

Project Finance: Practical Case Studies

Second Edition

VOLUME I

Power and Water

Henry A. Davis



Project Finance: Practical Case Studies

Second Edition

VOLUME I

Power and Water

Published by
Euromoney Books
Nestor House, Playhouse Yard
London EC4V 5EX
United Kingdom

Tel: +44 (0) 20 7779 8999 or USA +1 800 437 9997

Fax: +44 (0) 20 7779 8300

www.euromoneybooks.com

E-mail: hotline@euromoneyplc.com

Copyright © 2003 Euromoney Institutional Investor PLC

The authors give notice of their right under Section 77 of the Copyright, Designs and Patents Act 1988 to be identified as the authors of this book.

ISBN 1 85564 845 8

All rights reserved.

This publication is not included in the CLA Licence. No part of this book may be reproduced or used in any form (graphic, electronic or mechanical, including photocopying, recording, taping or information storage and retrieval systems) without permission by the publisher.

Euromoney Institutional Investor PLC believes that the sources of information upon which the book is based are reliable and has made every effort to ensure the complete accuracy of the text. However, neither Euromoney, the author, nor any contributor can accept any legal responsibility whatsoever for consequences that may arise from errors or omissions or any opinions or advice given.

This book is intended to serve as a guide only. It is not a substitute for seeking professional advice at all stages.

Printed in England by Hobbs the Printers Ltd

Contents

| | |
|--|----|
| About the author | ix |
| Acknowledgements | x |
| Foreword | xi |
| | |
| Introduction | 1 |
| The nature of project finance | 4 |
| Trends in project finance | 6 |
| Effect of Enron | 12 |
| Caution among lenders and investors | 15 |
| Common themes | 20 |
| Reasons for financial difficulty | 21 |
| Lessons learned | 24 |
| | |
| Power plants | |
| | |
| 1 Laibin B – Coal fired power plant | 30 |
| Introduction | 31 |
| Project summary | 31 |
| Background | 32 |
| How the financing was arranged | 34 |
| Government approvals and support | 34 |
| Risk analysis | 35 |
| Principal contracts | 37 |
| Lessons learned | 38 |
| | |
| 2 Meizhou Wan – Pulverised-coal-fired power plant | 39 |
| Introduction | 40 |
| Project summary | 40 |
| Background | 40 |
| Principal contracts | 42 |
| How the financing was arranged | 43 |
| Lessons learned | 43 |
| | |
| 3 TermoEmcali – Gas-fired power plant | 45 |
| Project summary | 46 |
| Project economics | 48 |
| Ownership and contractual relationships | 48 |
| Financing structure | 53 |
| Risk analysis | 54 |
| Structure of financing | 59 |

CONTENTS

| | | |
|----------|--|-----|
| | Lessons learned | 64 |
| 4 | Azito – 288 MW power plant and 225 kV transmission system | 69 |
| | Project summary | 70 |
| | The power sector in Côte d'Ivoire | 70 |
| | Project description | 72 |
| | Project risk factors | 75 |
| | Critical success factors and lessons learned | 76 |
| 5 | Dabhol Power Company – Power station and port facilities | 78 |
| | Project summary | 79 |
| | Background | 80 |
| | Lessons learned | 92 |
| 6 | PT Paiton Energy (Paiton I) – Coal-fired power plant | 94 |
| | Project summary | 95 |
| | Background | 95 |
| | Lessons learned as of 1996 | 103 |
| | Developments since 1996 | 104 |
| | Lessons learned as of 2003 | 112 |
| 7 | Samalayuca II – Power plant | 113 |
| | Introduction | 114 |
| | Project summary | 114 |
| | Background | 115 |
| | Lessons learned | 122 |
| 8 | Merida III – Power plant | 124 |
| | Introduction | 124 |
| | Project summary | 124 |
| | Background | 125 |
| | Lessons learned | 127 |
| 9 | Bajío, La Rosita and TEG – Natural-gas-fired power plants | 128 |
| | Introduction | 128 |
| | Mexican power projects following Samalayuca II and Merida III | 129 |
| | Bajío | 129 |
| | La Rosita I and II | 130 |
| | TEG I | 131 |
| | TEG II | 133 |
| | Fuel supply issues | 133 |
| | Future structure of the Mexican power industry | 134 |
| | Lessons learned | 134 |

| | | |
|-----------|---|-----|
| 10 | CBK – Hydroelectric power plant and pumped storage facility | 136 |
| | Project summary | 136 |
| | Background | 137 |
| | Arrangement of finance | 139 |
| | Project debt service coverage ratios | 139 |
| | Political risk insurance | 140 |
| | Lessons learned | 142 |
| 11 | Quezon Power – Pulverised-coal-fired power plant | 144 |
| | Project summary | 145 |
| | Background | 145 |
| | How the financing was arranged | 150 |
| | Principal project contracts | 152 |
| | Description of additional agreements | 154 |
| | Other project documentation | 156 |
| | Risk factors | 158 |
| | Lessons learned | 170 |
| 12 | Drax – Coal-fired power plant | 171 |
| | Project summary | 171 |
| | Power plant description | 172 |
| | Background | 172 |
| | How the financing was arranged | 175 |
| | Sources and uses of funds | 177 |
| | Independent consultants' reports | 179 |
| | Initial credit ratings | 182 |
| | Subsequent developments | 183 |
| | Lessons learned | 191 |
| 13 | Panda Energy–TECO Power joint venture – Two natural-gas-fired power plants | 193 |
| | Project summary | 193 |
| | Background | 194 |
| | Credit and risk management | 200 |
| | Contracts | 201 |
| | How the financing was arranged | 203 |
| | Environmental permits | 205 |
| | Risk summary | 205 |
| | Financial projections | 208 |
| | Subsequent developments | 208 |
| | Lessons learned | 213 |
| | Power project portfolio | |
| 14 | Calpine – Power plant portfolio | 214 |
| | Summary of approach to projects | 214 |
| | Background | 215 |

CONTENTS

| | |
|--|-----|
| Financing methods | 216 |
| Risk considerations and credit ratings | 219 |
| Lessons learned | 225 |
| | |
| Water and power | |
| 15 Casecnan Water & Energy Company – Irrigation and hydroelectric | |
| power facility | 226 |
| Project summary | 226 |
| Background | 227 |
| Events since 1996 | 231 |
| Lessons learned | 237 |

About the author

Henry A. Davis is a writer and consultant working in the fields of banking and corporate finance. He currently serves as managing editor of three quarterly professional journals, the *Journal of Investment Compliance*, the *Journal of Structured and Project Finance*, and *Strategic Investor Relations*, published by Euromoney's US affiliate, Institutional Investor. Mr Davis has also written or co-authored 11 books including *Financial Turnarounds: Preserving Value* with William W. Sihler (Financial Executives Research Foundation, 2001 and Financial Times-Prentice Hall, 2002), *Project Finance in Latin America: Practical Case Studies* (Euromoney Books, 2000), *Building Value with Capital Structure Strategies* with William W. Sihler (Financial Executives Research Foundation, 1998), *Cash Flow and Performance Measurement: Managing for Value* (Financial Executives Research Foundation, 1996), *Project Finance: Practical Case Studies* (Euromoney Books, 1996), *Lender's Guide to the Knowledge-Based Economy* with Richard D. Crawford (Amacom Books, 1996), *Foreign Exchange Risk Management: A Survey of Corporate Practices* with Frederick C. Militello (Financial Executives Research Foundation, 1995) and *The Empowered Organization: Redefining the Roles and Practices of Finance* with Frederick C. Militello (Financial Executives Research Foundation, 1994). He has contributed articles to numerous financial publications, including *International Treasurer*, *Latin Finance*, and *Risk*. Mr Davis began his career in banking, working for Bankers Trust Company and Bank of Boston, and worked for two consulting firms, the Globecon Group and Ferguson & Company. He earned his Bachelor's degree at Princeton University and his MBA at the Darden Graduate Business School at the University of Virginia.

Acknowledgements

A detailed book of case studies cannot be completed without information and advice from many experts. In particular, the author would like to acknowledge the never-ending patience of Stuart Allen, Johanna Geary, Elizabeth Gray and Paul McNamara of Euromoney Books and the generous assistance provided by the following individuals, listed alphabetically.

Dino Barajas, Milbank, Tweed, Hadley & McCloy
Brandon A. Blaylock, GE Capital Services Structured Finance Group
Jonathan D. Bram, CS First Boston
William H. Chew, Standard & Poor's
Rohn Crabtree, Calpine
Ana Demel, Cleary, Gottlieb, Steen & Hamilton
Elizabeth U. Eshbach, Darden Graduate Business School Library, University of Virginia
Benjamin Esty, Harvard Business School
Roger D. Feldman, Bingham McCutchen
Barry P. Gold, Citigroup
David Gore, Société Générale Asia
James F. Guidera, Credit Lyonnais
Richard Hunter, Fitch Ratings
Ken Hawkes, Mibank, Tweed, Hadley & McCloy
Piyush Joshi, British Gas India
Stephen T. Kargman, Export-Import Bank of the United States
Kenneth M. Koprowski, GE Capital Services Structured Finance Group
John W. Kunkle, Fitch Ratings
Barry N. Machlin, Mayer, Brown, Rowe & Maw
Jan Willem Plantagie, Standard & Poor's
John S. Strong, School of Business Administration, College of William & Mary, and World Bank
Robert L.K. Tiong, Nanyang Technological University, Singapore
Brian Urban, Panda Energy
Enid Veron, Bingham McCutchen
Gary Wigmore, Milbank, Tweed, Hadley & McCloy
Jacob J. Worenklein, Société Générale

Foreword

Jacob J. Worenklein

*Managing Director and Global Head of Project and Sectorial Finance Group
Société Générale*

Henry A. Davis's survey of the major project financing developments in the power sector appears at a critical time for the industry globally. In both the developing world and the richest nations, major portions of the power and infrastructure sectors are convulsed by crisis.

In the developing world, the largest and most important private-sector power projects of the 1990s – including the multi-billion dollar Dabhol and Paiton projects in India and Indonesia discussed in Chapters 5 and 6 of this book – went into default. The Indian government was unwilling, and the Indonesian government and others were unable, to honour their obligations to some of the world's largest industrial and financial companies, as well as to the governments of the United States, Japan and Germany. These companies, banks and governmental agencies had shown their confidence in these countries – as well as others such as Argentina and Brazil – by investing billions of dollars in the largest power projects that these developing nations ever had undertaken. This confidence, however, was shattered and investors learned tough lessons that, sadly, will hurt developing countries seeking private-sector infrastructure investments for years to come.

In the United States and the United Kingdom too, the power sector has been racked by the loss of confidence in the industry among investors, beginning with the failure and fraud of Enron, and by collapsing power prices arising from excess capacity; the freezing of deregulation midstream, which created an uneven playing field between regulated and unregulated entities; the elimination of long-term contracting capability among most power marketers and traders; and other factors. As a result, many now question both the business models that took hold in the power sector and the credibility of deregulation. Hal Davis's excellent studies of Drax in the United Kingdom (see Chapter 12) and Panda-TECO in the United States (see Chapter 13) demonstrate how the confluence of many seemingly unrelated events can inflict significant pain on major participants in these projects. When major corporations fail, such as TXU Europe and Enron in these two cases, they spread havoc even in unexpected places, as the failure of Enron did in destroying its subsidiary Nepco, the Panda-TECO contractor.

Focusing on the US and UK power sectors, the magnitude of the financial pain is unprecedented. The collapse of power prices and asset values, along with the failure of many of the major players in the unregulated power business (which led to the cascading collapse of additional players and projects), has resulted in the loss of several hundred billion dollars by equity and debt investors. The equity market capitalisation of nine of the US industry's players alone declined in one year from some US\$130 billion to less than US\$10 billion. The carnage permanently destroyed the merchant power model for generation, ensuring that neither equity investors nor lenders will finance future capacity on a merchant-power basis with-

out long-term contracts from load-serving, regulated utilities.

What will replace the merchant model for power generation remains to be seen, but it is likely to be founded on a central role for the load-serving utilities. At a minimum, regulatory commissions will encourage or compel power generators to enter into contracts for capacity that are sufficiently in advance of need, in order that shortages do not arise (and market participants can observe that they will not arise) and power prices do not reach the astronomical levels that would result if shortages were to materialise. Some regulatory commissions are likely to encourage their regulated utilities to add capacity themselves to play it safe.

Disengagement of investors and lenders

In the meantime, investors have disengaged themselves from much of the power sector, causing a collapse of prices and withdrawal of capital. This is the natural result of the loss of confidence among investors who thought that they understood the rules governing the power system, but then invested in companies and projects that collapsed. It is reasonable to expect that this disengagement will last until investors gain an understanding of the new reality and believe that the environment is stable. Re-establishing such confidence requires a great deal of time. Regulators should understand that it is a key part of their job to help create a climate of stability in which the reasonable expectations of investors can be realised.

If a collapse of confidence is the case for the power sectors in the United States and the United Kingdom, it is even more evident in the developing world – and more dangerous for its prospects. In one way or another, the necessary investment will be forthcoming for the richest countries, such as the United States and the United Kingdom. However, we have no basis for believing that the same will be true for the world's developing countries.

Indeed, private-sector investment in infrastructure such as power, water and transportation in the emerging markets has been dealt a severe blow. A new model is needed to ensure that capital can continue to flow where it is so greatly needed.

The powerful idea of private sector investment in infrastructure

Most of us in the project finance business have dedicated our professional lives to implementing around the world one great and powerful idea: that supplying energy, water, transportation and other infrastructure to the world through a competitive private sector will do much good for the world, including the alleviation of poverty through economic development, and will create excellent businesses for our companies.

Massive amounts of capital have flowed around the world in support of this great idea — US\$1 trillion for the power sector alone in the past 10 years. Great companies have been built in pursuit of this idea, with public and private equity markets embracing — up to now — the vision of growth and profitability. This confidence, however, is now gone and will be hard to restore.

Vulnerability of emerging markets infrastructure

Hal Davis's case studies underscore the lesson that emerging markets projects are highly vulnerable to economic problems in their host countries. This clearly has been seen in the past 10 years in Argentina, Brazil, Colombia, Indonesia, Mexico, Pakistan and Thailand. Most dis-

trussing are projects where the will to pay was lacking, as in the case of projects such as Dabhol in India (see Chapter 5) and Meizhou Wan in China (see Chapter 2).

Common aspects among most of these cases were:

- severe foreign exchange crises in the host country;
- national political instability and changes in government;
- allegations of corruption in obtaining contracts; and
- economic problems resulting in overestimating the need for power.

On balance, the governments involved were not able, or did not feel a compelling need, to perform their obligations

Among the lessons we have learned, as evidenced in a number of Henry Davis's case studies, is that the expected political risk protections built into many projects often have proved illusory. Political risk 'protection' provided by the involvement of major multilateral agencies and export credit agencies (ECAs) has proved to be weaker than expected because of their conflicting national or supranational interests. For example, in the early 1990s, when Thailand abrogated its commitment to increase tolls in the Bangkok Second Stage Expressway (a project with large Japanese involvement), the Japanese government was remarkably quiet considering the other major interests of Japan in Thailand. The United States similarly felt that it had broader national interests in Indonesia, given the political turmoil in that country in the late 1990s, than to insist on payment to power projects undertaken by US companies and funded significantly by US government agencies (see the case study on Paiton Energy, Chapter 6).

Certainly the involvement of major multinationals has not proved to be a deterrent to politically inspired action against projects. Moreover, the agreement of host countries and project sponsors on the independent arbitration of disputes under clear international rules, in places such as London and Stockholm, in reality often has been frustrated by the actions of host governments, as the author points out in several of his case studies.

Context of continued decline of net private capital to emerging markets

The crisis in emerging-market infrastructure projects is part of a broader crisis of private capital flows to emerging markets. In 2001 these flows stood at the lowest level in 10 years: US\$115 billion, down US\$54 billion from 2000. This is less than half the average in 1995-97.

New lending to emerging markets as a whole was close to zero from 1998 through to 2001. In 2001, total private lending to emerging markets (including new bond issuances) was minus US\$32 billion. In other words, more money was repaid to global lending institutions and bondholders than was borrowed. Net official flows were expected to total US\$18 billion in 2002.

Equity investors do not buy the story of emerging markets infrastructure

That shortfalls are likely to continue in private infrastructure investment in these countries has become particularly clear during 2002 and 2003. Some of the best global power companies with large emerging markets businesses, such as AES, have seen their stock prices devastated as a result of problems in some of their emerging markets investments, particularly in Latin America.

Equity investors today are not buying the story that emerging-market infrastructure is a

good business — at least not in the current model of how the business has been done. Under this model, infrastructure projects in emerging markets will not be the beneficiaries of major private capital flows for a long time.

Emerging markets: rethinking Public-Private Partnerships

The private build-own-transfer (BOT) or build-own-operate (BOO) model does not appear to be as powerful an answer to the infrastructure needs of the developing world as it was once thought to be. New models for partnership between the public and private sectors in the developing world are needed to provide greater assurance of project viability and greater incentives for performance by governmental parties.

Some constructive approaches include the following:

- insisting that projects be part of a well-structured regulatory approach for the industry as a whole (for example, the Azito project in Côte D'Ivoire, discussed in Chapter 4), with a focus on the health of the distribution system, and not merely adding islands in a bankrupt system (as was done in the Dabhol project, discussed in Chapter 5);
- co-investment in projects by host-government agencies through loans and minority equity ownership, with a waterfall of equity payments directed first to private sector investment and then to government;
- the purchase of political risk insurance for emerging-market projects on a more routine basis;
- the greater use of targeted, 'enhanced' political risk insurance aimed at major specific risks of the project or privatisation, including default in performance of obligation by a government or related entity. Such insurance may come from private-sector entities (as in the case study of the CBK project in the Philippines, discussed in Chapter 10) as well as from governmental entities;
- creative approaches being pursued by the World Bank, the International Finance Corporation (IFC), other multilaterals and ECAs. One approach of particular promise is the IFC's consideration of a liquidity facility to provide several years of transitional project support during periods of currency crisis (to keep interest current, for example);
- a greater financing role by multilateral agencies, ECAs and other governmental entities (although this is not a panacea, as case studies in this book make clear); and
- the creative application of the IFC's partial-credit guarantee to support local-currency financing of projects and longer tenors in local markets.

In general, much greater respect is warranted for the value that can be added by multilaterals, ECAs and other governmental agencies — despite the resulting delays — than most project financiers have recognised in years past, when most focused on the ability to finance many emerging-market projects in stronger countries through bank and bond markets without multilateral and ECA support. This was not wise — it was a triumph of optimism over experience — and is no longer a viable approach.

New form of Public-Private Partnerships needed in the poorest countries

In the poorest countries in the developing world in particular, the classic project finance approach does not work. In these countries governments and people are often too poor to pay for the critical water, power, transport, health and other infrastructure facilities that they need. For many of the world's poorest countries it is not realistic to expect that, at this stage in their development, they can attract sufficient trade and investment to help them break the cycle of poverty.

In the United States and other countries development assistance needs to be put back on the national agenda — but in a more effective form.

Implementing development assistance through Public-Private Partnerships in poorest countries

Development assistance would be implemented more effectively and quickly, and with fewer concerns about waste and corruption, if the private sector played a key role in the execution of development assistance projects. A private sector initiative for the development of critical water, transport, power, health and other facilities in the world's poorest countries is needed in partnership with local governments, Western government donors and multilateral institutions.

Under one approach for such a partnership:

- private-sector companies would take the lead in developing, financing, implementing, owning and operating critical health, water, transport, power and other projects deemed to be of the highest priority by the governments of the recipient countries and by Western donor countries; and
- Western donor countries would pay for the services provided by these projects as part of a programme of official development assistance (directly or through multilateral institutions such as the World Bank).

Governmental payments would be made through an agreed schedule of payments for services delivered to provide the greatest incentives for effective service delivery. Where payment for services is not a practical approach, government donors may need to help pay for the funding of construction and operation, particularly in the most difficult countries.

Placing the responsibility and the flow of funds for these projects in the private sector would help address public concerns in the United States and elsewhere that foreign aid is wasted, being spent on ineffective 'vanity projects' that do not help the recipient countries significantly, and that a large portion of the funds historically has been diverted to the pockets of corrupt politicians.

Building on the project finance Public-Private Partnership model

The Public-Private Partnership approach would be based in part on the project finance model, through which more than US\$100 billion per annum of power, water, transport and other infrastructure projects have been implemented in both the developed and developing worlds.

There are encouraging examples of successful projects, such as the provision in Buenos Aires over the last eight years of a drinking water network for 1.6 million people and a sewage system for nearly one million people, but these are exceptions.

Necessary infrastructure projects are rarely implemented in the world's poorest areas

FOREWORD

because of the need for adequate credit quality of the off-takers, but it is in these countries that the need is greatest.

Project finance will continue to play a major role

As the model for infrastructure projects throughout the world continues to be refined to apply the lessons learned, it is likely that project financing will continue to play a major role in the sound and creditworthy structuring of projects. Despite the losses experienced in some of the projects discussed by Hal Davis and alluded to in this foreword, the fact remains that even these projects have, in most cases, proved to be resilient over time.

One of the key lessons learned is that projects that fill an important social need, are fundamentally sound and low-cost, and have sponsors with the financial resources and patience to work through problems have enabled investors and lenders to recover a much higher percentage of their investment than have similarly rated corporate investments. This reflects the secure nature of these investments, the strategic nature of the facilities being financed and the careful structuring of all contractual, and other, aspects of the projects.

Examples of such projects include the Indonesian power projects, including Paiton Energy (discussed in Chapter 6) and Jawa Power (not in this book), which are on the path to recovery, and the Indonesian telecommunications projects (not in this book), which are expected to recover. Similarly, the success of International Power in working through the problems of its Pakistan projects (not in this book) is encouraging.

Government agencies in these countries have worked through project problems in the midst of great domestic difficulties, but still have demonstrated much higher recovery rates than similarly rated corporate transactions.

Role of private sector in global power and infrastructure

The common element in all of the initiatives discussed in this important book is the creativity of the private sector, working with governments and other affected parties, in building key facilities needed by people around the world to live better lives. Henry Davis's excellent introduction and case studies demonstrate the great challenge we face in the development and financing of critical infrastructure on a global basis, particularly in the developing world. We have learned many lessons from our mistakes, and Henry Davis teaches them well. This book comes at a time of crisis. It makes an important contribution to our understanding of what can go wrong and what is needed to implement better the critical power and infrastructure facilities that the world needs.

