix 7: Tariff Sensitivity on Coal Price, Interest on Loans, Loan Repayment Period, and ROE

Equity Right Off

Financial Parameters

1. Debt Equity Ratio	73%/27%		
2. Loan	100% Commercial Loan		
% of Total Loan	**Lender**	**Interest**	**Repayment**
29.7%	US Exim Loan	6%	29
29.7%	J Exim - Tranche A: Loan	6%	29
19.8%	J Exim - Tranche B: Co-financing	6%	29
11.0%	OPIC Loan	6%	29
9.9%	Bonds	6%	20
3. Discount Rate	14%		

Technical Parameters

1. Net Dependable Capacity	2x615	MW
2. Availability Factor	83%	
3. Net Plant Heat Rate	2447	kcal/kWh
4. HHV Coal	5215	kg/kcal
5. Contract Terms	30	years
6. Fixed O&M	0.3220	c/kWh
7. Variable O&M	0.1522	c/kWh
8. EPC Unit Cost	1440.89	US$/kW

ROE 17%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	17.00%	256,568,852	**2.6759**	0.3220	**0.9197**	0.1522	**4.0698**
23.0	4.2763	17.00%	256,568,852	**2.6759**	0.3220	**1.0073**	0.1522	**4.1574**
30.0	4.5829	17.00%	256,568,852	**2.6759**	0.3220	**1.3139**	0.1522	**4.4640**
34.9	4.7975	17.00%	256,568,852	**2.6759**	0.3220	**1.5285**	0.1522	**4.6786**
39.7	5.0077	17.00%	256,568,852	**2.6759**	0.3220	**1.7388**	0.1522	**4.8889**

ROE 16%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	16.00%	249,761,278	**2.6049**	0.3220	**0.9197**	0.1522	**3.9989**
23.0	4.2763	16.00%	249,761,278	**2.6049**	0.3220	**1.0073**	0.1522	**4.0865**
30.0	4.5829	16.00%	249,761,278	**2.6049**	0.3220	**1.3139**	0.1522	**4.3931**
34.9	4.7975	16.00%	249,761,278	**2.6049**	0.3220	**1.5285**	0.1522	**4.6077**
39.7	5.0077	16.00%	249,761,278	**2.6049**	0.3220	**1.7388**	0.1522	**4.8179**

ROE 15%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	15.00%	242,963,292	**2.5340**	0.3220	**0.9197**	0.1522	**3.9280**
23.0	4.2763	15.00%	242,963,292	**2.5340**	0.3220	**1.0073**	0.1522	**4.0156**
30.0	4.5829	15.00%	242,963,292	**2.5340**	0.3220	**1.3139**	0.1522	**4.3222**
34.9	4.7975	15.00%	242,963,292	**2.5340**	0.3220	**1.5285**	0.1522	**4.5368**
39.7	5.0077	15.00%	242,963,292	**2.5340**	0.3220	**1.7388**	0.1522	**4.7470**

ROE 14%

Coal Price ($/tons)	Debt: US$ 1,820 million, Equity: US$ 680 million							
	ALC (c/kWh)	ROE	CCR (US$/year)	A (c/kWh)	B (c/kWh)	C (c/kWh)	D (c/kWh)	Total Tariff (c/kWh)
21.0	4.1887	14.00%	236,165,305	**2.4631**	0.3220	**0.9197**	0.1522	**3.8571**
23.0	4.2763	14.00%	236,165,305	**2.4631**	0.3220	**1.0073**	0.1522	**3.9447**
30.0	4.5829	14.00%	236,165,305	**2.4631**	0.3220	**1.3139**	0.1522	**4.2513**
34.9	4.7975	14.00%	236,165,305	**2.4631**	0.3220	**1.5285**	0.1522	**4.4659**
39.7	5.0077	14.00%	236,165,305	**2.4631**	0.3220	**1.7388**	0.1522	**4.6761**

Chapter 9: Conclusion

9.1. Regarding the Paiton I Project Deal

With respect to the Paiton I project deal, the thesis arrives at the following conclusions:

1. The Best Practice Analysis

The inception of the Paiton I project was not fully prepared. The Indonesian legal and regulatory framework for private power was not fully developed. The procurement bidding process did not promote competition and transparency. The Paiton I model power purchase agreement also did not promote competition for cost effective development towards competitive electricity market.

The IPP best practice feature is outlined in subchapter 2.4. Competition, risk mitigation, and transparency should be embodied in the legal and regulatory framework, procurement process, and power purchase agreement. The use of benchmarking analysis during renegotiation process is very important to assure the cost-effective development of the project.