Introduction

The scope of project finance both changed and expanded in the 1990s. The growing need for power and other infrastructure facilities increased the demand for project financing, while the sources of project finance broadened to include the capital markets. Financial tools such as pooling, securitisation and derivatives provided new ways to mitigate project risks. As investors and lenders became more familiar with project finance, they showed increasing risk tolerance. As a result, the boundaries of project finance have widened. In the mid-1990s banks and institutional investors financed projects with structures and terms that would have been hard to imagine just five years before. The total worldwide volume of project finance increased rapidly from 1994 to 1997, lessened after the Asian financial crisis in 1997 and then increased to a new high in 2000. Project finance then declined once again along with the collapse of equities, particularly in technology and telecommunications; the related decline in technology and telecom capital expenditures; and the Enron bankruptcy and associated scrutiny of power companies' trading activities and balance sheets (see Exhibit A).

Project Finance: Practical Case Studies consists of 38 case studies of recent project financings. This first volume covers power and water (irrigation) projects, and *Volume II* covers resources and infrastructure projects. The project case studies were selected to exhibit the types of projects most frequently financed in a variety of countries. Because these case studies illustrate different aspects of project finance across the major geographical areas, the nature of their content varies considerably. For example, some contain a detailed description of project documentation while others do not cover documentation at all. Some power project case studies are concerned primarily with negotiating contracts in countries that are just

Exhibit A

Global facility-type breakdown for project financings closed, 1994–2002

| Year | Loan amount (US\$ millions) | Per cent of total | Bond amount (US\$ millions) | Per cent of total | Sponsors' equity (US\$ millions) | Per cent of total | Total (US\$ millions) | Number of deals | Average deal size (US\$ millions) |
|------|-----------------------------|-------------------|-----------------------------|-------------------|----------------------------------|-------------------|-----------------------|-----------------|-----------------------------------|
| 1994 | 28,603.44 | 85.3 | 564.00 | 1.7 | 4,380.70 | 13.0 | 33,548.14 | 85 | 394.68 |
| 1995 | 59,361.72 | 76.8 | 3,920.90 | 5.1 | 14,055.58 | 18.1 | 77,338.20 | 323 | 239.44 |
| 1996 | 113,810.40 | 64.6 | 13,789.45 | 7.8 | 48,649.81 | 27.6 | 176,249.66 | 649 | 271.57 |
| 1997 | 142,545.29 | 66.3 | 18,654.07 | 8.7 | 53,714.85 | 25.0 | 214,914.21 | 560 | 383.78 |
| 1998 | 115,103.37 | 61.3 | 18,141.53 | 9.7 | 54,545.66 | 29.0 | 187,790.56 | 485 | 387.20 |
| 1999 | 119,139.82 | 61.0 | 23,673.62 | 12.1 | 52,571.89 | 26.9 | 195,385.33 | 464 | 421.09 |
| 2000 | 161,556.30 | 67.3 | 23,544.30 | 9.8 | 54,893.64 | 22.9 | 239,994.24 | 459 | 522.86 |
| 2001 | 96,033.69 | 69.2 | 14,573.22 | 10.5 | 28,166.74 | 20.3 | 138,773.65 | 308 | 450.56 |
| 2002 | 56,062.16 | 72.7 | 7,782.03 | 10.1 | 13,252.75 | 17.2 | 77,096.94 | 247 | 312.13 |

Source: Dealogic ProjectWare.

Exhibit B

Summary of projects by industry and geographical area

| | <i>Africa</i> | <i>Asia</i> | <i>Europe (including the United Kingdom)</i> | <i>Latin America (including Mexico)</i> | <i>North America</i> | <i>Multi- national</i> |
|------------------------------|---------------|-------------|--|---|--------------------------|----------------------------|
| Power projects/portfolios | 1 | 6 | 1 | 6 | 2 | |
| Power and water (irrigation) | | 1 | | | | |
| Pipelines | 1 | | | 3 | | |
| Mines | 3 | | | 2 | | |
| Oil field | | | | 1 | | |
| Refinery | | | | 1 | | |
| Toll roads | | | 3 | 1 | 1 | |
| Airports | | | 1 | 1 | | |
| Telecom | | | | 2 | | 1 |

beginning to privatise their electricity sectors, while others concentrate on new financing techniques and adapting to a merchant power environment.

The case studies in these volumes cover a broad range of industries and geographical areas as illustrated in Exhibit B.

Industry sectors

Volume I – Power and Water covers issues such as the privatisation and deregulation of the electricity industry, adaptation to merchant sales and pricing environments, negotiating initial independent power projects in developing countries, political risk, recent financing innovations, and the worldwide ripple effect of the California power crisis and the Enron bankruptcy, including the pullback of large international power players.

In *Volume II – Resources and Infrastructures*, the pipeline project case studies discuss the increasing willingness of both the bank and capital markets to take risks in a developing country; the requirements for multilateral agency participation; and the need to address environmental, social, and sustainability issues. The oil field production project case study demonstrates how the credit rating of a solid export-oriented project with strong sponsors can pierce the sovereign ceiling of a country with political difficulties. Similarly, the refinery case study presents an example of a project with pure emerging-market risk that can survive in a difficult economic environment. The mining project case studies demonstrate sensitivity to commodity price risk, the negotiation of a basic legal structure with a host government, and the construction and operating difficulties involved. The toll road project case studies outline bridge construction challenges, and issues related to the respective roles of the government and the private sector in assuming construction and traffic risks, a flexible repayment mechanism to cope with traffic risks, and problems when traffic does not meet projections. The airport case studies present an example of a whole-business securitisation, and describe difficulties related to lower-than-projected passenger traffic and ongoing negotiations with the government on concession issues. Finally, the three telecommunications project case studies discuss topics such as a creative lease structure that provided financing for

a state-owned telephone company, an aggressive multinational network expansion that could not be supported when telecom capital expenditures collapsed and an international consortium's overpayment for a local cellular telephone licence.

Geographical areas

The case studies in these volumes were intentionally selected to provide geographical diversity. Although, over the long term, there is not a great deal of difference between project financings in geographical areas *per se*, recent regional economic difficulties, such as the Asian financial crisis, the Russian default and the Brazilian devaluation, have had medium-term effects both on sponsors' abilities to finance projects and on the terms of available financing. There also is a significant difference between financing projects in member states of the Organisation for Economic Cooperation and Development (OECD) and developing countries. Among worldwide emerging-market considerations for projects across all industry sectors are prolonged negotiations; the familiarisation of government officials, lawyers and bankers with financial and legal concepts new to the local market; and the enactment of new laws to cover a broad range of issues, including commercial contracts, collateral and security interests, power and fuel purchase agreements, mineral rights and repatriation of profits and capital. These issues are particularly apparent in Africa, which became a significant project financing venue in the 1990s.

Content and research method

Prior to delving into the case studies in this volume, and those in *Volume II – Resources and Infrastructure*, this introductory, analytical chapter, replicated in each volume, discusses current trends in project finance and important themes that run through the case studies. When a specific case is referred to, the chapter in which it is discussed is noted if it appears in this volume and a note to see *Volume II – Resources and Infrastructure* is provided if it appears in *Volume II*. Information for both this chapter and the case studies was gathered from the financial press; credit rating agency analytical reports; and on-site and telephone interviews with commercial bankers, investment bankers, project sponsors, institutional investors, rating agency analysts and others. On-site interviews generally ranged between

Exhibit C

Author's project finance interview protocol

- Description of project, including type, location, size and other specifications
 - Reason for project and sponsors' needs
 - How project participants were assembled
 - Legal structure of project entity, including a diagram of project structure
 - Analysis of project risks and economic viability
 - Most important project contracts and principal provisions
 - Alternative sources of finance considered
 - How the financing team was assembled
 - Structure of financing
 - Pricing, maturity and other financing terms, including guarantees and other third-party sources of support; insurance, collateral, and other forms of protection; and important features of financing documentation
 - Accounting and tax considerations for sponsors and investors
 - Credit analysis from the investors' and lenders' perspectives
 - Credit rating
 - Principal problems encountered with project and financing
 - Investors' and lenders' concerns before and since notes were issued
 - Most innovative features of the project
 - Most important lessons learned
 - How the project illustrates current regional and country trends
-

one and two hours. The interviews were taped and the case studies were approved for accuracy by the interviewees. To help focus the interviews and the content of the case studies, the author developed an interview protocol and used the 'Checklist for a successful project financing' from *Project Financing Seventh Edition*¹ (see Exhibits C and D). For more than 25 years, the seven editions of *Project Financing* have been one of the most widely used sources of basic information on project finance. For each project, it was understood that some items on the interview checklist were more applicable than others. The interviewees' comments and the contents of the case studies generally concentrate on aspects of the project financings that were the most interesting, unusual or useful to the practitioner. Each project has its own purpose and momentum, and the case studies are not intended to touch on all of the same issues.

The nature of project finance

Project finance is generally defined as the provision of funds for a single-purpose facility (or facilities) that generates cash flow to repay the debt. Debt is secured by the project's assets and cash flows, not by the assets or general credit of the project's sponsor(s). Therefore the debt generally is issued with no recourse, or, in some cases, with limited recourse, to the project sponsors. Project finance often is used for capital-intensive facilities such as power plants, refineries, toll roads, pipelines, telecommunications facilities and industrial plants. Before the 1970s the majority of project lending was for natural resource ventures such as mines and oil-fields. Since then the applications of project finance have broadened considerably, but power has been the largest sector.

For lenders and investors the essence of project finance is the analysis of project risks,

Exhibit D

Checklist for successful project financing

1. A credit risk rather than equity risk is involved.
 2. A satisfactory feasibility study and financial plan have been prepared.
 3. The cost of product or raw material to be used by the project is assured.
 4. A supply of energy at a reasonable cost has been assured.
 5. A market exists for product, commodity, or service to be produced.
 6. Transportation is available at a reasonable cost to move the product to the market.
 7. Adequate communications are available.
 8. Building materials are available at the costs contemplated.
 9. The contractor is experienced and reliable.
 10. The operator is experienced and reliable.
 11. Management personnel are experienced and reliable.
 12. New technology is not involved.
 13. The contractual agreement among joint venture partners, if any, is satisfactory.
 14. A stable and friendly political environment exists, licences and permits are available, contracts can be enforced, and legal remedies exist.
 15. There is no risk of expropriation.
 16. Country risk is satisfactory.
 17. Sovereign risk is satisfactory.
 18. Currency and foreign exchange risks have been addressed.
 19. The key promoters have made an adequate equity contribution.
 20. The project has value as collateral.
 21. Satisfactory appraisals of resources and assets have been obtained.
 22. Adequate insurance coverage is contemplated.
 23. *Force majeure* risk has been addressed.
 24. Cost over-run risk has been addressed.
 25. Delay risk has been considered.
 26. The project will have an adequate return for the investor.
 27. Inflation rate projections are realistic.
 28. Interest rate projections are realistic.
 29. Environmental risks are manageable.
 30. Compliance with US Foreign Corrupt Practice Act of 1977.
-

Source: *Project Financing Seventh Edition*.

including construction risk, operating risk, market risk (applying to both inputs and outputs of a project), regulatory risk, insurance risk and currency risk. These risks often are allocated contractually to parties best able to manage them through construction guarantees, power purchase agreements (PPAs) and other types of output contracts, fuel and raw material supply agreements, transport contracts, indemnifications, insurance policies, and other contractual agreements. However, with projects in all sectors, sponsors, lenders and bank investors are exposed to significant market risk. Although recourse to sponsors is usually limited, they often provide credit support to the project through guarantees or other contractual undertakings. For example, an industrial sponsor of a cogeneration project may contract to buy steam from a project and another sponsor may contract to sell power to it. Sponsors' economic interests in the success of a project make impressive contributions to the project's creditworthiness.

Project financing generally is done without recourse to project sponsors, and projects are often, but not always, off corporate sponsors' balance sheets. As it does with a subsidiary, a sponsor includes a project's assets and liabilities on its balance sheet when a project is consolidated. When the equity method of accounting is used the sponsor's investment in a project is shown as a single amount on its balance sheet, and gains or losses on the project are shown as a single amount on its income statement. A sponsor generally uses the equity method to account for an investment in a project where it owns less than 50 per cent but can still influence its operating and financial decisions. If a sponsor has less than a 20 per cent interest in a project it is presumed to lack significant influence over the project's management and neither consolidation nor the equity method is required. Presumably, a sponsor's investment in a project and the related income or losses would be combined with other items on its balance sheet and income statement. It would be considered good practice on the part of the sponsor to include some mention of the project investment in the footnotes, particularly given the emphasis on disclosure and transparency in today's post-Enron environment.

Why project finance is used

Project finance can be more leveraged than traditional on-balance-sheet financing, resulting in a lower cost of financing. In countries with power and other infrastructure needs, project finance allows governments to provide some support without taking on additional direct debt. The growth of project finance in recent years has coincided with a trend toward privatisation.

For sponsor companies project finance may accomplish one or more of the following objectives:

- financing a joint venture;
- undertaking a project that is too big for one sponsor;
- assigning risks to parties that are in the best position to control them;
- insulating corporate assets from project risk;
- keeping debt off the corporate balance sheet;
- protecting their corporate borrowing capacity;
- maintaining their credit rating;
- improving corporate return on equity (ROE);
- restricting proprietary information to a limited number of investors;

- avoiding double taxation;
- sharing ownership of projects with employees; and/or
- establishing a business venture in a foreign country.

Sources of capital

Historically, commercial banks have provided construction financing for projects, while insurance companies have provided take-out financing with terms of 20 years or more. Banks have been relatively more comfortable with construction risks and short-term loans, while insurance companies have been more comfortable bearing the long-term operating risks after construction has been completed and the project has demonstrated its capability to run smoothly.

In the early 1990s, however, the investor base for project finance began to broaden. It now includes institutional investors, such as pension and mutual funds, and investors in the public bond markets in a growing number of countries around the world. Two important developments made institutional investors more receptive to project finance investments than they had been in the past: a ruling by the US Securities and Exchange Commission (SEC), and the issuance of project credit ratings by the major credit rating agencies.

SEC Rule 144a allows the resale of eligible, unregistered securities to qualified institutional buyers and eliminates the requirement that investors hold on to securities for two years before selling them. Recently, sponsors of some large power projects have aimed their financing solely at the institutional 144a market. Others have been able to reduce their financing costs by committing themselves to full registration for sale in the public markets within six months after their 144a securities are issued, thereby providing a more liquid market for the institutional investors that hold the securities.

With respect to project credit ratings, as the capital markets became an important source of funding the amount of rated project debt grew rapidly. For example, in 1993 Standard & Poor's (S&P) portfolio of rated project debt was US\$5.8 billion. The agency then established a project rating team in 1994. By mid-1996 it had rated US\$16.3 billion and by the end of 2002 US\$106 billion of project debt had been rated. Debt rated by the two other leading credit rating agencies, Moody's and Fitch Ratings, has grown in a similar fashion.

Institutional investors' needs

For institutional investors project finance offers a way to diversify and earn very good returns for the amount of risk taken. As more power and other infrastructure projects are financed and demonstrate a track record, more investors are becoming comfortable with the risk. William H. Chew, Managing Director of Corporate and Government Ratings at S&P, sees project finance as not just another Wall Street invention, but a growing investment vehicle with a strong demand on both the buy and the sell sides. It provides the uncorrelated returns for which portfolio managers have been looking, and risks that are different from the credit of the sponsor or the offtaker of the project's product.

Trends in project finance

Recent trends in project finance include the following.

Infrastructure requirements

There continue to be massive infrastructure requirements, particularly in developing countries. For example, the World Bank estimated that between 2001 and 2006 Latin America alone would need more than US\$70 billion per year in infrastructure investment to meet the needs of its growing and largely impoverished population. Developing countries in other regions have needs of a similar magnitude.

Privatisation

This is a worldwide trend that both reflects political currents and provides a way to supply needed infrastructure in the face of government budgetary limitations. Variations on this trend include public/private partnerships, notably the Private Finance Initiative in the United Kingdom.

Legislative and regulatory frameworks

Historically, the lack of legislative and regulatory frameworks has been an impediment to project financing in developing countries. Some case studies in these volumes, however, show how sponsors of first-of-their-kind projects have worked with host governments to develop legal and regulatory structures for future projects in emerging markets in Africa, Asia and Latin America.

Financial innovation

As innovations are made in other financial disciplines, such as leasing, insurance and derivatives-based financial risk management, they are applied quickly to project finance.

Broadened sources of funding

An ongoing trend since the early 1990s has been the growing use of bonds, both investment-grade and high yield, for project financing. These bonds have been sold to a broadening base of institutional investors, leading to a growth in credit-rated project debt. Connected to this trend, power project portfolios and investment funds comprising projects from different industries are providing investors with a way to spread risks and project sponsors with an additional source of financing. Also related is the growing flexibility between bond and bank financing, which is helped by the increasing number of financial institutions with both commercial and investment banking capabilities which can offer both loan and bond alternatives in a single project financing package.

Local currency financing

As the role of pension funds and other institutional investors broadens in many emerging markets, local-currency funding is becoming increasingly available for project financing. This development is particularly helpful to sponsors of infrastructure projects that generate local-currency revenues, as it allows them to avoid mismatches between those revenues and dollar-denominated debt.

Blending of project and corporate finance

A lack of risk tolerance and market liquidity sometimes prevents projects from being financed off the corporate balance sheet on a pure non-recourse basis. Projects today are financed along a spectrum ranging from pure project finance to pure corporate finance. A company such as Calpine, which is essentially a power plant portfolio, is one example of the blurring of the line between corporate finance and project finance.

Insurance

The role of insurance in project finance has increased steadily in recent years. Historically, the insurance industry has provided property and casualty coverage, and political risk coverage. Recently, insurers have become more active in covering completion risk, operating risk, off-take risk and residual value risk.

Residual value insurance, for example, can help sponsors and lenders to refinance risk when projects require loan pay-outs with longer terms than are available in the bank market. If a balloon payment (the repayment of most or all of the principal at maturity) is not made, or a project cannot be refinanced and the loan goes into default, the lender can seize the asset. If liquidation proceeds are less than the amount of residual value coverage, a claim for the difference can be made against the policy.²

Highly rated insurance companies with dynamic risk management capabilities can close the gaps in capital structures of projects exposed to market risks. For example, in 1999 Centre Group guaranteed the subordinated debt tranche for the Termocandelaria merchant power project in Colombia. If the project's cash flow was insufficient to make a debt payment, the insurance company agreed to step in and make that payment. An insurer can provide a take-out guarantee for project lenders when a PPA matures before a loan. Insurers can guarantee that a project receives a minimum floor price, regardless of what happens to the market price of its output. Insurers can provide standby equity and subordinated debt commitments and residual-value guarantees for leases.³

The events of 11 September 2001 exacerbated an already difficult insurance market and created a new problem for the insurance industry: how should exposure to terrorism be managed? The combination of reduced capacity, underwriter defections and shock losses from 11 September has, at the time of writing, created one of the most difficult insurance markets in history. Among the implications for project sponsors are increases in deductibles, which require projects to assume additional risk; the reduced availability of coverage for terrorism, new or unproven technologies, and catastrophic perils, such as earthquakes and floods; and substantial premium increases.⁴

Over recent years the credit ratings of many infrastructure bond deals have been raised to the 'AAA' level by guarantees or 'wraps' AAA-rated monoline insurance companies. However, as the monoline insurers themselves have diversified from their US municipal bond base their own risks have increased, leading to higher spreads on monoline-wrapped paper.

An emerging trend in project and concession financing is the use of targeted risk coverage, a structured financial mechanism that shifts specifically identified project risks to a third party, such as a multiline insurance or reinsurance company, a designated creditor, or, conceptually, any party that is willing to assume those risks, including project sponsors. The following have been among recent applications of targeted risk coverage:

- revenue risk mitigation, including coverage against commodity pricing risk, revenue guarantees for toll road projects and coverage against default of offtakers;
- substitutes for liquidity mechanisms, such as fully funded debt-service reserves and standby letters of credit; and
- political risk coverage.

Contingent capital is a form of targeted risk coverage that can reduce a project's cost of financing. The insurer provides a facility under which capital is injected into the project in the form of debt, equity or hybrid securities upon the occurrence of a predefined trigger event or set of events. In this way contingent capital allows the project to increase its capital base only when necessary, thereby increasing its return on invested capital.⁵

Recent crises in Asia, Latin America and Eastern Europe have reminded lenders and investors that political/economic events do not merely have the potential to cause losses, but actually cause them, according to Gerald T. West, Senior Advisor at the Multilateral Investment Guarantee Agency in Washington, DC.⁶ These events have stimulated the demand for political risk insurance, leading to expanded coverage and new products from multilateral agencies, national agencies and private insurance providers. In recent years private insurers have lengthened the terms of their coverage and increased their share of the political risk insurance market. Recent innovations include capital markets political risk insurance, which can be used to raise the credit ratings of bonds that finance projects in emerging markets.

Increasing and then decreasing risk tolerance

Until 1997, there were trends of lengthening maturities, thinning prices (which was reflected in spreads over benchmark funding indices), loosening covenants, extending project finance to new industries and geographical regions, and a willingness on the part of lenders and investors to assume new risks. This was partly a result of more institutional investors becoming interested, and developing expertise, in project finance. These trends reversed as a result of the worldwide ripples caused by the Asian financial crisis starting in 1997, the Russian default in 1998 and the Brazilian devaluation in 1999. Banks became less willing to commit themselves to emerging-market credits, and spreads on emerging-market bonds widened. To be financed, projects required increasing support from sponsors, multilateral agencies, export credit agencies (ECAs) and insurance companies. Since the Enron debacle, investors and lenders have reduced their tolerance for risk related to power companies with trading activities, overseas operations and difficult-to-understand financial statements.

Commodity price volatility

Prices below long-term forecast levels sometimes place commodity-based projects such as mines, petrochemical plants and oilfields 'under water' in terms of profitability. With deregulation and merchant power, the 'spark spread', the difference between a power plant's input (fuel) costs and output (electricity) prices, may at times not be sufficient for profitability.

Interest rate volatility

In the early 1990s, declining interest rates increased the number of financially viable projects. Although interest rates then rose slightly, they are again, at the time of writing, relatively low.

Bank capabilities

The number of financial institutions with broad project finance syndication capabilities is shrinking, as is the number with specialised project finance groups. Institutions with broad geographical scope and with both commercial and investment banking capabilities have a competitive edge in today's market.

Bank capital requirements

In 2002, the Basle Committee on Banking Regulation charged its Models Task Force with the role of analysing the unique credit considerations of structured credit products that merited special attention, including project finance. In its initial hypothesis, the Task Force determined that project finance should have a higher capital weighting than unsecured corporate loans because of its unique risk characteristics. Higher capital requirements for project loans could both impair the profitability of such loans for banks and raise loan pricing to uncompetitive levels, deterring banks from participating in loan syndications. An initial four-bank study conducted by S&P Risk Solutions indicated that project finance loans have lower losses subsequent to defaults than unsecured corporate loans, partly because of credit enhancements that mitigate risk, such as first-priority liens, cash-flow sweeps, covenant triggers and limitations on indebtedness. Banks often use such features as early-warning mechanisms to both alert themselves to project difficulties and encourage sponsors to cure defaults by providing equity or other forms of sponsor support, or to work with the banks to restructure the loans.⁷

Rating triggers

The fall of Enron and numerous recent power company defaults have been caused by 'rating triggers', which are provisions in loan agreements that define credit-rating downgrades below certain levels, often the minimum investment-grade level, as events of default.

Merchant power

Because of power price volatility and other recent market events, merchant power businesses have been downgraded by credit rating agencies and have had increasing difficulty in raising new financing.

Refinancing of mini-perms

In the past several years, numerous merchant power plants have been financed by four-to-six-year 'mini perm' bank loans. Refinancing these loans will be a challenge in the current environment. S&P notes that to do so power companies may be required to put up increased equity, structure cash sweeps and provide increased security.⁸

Declining importance of trading

In an article published in October 2002, Robert Sheppard, a consultant and attorney based in North Carolina, predicted that the role of trading in the electric power industry would diminish in the coming years. He pointed out that supply/demand imbalances and price uncertainty in the 1990s were caused largely by an uncertain and changing regulatory environment, and that the electricity market does not have many of the characteristics of other commodity markets in which users need to hedge, such as the unpredictability of supply or the potentially ruinous consequences for producers or users who do not hedge. The majority of consumers can bear electricity price risk without the benefit of risk-management intermediaries. Sheppard believes that the historical business practices of the electric power industry will reassert themselves as distribution companies once again recognise the benefits of stable, long-term sources of supply, and that project developers will rediscover the advantages of long-term debt supported by long-term contracts with highly rated power purchasers.⁹

Regulation of trading

As abuses such as power swaps transacted simply to inflate the revenues of counterparties come to light, attempts are being made to reign in the largely unregulated energy trading market. For example, in the summer of 2002 Richard Green, Chairman of Aquila, testified before the US Senate Agriculture, Nutrition and Forestry Committee in favour of more regulation and overseeing of the energy derivatives trading market, to remove uncertainty and increase competitive power price transparency. He was in support of a bill introduced by Senator Dianne Feinstein that would mandate the US Commodity Futures Trading Commission (CFTC) and the Federal Energy Regulatory Commission (FERC) to oversee all energy transactions with respect to fraud, and to require all energy derivatives trades to be subject to registration, reporting, disclosure and capital requirements. (It is noted in the Panda-TECO case study, in Chapter 13, that later in 2002 Aquila decided to withdraw from energy trading and return to its roots as a traditional utility, having acknowledged its own difficulty in managing risk and making a profit in this volatile and shrinking market.)

Scepticism about deregulation

Along with privatisation, deregulation in the power industry was intended to attract capital and ultimately result in lower consumer prices. However, the crisis that resulted from a flawed and poorly implemented deregulatory structure in California has caused scepticism and slowed the pace of worldwide power industry deregulation. In an article published in October 2002, Eric McCartney, Head of Project Finance for the Americas at KBC Global Structured Finance, pointed to the overall questioning and reassessment of why there has been such a push for electricity deregulation in the United States and other markets. Some interest groups are making pleas to roll back electricity reform and return to the concept of vertically integrated monopolies and cost-of-service regulation. McCartney notes that electricity prices in the United States dropped 35 per cent in real terms between 1985 and 2000 but questions whether deregulation had any influence on it. He also cites studies that conclude that less than 5 per cent of retail consumers care about electricity deregulation because differences between suppliers would amount to only a few dollars per month on their electricity bills. Industrial power users, on the other hand, may stand to benefit more from deregulation.¹⁰

Uncertainties concerning transmission

One of the problems cited in the Panda-TECO merchant power case study is that insufficient transmission capacity limits the potential of an Arizona power plant to sell electricity in the California market. As substantial numbers of new electric generation facilities are added to the US grid, transmission congestion can be expected to intensify, particularly in high-growth urban areas, causing bottlenecks and pricing aberrations.¹¹ McCartney of KBC notes that one of the reasons for inefficiency in the US electricity market is the lack of investment in the transmission sector. This in turn is the result of regulatory uncertainty concerning transmission siting, transmission pricing methodologies, interconnection rules and practices, the authority of the FERC over regional transmission organisations (RTOs), and a scheme for investors in transmission facilities to recover their costs and earn a fair profit. McCartney believes that the transmission sector has potential for the application of the project finance model and financing in the commercial market, but the development of that market is not yet sufficiently advanced and the risks are not adequately quantified. He observes that the project finance model needs a stable regulatory regime and a dependable stream of cash flow on which it can depend to service debt. He sees the FERC regulated-return concept as a proven model that would have a stabilising effect on the development of the transmission and distribution business, thus encouraging much needed investment.¹²

Telecoms meltdown

The bankruptcy described in the FLAG (Fiberoptic Link Around the Globe) case study (see *Volume II – Resources and Infrastructure*) illustrates problems faced by highly visible under-sea cable competitors, such as Global Crossing and other recent projects, throughout the telecommunications industry. Aggressive network expansion financed with high leverage may have been a viable strategy while internet use, telecom traffic and related capital spending were growing rapidly, but when the telecom market collapsed FLAG and many other telecom projects did not have the cash flow to service their debt.

Effect of Enron

Many trends in project finance over the past year have been related to the collapse of Enron. The role of off-balance-sheet, special-purpose entities in Enron's loss of confidence and subsequent bankruptcy has led some to question what the proper boundaries of project finance are. However, a survey that the author conducted for an article in *The Journal of Structured and Project Finance* (Spring 2002) found traditional project finance to be alive and well, and not adversely affected by the Enron debacle.

The Enron bankruptcy and related events have changed neither the nature nor the usefulness of traditional project finance, but they have led to a slowing down of some of the more innovative forms of structured project finance. Among the other direct and indirect effects of Enron have been increased caution among lenders and investors about the energy and power sectors; increased scrutiny of off-balance-sheet transactions; increased emphasis on counterparty credit risk, particularly with regard to companies involved in merchant power and trading; and deeper analysis of how companies generate recurring free cash flow. There is now increased emphasis on transparency and disclosure, even though disclosure in

traditional project finance always has been more robust than in most types of corporate finance. At the time of writing, for reasons that extend beyond Enron, some power companies in the current market environment have been cancelling projects and selling assets to reduce leverage, resorting to on-balance-sheet financing to fortify liquidity, and reducing their trading activities.

The immediate cause of the Enron bankruptcy was the loss of confidence among investors caused by Enron's restatement of earnings and inadequate, misleading disclosure of off-balance-sheet entities and related debt. However, because Enron was a highly visible power and gas marketer, and involved in far-flung activities ranging from overseas power plants to making a market in broadband capacity, its failure brought scrutiny to all aspects of the energy and power business, and particularly to the growing sectors of merchant power and trading.

Even before the Enron bankruptcy, as Jacob J. Worenklein, Managing Director and Global Head of Project and Sectorial Finance at Société Générale points out, the confidence of many power and gas companies was shaken by other devastating events during 2001, including the California power crisis; the related bankruptcy of Pacific Gas & Electric Company (the regulated utility subsidiary of PG&E Corporation); falling spot-power prices in US markets; the effects of 11 September; and the collapse of the Argentine economy and financial system. The California power crisis, as evidence of a flawed deregulation structure, caused a global setback in power deregulation and paralysed US bank markets for much of the first half of 2001. Worenklein explains that falling spot power prices were caused primarily by the overbuilding of new projects and overdependence on the spot market.

Worenklein observes that the combination of these events in 2001, accentuated at the end of the year by the Enron bankruptcy, caused a dramatic change in the perception of risk among investors, lenders and rating agencies. In particular, these parties began to perceive independent power producers (IPPs) and traders to be riskier than they ever had before. They considered trading businesses difficult to evaluate. They suspected earnings manipulation through the marking to market of power contracts and off-balance-sheet vehicles, particularly in the case of thinly traded contracts that companies marked to market purely on the basis of their own calculations. They feared sustained low power prices in the US market. After problems in countries such as Argentina, Brazil, India and Indonesia, emerging-market IPP projects began to seem to offer more danger than opportunity. Investors and lenders started to perceive earnings in the IPP and trading business to be less predictable and sustainable than they had before. As a result, they discounted the growth prospects of these companies, and focused on liquidity and leverage in light of higher perceived risk.

By the beginning of 2003 the US power market seemed to be at a much greater level of crisis than Worenklein and others had anticipated just a few months earlier. The collapse of forward prices in the merchant power market was far worse than anyone had anticipated. Forward prices in late 2002, for delivery in 2003, were one quarter to one third of comparable prices two years earlier. Worenklein notes that the effect of these prices on the economic viability of merchant power was greatly aggravated by gas price increases, which compressed spark spreads to levels that did not provide an adequate margin for capital recovery. This greatly exacerbated the power crisis in the United States, resulting in project downgrades by the credit rating agencies and significantly contributing to the collapse of two major unregu-

lated power suppliers in 2002: PG&E National Energy Group, which had been one of the most highly respected developers and owners of merchant power plants in the United States and NRG. At the same time financial pressure was increased on such players as El Paso, Dynegy and Mirant.

From a credit market perspective, the effect of all this was a significant increase in both the level of writeoffs and the provisioning for losses by the major commercial banks and other investors in the US power and project finance sectors. Worenklein believes that the result is likely to be a reduction in the amount of capital that will be available to the power sector in the United States, even outside the merchant power and trading arenas, as some players decide to reduce their overall exposure to the US power sector.

Some energy players have been hit by what Dino Barajas, an attorney with Milbank, Tweed, Hadley & McCloy, describes as a 'perfect storm'. They have had exposures in foreign markets that have collapsed; they have had to cancel advance purchase orders for turbines because of a slowing US power market; their stock prices are tumbling as a result of reduced growth prospects; and they are facing a credit crunch from lenders, some of which are 'gun-shy' from recent losses related to PG&E or Enron. The energy and power market has been affected by both the Enron bankruptcy and other situations, caused by a combination of all the factors discussed above. Before going further, let us look at how Enron has affected pure, traditional project finance.

Effect on traditional project finance

Jonathan B. Lindenberg, Managing Director at Citigroup, reminds us that traditional project finance is cash-flow-based, asset-based finance that has little in common with Enron's heavily criticised off-balance-sheet partnerships. According to Roger Feldman, Partner and Co-Chair of the Project and Structured Finance Group at Bingham McCutchen, the historic elements of project finance are firmness of cash flow, counterparty creditworthiness, the ability to execute contracts over a long time frame and confidence in the legal system. Barry P. Gold, Managing Director at Salomon Smith Barney, points out that project finance is a method of monetising cash flows, providing security and sharing or transferring risks. The Enron transactions had none of these characteristics. They were an attempt to arbitrage accounting treatment, taxes and financial disclosure.

Traditional project finance, in Lindenberg's view, is based on transparency, as opposed to the Enron partnerships where outside investors did not have the opportunity to do the due diligence upon which any competent project finance investor or lender would have insisted. Those parties are interested in all the details that give rise to cash flows. As a result there is a lot more disclosure in project finance than there is in most corporate deals.

Gold points out that, in traditional project finance, analysts and rating agencies do not have a problem with current disclosure standards; project financing is not hidden and it never has been. First, analysts and rating agencies know that project financing is either with or without recourse, and either on or off the balance sheet. For example, in the case of a joint venture where a company owns 50 per cent of a project or less, the equity method of accounting is used. On both the income statement and the balance sheet, the company's share of earnings from the project is included below the line in the equity investment in unconsolidated subsidiaries. Therefore, whether a project is financed on or off the balance sheet, analysts know where to look.

Off-balance-sheet treatment, Lindenberg explains, may not be the principal reason for most project financing. It usually is carried out to transfer risk or to provide a way for parties with different credit ratings to jointly finance a project (if parties provided the financing on their own balance sheets, they would be providing unequal amounts of capital because of their different borrowing costs). None of these considerations has anything to do with the Enron partnerships, where a 3 per cent equity participation from a financial player with nothing at risk was used as a gimmick to get assets and related debt off the balance sheet. This abuse has caused the US Financial Accounting Standards Board (FASB) to re-examine the accounting for special-purpose entities.

Structured project finance

Even though pure project finance has not been affected greatly by Enron, both Lindenberg and Worenklein see some slowing of activity in the more innovative types of structured finance, such as synthetic leasing, structured partnerships and equity share trusts – at least for the time being. Lindenberg notes that synthetic leases are a mature product, understood by rating agencies and accountants, in which billions of dollars-worth of deals have been done. (A synthetic lease is an operating lease for accounting purposes, but structured as a debt financing for tax purposes. The lessee retains the tax benefits of depreciation and interest deduction. A true lease is structured as a lease for both accounting and tax purposes.) The problem, however, is ‘headline risk’: one can hardly pick up a newspaper today without seeing yet another company with disclosure issues. Even though synthetic leases are transparent and well-understood, they have an off-balance-sheet element that creates headlines in today’s environment. More synthetic leases may be arranged in a year or two.

Special-purpose entities

By using corporate stock as collateral, and by creating conflicts of interest, Feldman of Bingham McCutchen believes that Enron undermined the pristine nature of the special-purpose, non-recourse entity and caused all such structures to look suspect. He stresses that, in traditional project finance, a special-purpose, non-recourse entity must be clean and fully focused on the transaction concerned. In the immediate aftermath of the Enron bankruptcy, project sponsors, and the bankers and lawyers who support them, will have to make a special effort to explain the legitimate business reasons for these entities.

Caution among lenders and investors

Because they may have been stung by PG&E or Enron, and because of other recent market factors such as declining power prices and emerging-market problems, lenders and investors recently have approached all energy and power companies with increased caution. They are scrutinising merchant power and trading businesses with particular care, and they are doing deals mainly with prime names that have proven staying power. Lindenberg sees bankers focusing on straightforward project deals with healthy sponsors, conservative structures and strong offtakers. Although that always has been a banker’s focus, it is more intense now.

Rating agency downgrades

Rating agencies are downgrading hitherto fast-growing independent power companies, or requiring them to reduce their leverage to maintain a given rating. Among the agencies' concerns in the current market environment are the exposure of these companies' merchant plants to fluctuating fuel and electricity prices, and the companies' reduced access to equity capital. Having been criticised for not downgrading Enron soon enough, the rating agencies are particularly sensitive about the energy and power sector. In the context of these volumes, however, it is important to remember that the fast-growing power companies using innovative revolving credits to finance the construction of new power plants are single sponsors with fully disclosed on-balance-sheet debt. Even though the collapse of Enron is one of the factors that have discouraged banks from increasing their industry exposure, most of the restrictions that the markets are placing on the growth of independent power companies are related to the market factors discussed above, all of which were evident before the Enron bankruptcy.

Like lenders and investors, companies that trade with each other are becoming more concerned about counterparty credit risk. In evaluating the creditworthiness of a given counterparty, they are looking at the whole portfolio to see if — diversification benefits aside — one risky business, such as merchant power or energy trading, could drag the others down. For example, a company with primarily merchant plants in its portfolio is more vulnerable to overbuilt power plant capacity than is a company with mainly power purchase agreements.

Sources of free cash flow

William H. Chew, Managing Director of Corporate & Government Ratings at Standard & Poor's, recalls that immediately after Enron filed for bankruptcy protection some questioned whether project and structured finance would survive in their current form. Indeed, some corporations with large amounts of off-balance-sheet financing and inadequate disclosure were subjected to increased scrutiny, and sustained sharply reduced valuations for both their equity and debt. In response such companies expanded their liquidity and reduced their debt to the minimum possible. Chew however, believes that, as time passes, the main fallout of the Enron bankruptcy and other recent market shocks may not be a turning away from project finance, but rather a greater stress on bottom-up evaluation of how companies generate recurring free cash flow and what might affect that cash flow over time. Chew believes that in this process project, as well as structured, finance will probably continue to play an important role. The change, in his view, is that the focus will be not only on the project structures, but on how these structures may affect corporate-level cash flow and credit profiles. Examples of these effects might include springing guarantees and potential debt acceleration, calling on contingent indemnification and performance guarantees, negative pledges and their limits at both the project and the corporate holding company level, and the potential for joint-venture and partnership dissolution to create sudden changes in cash flows. S&P reminds us in its project as well as its corporate credit analysis that there can be a big difference between GAAP accounting and cash flow analysis.

Security interests

Feldman of Bingham McCutchen notes that the power business, in part, has shifted from a

contract business to a trading, cash-flow kind of business in which the counterparty becomes critical to the viability of a transaction. The security in the transaction is less the asset itself and more what the trading counterparty does with the asset. That asset has an option value in the hands of a counterparty, and a very different value if a bank has to foreclose on it — a value that the bank would rather not find out.

Enron's alleged tendency to set its own rules for marking gas, electricity and various newer, thinly-traded derivative contracts to market raises some interesting questions about collateral and security, in Feldman's opinion. Historically, the security in a power plant financing has consisted of contracts, counterparty arrangements and assets. However, if a lender's security depends on marking certain contracts to market and there is some question as to the objectivity of the counterparty that is marking them to market, additional questions are raised. For example, what is an adequate sale, what is adequate collateral, how does a lender take an adequate security interest, how does a lender monitor the value of its security interest, and what does a lender need to do to establish a sufficient prior lien in the cash flow associated with the transaction? Feldman believes that in the case of a structured finance transaction, the key question remains the same: is the security real and can lenders get their hands on it?

How companies have responded

Worenklein of Société Générale has seen affected companies respond rapidly and decisively to the current market environment, strengthening their liquidity by issuing new equity, cancelling projects, selling assets, unwinding structured finance deals or putting them on the balance sheet, and increasing transparency and disclosure (further discussed below).

Even though traditional project finance has little to do with the off-balance-sheet entities that brought Enron down, Barajas of Milbank Tweed fears a backlash that could affect project finance in the event of a credit crunch. If that happens, one possible solution could be simply to finance more projects on the corporate balance sheet. Some power companies have set up massive credit facilities for doing just that on the basis of their overall corporate cash flow and creditworthiness. Another option for a company is to borrow against a basket of power projects, allowing the lenders to diversify their risks. Such a facility, however, is still largely based on the credit fundamentals of the corporation. Barajas believes that project financing on an individual-plant basis may be preferable to either of these approaches, for both project sponsors and lenders. For example, say a company is financing ten projects and three of them run into trouble. The company can make a rational economic decision as to which of these projects are salvageable and which do not merit throwing good money after bad. The company might let one go into foreclosure, to be restructured and sold. If a company is financing ten projects together, however, its management may feel compelled to artificially bolster some of its other projects so that the failure of one does not bring the entire credit facility down. Making such an uneconomic decision for the near term would not be in the company's long-term interests.

Increased transparency and disclosure

Worenklein reports that major players generally are releasing much more information about their businesses and financing arrangements than before. Similarly, Gold of

Salomon Smith Barney sees an overriding atmosphere of conservatism in disclosure — for example, in conference room discussions while drafting prospectuses for project finance deals. Bankers are making an extra effort to confirm that deals are being disclosed and explained the right way. Given the current tarnishing of the merchant power sector, bankers might explain that a company's trading is not speculative and that it is using accepted risk management measures such as value at risk (VaR). They also might break out the percentage of sales from power sales and from 'marketing' – a term that sounds better than trading in today's environment.

Worenklein believes that strong management actions are needed to restore belief in the honesty of numbers. A company's management needs to demonstrate the same passion for integrity as it has for growth in the past. It needs to get rid of gimmicks, and consistently communicate and execute a simple, clear strategic vision. This involves cleaning up the balance sheet by putting transactions that have significant recourse to the sponsor back onto it. Only true non-recourse deals should be left off the balance sheet. To convey an accurate, fair picture of the business, companies need to communicate — to the point of obsession — information and assumptions about how earnings, including mark-to-market transactions, are recognised. In Worenklein's view, managing earnings is out and managing cash flow is in, and, as Chew notes above, that is what the rating agencies are looking at.

Some of the measures that Worenklein recommends go beyond financial reporting. Companies may need to re-examine their strengths and weaknesses, and refocus and simplify their basic business strategies. As companies implement the US Sarbanes–Oxley Act of 2002 their boards of directors and audit committees might become more helpful in this process with the addition of non-executive members who understand the business. (The corporate governance reforms in Sarbanes–Oxley apply not only to US companies but to other companies that list their securities on US exchanges.) For companies with low stock prices, it is too late to panic, so Worenklein recommends looking at the bright side. Now might be the time to fix the business, clean up earnings, take losses and rebalance. Unfortunately, now is not the greatest time to clean out the attic and sell non-strategic assets, because there are more sellers than buyers. However, the key, in Worenklein's view, is to be patient and thoughtful about prospective buyers, including, in some markets, local buyers that can see the greatest value in such assets.

Lessons learned from Enron

A great deal has been written about the Enron debacle, but we are not yet far enough away from the event to give proper weight to the various lessons to be learned, according to James F. Guidera, Senior Vice President and Head of Project Finance at Credit Lyonnais Americas. Nonetheless, Guidera sees some general lessons that can be learned from Enron that go beyond the realm of structured and project finance, and others that are more particular to project and structured finance. The following are among the more general lessons.

- It is risky to over-invest in business sectors such as broadband or water.
- A power trading business, though potentially profitable, is highly vulnerable to liquidity crises and has a low liquidation value.
- Trading to hedge a power company's inherent physical position in power or gas should

not be regarded as a suspect business *per se*, but it can involve the risk of sudden liquidity crises – especially for companies rated ‘BBB–’ that don’t want to slip below investment-grade status.

- Mark-to-market accounting rules can mislead investors, lenders and analysts about the extent of non-recurring earnings, even in the absence of fraud.

Among the lessons more directly related to project and structured finance, Guidera identifies the following.

- The transfer of assets, intangible and otherwise, into non-consolidating vehicles controlled by a sponsor may mislead investors as to the extent of non-recurring earnings or deferred losses, even in the absence of fraud.
- There is a risk of low recovery rates on structured transactions secured by intangible assets (such as investments, contracts and company stock) or by tangible assets whose values are not established on an arm’s-length basis.
- Having been badly burned by the Enron bankruptcy, banks and investors in Enron’s structured and project financings, and in the energy sector generally, will be especially conservative, limiting credit and capital access for many clients in the sector, and creating a general liquidity issue for these customers.