2. The Power Purchase Agreement

The PPA tariff structure places demand risks, currency risks, inflation risk, and coal price fluctuation risk to the public utility. Force majeure risks and change of law risks are also transferred to the utility under certain PPA terms and conditions. The level of the *take-or-pay* in the pricing mechanism is high, with the fixed capacity charges being an average of 71% of the total payment and the availability factor being an average of 83%.

For better arrangement, the risks arrangement embodied in the PPA should be balanced by allowing IPPs to assume certain level of risks. Such major concerns as market risks, currency risks, and force majeure risks should be well distributed equally among the contracted parties, instead of putting the entire burden either to government or public utility alone.

With respect to market risks, demand risks should be partly allocated to IPPs. The mechanism could probably be by reducing the level of *take-or-pay* payment and the availability factor and/or selling part of the capacity charge at the prevailing market price rate while the public utility is only responsible for part of the charge. This way, when economic condition of the host country changes sharply, thereby affecting the demand of the project output, the burden will not be solely in the public utility, but also in the private investors.

3. The Equity Arrangement

The equity arrangement of the Paiton I was considered as a "debt-like" arrangement, with the *take-or-pay* PPA obligating the public utility to make fixed payments regardless the country's economic condition and demand condition for the project output.

For better arrangement, even under the "debt-like" arrangement, risks should be properly allocated so that the public entity would not assume such a high level of risk as to be politically untenable. Most importantly, any government guarantee securing the "debt-like" equity arrangement should be specified in details to avoid misunderstanding or misinterpretation of the guarantee intention.

4. The Local Participant

The politically well-connected local participant, who might have been intended to reduce political risk, eventually increased the political risk itself when the government changed. The lack of transparency during the procurement and the negotiation process has fueled the allegations that the high project cost of the Paiton I project is the result of cronyism and corruption practices. Furthermore, the "loan-financed" equity arrangement of the local participant has fueled the allegation that contracts were obtained through corruption.

For better arrangement, the hidden political risks beyond a sound local participant should be well understood. If possible, local participant arrangements could be diversified by involving not only the politically well-connected people but also those perceived as ordinary companies. With respect to the "loan financed" equity arrangement for local participants, it would have probably reduced the political risk if the local participants also contribute shares from the project initial stage. This way, the local participants would be perceived as being fully involved in assuming project risks and being more committed to the project when relations with the host government eventually turns sour.

5. The Dispute Resolution

The international arbitration's decisions imposing payment obligations to the public utility were difficult to implement especially in times of crisis since the utility simply did not have the cash to make the payments.

For better arrangement, the international arbitration would play a very useful role if it allows for changes and helps risk re-allocation efforts that could be applied under the prevailing economic condition of the host country when such changes are actually inevitable. In other words, instead of freezing the host government and the private investors under certain contract terms and conditions for long period, the contract itself would play a useful role if it allows certain changes under certain prevailing conditions when changes are indeed inevitable; the international arbitration can help in making the changes appropriate and smooth.

6. Electricity Market Projection

The electricity demand projection was over optimistic. The demand was projected as a target, not a natural growth. With respect to electricity tariff, to assess the viability of IPPs' tariff to the utility, the IPPs refer solely to the projection of increase in public utility's tariff to the end consumers. If the increase does not actually materialize, the tariff would significantly exceed the utility's tariff. In addition, the electricity purchase power varies in various areas within the country; even though some areas lack electricity, at the same time, they cannot afford it.

For better practice, IPPs should rely on the natural growth of electricity demand, taking into account the effect of the IPP boom in the country. IPPs also should take into account the purchasing power of the surrounding regions where the IPPs operate.

7. The Project Financial Parameters

The approximation of the cash flow analysis for the Paiton I project shows the common practice of infrastructure in developing countries with a 15% IRR on project and a 25% ROE.

According to one of the IPP better practice features, IPPs should use the wholesale electricity tariff of the utility, instead of the return on equity, as a basis to set up tariff for the IPP-generated power. In addition, the increasing competition of the electricity generating business demands lower ROE, with some cases showing a surprisingly single digit ROE.

9.2. Regarding the Tariff Benchmarking Analysis

The core problem in the case of the Paiton I project is that while public utility's tariff to consumers was low, the IPP's tariff to the utility was high as a result of a high project cost; therefore, the utility could not afford the IPP's tariff.