Christopher Dymond, Director of Taylor-DeJongh, a boutique investment bank based in Washington, DC, that specialises in project finance, has several recommendations concerning accounting treatment and disclosure.

- An effort must be made by all in the project finance industry and investor relations to underscore the distinction between true non-recourse structures and Enron’s activities.
- The terms ‘non-recourse’ and ‘off balance sheet’ should remain synonyms. Liabilities that truly have no recourse to a company’s shareholders can justly be treated as off the balance sheet. Enron appears to have violated this principle because the undisclosed liabilities in the off-balance-sheet partnerships actually had significant recourse to Enron shareholders through share-remarketing mechanisms.
- Many project finance structures are ‘limited’ rather than ‘non-’ recourse, and thus there is potentially a grey area in which accounting rules allow off-balance-sheet treatment, but there is nonetheless some contingent liability to the parent company’s shareholders. Full footnote disclosure of any potential shareholder recourse was advisable before Enron and is absolutely necessary now.

John W. Kunkle, Vice President at Fitch Ratings, reminds us of two basic tenets of project finance:

- the financing of hard assets has ongoing value through economic cycles; and
- high levels of sponsor expertise and commitment are required.

Kunkle observes that as Enron grew and expanded it seemed more interested in whether or not businesses or transactions would generate a certain return than if ventures would complement its existing core businesses. Enron invested in a number of businesses in which it did

not have the required expertise and was not particularly committed to those businesses when expectations were not met.

Common themes

As mentioned above, the project case studies in these volumes were selected to exhibit the types of projects most frequently financed in a variety of countries. As a result, common themes can be identified across the two volumes. Some of these are summarised below.

Infrastructure requirements

Power shortages motivated the privatisation of the electricity sector in China, Colombia, Côte d'Ivoire, India, Indonesia, Mexico and the Philippines, and led to commercial project financing of power projects in these countries.

Legal and regulatory

First-of-their-kind projects in developing countries typically introduce new legal concepts. In China, India, Indonesia, Mexico and the Philippines inadequate existing legal and regulatory frameworks meant that negotiating contracts according to international standards for each country's first IPP required both the introduction of legal issues, contract structures and financial concepts new to each country, and lengthy negotiations with government officials. A similar process was evident in contract and financing negotiations for Greece's first build-operate-transfer (BOT) toll road and Uruguay's first cellular telephone system (see *Volume II – Resources and Infrastructure*). Lack of coordination among government agencies and weak provisions in privatisation statutes has created problems for the SCL Terminal Aéreo Santiago project in Chile (see *Volume II – Resources and Infrastructure*). Project negotiations highlighted the need for concession contract law in Côte d'Ivoire (see Chapter 4) and for mining law in Tanzania (see *Volume II – Resources and Infrastructure*).

The availability of international arbitration was an issue in many project contract negotiations, including those for power projects such as Meizhou Wan in China (see Chapter 2), Azito in Côte d'Ivoire (see Chapter 4), Dabhol in India (see Chapter 5) and Paiton I in Indonesia (see Chapter 6). International arbitration was used, but largely failed, with Dabhol and Paiton I.

The refusal of host governments to honour contracts and guarantees is highlighted in the Dabhol (India) and Paiton I (Indonesia) case studies.

Credit risk

Political risk insurance is a necessity for project financing in most emerging markets. It was required to attract lenders to the Azito (Côte d'Ivoire) and CBK (Philippines) power projects (see Chapters 4 and 10) and the three Tanzanian gold mine project loans (see *Volume II – Resources and Infrastructure*). The CBK power and Geita gold mine (Tanzania) projects highlight the growing use of private political risk insurance.

The International Finance Corporation's A/B loans, which provide private commercial

banks the comfort of lending alongside a multilateral agency with so-called ‘preferred creditor’ status, were part of the financing for the Azito (Côte d’Ivoire) and Chad-Cameroon Pipeline projects (see *Volume II – Resources and Infrastructure*).

IPPs’ increasing assumption of merchant power risk and requirement to manage their spark spreads are important issues in the Mexican power projects (see Chapters 7, 8 and 9), where PPAs and fuel supply contracts are being delinked; the Panda–TECO projects (see Chapter 13), the two largest merchant power plants in the United States; and the Drax power plant in the United Kingdom (see Chapter 12), where the termination of a hedging contract, combined with high leverage and debt-service obligations, has led to debt restructuring.

Although capital-markets financing in the past had not been possible for emerging-market projects before construction, bonds were issued in 1995 for the Transgas pipeline project in Colombia (see *Volume II – Resources and Infrastructure*) and a flexible commercial bank/capital markets financing was arranged in 1997 for the TermoEmcali power plant, also in Colombia (see Chapter 3), before construction began. Market conditions have changed since then and pre-construction financing would not be available today for similar projects in Colombia or in many other emerging-market countries.

Because their exports generate hard currency captured in offshore accounts, credit ratings for the Mega project in Argentina and the Petrozuata project in Venezuela pierce their respective sovereign credit rating ceilings. Fitch maintained the credit rating for Ocesa, the Colombian oil pipeline, above its sovereign ceiling because lenders have access to the oil as collateral if transport fees are not paid. See *Volume II – Resources and Infrastructure* for case studies on these projects.

Social and environmental

The need for local government and community support, and the implementation of sustainable development programmes, are discussed in the Quezon Power (Philippines) case study in Chapter 11, and the Chad–Cameroon pipeline and Tanzanian gold mines case studies in *Volume II – Resources and Infrastructure*.

Strategic

The Enron bankruptcy has resulted in more intensive investor and lender scrutiny of power companies with trading operations, international networks and difficult-to-understand financial statements. Calpine and AES, owner of the Drax power plant in the UK, have scaled down their capital expenditure programmes, sold assets and reduced their leverage (see Chapter 14). After TXU, a diversified energy company based in Dallas, Texas, decided to withdraw support for its European operations, which are now in administration (bankruptcy), a British TXU subsidiary’s fixed-price contract to purchase 60 per cent of Drax’s power output was cancelled. Aquila, soon to be replaced as a risk manager for the Panda–TECO project (see Chapter 13), is discontinuing its energy trading operations and returning to its roots as a Midwestern US utility.

Reasons for financial difficulty

Among the 38 projects studies, 11 have defaulted, come close to default or encountered some

degree of financial difficulty. The reasons for financial difficulty fall into eight categories. Exhibit E lists these categories and shows the number of projects in each. For many of the projects, there were several reasons for financial difficulty.

By far the most frequent cause of financial difficulty was market risk, which relates to passenger traffic, vehicle traffic or customers' capital expenditures not meeting projections; a decline in power or commodity prices to uneconomic levels; and financial market conditions that made refinancing difficult. Currency risk was evident in four infrastructure projects that generated local-currency revenues but had to service US dollar-denominated debt. Counterparty risk was evident in the case of three power project off-takers and one bank issuer of a standby letter of credit. High leverage was a problem with three projects; in two of these cases the sponsors took on high debt to acquire the projects for prices that some observers considered excessive. The need for political risk insurance to attract lenders to developing countries is evident in many of the case studies. For two of the projects political risk materialised when government entities refused to honour contract obligations. For another a deteriorating political situation was the primary cause of a depressed economy. Construction and operating risks are apparent in the financing of most projects, but measures to protect against them are usually successful. Each of these risks materialised in just a single case study.

The reasons for financial difficulty in 11 of the case studies are summarised below.

Exhibit E

Reasons for financial difficulty

| <i>Cause of difficulty</i> | <i>Number of projects</i> |
|----------------------------|---------------------------|
| Market risk event | 8 |
| Counterparty risk event | 4 |
| Currency risk event | 4 |
| High leverage | 3 |
| Political risk event | 3 |
| High purchase price | 2 |
| Construction risk event | 1 |
| Operating risk event | 1 |

Market risk

Vehicle traffic for the PYCSA toll road in Panama did not meet the projections made at the time of the project financing. Similarly, air passenger traffic through the Arturo Merino Benitez International Airport in Santiago, Chile, did not meet projections made by the airport concessionaire, SCL Terminal Aéreo Santiago, at the time of the project financing. See *Volume II – Resources and Infrastructure* for more on these projects.

Market risk, high leverage, high purchase price

Among others, Ofgem, the UK power industry regulator, warned that electricity prices would decline when the New Electricity Trading Arrangements (NETA) were implemented. Despite these warnings international power companies such as AES continued to pay high prices for assets such as Drax. The effects of NETA on the Drax power plant in the United Kingdom were underestimated. After a fixed-price contract for 60 per cent of its output was cancelled Drax faced the prospect of operating on a merchant basis with a heavy debt load in an unfavourable electricity-price environment. When default on its debt became inevitable Drax entered into restructuring negotiations with its bondholders and lenders. As a high-growth, high-leverage company Drax's parent AES was vulnerable to the combina-

tion of a worldwide drop in wholesale electricity prices, economic collapse in Argentina and the ripple effects of the Enron bankruptcy. AES recently has implemented its own restructuring to avoid bankruptcy. See Chapter 12 for more information on the Drax power plant and AES's restructuring plan.

Market risk, political risk

The Maharashtra State Electricity Board cancelled the PPA for the Dabhol power project in India (see Chapter 5) because it could not afford to pay the tariff and there was an oversupply of power in the state. Regulations prevented the plant from selling electricity to other states that needed it. Both the federal and the state government dishonoured their guarantee obligations.

Market risk, counterparty risk, currency risk, political risk

Perusahaan Listrik Negara (PLN), the Indonesian state-owned utility, refused to make US dollar-indexed payments for electricity to Paiton Energy after the value of the Indonesian rupiah plunged during the Asian financial crisis (see Chapter 6). PLN and Paiton reached an interim agreement in 2000 that allowed the utility to purchase power at reduced rates. The original 1994 PPA was amended in 2002.

Counterparty risk, political risk

In May 2002 the Fujian provincial government reportedly reneged on its obligations under its PPA with the Meizhou Wan power project (see Chapter 2) and proposed that the tariff be reduced. After prolonged negotiations with the provincial government the project sponsors were reportedly trying to replace the project's US dollar-denominated loans with local-currency financing because the reduced revenues proposed by the provincial government would not be sufficient to service the original project financing provided by the foreign bank consortium and the Asian Development Bank.

Market risk, currency risk, political risk, high purchase price

BCP paid US\$2.5 billion, an unexpectedly high price, for its cellular telephone licence in São Paulo, Brazil, and financed it with a high level of debt. Although operating performance, and earnings before interest, taxes, depreciation and amortisation (EBITDA), exceeded its business plan, BCP had difficulty rolling over its local-currency paper every two years and servicing its US dollar-denominated debt as the value of the Brazilian real declined. Debt restructuring was impeded by a disagreement between two deadlocked 47-per-cent shareholders.

Market risk, high leverage

FLAG was able to repay its original project debt, but then continually borrowed and reinvested to expand its undersea cable network, and could not service its debt after a worldwide drop-off in spending by major telecom carriers. The company declared bankruptcy in

early 2002 and then re-emerged six months later (see *Volume II – Resources and Infrastructure*).

Market risk, operating risk

The Andacollo gold mine in Chile was closed earlier than projected and its parent, Dayton Mining, merged because of higher-than-expected production costs and lower-than-expected gold prices (see *Volume II – Resources and Infrastructure*).

Counterparty risk, political risk

TermoEmcali, a natural-gas-fired power plant that serves Cali, Colombia's second largest city, has been a successful project aside from a minor construction delay. Its problems stem from the financial difficulty of Emcali, its sole offtaker, which relates to a weak underlying economy and financial mismanagement (see Chapter 3).

Counterparty risk, construction risk

The Casecanan Water & Energy project in the Philippines is viable under the ownership of MidAmerican Energy Holdings despite a construction delay, but its original engineering, procurement and construction (EPC) contract contractor defaulted, and Korea First Bank refused to honour its standby letter of credit backing the contractor's obligations. The bank finally paid MidAmerican after a prolonged legal battle in US courts (see Chapter 15).

Lessons learned

The case studies in *Volume I – Power and Water* and *Volume II – Resources and Infrastructure* allow for the identification of certain lessons that may benefit future sponsors and investors of project financing. Among the lessons learned from the 38 case studies in these volumes are the following.

Negotiating process

Brandon Blaylock of the GE Capital Services Structured Finance Group believes that project participants in emerging-market projects must be prepared to both learn and teach. A successful project requires close teamwork among all project participants, and sensitivity to each other's issues and needs. As those involved in concurrent IPP ventures in other developing countries would agree, financing takes longer than expected in any first-of-its-kind project, especially when there are difficult risk-allocation issues. Often the process is just as important as the substance.

Local community sensitivity and sustainable development programmes

The success of the Chad–Cameroon pipeline project (see *Volume II – Resources and Infrastructure*), the Quezon Power project in the Philippines (see Chapter 11), and the Tanzanian gold mine projects (see *Volume II – Resources and Infrastructure*) depended part-

ly on sensitivity to local community concerns, as they provided local communities with needed infrastructure improvements and other resources in return for dislocations and other inconveniences related to the projects, and on implementing environmentally sensitive, sustainable development programmes.

Banks with local branch presence

ABN AMRO, in the Ancel cellular-telephone project in Uruguay, and Barclays, in the Tanzanian gold mine projects, benefited from local branch presence, the ability to deal in local currency and contact with local government officials at all levels. See *Volume II – Resources and Infrastructure* for more on these projects.

Government and legal system

Laibin B's high visibility as a pilot for future BOT projects in China helped the often-cumbersome multi-agency government approval process (see Chapter 1). Multiple letters of support at the central government level and the local need for power are helpful factors that reduce project risk at a time when governments are reluctant to issue guarantees. However, recent experience in India and Indonesia shows that support letters and even guarantees can be unreliable.

Foreseeing a trend towards less government support in the future, the sponsors of the Meizhou Wan power project demonstrated that true limited-recourse project financing could be achieved outside the BOT scheme in China (see Chapter 2).

Among the critical factors behind the success of the Azito project financing in Côte d'Ivoire (see Chapter 4) were the government's acknowledgment of the need for concession laws; the financial, managerial and negotiating skills of the government team; and the government's clear notions concerning the role of private participants and social goals such as rural electrification as a result of its recent work in power sector reform. The lack of concession law and a government template for infrastructure financing contributed to the length of negotiations and the complexity of documentation for the Athens Ring Road project in Greece (see *Volume II – Resources and Infrastructure*).

Role of government, market and construction risk

The case study of Highway 407 (see *Volume II – Resources and Infrastructure*) in the Greater Toronto area describes how the government assumed environmental, technology, construction and traffic risks to build the first 69-kilometre section of a 108-kilometre toll road. After these risks had been significantly reduced a private firm was best equipped to manage and develop the road's future growth. Amid controversy the privatisation process was facilitated by the Ontario government's consistent and unwavering commitment to carry it through, and the sale of the road was facilitated by a clean, clear and transparent bidding process.

Financing of the A2 motorway in Poland, a country with virtually no toll-road experience, was made possible by a strong mandate from the government, a government guarantee of 40 per cent of the debt, a strong commitment from the European Investment Bank and concessions by all the major parties, including senior lenders that accepted a flexible repayment

schedule, and sponsors that increased their equity participation and provided a contingent equity facility (see *Volume II – Resources and Infrastructure*).

Role of multilaterals

The case study on the Chad–Cameroon pipeline project demonstrates that project sponsors wishing to involve the World Bank Group in future projects may have to accept some degree of monitoring to ensure that they meet their environmental commitments and that project revenues are directed as planned (see *Volume II – Resources and Infrastructure*). By the same token, an organisation of the World Bank’s stature was required to make a convincing statement that the environmental and social concerns of other special-interest groups would be addressed in a responsible manner.

Commercial bank versus capital market financing

The TermoEmcali power project in Colombia (see Chapter 3) demonstrated that it is efficient to provide a bond issue and a standby commercial loan facility from the same financial institution, with flexibility between bank and capital-market debt depending on market conditions. Common terms between commercial lenders and bondholders, as defined in the Common Security Agreement for the Petrozuata financing in Venezuela (see *Volume II – Resources and Infrastructure*), provided the flexibility to adjust the respective amounts of bank and bond financing depending on market conditions.

Construction risk

The Transgas (see *Volume II – Resources and Infrastructure*) and TermoEmcali (see Chapter 3) projects in Colombia showed that infrastructure projects, such as power plants and pipelines, that generate local revenues in a developing countries can be financed ‘out of the box’ (prior to construction) under the right circumstances. However, these circumstances have changed considerably since the project financing of these projects was done in 1997, particularly in Colombia, where the economic and political situation has deteriorated considerably.

Based on his experience in lending to three gold mining projects in Tanzania (see *Volume II – Resources and Infrastructure*), Milo Carver of Barclays Capital concludes that lenders need to be assured that sponsors are not relieved of their pre-completion support undertakings before a project has passed meaningful completion tests. Such projects require documented tests covering categories such as operating performance, environmental management, cost control and budgeting.

The EPC contractors were recognised as weak links at the time of the Casecan Water & Energy project financing. EPC contractors often do not fail, standby letters of credit often are not called upon and, when they are, they are often dishonoured by their opening parties. Casecan Water & Energy reminds us that these risks do materialise from time to time.

Counterparty risk

The Maharashtra State Electricity Board’s failure to honour its obligations under its PPA with

the Dabhol power project in India (see Chapter 5). PLN's refusal to pay under its PPA with Paiton Energy in Indonesia (see Chapter 6) and the Fujian (China) provincial government's disavowal of its PPA obligations related to the Meizhou Wan project (see Chapter 2) showed that contract parties – even when they are government organisations – do not honour their contractual obligations when it is beyond their economic ability, or not in their economic interest, to do so. The unwillingness of the Indian federal and state governments to make policy changes that would allow Dabhol to sell electricity to out-of-state entities illustrates a painful principle of project restructuring: preventative restructuring is rare. Contract parties usually do not make concessions until there is a crisis.¹³

The Paiton Energy case study shows that contracts are of diminished value when a project participant can no longer afford to abide by their terms. Nonetheless, the PPA provided a framework and set the boundaries for several years of negotiations. The strength of the agreement, and the likelihood of litigation and arbitration ultimately favouring Paiton Energy, were important restraints on the government-owned utility and power off-taker.

Political risk

The TermoEmcali case study (see Chapter 3) shows that in a developing country such as Colombia the political and economic situation, as well as the credit-worthiness of the off-taker, can change considerably in just a few years, not to mention over the term of a PPA or a bond.

By not honouring their guarantee and counter-guarantee obligations the governments of India and Maharashtra undermined the foundation of the Dabhol power project. Such political decisions could be considered creeping forms of expropriation. International arbitration was relatively ineffective for both projects.

Persistence, including consistent, steadfast denial of corruption charges and willingness to explore alternatives such as extending the term of the contract and building new power capacity, helped the sponsors of Paiton Energy to salvage a difficult situation.

An International Development Agency partial risk guarantee for the Azito power project (see Chapter 4) was critical in attracting lenders to Côte d'Ivoire, which was not yet an established international borrower. With respect to the Golden Pride, Bulyanhulu and Geita gold mining projects (see *Volume II – Resources and Infrastructure*), Carver of Barclays comments that the maximum size of a deal in a country such as Tanzania is driven by how comfortable the bank and insurance markets are with the political risks.

Market risk

For a project such as the El Abra copper mine in Chile, which depends on commodity prices, lenders must know where prices are in relation to long-term cycles. The Andacollo gold mine in Chile showed that mining projects are subject to the risk of falling commodity prices and the risk that, despite the results of expert feasibility studies, ore grades and production costs will not meet expectations. (See *Volume II – Resources and Infrastructure* for case studies on these projects.)

Carver of Barclays observes that gold price hedging has been a one-way bet during a long period of falling gold prices. Through hedging gold projects consistently have been able to sell at above-market prices. If the gold market were to reverse and enter into a long-term price upswing, Carver wonders whether gold producers would maintain their appetite for hedging.

The leverage of the Drax power plant in the United Kingdom (see Chapter 12) was too high to withstand the deterioration of wholesale electricity prices and the related upheaval in the UK electricity market. The effect of the NETA on wholesale electricity prices was greatly underestimated.

Lower-than-expected power demand in one market served by the Panda Energy–TECO Power joint venture (see Chapter 13), combined with lagging development of transmission facilities in another, highlights the risk of merchant power when combined with high leverage. A few credit problems with prominent merchant power players, combined with scepticism concerning the purpose and benefits of electricity deregulation, could begin to push power companies back toward the traditional integrated-utility business model.

The financial difficulty of the PYCSA toll road project in Panama (see *Volume II – Resources and Infrastructure*) shows that the rate of growth in the use of a new toll road is difficult to predict. It is easy to be unrealistically optimistic when estimating how rapidly people will change their habits, especially when tolls are relatively high considering the average personal income in the area. Given these risks and Poland's lack of experience with toll roads, financing of the A2 Motorway (see *Volume II – Resources and Infrastructure*) required significant government and multilateral agency support, as mentioned above.

Currency and financial market risk

Financial problems with the BCP cellular telephone project in São Paulo, Brazil (see *Volume II – Resources and Infrastructure*), remind us that, given currency volatility, it is difficult for a project generating revenues in a domestic currency to depend on US dollar debt. On the other hand, the project required financing with longer terms than were available in the Brazilian market and therefore faced constant risks related to the rolling over of most of its debt every two years.

High leverage

Unexpectedly high purchase prices financed with high leverage accentuated problems with the Drax power plant in the United Kingdom (see Chapter 12) and the BCP cellular telephone project in Brazil (see *Volume II – Resources and Infrastructure*). For the FLAG under-sea cable project, aggressive network expansion financed with high leverage may have been a viable strategy while internet use, telecommunications traffic and related capital spending were growing rapidly, but FLAG did not have sufficient cash flow to service its debt when the telecommunications market collapsed (see *Volume II – Resources and Infrastructure*).

¹ Nevitt, Peter K., and Frank J. Fabozzi, 'Checklist for a successful project financing', *Project Financing Seventh Edition*, London, Euromoney Books, 2000, p 3.

² Percopo, Bob, and Peter J. Haller, 'Insurance Solutions for Project Finance', *The Journal of Project Finance*, Summer 1999, p. 23.

³ Marti, Stephan, and Lowell Keith, 'Cash Flow Volatility as Opportunity: Adding Sophisticated Insurance Capital to the Project Finance Mix', *The Journal of Project Finance*, Fall 2000, p. 9.

⁴ Moreland, Ron, and Bruce Wineman, 'Insuring Projects After September 11', *The Journal of Structured and Project Finance*, Spring 2002, p. 5.

- ⁵ Hsiao, Henry, 'The Use of Financial Guarantees and Contingent Capital in Project Finance', *The Journal of Project Finance*, Spring 2001, p. 19.
- ⁶ West, Gerald T., 'Political Risk Investment Insurance: A Renaissance', *The Journal of Project Finance*, Summer 1999, p. 5.
- ⁷ Beale, Chris, Michel Chatain, Nathan Fox, Sandra Bell, James Berner, Robert Preminger and Jan Prins, 'Credit Attributes of Project Finance', *The Journal of Structured and Project Finance*, Fall 2002, p. 5.
- ⁸ Standard & Poor's, 'Refinancing of Over \$90 Billion Medium-term Debt May Strain Power Sector and Associated Banks', 6 November 2002.
- ⁹ Sheppard, Robert, 'Why Energy Trading Will Decline in the U.S. Electricity Market', *Project Finance International*, 2 October 2002, p. 56.
- ¹⁰ McCartney, Eric, 'The Transmission Buzz – A Financing Paradox', *Project Finance International*, 2 October 2002, p. 62.
- ¹¹ Brown, Ken, Anthony Damiano, Brian Jenkins and Michelle Tisdale, 'Congestion Pricing: New Risks for Lenders', *The Journal of Project Finance*, Winter 2001, p. 21.
- ¹² McCartney, Eric, op. cit, p. 63.
- ¹³ Joshi, Piyush, 'Dabhol: A Case Study of Restructuring Infrastructure Projects', *Journal of Structured and Project Finance*, Spring 2002, p. 28.

Laibin B, China

Type of project

2 x 350 MW, coal-fired power plant.

Country

People's Republic of China (PRC).

Distinctive features

- First project in China open to international bidding.
- First Chinese infrastructure project financed entirely with foreign capital.
- First Chinese infrastructure project to be developed by a wholly foreign-owned project company under a BOT framework.
- First BOT project to be formally approved at the state level by the State Planning Commission (SPC).¹
- Documentation serves as a model for future BOT power projects in China.
- French ECA Coface took project risk for only second time in its history.

Description of financing

The The US\$616 million project cost was financed in 1997 with US\$154 million equity from the project sponsors and US\$462 million in debt facilities. These debt facilities consisted of:

- US\$303 million commercial bank loan backed by Coface at 135 basis points (bps) over the London interbank offered rate (Libor) pre-completion and 75 bps over Libor post-completion, with participation fees of 45 bps for lead managers taking US\$35 million or more and 30 bps for managers taking from US\$25 million to US\$34.9 million;
- US\$159 million uncovered commercial bank tranche, with fees of 80 bps for lead managers lending US\$35 million or more and 65 bps for managers committing US\$25 million to US\$34 million; and
- US\$100 million standby financing consisting of US\$60 million equity commitment from sponsors and US\$40 million debt commitment from commercial banks.

Introduction

This dual case study (in this chapter and the next) is a comparison of Laibin B and Meizhou Wan, the first two wholly foreign-owned power projects in China. Laibin B was intended to provide a template for future build-operate-transfer (BOT) projects. Meizhou Wan was financed without implied government support, completely outside the BOT framework.

The first BOT power project in China, and indeed in Asia, was the Shajiao B plant in Guangdong Province. Despite the province's success with this BOT project, the central government became concerned that developers would have opportunities to make excessive profits when BOT projects were competitively bid, based on the price of power, and the government had no other financial controls over such projects.

Laibin B was the first pilot project under a new legal and regulatory infrastructure to support BOT projects; its structure was intended to become the blueprint for future BOT projects. Two key innovations of this project were that the concession was awarded in a competitive bidding process and that the project was 100 per cent foreign-owned.

Meizhou Wan, financed during the depth of the Asian currency crisis, was China's first wholly foreign-owned power project successfully financed outside the state-sponsored BOT programme. Not being bound by the BOT programme, the sponsors had more freedom to design project arrangements and a financing package tailored to the project. However, without the benefit of the BOT programme to fast-track approvals, they had to obtain approvals one by one from various authorities in state and provincial governments. The project sets an important precedent for project financing in China because the government may not continue to provide the benefits seen in prior BOT projects.

Project summary²

The project involved the financing, design, construction, procurement, operation, maintenance and transfer of a 2 x 360 MW coal-fired power plant located in Laibin County in the Guangxi Zhuang Autonomous Region (Guangxi Province). The project, costing US\$616 million, is entirely foreign-owned and foreign-financed. Construction began in September 1997 and was expected to be completed in three years. The Concession Agreement called for the project to be transferred to the Guangxi autonomous regional government after 15 years of commercial operation by the two project sponsors. Guangxi, on the Vietnam border, is one of China's poorer provinces and therefore the credit risk of the Guangxi Power Industry Bureau (GPB) was an issue. Also, at the time there had been little foreign investment in the area and the Guangxi provincial government had no exposure to the international syndicated loan market.

The project company is a wholly foreign-owned enterprise incorporated in China. It is 60 per cent owned by Électricité de France International (EDFI) and 40 per cent owned by Alstom, formerly GEC Alsthom. EDFI is a wholly owned subsidiary of Électricité de France (EDF), which is 100 per cent owned by the French government. GEC Alsthom was jointly owned by General Electric Company plc of the United Kingdom and Alcatel Alsthom of France until its initial public offering in 1998, when it was renamed Alstom.

The Construction Services Contractor was a special-purpose joint venture between Alstom Export Compagnie Financière de Valorisation pour L'Ingénierie.

The Equipment Supplier was a consortium comprised of GEC Alsthom Centrales Energetiques SA and EDF, acting through its division CNET.

The Operator is an 85 per cent owned subsidiary of EDFI, with the balance of ownership held equally by the GPIB, the power purchasing entity of the Guangxi government, and the Guangxi Investment and Development Company, Ltd.

Background

The need for power

In recent years the PRC has enjoyed one of the fastest growing economies in the world, with annual GDP growth averaging 12 to 14 per cent and a need to build new power-generating capacity at a similar rate. In the mid-1990s China ranked fourth in the world in installed generating capacity but 80th in per-capita energy consumption. About 120 million rural residents had no access to electricity.³ Consequently, the country planned to put 35,000 megawatts of new, independently produced power capacity in place by the turn of the century.

Power plant financing

Prior to the 1990s the majority of power plants in China were domestically owned and operated, using local technology and equipment. Direct foreign investment was rare and mostly through joint venture agreements, with projects awarded on a negotiated rather than a competitive-bidding basis; the sale of foreign technology to Chinese power plants was more common.⁴ Between 1979 and 1996 about 10 per cent of investment in the local power sector came from foreign sources such as foreign direct investment, foreign indirect investment and soft loans.⁵

Shajiao B: the first BOT project

The first BOT power project in China, and indeed in Asia, was the 2 x 350 MW Shajiao B plant in Guangdong Province, located in an economically strong region near Hong Kong. This project was negotiated and implemented at the provincial level. It was a joint venture of Hopewell Holdings Limited (Hong Kong) and the Shenzhen Special Economic Zone Power Development Company of China. The plant was constructed between 1984 and 1987 by Consolidated Electric Power Asia (CEPA), a subsidiary of Hopewell Holdings. Hopewell is an investment, construction and engineering conglomerate controlled by Gordon Wu, who is considered one of the power industry's pioneers in Asia. Hopewell raised funds for the project, constructed it in 33 months, operated it for 10 years and then transferred it to the Chinese co-sponsor. The project cost of US\$512 million was funded by a combination of shareholder equity, subordinated loans and debt financing. Most of the debt financing was in the form of a supplier credit from Japan arranged by Mitsui Corporation and backed by the Export Import Bank of Japan.

In an article in the *Journal of Structured and Project Finance* (Spring 2002; formerly the *Journal of Project Finance*), Lin Qiao, Shou Qing Wang, Robert L.K. Tiong and Tsang-Sing Chan cite the following reasons why the Shajiao project succeeded:

- the leadership of an entrepreneur;
- the participation of credible contractors;
- huge demand for electrical power in the project region;

- the willingness of the Chinese government to apply the BOT concept, as well as its strong support for the project;
- the application of a proven technology;
- a refinancing arrangement;
- an early completion bonus; and
- a guaranteed minimum purchase price.

Despite Guangdong Province's success with this project, the central government became concerned that developers would have opportunities to make excessive profits when BOT projects were competitively bid, based on the price of power, and the government had no other financial controls over such projects.

Soon afterwards numerous international independent power producers and other developers proposed additional power plants, but they were discouraged by the 12 to 15 per cent limit on a project's internal rate of return (IRR) imposed by the Ministry of Electric Power (MOEP). Wu directed his efforts toward Indonesia, the Philippines, India and Pakistan.⁶ At the same time, several Chinese power companies began to raise capital in world markets. Shandong Huaneng Power Development Company and its parent Huaneng International Power Development Company are both listed on the New York Stock Exchange.

New regulations

In March 1994 the Ministry of Power Industry (MOP) issued Interim Regulations for the Use of Foreign Investment for Power Project Construction, which set out guidelines for all types of foreign investment in Chinese power plants. The document stated that foreign investors were permitted to invest in the construction and operation of new power plants or in the expansion, upgrading or equity of existing plants. The foreign equity interest in existing plants generally was limited to 30 per cent, but foreign investors could apply to the SPC for approval to establish new, wholly foreign-owned and operated power plants. Although existing legislation set no limit on the term of joint ventures, the 1994 MOP guidelines limited the term of cooperation to 20 years for thermal power plants and 30 years for hydroelectric power plants. The guidelines stated that Chinese parties should retain a controlling stake in power projects with a total capacity of 600 megawatts or more.⁷

Development of BOT law

China had been slow to develop the legal and regulatory infrastructure to support complex project contracts and related financial documentation. When the Laibin B project contracts were being negotiated there was no BOT law. In 1996 the Chinese central government selected a group of road, bridge, water supply and power projects to implement the BOT scheme on a trial basis, in an attempt to attract more foreign capital for infrastructure projects. Laibin B was the first pilot project; its structure was intended to become the blueprint for future BOT projects. If the Laibin B project was successful, the Chinese government hoped that financing power projects would become easier than it had been in the past.⁸

Two key innovations of this project were that the concession was awarded in a competitive bidding process and that the project was 100 per cent foreign-owned. By initiating competitive bidding, the government shifted its emphasis to the price per megawatt of power and

moved away from negotiating over documentation details, trying to shave costs and limiting the project's rate of return. Under the new framework, however, project sponsors were concerned about the reliability of their revenue streams and their ability to raise tariffs. They were also concerned that western-style contractual arrangements might be more legally and financially complex than the Chinese regulatory framework could handle.⁹

Bid tender and award

In early 1995 the SPC commissioned Bridge of Trust Infrastructure Consulting Company, Ltd to conduct a feasibility study on implementing the Laibin B project on a BOT basis. Bridge of Trust was a private firm with substantial experience in government infrastructure projects. On behalf of the SPC, Bridge of Trust sent invitations to pre-qualify in the third quarter of 1995. Fourteen developers pre-qualified and six submitted bids in May 1996. The SPC formally awarded the project contract to the consortium of Électricité de France and GEC Alstom in November 1996. One of the important reasons that consortium won the bid was that it offered the lowest tariff (RMB0.4/kWh, less than US\$0.05/kWh) – close to the then-current electricity tariffs in large Chinese cities. The consortium was able to minimise its cost structure by acquiring turbines from a Chinese manufacturer rather than importing them.¹⁰

How the financing was arranged

When the SPC awarded the mandate to the sponsors, it required that the financing be structured within 12 months. Other recent power project negotiations had become bogged down and delayed. This time the SPC wanted to show what was possible in China and what it expected in the future. The financial closing occurred just two months after the target date.

All of the major documents are in both Chinese and English. Translation and checking one version against the other were slow and painstaking processes. Under the terms of the concession both versions have equal effect in law. An interesting though perhaps only hypothetical issue could be which law took precedence if both stood up in court, but opposing lawyers interpreted the two versions of the documents differently.¹¹

Government approvals and support

Because the Laibin B project was designated as the official pilot to set the benchmark for future BOT projects, it received strong support from the central government. The project was approved by the State Council, and the SPC and the MOP participated throughout the project development, tendering, bid evaluation and tendering process.

Although the SPC served as the ringleader, the project sponsors also needed to reach agreements with, and receive approvals from, the Ministry of Foreign Trade and Economic Cooperation (MOFTEC), the MOEP, the State Administration of Exchange Control (SAEC), the Tax Bureau, the Pricing Bureau, the Guangxi provincial government, the Guangxi MOFTEC, the Guangxi SAEC and the GPIB.¹²

To demonstrate the central government's commitment and to back up the Guangxi government, the SPC, the MOP and the SAEC each issued letters of support. However, the letters did not imply any form of direct central government guarantee.¹³ In 1995 the Chinese central government had adopted a policy of not issuing guarantees for projects.

The SPC's letter of support, issued in March 1997, was short but critically important. The main points in the letter were that:

- even though there was no BOT law in China, the contract documentation for Laibin B was legal;
- the project sponsors' contracts with the Guangxi provincial government were acceptable to the SPC in Beijing; and
- the central government assumed responsibility for the Laibin B project.

The SAEC had issued a letter in January 1996, stating that it would guarantee any investor's ability to convert renminbi to foreign exchange, and the MOEP issued a similar letter guaranteeing the investor's ability to convert the project company's dividends and remit them abroad. There was still some doubt as to investors' ability to convert and repatriate amounts beyond those required to service the project's debt.¹⁴ However, the Guangxi provincial government, in the Concession Agreement, also promised to assist the sponsors with conversion and remittance of renminbi-denominated funds to cover debt service, payment of dividends and repatriation of capital. It also assured the sponsors that they would be permitted to open US-dollar-denominated accounts in China and to transfer dollars from those accounts to other accounts outside China.

Risk analysis

In an article in the *Journal of Project Finance* (Winter 1999), Robert L.K. Tiong, Sjou Qing Wang, S.K. Ting and D. Ashley describe two risks – tariff adjustment and counterparty credit – as critical, alongside other normal risks to be expected for a project of this nature.

Tariff adjustment

The requirement that tariff increases be approved annually by the pricing bureau creates an element of uncertainty with regard to tariff adjustment and project economics. That risk was addressed in several ways in the Concession Agreement, the Power Purchase Agreement (PPA) and the SPC's support letter. The PPA and its tariff structure were approved by the SPC. The SPC controls the central pricing bureau and the Guangxi government controls the provincial pricing bureau. The SPC, in its support letter, affirms that it and the Guangxi government have approved the principles of the tariff structure, the payment mechanism and the tariff adjustment scheme. The Concession Agreement states that the central pricing bureau will simply verify the correct application of the pricing formula specified in the PPA and also defines the GPIB's obligation to pay the tariff as a commercial obligation.

Counterparty credit

The offtaker and the sole source of revenue for the project is the power bureau of one of the poorest provinces in China. This counterparty credit risk is mitigated by the Guangxi government's commitment for the project to succeed. The project is a key to alleviating a significant power shortage, which has been an impediment to economic growth. The Guangxi government's commitment has the support of both the SPC and the MOP. The SPC's support

letter affirms that the Concession Agreement, the PPA, and the Fuel Supply and Transportation Agreement (FSTA) comply with current laws and regulations, and that the Guangxi government has the authority to sign the Concession Agreement.

Dispatch constraint

Under the PPA the GPIB is committed to take or pay for a minimum net electricity output (MNEO) of 3.5 billion kilowatt hours per year, or about 63 per cent of the plant's output, which the sponsors estimate would be sufficient to service the project debt. In addition, in the PPA the GPIB commits itself not to discriminate against the power plant and to apply the principles of economic dispatch to the purchase of additional power from the plant.

Change in law

The Concession Agreement protects the project company against possible changes in law after the bid submission date (7 May 1996) in two ways:

- if the project company is prevented from fulfilling its obligations by a change in law, it is entitled to receive MNEO payments irrespective of its ability to supply electricity; and
- the project company is to be restored to its original economic position if a change in law subjects it to expenses over an agreed threshold.

Exchange rate and convertibility

Exchange rate risk is addressed mainly by the project company's ability to adjust the floating portion of the tariff, which is payable in renminbi but indexed to the US dollar, to reflect renminbi/dollar exchange rate fluctuations. The project sponsors bear the risk of the first 5 per cent movement from the base rate under the PPA. The foreign exchange conversion and remittance approval in the SAEC's support letter affirms that the project's foreign exchange requirements have been incorporated into the National Foreign Exchange Balancing Plan, and states that such approval will not be adversely affected by changes in laws and regulations.

Political risks

Political risks for the project were assumed primarily by the Guangxi government. They included expropriation, change in law, development approvals, provision of utilities, increase in taxes, termination of the concession or payment failure by the government, other adverse government actions and political *force majeure*.

Construction and completion risks

As with most projects of this nature, the project sponsors assumed the majority of construction and completion risks. They included cost overruns, increases in financing costs, construction delays and quality problems.

Market, revenue and fuel cost risks

The Guangxi government assumed basic market and revenue risks concerning power demand and transmission as they related to the minimum power output it contracted to purchase. The sponsors assumed risks related to power sales above that minimum.

Operating risks

While the project company and the Guangxi government shared some operating risks related to labour or a *force majeure* event, the project company bore most of the other operating risks related to operator ability, environmental damage, technology and prolonged downtime.

Principal contracts

The Laibin B project is underpinned by three major contracts: the Concession Agreement, the PPA and the FSTA.

Concession Agreement

The Concession Agreement is the overriding document that summarises the major rights and obligations of the project company and the Guangxi provincial government with respect to the concession. The Guangxi government is the counterparty to the consortium under the Concession Agreement, and the primary obligor under both the PPA and the FSTA. The Concession Agreement defines the concession period, which is to run 18 years, including the three-year construction period, from the financial closing date of 3 September 1997, when the contract documents were signed. During the concession period the consortium has the right to own and operate all of the project's assets, equipment and facilities, to mortgage them for the purpose of financing and to assign the right to operate them.

Power Purchase Agreement

The GPIB, the offtaker, agreed to buy about 63 per cent of the plant output based on 100 per cent of baseload factor. The sponsors estimated that a 63 per cent output level would be sufficient to service the project debt and thus saw an opportunity for profit on the sale of power beyond that minimum.

The project sponsors had good reason to expect strong demand for extra power capacity. First, Guangxi Province was short of power and demand was expected to increase about 13 per cent per year. Second, much of the Guangxi grid was based on hydropower, which was less effective during the dry season. As a coal-fired plant, Laibin B would provide year-round reliability.¹⁵

The PPA provided for a fixed tariff with pre-agreed annual adjustments. This contrasted with the Chinese government's previous approach to projects with foreign participation, in which it sought to limit developers' IRRs to about 15 per cent. The tariff is paid in renminbi. The sponsors assume foreign exchange risk for the first 5 per cent of the tariff, after which the tariff is adjusted to reflect depreciation of the Chinese currency against the dollar.

Fuel Supply and Transportation Agreement

Under the FSTA the Guangxi provincial government agreed to supply fuel to the project through its subsidiary, the Guangxi Construction and Fuel Corporation (GCFC). The project sponsors have the right to reject coal that does not conform with specifications in the agreement. The base price is fixed every year, but adjustments are made to the price of each delivery based on the quality of the coal, which must be within a defined range. The FSTA specifies the mines that will supply the coal and is backed by a comfort letter from GCFC assuring the sponsors of alternative coal supplies.

Lessons learned

Laibin's high visibility as a pilot for future BOT projects helped in the often cumbersome multi-agency government approval process. Multiple letters of support at the central government level and the local need for power are helpful factors that reduce project risk at a time when governments are reluctant to issue guarantees, although recent experiences in India and Indonesia show that support letters and even guarantees can be unreliable.

¹ Tiong, Robert L.K., Shou Qing Wang, S.K. Ting, and D. Ashley, 'Risk Management Framework for BOT Power Projects in China', *Journal of Project Finance*, Winter 1999, p. 60.

² This case study is based on various articles in the financial press, and on follow-up interviews with Robert L.K. Tiong, Associate Professor of Civil Environmental Engineering, Nanyang Technological University, Singapore, and Gary Wigmore, Partner of Milbank, Tweed, Hadley & McCloy.

³ Sherman, Robert T., Jr., 'Power in the PRC', *Independent Energy*, October 1994, p. 27.

⁴ Gibbons, Robin J., 'Power Funding', *The China Business Review*, November/December 1993.

⁵ Li Xiaolin, 'FDI in China', *Independent Energy*, July/August 1997, p. 24.

⁶ Starke, Kevin, 'Gordon Wu, Hopewell Holdings, Ltd.', *Independent Energy*, July/August 1995, p. 48.

⁷ Wang, S.Q. and L.K. Tiong, 'Case Study of Government Initiatives for PRC's BOT Power Plant Project', *International Journal of Project Management* 18, 2000, p. 70.

⁸ Ibid.

⁹ Orr, Deborah, 'China's New Rules', *Infrastructure Finance*, December 1997/January 1997, p. 38.

¹⁰ Tiong, Robert L.K., Lin Qiao, Shou Qing Wang and Tsang-Sing Chan, 'Critical Success Factors for Tendering BOT Infrastructure Projects in China', *Journal of Structured and Project Finance*, Spring 2002, p.50

¹¹ Gailey, Colin, 'The Power of Persuasion', *Asiamoney*, London, October 1997, p. 16.

¹² Ibid., p. 17.

¹³ Tiong, Robert L.K., Shou Qing Wang, S.K. Ting and D. Ashley, op. cit., p. 71.

¹⁴ Sayer, Rupert, 'Waiting for Revolution', *Project and Trade Finance*, July 1996, p. 36.

¹⁵ Gailey, Colin, 'The Power of Persuasion', *Asiamoney*, October 1997, p. 16.

Meizhou Wan, China

Type of project

724 MW (net) pulverised-coal-fired power plant with two 362 MW units.

Country

People's Republic of China (PRC).

Distinctive features

- First wholly foreign-owned power project successfully financed outside China's state-sponsored build-own-transfer (BOT) programme.
- Second entirely foreign-owned project in China.
- Lack of implied central government support.
- Multilateral agency both provides cover and holds equity stake.
- Two export credit agencies (ECAs) involved.
- Financed during depth of Asian currency crisis.
- Tariff protocol and project documentation serve as models for other power projects in China.
- Power Purchase Agreement (PPA) terms repudiated by provincial government.