With respect to the proposed renegotiation approach, the IPP's tariff would be benchmarked against the utility's tariff. This approach is in accord with the suggestion of the APEC Energy Working Group that one of the best practice features for IPPs is to use the wholesale electricity tariff, rather than the rate of return on equity, as the basis for negotiating PPA.

The benchmarking analysis for the Paiton I tariff takes into account several assumptions including the Paiton I EPC cost benchmark result (the EPC cost of US$ 839.84 per kW) by the SNC-Lavalin Group and the increasing competition in the electricity generating business that demands lower ROE. The results of the benchmarking for the Paiton I project are: with 17% ROE, the tariff could be reduced to the range from US$ 4.2 cents/kWh to US$ 5.0 cents/kWh depending on the coal price, while with 14% ROE, the tariff could be reduced to the range from US$ 4.1 cents/kWh to US$ 4.9 cents/kWh also depending on the coal price.

If the public utility is willing to increase its current tariff of US$ 3.2 cents/kWh to US$ 4.1 cents/kWh, since the IPP's tariff is benchmarked against the utility's tariff, in the renegotiation, the IPP is expected to arrive at the utility's tariff of US$ 4.1 cents/kWh. To arrive at this tariff value, the IPP need to undertake a hard renegotiation efforts, as follows: 1) ROE reduction to 14%; 2) Coal Price Renegotiation to US$ 21 per tons; 3) Debt structuring negotiation: interest rate reduction to approximately 6% and loan repayment period stretched out to approximately 20 years for the main lenders and 14 years for bonds; and 4) Equity Right Off.

The thesis's conclusions and results with respect to the Paiton I project arrangement and the tariff benchmarking analysis are expected to serve as an input that may generate a more creative approach as to the most appropriate solution for the contracted parties.

Bibliography

Adnan Buyung Nasution & Partners, "PLN filed a lawsuit against Paiton Energy", *Press Release*, October 7, 1999.

Albouy, Yves, and Reda Bousba, "The Impact of IPPs in Developing Countries—Out of the Crisis and into the Future", *Public Policy for the Private Sector*, The World Bank Group, December 1998.

APEC Energy Working Group, "Manual of Best Practice Principles for Independent Power Producers", The APEC Energy Working Group Secretariat: Energy Division, August 1997.

Arisanto, "Renegosiasi Listrik Swasta Untuk Menyelamatkan PLN (Private Power Renegotiation to Save PLN)", *Business News*, Jakarta, February 18, 1999.

Asian Power, "Malaysia Market Report: Restructure, Reform, and Reward", *Asian Power*, March-April 2000.

Asian Wall Street Journal, February 14, 1994

Beidleman, Carl L., Donna Fletcher, and David Vesbosky, "On Allocating Risk: The Essence of Project Finance", *Sloan Management Review*, MIT Sloan School of Management, Cambridge.

Besant-Jones, John E., "The England and Wales Electricity Model—Option or Warning for Developing Countries", *Public Policy for the Private Sector*, The World Bank Group, June 1996.

Boston Consulting Group, "Deconstruction for the New Millennium: Building the Competitive Utility Company", *2000 Asian Utility CEO Conference*, Singapore, March 9-10, 2000.

Bradley, David G., "Managing Against Expropriation," *Harvard Business Review*, July/August 1977, pages 75-83.

CS First Boston Chase Securities, Inc., "Confidential Offering Circular for the Paiton I proposed bond offering", March 21, 1996.

Dinas Peraturan dan Perundang-undangan: Divisi Humas PLN Pusat. "Keputusan Presiden Nomor 37 tahun 1992 tentang Usaha Penyediaan Tenaga Listrik oleh Swasta: Pasal 5 (President Decree No. 37/1992)". July 9, 1992.

Driseoll, Robert E., "P.T. Paiton Energy Company", A letter dated May 6, 1999 from Robert E. Driseoll, the Senior Vice President of the Asia Pacific Region of Edison

Mission Energy, to Ralph A. Matheus, the Acting Vice President for Finance of OPIC, Source: OPIC.

Finnerty, John D., "Project Financing: Asset-based Financial Engineering", John Wiley & Sons, Inc., New York, 1996.

Frederick, Pamela, "Paiton/Indonesia—Advocacy Letter", An email dated September 29, 1994 from Pamela Frederick to David Cralle, Source: OPIC.

Gooding, Gregory, Debevoise & Plimpton, "Indonesia", *Power in Asia*, September 1995.