Description of financing

The US\$725 million project cost was financed in 1998 by US\$158 million in equity contribution from sponsors and US\$567 million in debt financing, the latter comprising:

- US\$40 million as a 16-year Asian Development Bank (ADB) direct loan;
- US\$150 million as a 12-year ADB complementary loan at 195 basis points (bps) over the London interbank offered rate (Libor);
- US\$53 million as a 16-year Compagnie Française d'Assurance pour le Commerce Extérieur (Coface) facility at 150 bps over Libor pre-completion and 75 bps over Libor post-completion;
- US\$76 million as a 16-year Compania Española de Seguros de Credito a la Exportación (Cesce) facility at 125 bps over Libor;
- US\$218 million as a 12-year uncovered commercial loan at 210 bps over Libor; and
- US\$38 million as a 10-year working capital facility at 210 bps over Libor.

Introduction

This dual case study (in this chapter and the previous one) is a comparison of Laibin B and Meizhou Wan, the first two wholly foreign-owned power projects in China. Please refer to the 'Introduction' in Chapter 1 for a brief overview of the projects.

Project summary¹

Meizhou Wan is a 724 MW (net) pulverised-coal-fired power plant in Fujian Province. InterGen, owned by Bechtel Enterprises Energy BV and Shell Generating (Holding) BV, owns 70 per cent of the plant; Lippo China Resources owns 25 per cent; and the ADB owns 5 per cent.

The project was built by Bechtel Power and its affiliates. Turbines were supplied by GEC Alsthom and boilers by Foster Wheeler, a major supplier of power plant equipment to China.

Fujian province, located on the Taiwan Straits, has been building up its infrastructure to capitalise on growing communications and trade between the PRC and Taiwan. The Meizhou Wan plant is part of a proposed mixed-use commercial, industrial and leisure development called Tati City in Putian, originally proposed by the Lippo Group in the early 1990s. The Lippo Group is a US\$12 billion financial and real estate conglomerate based in Indonesia.

Background

Putian was the home town of Dr Mochtiar Riady, the successful overseas Chinese businessman who founded the Lippo Group. Because of the bond between Dr Riady and his hometown, and local desire for infrastructure investment, the project received strong government support from the beginning.

The PRC's State Planning Commission (now the State Planning Development Commission) originally approved the project in 1993. However, during the five years between then and the project's financial closing there were changes in the project ownership, the Fujian Provincial Electric Power Bureau, and Chinese laws and regulations related to power projects.

The project consortium originally had four members, including Bechtel Enterprises, with the Lippo Group in the lead role. In 1996, however, after many project delays and changes, two of the four consortium members withdrew and InterGen increased its investment in the project.

When the project first was conceived, early in the 1990s, the Power Bureau was a government utility in dire need of new generating capacity. By 1997 it had relieved some of those supply pressures by building new plants and refurbishing old ones. Also, in line with other Chinese entities moving towards the private-sector model, the Power Bureau had become incorporated and had started to assume a more aggressive stance in the negotiation of project agreements.

The new laws and regulations enacted during the constantly evolving project negotiations included the Security Law, passed in October 1995, the Electric Power Law, passed in April 1996, and the Administration of Standardised Power Purchase Contract Tentative Measures, announced in September 1996. As each new law came into effect the project sponsors had to review how it applied to the project and to the required approvals. The provincial and local government authorities had no relevant experience with the approvals and permits

required by the project, and therefore required more education and processing time than the sponsors had originally anticipated.

The project sponsors' negotiations for approval and support were more at the provincial than at the central government level. Even though various provincial government support letters did not represent legally enforceable obligations, they were viewed positively by the project lenders because they were evidence of strong local support for the project. The project's unique, pathbreaking nature could not escape the attention of the central government, but the Meizhou Wan project has no explicit guarantees or even support letters from central government ministries or authorities. Nonetheless, the State Planning Commission approved and reapproved the project, and the Ministry of Foreign Trade and Economic Cooperation approved the establishment of a wholly owned foreign enterprise. Central government authorities also orally confirmed their support of the project to the lenders during the due diligence process and presumably kept abreast of the project negotiations.

Gary Wigmore and Desiree Woo of Milbank, Tweed, Hadley & McCloy explain that for many years developers had looked for ways to apply true project finance in China, but had been held back by factors such as the need for local partners to ease the way, the lack of infrastructure regulations, and the reluctance of lenders to rely solely on project revenues in this uncertain legal and regulatory environment. From the beginning of their efforts the developers of the Meizhou Wan project envisioned a structure in which a wholly foreign-owned entity would complete the development and obtain true limited-recourse financing from international lenders. Such a financing required world-standard documentation that never had been used in China. As in many other developing countries, the first financing of its kind required lengthy, painstaking education of, and negotiation with, local government officials.

Unlike the Laibin B, Changsha and other BOT projects, the Meizhou Wan project does not rely on the state-sponsored BOT programme. As a result the sponsors could not take advantage of a comprehensive concession agreement with the provincial government or a preassembled regulatory approval and government support package. Without the benefit of the BOT regulations to fast-track any approvals, the sponsors had to obtain approvals one by one from various authorities at the state and provincial levels. However, their not being bound by the BOT programme gave the sponsors more freedom to design project arrangements and a financing package tailored to the project. For example, they were able to draft and execute various support and clarification letters, to demonstrate and verify the commitment by numerous government bodies to support the project and carry out the intentions of the underlying project documents.

Among other legal issues that the sponsors had to resolve before financial closing was the enforceability of arbitration in China. As with other joint ventures between Chinese and foreign entities, the agreements between the project company and the Power Bureau provided for arbitration by the China International Economic and Trade Arbitration Commission (CIETAC). However, the project company, notwithstanding its 100 per cent ownership by foreign interests, was an entity established under Chinese law. The project lenders had doubts about CIETAC's jurisdiction over disputes between Chinese entities and sought to duplicate the central government's support for CIETAC arbitration as provided to the BOT projects. Unlike the BOT projects, the Meizhou Wan project was not state sponsored. One of the benefits of delay was that the problem resolved itself over time. In May 1998 CIETAC's arbitration rules were amended, explicitly giving it jurisdiction over disputes between domestic Chinese entities and foreign investment enterprises such as cooperative joint ventures, equity joint ventures and wholly foreign-owned enterprises.

Principal contracts

The PPA, the dispatch agreement, and the operations and maintenance (O&M) agreement were formally signed with the Power Bureau in April 1998, demonstrating that the sponsors had been able to bridge the requirements of the Chinese power industry and those of the international sponsors and lenders.

Power Purchase Agreement

The Power Bureau is to purchase the plant's electrical output under the 20-year PPA. The original draft of the PPA, proposed by the sponsors in 1993 when negotiations began, was the Bureau's first exposure to an international-standard document. According to Wigmore and Woo of Milbank, Tweed, the Bureau's concerns about the document's length and drafting style initially overshadowed any substantive discussion of its commercial terms. Then, between 1993 and 1997, the Bureau developed new ideas as it negotiated with other power project sponsors. At one point the Bureau presented its own approach to a contract, leading to what Wigmore and Woo describe as a classic battle of the forms. The Bureau's draft reflected a Chinese approach to written agreements: it was shorter, and the language was more open-ended and ambiguous. The final agreement drew from both the sponsors' English drafts, translated into Chinese, and the Bureau's Chinese drafts, translated into English. As with Laibin B, many of the project agreements have equally binding English and Chinese versions. The dual-language negotiation and documentation added considerable complexity and cost to the project.

One of the most important issues that the project sponsors faced was how to be assured of receiving sufficient revenues. In their opinion, recent tariff agreements for other Chinese power projects had lacked sufficient detail and left too much discretion to local pricing authorities in the annual tariff review process. The sponsors were determined to negotiate a more detailed tariff protocol that would include an adjustment mechanism for interim fluctuations in various cost components, thus minimising subjectivity and disputes when electricity prices were reset each year. They also negotiated a foreign-exchange indexation mechanism, providing comfort to foreign lenders that had suffered recent bad experiences with Indonesian and Thai borrowers.

Engineering, procurement and construction contracts

Bechtel Power and its affiliates built the plant according to a turnkey engineering, procurement and construction (EPC) arrangement that embodied offshore design and engineering contracts, and onshore construction contracts.

Fuel supply and transportation contract

PT Kaltim Prima Coal of Indonesia committed itself to supplying and transporting coal to the power plant under a long-term supply and transportation contract.

Operations and maintenance agreement

Under an innovative 20-year O&M contract the Power Bureau and its technical staff are to

operate and maintain the plant under normal circumstances, taking responsibility for liquidated damages and other obligations normally assumed by experienced power plant operators. However, if the Power Bureau has difficulty running the plant, it can require InterGen to take over responsibility for running it under a 20-year backup O&M agreement.

Land use rights transfer agreements

In the early stages of negotiation with the Power Bureau the project sponsors thought that they had done everything that was required to acquire the plant site. However, in 1997, just after the sponsors and local land bureau had signed the Land Use Rights Transfer Agreements, the central government issued a moratorium on the grant of arable land. The land bureau delayed issuing the land use rights certificates that were required to mortgage the land use rights to the project site until it had sorted out the ramifications of the moratorium on the Meizhou Wan project.

How the financing was arranged

Originally the International Finance Corporation (IFC), the private financing arm of the World Bank, and the ADB were expected to provide most of the financing. After two years, however, the sponsors decided not to go forward with the IFC component of the financing and to rely on the ADB, along with strong underwriting and syndication commitments from four commercial banks: Banque Paribas, Bank of America, Credit Suisse First Boston and Tokai Bank. This was the first project in China in which the ADB took an equity interest in addition to providing cover.

Additional financing commitments came from Coface, the French ECA; Cesce, the Spanish ECA; and the lenders that joined the commercial bank syndicate. The Coface facility provided both political and commercial risk cover, while the Cesce facility provided political risk cover only. The presence of two ECAs led to complex security and intercreditor issues, especially in a country such as China, where law develops on a provincial rather than a national basis and therefore lessons learned from provinces other than Fujian are of limited value.

Although many recent joint-venture projects between Chinese and foreign entities had been financed partly in Chinese currency (renminbi (Rmb)), the sponsors preferred to rely only on US dollar-denominated debt facilities. In this way they were able to avoid lengthy intercreditor negotiations with renminbi lenders.

In May 2002 the Fujian provincial government reportedly reneged on its obligations under the PPA and proposed that the tariff be reduced from Rmb0.56 to Rmb0.44 per KW hour.² After prolonged negotiations with the provincial government, the project sponsors were reported in November 2002 to be trying to replace the project's dollar-denominated loans with renminbi-denominated financing. They were reported to believe that the reduced revenues proposed by the provincial government would not be sufficient to service the original project financing provided by the foreign bank consortium and the ADB.³

Lessons learned

Wigmore and Woo of Milbank, Tweed believe that Meizhou Wan serves as a model for what can and must be done to close a large, complex project financing in the turbulent Asian envi-

ronment. It required weaving together strong commitments from reputable and reliable ECAs, multilaterals and private lenders; adding the necessary level of equity support, management involvement and technical expertise from world-class project sponsors; and documenting the transaction to international standards.

The Meizhou Wan project demonstrates that true international limited-recourse project financing can be achieved in China outside the BOT scheme. Unlike the Laibin B, Changsha and similar projects, the Meizhou Wan project has no special concession agreement with a Chinese governmental authority. Wigmore and Woo believe that Meizhou Wan sets an important precedent for the future of project financing in China, because, in their view, the government is unlikely to continue providing the benefits seen in earlier BOT projects. They see a trend towards less government support, requiring sponsors and lenders to structure deals that resemble Meizhou Wan more than previous transactions financed in China.

¹ This case study is based on various articles in the financial press, and on follow-up interviews with Robert L.K. Tiong, Associate Professor, Civil & Environmental Engineering, Nanyang Technological University, Singapore, and Gary Wigmore, Partner, Milbank, Tweed, Hadley & McCloy.

² 'Meizhou Wan in Trouble', *Project Finance International*, 1 May 2002, p. 25.

³ 'Meizhou Wan May Refinance', *Project Finance International*, 13 November 2002, p. 26.

TermoEmcali, Colombia

Type of project

Build-own-transfer, combined-cycle, gas-fired power plant.

Country

Colombia.

Distinctive features

- Infrastructure project generating local-currency revenues financed ‘out of the box’ with bonds.
- First power project in Colombia financed through Rule 144A private placement.
- Longest-term bond issued to date for Colombian borrower.
- Bond issue backed by commercial loan commitment.
- No state guarantees or state-owned offtakers.
- Obligations of private offtakers guaranteed by pledge of receivables.
- Debt-service reserve and working capital account.

Description of financing

Senior secured notes in a principal amount of US\$165 million with a 17-year maturity were issued in 1997 under Rule 144A, underwritten by Bear Stearns. Project credit facilities, underwritten by a group of commercial banks, led by Dresdner Kleinwort Benson were:

- US\$13.2 million, five-year debt-service reserve letter of credit with a fee of 2.5 per cent per year and a margin over the London interbank offered rate (Libor) of 2.75 per cent per year;
- US\$12.0 million working capital facility maturing no later than seven years from financial closing with a commitment fee of 0.5 per cent per year and a margin over Libor of 1.875 per cent per year; and
- US\$15.5 million, five-year project contract letters of credit with a fee of 2 per cent per year a margin over Libor of 2.625 per cent per year and a commitment fee of 0.5 per cent per year.

If the credit rating for the project changes, there is a provision for the spread over Libor of the project credit facilities, defined as the applicable spread, to change accordingly.

Project summary¹

This build-operate-transfer (BOT) power project serves the city of Cali in Colombia. It is owned by Emcali, the local utility and sole offtaker, and International Generating Company Ltd (InterGen), an affiliate of Bechtel Enterprises Energy BV and Shell Generating (Holding) BV. While the marginal cost of this natural-gas-fired plant is usually higher than wholesale market energy prices, and the plant therefore serves primarily in a standby capacity, the rationale for the plant is to reduce the region's dependence on hydroelectric power and the tendency to blackouts during droughts. TermoEmcali was financed 'out of the box' in the Rule 144A private placement market with a backup commercial loan commitment. The project's bonds had the longest term to date for a Colombian borrower and originally received an investment-grade credit rating. A bank debt-service letter-of-credit facility replaces the government guarantee or Power Purchase Agreement (PPA) common in previous project financings. In addition to a conventional security package, Emcali's payment obligations to TermoEmcali under the PPA are secured by a *fiducia*, a trust that grants the project company a priority interest in a portion of Emcali's operating cash collections in case the latter defaults on its payment obligations. Fixed-price, turnkey construction contracts provided for plant completion in 22 months. After a short delay at the beginning of commercial operations, caused by problems with the combustion chamber, the performance of the power project has been satisfactory. Nonetheless, TermoEmcali's credit rating has been downgraded because Emcali, the offtaker, is in poor financial condition and faces an uncertain future.

In 1994 InterGen began development of the 233.8 MW natural gas-fired power plant, located approximately 10 km outside Cali. Construction began in January 1997 and commercial operations began in January 1999.

Affiliates of InterGen, as the majority partners, along with two Colombian partners, Empresas Municipales de Cali (Emcali) and CorfiPacífico, formed TermoEmcali for the purpose of developing, owning and operating the project. At the end of the 20-year PPA Emcali will assume full ownership, without payment of additional consideration. The total sum of project loans is US\$209.8 million, of which 79 per cent was financed through the issuance of senior secured notes pursuant to Rule 144A and Regulation S of the US Securities Act 1933.

The plant consists of a single Westinghouse model 501F advanced combustion turbine generator, nominally rated at 155 MW, which exhausts to an unfired Distral natural circulation heat recovery steam generator. Steam is produced in the heat recovery steam generator and delivered to a Westinghouse steam turbine generator nominally rated at 84 MW.

In the past Emcali has purchased all of its power from the Bolsa, the national grid. The TermoEmcali project assists in meeting the growing demand for electricity in the Cali area. It also enhances the security of the national power supply and reduces the strain on the Colombian national power system.

Natural gas will be supplied to the project through the TransGas natural gas pipeline, which transports gas to the Cauca Valley. As a result, the project provides a low-cost and secure supply of thermal power to meet Emcali's existing and forecasted demand. The project pipeline route is shown in Exhibit 3.1.

Exhibit 3.1
Pipeline route



Project economics

Colombia's power industry

Before the TermoEmcali project was completed Colombia had 10,500 MW of installed power-generating capacity, of which 75 per cent was hydroelectric and 25 per cent was thermal. Heavy dependence on hydroelectric power led to unreliable service and sharp swings in electricity prices. Frequent brownouts and blackouts encouraged the development of a fossil-fuel generation plan to take advantage of Colombia's abundant natural gas resources. The cornerstone of this plan has been the construction of a pipeline system to bring gas to the larger cities. Gas-fired power plants such as TermoEmcali provide anchor demand for the pipelines.

Project's importance to Emcali

When completed TermoEmcali was expected to account for 25 per cent of Emcali's expected customer load. The estimated project price averaged 4.6 cents (US) per kilowatt hour (kWh), compared to Emcali's average cost of five cents per kWh in 1996. It therefore represents lower costs to Emcali. The project was meant to establish a degree of certainty in Emcali's power costs, which in the past had been subject to change with each new two-year contract. As a result Emcali expected to be able to offer long-term contracts to its customers.

Ownership and contractual relationships

InterGen

InterGen was formed in 1995 by subsidiaries of Bechtel Enterprises and Pacific Gas & Electric (PG&E) to develop, own, and operate power projects outside the United States. In 1996, because of a change in business strategy, PG&E sold its interest to Bechtel. Bechtel later sold an interest in InterGen to Shell Generating Company.

InterGen's primary business is to develop power plants overseas. InterGen won the project in a competitive bidding process. It is responsible for development, operation and financing of the project. In 1996 InterGen arranged for the financing of more greenfield power plants, measured in total megawatts, than any other developer. Other InterGen-financed projects include: in 1996, the 690 MW Samalayuca II plant in Mexico, the 725 MW Rocksavage plant in the United Kingdom and the 440 MW Quezon plant in the Philippines; in 1997, Mayakan in Mexico; and in 1998, Meizhou Wan in China and Coryton in the United Kingdom.

Emcali

Emcali, with a 43 per cent interest in the project, is the third largest utility in Colombia. Established in 1955, it is municipally owned. Emcali is the exclusive distributor of electricity, and the exclusive provider of water, sewer and telephone services to the city of Cali. Before the TermoEmcali project was completed Emcali had no electric generating facilities. As of the end of 1996 Emcali had a 'BBB+' local and a 'BBB-' international credit rating from Standard & Poor's, and 'BBB' local and international ratings from Duff & Phelps (now Fitch).

In 1996 electricity distribution accounted for 58 per cent of Emcali's revenues. Of total electricity sales in 1996, 32 per cent were to industrial customers, 31 per cent to residential customers, 22 per cent to commercial customers and 15 per cent to other customers. The total

number of Emcali's customers increased from 357,000 in 1992 to 420,000 in 1996. Peak electricity demand in 1996 was 651 MW.

Emcali reorganised itself in 1997, creating a holding company and four operating subsidiaries for power generation, power distribution, water and sewer services and telephones. The PPA and TermoEmcali ownership were transferred to the power generation subsidiary, but obligations under the PPA continued to be covered by joint, and several guarantees of the holding company and the four operating subsidiaries.

CorfiPacífico

CorfiPacífico is one of 17 private Colombian *financieras* that provide commercial and investment banking services. It holds a 3 per cent interest in the project as a portfolio investment.

Ownership structure

TermoEmcali is a Colombian mixed-economy *sociedad en comadita por acciones* formed to develop, construct and own the power plant. As shown in Exhibit 3.2, it is owned by Empresas Municipales de Cali EICE (Emcali), Cauca Valley Holdings Ltd (Cauca Holdings), TermoEmcali Holdings Ltd (Termo Hold), Mayflower Holding Inc. and Corporación Financiera del Pacífico (CFP).

InterGen Colombia Leasing Ltd (Leaseco), a Cayman Islands company, is owned and controlled by BENICO and BTH. BENICO and BTH are Bechtel subsidiaries and InterGen affiliates. Leaseco, in turn, is a part owner of the project company. Mayflower Holding Inc., owned by an individual who also owns shares in CFP, will acquire a nonvoting interest in Leaseco. (See also the section 'Financing structure' below.)

The project contract structure is shown in Exhibit 3.3.

Power Purchase Agreement

Emcali purchases power from the facility under a 20-year dispatchable PPA, with fixed capacity payments and variable energy payments. The capacity payments are designed to cover all fixed operating costs, including debt service and return on investment. The energy payments pass through actual fuel-supply and transport costs and other variable operating expenses. TermoEmcali's tariffs are US dollar-indexed. Under the PPA, tariffs are protected from a change in law. Emcali sells power into the Bolsa when dispatched by the national dispatch centre and directly to unregulated customers under contracts. At the end of the first 20 years the project's ownership will be transferred to Emcali without additional consideration.

The PPA for Emcali was one of the last such agreements signed in Colombia. The original agreement was modified several times to accommodate the market's move toward the relatively unregulated, free-auction Bolsa system.

At the time of the project financing Thomas E. Lake, then Vice President for Project Finance at Dresdner Kleinwort Benson, considered the PPA conservative and typical of PPAs signed in various countries at the time. Emcali is obliged to purchase electricity from the plant subject to certain performance requirements.

In addition to having the protection provided by the PPA, the commercial lending banks wanted to know how TermoEmcali would add value to Emcali as a utility. They com-

Exhibit 3.2
Project ownership structure

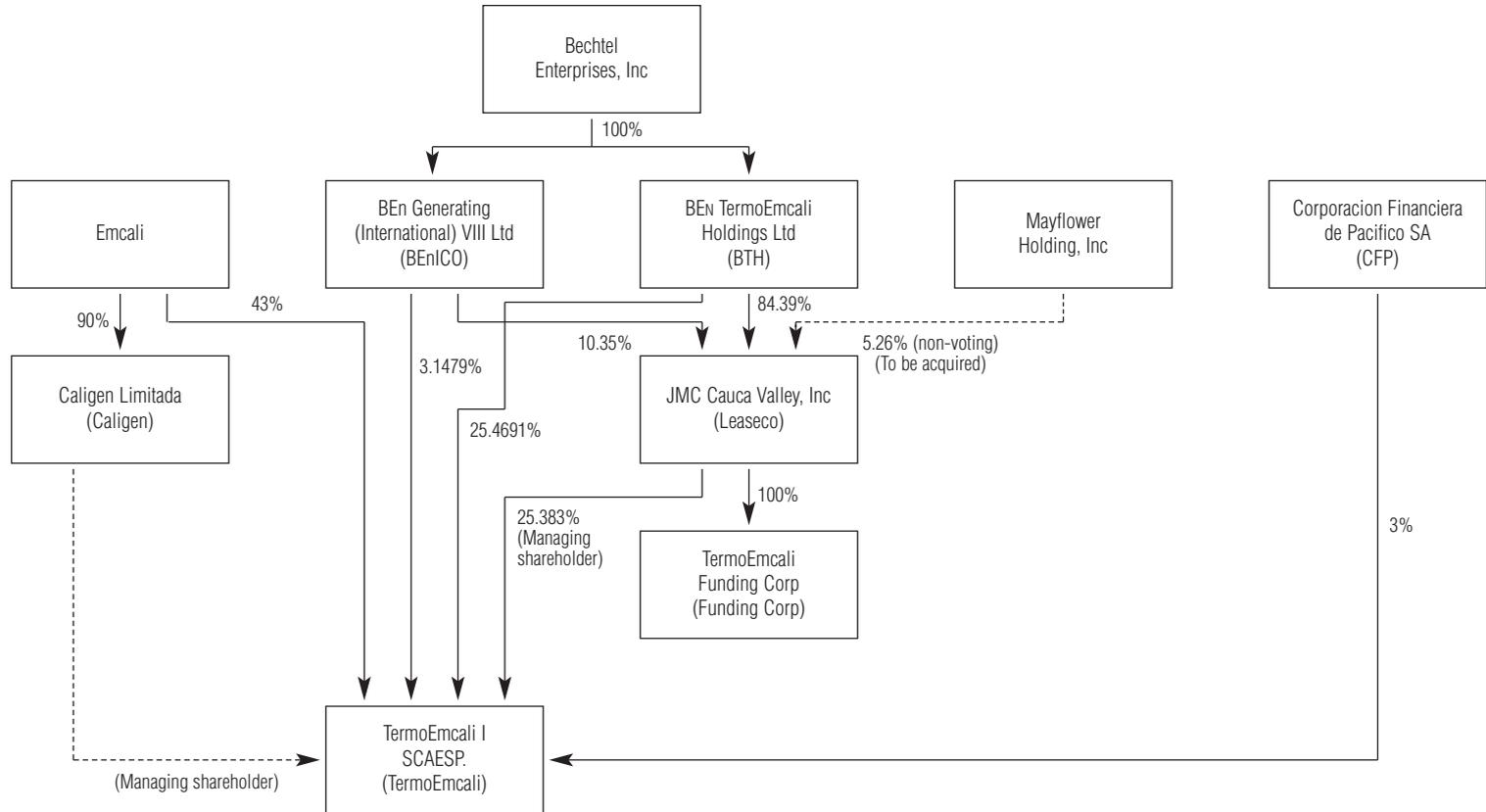
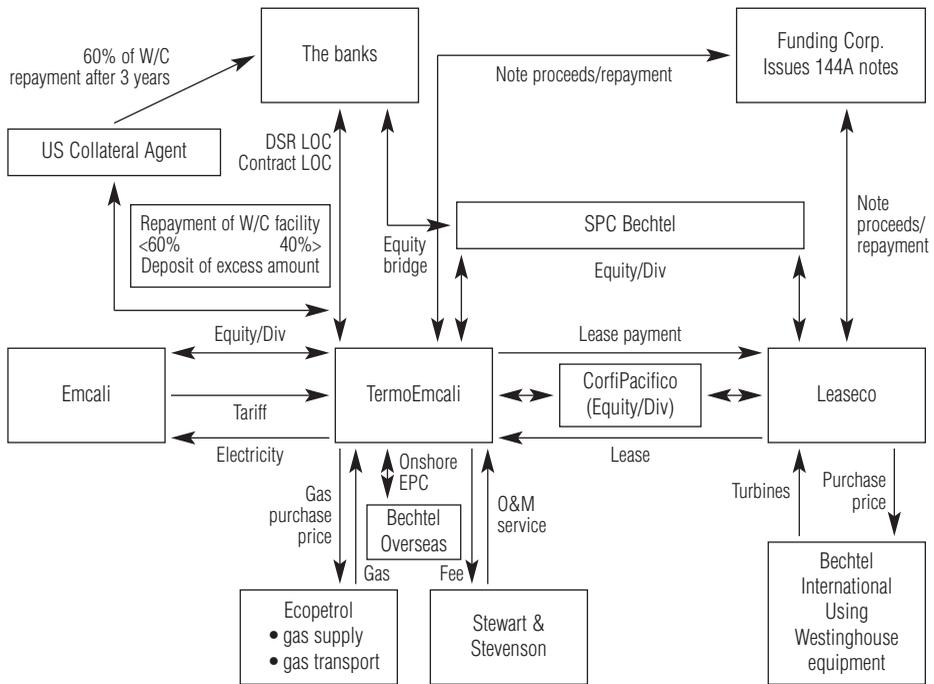


Exhibit 3.3

Project contract structure

missioned a dispatch study to determine how competitive TermoEmcali would be compared to other power sources. The study concluded that TermoEmcali would reduce the dependence of the Colombian power system on hydrology and thereby reduce the volatility of power prices.

Engineering, procurement and construction (EPC) contracts

The project company entered into fixed-price, turnkey construction contracts, to a total value of US\$124.1 million, with two Bechtel affiliates, Bechtel Overseas Corporation (the onshore contractor) and Bechtel International Corporation (the offshore supplier). The EPC contracts are split between the onshore contractor and the offshore contractor to take advantage of a provision in Colombian tax law that allows imported equipment to be leased, and therefore allows tax deductions for lease payments to the offshore contractor. The performance obligations and liabilities of both contract parties are guaranteed by Bechtel Power Corporation. Following a three-month interim notice-to-proceed period that commenced on 24 December 1996, the contractors were given a full notice to proceed on 31 March 1997. They committed themselves to completing the project in 22 months. The contractors had an unlimited obligation to achieve mechanical completion, which entailed installing all components and systems required by the EPC contract, and preparing the plant to begin performance testing. Liquidated damages totalling up to 40 per cent of the EPC price were payable for schedule delays and performance deficiencies, which were defined in the EPC contract in terms of net

POWER PLANT

electrical output and heat rate. Similarly, bonuses could be earned if schedule and performance goals were exceeded.

Gas supply agreement

The project executed a 16-year firm gas supply agreement with Ecopetrol, commencing 1 January 1999, for up to 42,000 million Btu per day. Ecopetrol is Colombia's state-owned oil and gas company. The project initially paid on an annual take-or-pay basis for 10,000 million Btu per day, which is equal to 25 per cent of the firm quantity available to the project. The project has an option to convert all or a portion of the remaining 31,000 million Btu per day to a take-or-pay basis if, and to the extent that, Ecopetrol provides notice that a new or existing customer requests a quantity of guaranteed gas that exceeds Ecopetrol's available supply.

Gas transportation agreement

The project executed a 10-year natural gas transportation agreement with Ecopetrol, which in turn had the contractual right to the capacity of the privately owned, project-financed TransGas pipeline system. The contract provides for the firm transportation and delivery of up to 42,000 million cubic feet a day to the project. Initially, 10,000 million cubic feet a day are subject to a fixed charge, regardless of usage. The project has an option to convert all or a portion of the remaining 31,500 million cubic feet a day to a fixed-charge basis to maintain a firm capacity if, and to the extent that, Ecopetrol provides notice that a third party seeks that capacity on a firm basis. The pipeline to supply natural gas to the project is on land adjacent to the project. It commenced service during the second quarter of 1997. As a backup, TermoEmcali stores a five-day supply of diesel fuel.

Ecopetrol is the state-owned company engaged in gas supply and transportation, as well as oil production, refining, distribution and marketing. As of the end of 1995 Ecopetrol had sales of US\$3.4 billion, net income of US\$172 billion and assets of US\$5.6 billion. It controlled gas reserves of 7,665 billion cubic feet, a 30-year supply.

TermoEmcali and Emcali have agreed to share the cost of any penalties imposed by Ecopetrol for transportation imbalances on a 50/50 basis, unless wilful gross negligence or misconduct can be proved by either party.

In the unlikely event of gas service interruption, backup fuel oil is to be supplied to operate the project. Provision for backup fuel has been made through an onsite storage tank equal to five days of project fuel needs; a requirement under the gas supply contract that Ecopetrol makes fuel oil available to the project during periods of gas unavailability; and a contract with Texaco Oil Company to provide a backup oil supply from its nearby oil terminal.

Operations and maintenance contract

Stewart & Stevenson originally operated the facility under a six-year operations and maintenance (O&M) contract that provides for cost reimbursement and a fixed fee with an escalator. Fees are subject to adjustment for shortfalls in availability, heat rate targets and expenses exceeding the operating budget.

Stewart & Stevenson was then the largest third-party operator of power facilities in the

world. The company's revenues in 1996 were US\$1.3 billion. It operated 36 plants with a total capacity of 3,500 MW, including four plants in Colombia. Stewart & Stevenson's fleet availability over the past four years had averaged over 94 per cent, with no single plant below 92 per cent availability. In 1998, Stewart & Stevenson sold its gas turbine operation, including the TermoEmcali O&M contract, to General Electric.

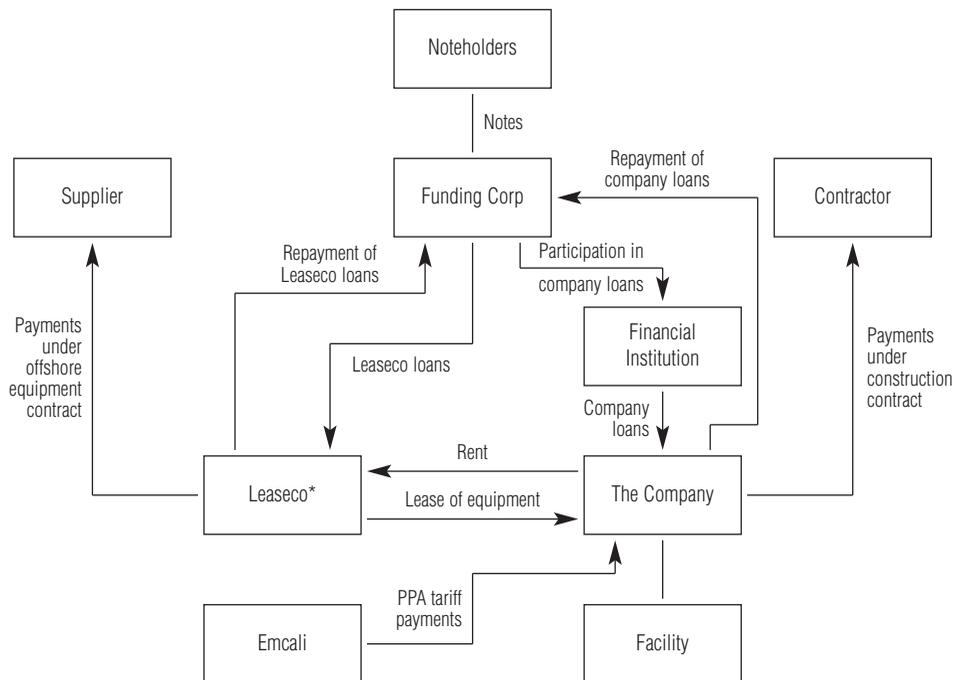
The O&M agreement provides incentives for Stewart & Stevenson to operate the plant as efficiently and cost-effectively as possible. The PPA requires the project company to contribute annually to a maintenance reserve for periodic equipment overhauls and to maintain business interruption insurance equal to 18 months of expenses.

Financing structure

The project financing structure is shown in Exhibit 3.4. TermoEmcali Funding Corporation, wholly owned by Leaseco, is established for the sole purpose of issuing the notes. It is a special-purpose corporation operating under the laws of the State of Delaware in the United States. TermoEmcali Funding lent a portion of the proceeds from issuance of the notes to Leaseco, which used those proceeds to acquire equipment for lease to the project company. This arrangement allows the project company to take advantage of tax deductions for lease payments. The project company thus owns some assets and has a leasehold interest in others.

Exhibit 3.4

Project financing structure



* Pursuant to the Leaseco guarantee, Leaseco will guarantee the obligations of Funding Corp under the financing documents.

Risk analysis

Construction risk

As with any major construction undertaking, many factors such as material shortages, labour disputes, bad weather, failure to obtain necessary permits or unforeseen engineering, environmental or geological problems could have caused a cost overrun or a delay in project completion. Except in the case of certain defined *force majeure* events, the contractor was required to pay schedule and performance-liquidated damages totalling 40 per cent of the contract price if the project was not completed on or before the guaranteed completion date (22 months from the full notice to proceed under the construction contract and 24 months from the financing date under the PPA). The contract also stipulated penalties if the plant did not satisfy the performance tests, including 233.8 MW capacity, by 365 days after the completion date. Emcali could terminate the PPA if construction was not complete within 24 months of the financing date and if plant capacity at the time of commercial operation was less than 196 MW. In addition, the company took out delay-in-completion insurance and set aside an owner's contingency of US\$10 million in its construction budget to cover budget overruns, *force majeure* events and other events that could delay completion of the facility.

Over the previous 10 years Bechtel had constructed 25 combined-cycle plants similar to the TermoEmcali project. In its history as an EPC contractor for combined-cycle plants, Bechtel had incurred neither delay penalties nor performance damages through to the date of the financing. Bechtel had a strong financial incentive to complete the project within the 22-month construction timetable and was further motivated by an obligation to pay up to 40 per cent liquidated damages to cover delay penalties owed to Emcali under the PPA; a holdback letter of credit equal to 10 per cent of the contract price; and unlimited liability to achieve mechanical completion.

Offtake risk

The PPA with Emcali provides fixed-capacity payments designed to cover all fixed operating costs, including debt service, and energy payments that pass through virtually all actual fuel supply, transportation and other variable costs. Emcali, rated 'BBB-' at the time of the project financing by Standard & Poor's, is contractually obligated to provide additional support in the form of a letter of credit and a *fiducia*, described below, to cover short-term payment disruptions. The project was considered to be of strong strategic importance to Emcali, providing it with low-cost power, reduced transmission costs and diversification away from hydroelectric power. Emcali's obligations under the PPA remain in effect if Emcali is reorganised or privatised.

Fuel supply/transportation risk

Ecopetrol is a national fuel company, obliged to provide fuel and firm transportation capacity under long-term contracts. Emcali's capacity-payment obligations to the project continue if fuel is unavailable, so long as the project remains available. Emcali is obliged to pay for substitute fuel if it is used. In the independent fuel consultant's report CC Pace estimated that there would be adequate transportation and more than an adequate supply of natural gas for the project's requirements during the term of the debt.

Technical risk

The power plant uses a 155 MW Westinghouse 501F gas turbine. (The Westinghouse turbine business is now part of Siemens.) At the end of 1996 there were 28 similar turbines in operation. In 1996, according to Westinghouse, average availability for its turbines installed in 1992 was 94 per cent, slightly above the 91 per cent availability in the project's base-case scenario. Westinghouse had four other turbines installed in Colombia.

Operating risk

As with any new project of this size and nature, operation of the facility could be affected by many factors, including startup problems, equipment breakdowns, failure to operate at design specifications, changes in law, failure to obtain necessary permits, terrorism, labour disputes or catastrophic events such as fires, explosions, earthquakes or droughts.

The monthly capacity payments by Emcali are based on the facility's available capacity and on an equivalent availability factor (EAF) that is equal to the facility's available capacity for any period divided by the facility's capacity on the day that commercial operations begin.

If the EAF of the facility is less than 60 per cent in any month, capacity payments from Emcali are reduced to zero. If the EAF is less than 60 per cent for any consecutive six-month period, the PPA can be terminated. Emcali will not make capacity payments during most *force majeure* events that prevent the facility from operating.

Environmental and permit risk

TermoEmcali received the necessary permits from the Colombian government and was in compliance with the World Bank environmental standards. Costs associated with future changes in Colombian environmental and tax laws, as well as other changes in Colombian law that affect the project's net economic return, are passthroughs under the PPA.

Restructuring risk

In December 1996 the City Council of Cali adopted an agreement that required Emcali to restructure its business by establishing separate power generation, power distribution, water and sewage, and telephone subsidiaries under a holding company. To accommodate this reorganisation, Emcali signed an agreement with the senior secured lenders that required each subsidiary to be jointly and individually liable for Emcali's obligations under the PPA, and also provided a priority interest in a portion of its operating revenues to the same extent as provided by Emcali before its restructuring. This agreement was intended to prevent the restructuring from having a negative impact on Emcali's creditworthiness.

Exchange rate risk

Emcali's PPA payments in Colombian pesos are indexed to US dollars, thereby mitigating the lenders' exchange rate risk.

Dispatch risk

The structure of the capacity and energy payments under the PPA was designed largely to insulate the project from variations in dispatch.

Bolsa risk to Emcali credit

The Bolsa, the wholesale electricity spot market in which generators and suppliers participate, is a bid-based system. A power shortage could therefore cause a substantial increase in Emcali's power costs and a consequent reduction in cash flow. The TermoEmcali project was intended to lock in the price for a portion of Emcali's power needs. Emcali's business diversity was considered to further mitigate the effects of a power price increase.

Country risk²

No political risk coverage was provided for this project financing. At the time Colombia had the following long-term investment-grade credit ratings: Duff & Phelps (now Fitch), 'BBB'; Moody's, 'Baa3'; and Standard & Poor's, 'BBB'.

Colombia is Latin America's fifth largest country by area and third largest by population. It claims to be the region's oldest democracy. Between 1945 and 1995 its economy grew at an average annual rate of almost 5 per cent.

For the past two decades Colombia has been the world's main supplier of cocaine. The country's central role in the illegal drug business has caused a wider breakdown in public order. The drug gangs have turned a generation of unemployed youth into hired killers. Revenues from the drug business have strengthened the Revolutionary Armed Forces of Colombia (FARC) and the smaller National Liberation Army (ELN), both on the left, and bands of paramilitary vigilantes on the right, most of whom are organised in the United Defence Forces of Colombia. Conflict between leftwing guerrillas and national security forces began four decades ago but has recently become more intense. The security forces enjoy the unofficial and increasingly unwelcome support of the paramilitaries.

Although most of the drug profits go to dealers in consumer countries, what filters back amounts to significant wealth for a developing country. Estimates of the amount repatriated by the drug trade range from US\$2.5 billion to US\$5 billion per year, or 2 to 4 per cent of GDP. For comparison, Colombia's defence budget is US\$2.8 billion, including army and police pensions.

As of the mid-1990s Colombia had an enviable reputation compared to its Latin American neighbours. The country had never defaulted on its sovereign debt; its fiscal accounts were in good order; it was considered a good place to do business; it had a long track record of legal stability, under which contracts were honoured and parties could be sued; and it had an investment-grade sovereign credit rating. Although leftwing guerrilla violence presented a safety problem, there had been no significant instance of expropriation, currency inconvertibility or contract abrogation by the central government. Trade liberalisation, and the privatisation or deregulation of key sectors such as electricity, other utilities and banking had helped to attract foreign direct investment, which had averaged 3 per cent of GDP in the period 1997–2001. During this period numerous projects had been financed successfully by international banks and through the capital markets. Among them were CentraGas, El Dorado, OCENSA, Termopaipa IV, TransGas and

Termobarranquilla. Nonetheless, Colombia's government spending rose from 11 per cent of GDP in 1990 to 18 per cent in 2001, resulting in a fiscal deficit of 3.3 per cent of GDP. Andrés Pastrana, President from 1998 to 2002, tried to take a fresh approach to the intractable civil war by personally negotiating with both the leftwing guerrillas and the rightwing paramilitaries, both financed by the drug trade. It was clear at the time that the problem would be difficult to solve until drug activity was either controlled or eliminated. Pastrana's successor, Alvaro Uribe, has attempted to shift the emphasis from negotiation to restoring law and order.

In the late 1990s several factors pushed Colombia into a recession. The exchange rate became overvalued, partly as a result of capital inflows from drug profits, oil exploration projects and Colombian firms borrowing abroad to take advantage of the country's investment-grade rating. Public spending rose from 24 per cent of GDP in 1990 to 36 per cent in 1998 because, among other factors, the central government was required by a new constitution to increase transfers to local governments, but failed to make corresponding cuts in its own spending, and the cost of internal conflicts was rising. During the recession property prices fell and a rising level of nonperforming loans caused several banks to fail. Among the country's current structural problems are excessive spending at both the federal and the local level, an expensive pension system for government and military workers, a costly bank bail-out programme and, as a result of the foregoing, a need for higher taxes.

Oil is Colombia's largest export by value. Coal recently became the second largest, pushing coffee back to third. Both the oil and coal businesses are capital-intensive, and largely dependent on foreign partners. Until the mid-1980s coffee accounted for more than half of Colombia's exports, but its leading position has been undermined by low-cost producers in other countries, including Brazil and Vietnam, which have created a glut in the market.

Many of the recent issues related to the Colombian economy are reflected in the sovereign credit ratings and explanatory comments from the rating agencies. In November 1997 Duff & Phelps (now Fitch) still rated the Republic of Colombia 'BBB'. Colombia stood favourably in comparison with other sovereigns in the triple-B category because of its proven commitment to uninterrupted debt service, its macroeconomic policy mix, which kept inflation under control, and the favourable trend in its balance of payments, supported by diversification of exports and rising oil revenues. Noting that Colombia's credit fundamentals had recently deteriorated because of slippage in public finances and the ongoing guerrilla conflict, the agency said that its rating and outlook over the medium term depended on reducing fiscal imbalances, restoring public order and enacting structural reforms, such as phasing out the backward indexation of prices, liberalising the labour market, developing the country's infrastructure, improving primary education and reforming the social security system.

Standard & Poor's cited many similar factors in reaffirming its triple-B-minus foreign currency sovereign rating in May 1998. Among the constraining factors that it cited were:

- structural flaws in public finances, stemming largely from constitutionally mandated transfers to local governments (as mentioned above) and a narrow tax base with poor compliance;
- the simmering guerrilla conflict; and
- sluggish progress on lowering inflation, then about 17 per cent, which was de facto evidence of a national preference for growth over price stability.

Duff & Phelps reduced its rating to 'BBB-' in September 1999, citing recent pressure on the peso, a deeper-than-expected recession, guerrilla-related violence and asset problems in the banking sector. The agency noted that efforts to reduce the deficit through tax reform and other fiscal measures had been frustrated by the economic slowdown. It recommended replacing the country's adjustable-band exchange rate system with either a crawling peg or floating currency. In the same month Standard & Poor's lowered its long-term foreign currency sovereign rating from 'BBB-' to 'BB+', citing the conflict with insurgent groups and its effect on the government's ability to implement economic policies.