Gray, R. David, and John Schuster, "The East Asian Financial Crisis—Fallout for Private Power Projects", *Public Policy for the Private Sector*, The World Bank Group, August 1998.

Husein, Ahmad, Andi Setia Gunawan, and Wuri Hardiastuti, "Impian Adhi Pupus di Tengah Jalan", *Gamma*, January 2, 2000.

International Finance Corporation, "Project Finance in Developing Countries", Washington D.C., 1998.

Izaguirre, Ada Karina, "Private Participation in Energy", *Public Policy for the Private Sector*, The World Bank Group, May 2000.

Izaguirre, Ada Karina, *"Private Participation in the Electricity Sector—Recent Trends", Public Policy for the Private Sector*, The World Bank Group, September 1998.

Jakarta Post, "PLN Criticized over Pricing of Private Electricity", November 29, 1994.

Jakarta Post, "PLN Under Fire for Cooperation", February 14, 1995.

Jakarta Post, "PLN ordered to pay U.S. Company $572m in damages", May 06, 1999.

Jakarta Post, "PT PLN underestimates arbitration ruling impact", May 7, 1999.

Jakarta Post, "PLN files lawsuit to encounter arbitration ruling", June 9, 1999.

Jakarta Post, "Court annuls arbitration ruling against PLN", July 23, 1999.

Johnston, Felton, and Robert Shanks and Ashoka Mody, "House of Cards: Government Guaranties for Infrastructure Project Financing", *Project & Trade Finance*, February 1996.

Kobrin, Stephen J., "Foreign Enterprise and Forced Divestment in the LDCs," *International Organization*, Winter 1980 (Vol. 34, No. 1), pages 65-88.

Lahmeyer International, "Final Report: Lessons learned from Paiton One", *Recommendations for Improving Indonesia's Private Power Program*, Volume 1, November 1993.

Lang, Larry H.P, "Project Finance in Asia", Netherlands, 1998.

Malhotra, Anil K., "Private Participation in Infrastructure: Lessons from Asia's Power Sector", *Finance & Development*, December 1997.

Nevitt, Peter K., "Project Financing Success: Keyed to Non-Recourse Structuring", *Private Power Executive*, July-August 1996.

OPIC, "Discussion and Recommendation for Approval by the Board of Directors", *OPIC Loan Guaranty*, December 6, 1994.

OPIC, "Paiton Energy Company—Fact Sheet (Paiton Swasta I)", source: OPIC.

P.T. PLN (Persero), "Intention of PT. PLN (Persero) to Commence IPP Contracts Rationalization", *Press Release*, Jakarta, December 22, 1998.

P.T. PLN (Persero), "Latar Belakang: Background", *Press Release*, 1999.

P.T. PLN (Persero), Transmission and Java Bali Control Center, March 30, 2000.

Potash, Daniel A., "Project Participants: Roles and Responsibilities Defined", *Private Power Executive*, May-June 1996.

Price Waterhouse Coopers, "Best Practice for Promoting Private Sector Investment and Competition in the Power Sector", Asian Development Bank, March 1999.

Price Waterhouse LLP, "Review of Indonesian Power Sector Development Issues", Energy Project Development Fund, USAID, May 1995.

Private Power Executive, "PPE's Guide to Financing Private Electric Power Projects", *Private Power Executive*, May-June 1996.

Razavi, Hossein, "Financing Energy Projects in Emerging Economies", Pennwell Books, Oklahoma, 1996.

Roger, Neil, "Recent Trends in Private Participation in Infrastructure", *Viewpoint*, The World Bank Group, September 1999.

Ruster, Jeff, "Mitigating Commercial Risks in Project Finance", *Public Policy for the Private Sector*, The World Bank Group. February 1996.

Samii, Massood V., "Project Finance Notes". *Readers for Course Construction Finance.* Massachusetts Institute of Technology, fall 1999.

Shuttleworth, Graham, and Sally Hunt, "Competition and Choice in Electricity", John Wiley & Sons, 1996.

Situmeang, Hardiv, "The objectives of Privatization", The International BIMP (Brunei, Indonesia, Malaysia, and Philippines) EAGA (East Asian Gross Area) Conference on Privatization, International Convention Center Brunei, an unpublished synthesis of the conference papers, Brunei, May 3-4, 2000.

Solomon, Jay, "Indonesian Audit Uncovers Inflated Cost of Power Plant", *The Wall Street Journal*, December 26, 2000.

Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim, "Mengapa Listrik Swasta Jadi Masalah? (Why do private power producers create problems?)", *Tempo*, 24 September 2000, page: 117.

Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story Tempo No. 29/XXIX/Sept. 18-24, 2000.

Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim, "Dapatkah PLN Lolos dari Jepitan Paiton? (Can PLN escape from Paiton?)", *Tempo*, 24 September 2000, page: 117.

Taufiqurohman, M., Dewi Rina Cahyadi, I.G.G. Maha Adi, "Two Steps Forward, Three Steps Back", Cover Story *Tempo* No. 29/XXIX/Sept. 18-24, 2000.

Taufiqurohman, M., Wenseslaus Manggut, Jalil Hakim, "Perjalanan Proyek Paiton I (The Journey of the Paiton I)?", *Tempo*, 24 September 2000, page: 120.

Technology Indonesia, Pusat Informasi Business dan Pembangunan Indonesia, P.T. Wahyu Promo Citra. "Energy: Technology and Development". 2nd Edition. September 1995. Jakarta, Indonesia.

Thomas, Eapen, "A Beautiful Place to Develop", *Infrastructure Finance*, April-May 1995.

Waldman, Peter, and Jay Solomon, "US Deals in Indonesia Draw Flak", *The Asian Wall Street Journal*, December 24, 1998.

Wells, Louis T., "Private Investment in Infrastructure: Managing Non-Commercial Risk", *Private Infrastructure for Development: Confronting Political and Regulatory Risks*, 8-10 September 1999, Rome, Italy.

Wells, Louis T, Eric S. Gleason, "Is Foreign Infrastructure Investment Still Risky?", *Harvard Business Review*, September-October 1995, page 4-12.

Wignjowijoto, Hartojo, "The Roles of Foreign Investors and International Financial Institutions in Electricity Sector", Session 1: The Roles of International Financial Institutions in Public Investments, *Seminar: Private Power Projects. Indonesian Corruption Watch in cooperation with PLN's Labor Organization*, Jakarta, October 12, 2000.

Worenklein, Jacob J., "Project Finance: Adapts to Changing Power Market", *Private Power Executive*, May-June 1996.

World Bank, "Infrastructure Development in East Asia and Pacific: Towards a New Public-Private Partnership", *The World Bank Publications*, Washington, D.C., 1996.

World Bank, "Submission and Evaluation of Proposals for Private Power Generation Projects in Developing Countries", *World Bank discussion papers,* Washington, D.C., 1994.

World Wide Websites

AKK, "Siapa Bermain di Paiton?", Gatra 19/V, 27 Maret 1999.
http://www.gatra.com/V/19/EKO2-19.html

Alexander's Gas & Oil Connections, "US Pressures Indonesia on Power Plant Contracts", Volume 3, issue #26—Monday, November 16, 1998.
http://www.gasandoil.com/goc/news/nts84702.html

CIA, "The World Factbook 2000: Indonesia".
http://www.cia.gov/cia/publications/factbook/geos/id.html

Edison International, "Edison International Announces Interim Agreement on Paiton Power Plant", March 2, 2000, http://www.prnewswire.com

Mahmudi, Ikhsan, "PLTU Swasta Paiton Menyengat PLN", Surabaya Post, January 26, 1999. http://www.surabayapost.co.id/99/01/26/01JANGKA.html

Mission Energy Company, "Industry:Energy, Country: Indonesia"
http://www.ita.doc.gov/td/advocacy/Mission.html

Mohammad, Herry, "Charge First before being Charged", *Gatra* 48/V, October 16, 1999.
http://www.gatra.com/_english/V/48/HUK1-48.html

"Power Plant Deal for Indonesia"
http://www.softwar.net/paiton.html

"Suharto Family Projects May be Put on Hold"
http://www.energyonline.com/Restructuring/news_reports/news_archive/g10indo.html

Toyo Engineering Company, "Paiton Project for Indonesia Moving Ahead".
http://www.toyo-eng.co.jp/BackNumbers/TECInformation/Dec96/paiton-e.html

US Embassy for Jakarta, Indonesia, "Indonesia: Electricity Sector Update—Focus on PLN", *Energy News*, May 1998. http://www.usembassyjakarta.org/econ/electric-pln.html

US Energy Information Administration, "Indonesia", February 2000.
http://www.eia.doe.gov/emeu/cabs/indonesia.html

US Energy Information Administration, "East Asia: The Energy Situation, August 1999.
http://www.eia.doe.gov/emeu/cabs/eastasia.html

2976-1/8