In March 2000 Moody's lowered its sovereign rating for Colombia from 'BBB-' to 'BB+', citing a strain on public finances caused by the revenue-sharing system, lower-than-anticipated oil exports, the guerrilla conflict and continued weakness in the financial sector. In May 2000 Standard & Poor's lowered its foreign-currency sovereign rating from 'BB+' to 'BB' because of concerns that the government would not be able to meet the deficit-reduction targets it set when the IMF extended a recent US\$2.7 billion credit facility, that continued guerrilla violence would impede economic growth and that the government's peace talks with FARC were faltering. Some economists predicted that the rating downgrade, legal delays and guerrilla attacks would impede the government's policy programme, which included the sale of more than a dozen electricity companies, a state coal company and several state banks for an estimated US\$2 billion.

In March 2002 Moody's revised its outlook from stable to negative for its 'Ba2' foreign-currency ceiling for bonds and its 'Ba3' foreign currency ceiling for bank deposits, citing increasing public debt, despite a narrowing of the fiscal deficit; the continuing need for fiscal adjustments and reform of the pension system; the effect of low commodity prices on export earnings; and economic problems in Venezuela, Colombia's main trading partner. The agency estimated that the cost of the ongoing civil war was 2 to 5 per cent of GDP.

Independent engineer's report

In the independent engineer's report Stone & Webster concluded that the facility would be able to achieve and maintain operating standards specified in the PPA; that projected operating results were a reasonable forecast of the project's economics; and that projected debt service coverage ratios were insensitive to reasonable changes in technical assumptions. The independent engineer considered liquidated damages to be adequate, but also recommended giving the contractor an incentive to achieve the guaranteed completion date. Stone & Webster noted that the power plant site was easily accessible and located next to a substation of the gas pipeline. Its riverside location simplified construction. Stone & Webster was commissioned to provide an ongoing review throughout the life of the project.

Gas consultant's report

In the gas consultant's report CC Pace concluded that the gas supply and transportation contracts provided sufficient volume to meet the project's requirements, and that Ecopetrol's gas reserves were more than adequate to meet the project's requirements. The firm noted that the diesel fuel storage capacity and local oil terminal facilities provided sufficient access to backup fuel supplies, and that the PPA insulated the project from fuel-related supply, transportation and price risk.

Structure of financing

Financing for the project was provided in 1997 by a US\$165 million Rule 144A/Regulation S debt issue lead-managed by Bear Stearns and co-managed by certain institutions, including Dresdner Kleinwort Benson North America LLC (now Dresdner Kleinwort Wasserstein), the US-based securities affiliate of Dresdner Bank AG. The final maturity of the notes is 2014, nearly 18 years from issuance. Average life is 12 years. The notes have a 12-year non-call with a declining call premium thereafter.

It is common for a power project to be financed with bank loans through the construction period and then be taken out with a bond financing. The TermoEmcali project financing was relatively aggressive with a bond financing ‘out of the box’.

Alternate standby facility

To ensure long-term financing for the project, Dresdner Kleinwort Benson committed itself to underwriting a US\$156 million alternate standby facility, to be used if the 144A note issue was unsuccessful or delayed because of poor market conditions. Although a bank term loan in place of the 144A note issue was conceivable, the terms and conditions for such a loan would have been more restrictive, so there was an incentive to refinance the facility as soon as possible.

Project contract letter of credit facility

The fuel performance letter of credit supports certain payment obligations under the gas supply agreement and the fuel transportation performance letter of credit supports certain payment obligations under the gas transportation agreement. Both are in an amount of US\$5.5 million, issued on the financial closing date and expiring in five years. Ecopetrol required that the fuel performance and fuel supply letters of credit be issued by a Colombian bank. A back-to-back letter of credit was created in which the lending-syndicate banks issued a letter of credit in favour of Citibank in Colombia, which in turn issued a letter of credit in favour of Ecopetrol, priced at the applicable margin.

The US\$8.5 million PPA construction-period letter of credit, issued on the financial closing date, was converted to a US\$10 million PPA operating-period letter of credit when commercial operations began.

The project-contract letters of credit support some of the project’s payment and performance obligations under the PPA. Drawings under the project-contract letters of credit mature no later than seven years from financial closing. The facility is expected to be renewed and extended annually on an ‘evergreen’ basis for additional one-year periods.

Working capital facility

A US\$12 million working capital facility was established to support the project’s working capital needs on the earlier of either the commercial operation date or the date that the project was obliged to make its first payment to purchase gas. Each working capital loan has a 180-day maturity, but is required to be repaid only up to the limit beyond which deposits with the Colombian central bank are required (as explained below). The remainder is deposited as cash collateral for the loans.

Shortly before the project financing was closed, Colombian regulations were changed, to prohibit the repayment of more than 40 per cent of a loan amount during the first three years that the loan is outstanding. Under the new regulations a borrower that pays more than 40 per cent is required to make a non-interest-bearing deposit with the central bank. To accommodate repayments of more than 40 per cent the lending banks created the Available Pledged Funds Account, a deposit account held by the US collateral agent. Loan repayments above the 40 per cent limit are held in the Available Pledged Funds Account until they can be repaid without a required central bank deposit. Deposits in this account are protected from claims by 144A note holders or any other senior secured parties. They continue to accrue interest at the applicable borrowing rate, even though they are cash-collateralised. For subsequent working capital needs, funds are drawn first from the Available Pledged Funds Account, to the extent available, and then new loans are extended under the working capital facility. Recent changes in Colombian law required this structure to be amended.

Debt service reserve letter of credit facility

In previous Colombian power projects, such as Termobarranquilla, state guarantees or undertakings were necessary. The bank letter of credit facility provided a credit enhancement partly to replace the government guarantee or power-purchase commitment common in previous power project financings.

The US\$13.2 million debt service letter of credit facility, equal to six months principal and interest payments, supports temporary shortfalls in debt service payments to the 144A note holders. Drawings are available at whichever is the earlier date among the commercial operation date, the guaranteed completion date under the EPC contract or a 'date certain' – defined as 34 months plus allowable *force majeure* delays. Principal payments are subordinated to the other senior loans. The debt service reserve lenders have a right to 'step up' or upgrade their principal repayment status to be *pari passu* with all senior secured indebtedness if loans under the facility are not paid on time or if the project debt is accelerated. Fees and interest on the facility rank *pari passu* and share collateral with senior debt.

Sources and uses of funds in connection with development, construction, financing, and commencement of commercial operation of the project were estimated, and are shown in Exhibit 3.5.

Exhibit 3.5

Sources and uses of funds

| <i>Sources</i> | <i>(US\$ million)</i> |
|---|-----------------------|
| Sponsor equity | 44.8 |
| 144A note issue | 165.0 |
| Total sources of funds | 209.8 |
| <i>Uses</i> | <i>(US\$ million)</i> |
| EPC price (net) | 123.3 |
| Interconnection/meter | 0.8 |
| Land purchase | 2.0 |
| Development budget | 15.0 |
| Legal fees during development | 7.6 |
| Financing and legal fees | 5.7 |
| Quorum engineering fees | 1.4 |
| Owner's construction administration | 2.5 |
| Independent engineering during construction | 0.2 |
| Startup costs | 5.6 |
| Insurance during construction | 2.9 |
| Taxes and duties during construction | 6.8 |
| Environmental management | 0.2 |
| Interest during construction (net) | 25.0 |
| Contingency | 10.0 |
| Pre NTP | 0.8 |
| Total uses of funds | 209.8 |

Source: Prospectus for project bonds.

Security package

Senior lenders are secured by a lien on and security interest in the collateral, subject to the priority of payment on the working capital facility loans. The collateral consists of real and personal property owned by TermoEmcali and Leaseco, including equipment, receivables, insurance, and other tangible and intangible assets; all of TermoEmcali's and Leaseco's rights, title, and interest in the project contracts; equity obligations of the project sponsors; all revenues of the borrower; all accounts established under the collateral agency agreement; and all permits and other approvals of the project.

Emcali support package

In addition to the security package, Emcali's obligations under the PPA are supported by a letter of credit and a *fiducia*. The *fiducia* is a trust that grants TermoEmcali a priority interest in a portion of Emcali's operating cash collections in case Emcali defaults on its payment obligations under the PPA. Emcali installed the *fiducia* after closing. Until the *fiducia* was in place, the letter of credit was oversized.

In the US\$424 million Termobarranquilla power project, closed in November 1995, the obligations of Corporación Eléctrica de la Costa Atlántica to pay for power were guaranteed by Financiera Energetica Nacional SA, an official Colombian government financial institution used to finance the electricity sector, as part of an emergency programme to increase generating capacity. The letter of credit and the *fiducia* were used in place of a government guarantee in the TermoEmcali project.

The PPA required a letter of credit, equal to four months of capacity payments during operations, issued by a creditworthy Colombian bank. A back-to-back letter of credit was to be issued in favour of the lenders by an international bank with at least an 'A' credit rating.

Emcali's customers pay their bills at designated banks. The *fiducia* covers collection accounts at those banks to the extent necessary to provide TermoEmcali access to two times average monthly capacity and energy payments to the project. If Emcali fails to maintain the requisite amount of collateral in the *fiducia*, it is required to pay an escalating premium that is added to the capacity payment. If Emcali defaults on its PPA payment obligation, the *fiduciaria* (trustee) has the right to use daily collections in the designated collection accounts. Exhibit 3.6 shows a sensitivity analysis of how the debt service coverage ratio would be affected by adverse factors such as delay in commercial operations, reduction in capacity, an increase in heat rate degradation or an increase in operating costs.

Exhibit 3.6

Sensitivity analysis in respect of debt service coverage ratio (DSCR)

| <i>Sensitivity case</i> | <i>Average DSCR</i> | <i>Minimum DSCR</i> |
|--|---------------------|---------------------|
| Base case | 1.62 | 1.54 |
| 0% dispatch | 1.64 | 1.52 |
| 1-year delay in commercial operation date | 1.63 | 1.54 |
| 2% reduction in capacity | 1.58 | 1.50 |
| 2% reduction in available capacity | 1.58 | 1.50 |
| 1% increase in average heat rate degradation | 1.61 | 1.53 |
| 10% increase in operating costs | 1.60 | 1.52 |
| 10 days per year on fuel oil | 1.65 | 1.56 |

Source: Prospectus for project bonds.

How the financing was arranged

Bear Stearns was engaged by InterGen before the banks were. InterGen wanted to do a bond financing ‘out of the box’, but recognised that this was an ambitious undertaking and therefore developed a backup plan in case the bond markets turned unfavourable. This requirement led to the idea of an alternate standby facility to serve as an insurance policy. InterGen tendered the standby letter of credit facility and the debt service working capital reserve facility to the banks for bids. Dresdner Kleinwort Benson arranged the standby facility, receiving approval from their respective credit committees to underwrite a syndicated loan for the full amount, but did not actually underwrite the facility because it was not needed.

Lake of Dresdner Kleinwort Benson noted that bonds can offer a borrower longer-term and lower financing cost, and, to a certain extent, more flexibility. However, except in unusual circumstances, a bank commitment is more reliable if credit markets change. A sponsor complying with a construction deadline under a PPA does not have the flexibility to wait until the credit markets improve to do a bond financing. The plan for a bond financing backed by an alternate standby facility provided InterGen with the advantages of both. A bond financing, in some ways, may allow sponsors more flexibility than a bank financing, because bonds are sold to a diverse group of institutional investors who cannot follow a project closely on a month-to-month basis and make judgements on such issues as temporary forgiveness of covenant defaults. On the other hand, disclosure issues sometimes make bond financings seem less flexible. In the case of other unusual risks and issues, commercial bankers can be more flexible than investment bankers. Commercial bankers are generally willing to discuss unusual situations and decide whether or not they are acceptable, but for investment bankers unusual situations may create difficult disclosure issues. The due diligence process requires that unusual risks be disclosed in a prospectus. Too much disclosure may exaggerate risks, raise pricing and scare off institutional investors. Also, the project parties may wish to minimise disclosure for competitive reasons, including pricing.

For a short time before the bond financing there was a possibility that the credit facility would be used. The bank group agreed on a term sheet with InterGen. Lake noted that the banks would have had to move quickly to draft all the required documentation and line up all the participating banks, but essentially they were ready to carry out the syndication.

Pricing the alternate standby facility presented a challenge to the banks because InterGen did not want to pay excessively for a facility that was just a backup in case the other facility did not work. On the other hand, Dresdner Kleinwort Benson needed enough compensation to justify their analysis and preparation in the event that the syndicated loan was required.

The banks agreed on a term sheet with InterGen that provided for a deadline and fees if the standby facility was used. The banks would be given 65 days to close the loan once the facility was activated. As soon as InterGen notified the banks that it wanted to use the facility, it would pay the first part of an upfront fee. Additional instalments of the upfront fee would be paid at three-month intervals at increasing rates. Presumably, the standby facility would be activated if there was a problem, and the longer the standby facility was used the greater the banks’ risk would be. This justified a fee that escalated over time.

Lake observed that there is inherent tension between an investment banking firm responsible for a bond underwriting and a commercial bank group offering a related standby facility. A client may decide not to do a bond issue because of market conditions or for other reasons. Later, however, if the client once again decides to do the bond issue, it may not be obliged to give the mandate to the same investment banking firm. Therefore the investment

banking firm risks doing a lot of work for minimal fees. Alternatively, the client may choose a universal bank to underwrite a facility that provides for a bond financing or a commercial loan, depending on market conditions. Once the universal bank receives the mandate, it knows that it will be compensated in one way or the other for its analysis, due diligence and other work. In the past the problem with this approach has been that few financial institutions have had really good capabilities in both commercial and investment banking, but that has begun to change as large commercial banks expand their investment banking groups and buy or merge with investment banking firms.

The bonds were oversubscribed. Lake saw several factors that made the bonds attractive to institutional investors. Investors were looking for attractive 'alternative investment' opportunities. The TermoEmcali bonds were investment grade, but also with a good spread. The engineering and contract structure of the project was sound. Emcali was a relatively strong credit. Colombia had an investment-grade credit rating and, despite recent problems with drugs, terrorism and political corruption, one of the strongest, best managed economies in Latin America.

Credit analysis

Debt-service coverage was projected to be 1.62 times average and 1.54 times minimum. The base case assumes a seventeen-and-three-quarter-year bond tenor (12.61-year average life) and a 318 bps spread over US treasuries, equating to an all-in fixed rate of 9.625 per cent. The PPA largely insulates the project from interest rate risk, since the capacity payment is adjusted to compensate for interest rate fluctuations within a range of 9.5 to 12 per cent. With the sale of the 144A notes, Emcali effectively locked in the passthrough cost of interest. The Colombian peso devaluation and inflation rates were assumed to be 15 and 19 per cent respectively.

Credit rating

At the time the bonds were issued, TermoEmcali was rated 'BBB' by Duff & Phelps and 'BBB-' by Standard & Poor's, whose rating for the Republic of Colombia at that time was 'BBB-'. Lake observed that the rating for a domestic infrastructure project such as TermoEmcali, with revenues collected in local currency, seldom pierced the sovereign ceiling.

The rating was based on the stability of cash flow to be derived from the power plant's sale of capacity and energy to Emcali, a corporation then rated 'BBB-' by Standard & Poor's. The agency stated that the rating was highly dependent on Emcali's ability and willingness to honour its obligations. As of September 1997 the agency concluded that construction risk detracted from the credit quality of the transaction. Although liquidated damages of 40 per cent of the EPC contract amount, a US\$10 million contingency built into the contract budget and a US\$5.8 million delay in opening insurance were protective features for bondholders, the agency believed that the 24-month construction time frame under the PPA could be tight if *force majeure* events or other scheduling problems occurred. It also noted, however, the additional 12-month cushion that could be obtained through payments for a schedule extension.

Standard & Poor's concluded that, as long as the plant was constructed properly and achieved startup, Stewart & Stevenson should be able to operate and maintain the plant with little difficulty, and therefore that operating risks associated with the project were negligible. It also concluded that fuel risk, borne primarily by Emcali, was minimal. The agency found

the transaction to be well-structured, with lenders enjoying the benefits of a comprehensive security package, but noted that there was no treaty or other agreement between the United States and Colombia for the reciprocal enforcement of judgements. Although New York law governs the financing documents, the exercise of remedies by the collateral agent in the event of a default would be likely to require litigation in the Colombian courts.

Lessons learned

The picture as of 1998

First, an infrastructure project such as a power plant that generates local-currency revenues in a developing country can be financed ‘out of the box’ with bonds under the right circumstances. In this case, the sponsors were of top quality; Colombia at that time had an investment-grade credit rating; and the alternate standby facility and debt service reserve were additional financing tools to bridge timing problems.

Second, it is more efficient to provide a bond issue and a standby facility out of the same financial institution.

Third, debt-service reserve facilities require careful risk analysis. Issues include:

- whether the drawdowns under such facilities are subordinated to amounts originally drawn down under a bond indenture or term loan agreement; and
- whether the pricing of those drawdowns should be comparable to subordinated debt, or senior debt, or somewhere in between.

Thomas E. Lake noted that in the subordination ‘waterfall’ interest payments and fees rank *pari passu* with senior debt. If a payment under a debt-service reserve facility is delayed, the lenders have the right to raise the status of those overdue obligations to the senior debt level. In Lake’s opinion it is important for bankers to understand and properly explain these structures. Generally, for a debt-service reserve facility sponsors are willing to pay a slight spread over the rate for their senior debt, but they try to avoid paying subordinated debt prices for such facilities.

Events since 1998

In April 1999, shortly before commercial operation was scheduled to begin, Duff & Phelps downgraded the rating of the US\$165 million TermoEmcali Funding Corporation senior secured notes from ‘BBB’ to ‘BB+’, reflecting a similar rating downgrade of Emcali. The agency explained that the offtake risk of the TermoEmcali PPA was that of Emcali and therefore that TermoEmcali’s credit rating was constrained by that of Emcali. Recent poor economic performance in Colombia, and particularly in Cali, had put pressure on Emcali’s operating performance and liquidity, reducing the company’s ability to meet monthly debt maturities and make timely payments to its energy suppliers. The agency saw an increasing probability that Emcali would have to restructure its bank debt and payments due to its fuel suppliers. Standard & Poor’s downgraded TermoEmcali from ‘BBB-’ to ‘BB’ in May, for similar reasons.

A series of events in early 1999, including problems with the combustion chamber, delayed the beginning of commercial operations, scheduled for April. In May Emcali claimed

that TermoEmcali was in technical default under the terms of the PPA because the beginning of commercial operations had been delayed and the plant had not been completed according to the standards defined in the agreement. The project sponsors asserted that there was no contractual basis for Emcali's claim because the events causing the delay did not constitute a default under the PPA. Standard & Poor's anticipated that the issues arising from Emcali's refusal to accept the plant could easily extend until September, at which time capitalised interest accounts would be depleted and the project company would have to draw funds from the debt-service reserve to meet interest payments.

In May the issues in the default letter were resolved except that Emcali refused to accept Stone & Webster as the independent engineer. To address that issue the project hired Sargent & Lundy as an independent consultant to provide a second opinion on the combustion chamber incident reports and to evaluate the technical performance of the power plant. In response to the resulting report, which supported the project's declaration of commercial operation, Emcali retracted its claim of default.

With the default issue resolved, Duff & Phelps stated that it was comfortable with Emcali's commitment to the TermoEmcali project, but was still concerned about the utility's financial ability to honour its 20-year obligation under the PPA. Emcali had been honouring its obligations to pay for the project's fuel costs during its testing phase, but Duff & Phelps was concerned about the company's ability to make its first capacity payment under the PPA, which was due later in May. The agency also cited high turnover among Emcali's top management as a possible problem for the company's long-term business and financial prospects.

By early 2000 Emcali was nearly insolvent. In February, as a proposed measure to help Emcali meet its financial obligations, the Mayor of Cali presented a recapitalisation plan to the city council. Under the plan 40 to 50 per cent of the utility would have been sold off to a strategic investor or another state utility company. The proposal was voted down because of concern among some unions, workers and politicians that it was a step toward eventual privatisation of the company. As a result of that vote, the mayor requested the intervention of the Colombian Public Service Superintendencia. Standard & Poor's noted that neither the Superintendencia nor the government was required to make a capital infusion to help Emcali to pay its creditors, but that the Superintendencia was likely to end the financial crisis by selling Emcali's energy company to outside investors.

In March Standard & Poor's downgraded the foreign currency rating of the TermoEmcali bonds to 'CCC'. In April the Superintendencia took management control of Emcali, stating that, if its financial problems were not resolved within three months, all of the utility's assets might be liquidated. Empresas Publicas de Medellín (EPM), a utility owed by the city of Medellín, and two private firms expressed interest in purchasing Emcali's assets. Standard & Poor's described EPM, the most likely buyer of the assets, as an efficient organisation with an adequate capital base and the expertise to run Emcali. The agency also surmised that a purchase by this city-owned company might be viewed favourably by the antiprivatisation groups.

In December 2000 and January 2001, 27 transmission towers in Antioquia and Uraba, provinces in southwestern Colombia, were destroyed by guerrilla attacks, causing blackouts in 15 municipalities and leaving more than 400,000 people without electricity. TermoEmcali's management said that it was prepared to relieve possible energy supply problems in the Cauca Valley region with 233 MW that could supply one third of the region's needs.

POWER PLANT

In early 2001, with Emcali still under its control, the Superintendencia developed a series of proposals for the utility's financial rescue and organisational restructuring. They included:

- privatisation via capitalisation of Emcali's electric distribution business, serving some 460,000 customers;
- privatisation via capitalisation of Emcatel, the utility's telecom unit;
- offering its water and sanitation business to a new private-sector concessionaire;
- restructuring the utility's existing debt with new bonds issued in the overseas market;
- revising its collective bargaining agreements; and
- renegotiating the PPA with TermoEmcali.

Meanwhile, the region's need for TermoEmcali's standby capacity was starting to become apparent. The power plant was reported to have functioned at 30 per cent of capacity in January, 54 per cent in February and 22 per cent in March, generating an average of 134 MW per hour during the first quarter of 2001.

One of Emcali's problems was that, even though TermoEmcali was available to supply emergency power to southwestern Colombia when there were shortfalls in the national transmission network, the new plant's marginal cost of generation, approximately 95 pesos/KWh, was considerably higher than wholesale energy market prices, about 50 pesos/KWh, and long-term contract prices, which ranged between 50 and 65 pesos/KWh. Further, Emcali had to make a capacity payment of US\$2.3 million each month, yet part of the rationale for TermoEmcali, as explained above, was to reduce the region's dependence on hydroelectric power. In the long term Emcali's management hoped that forecasted El Niño-related droughts and possible changes in industry regulations would drive up energy prices and make the plant more profitable.

In May Standard & Poor's reaffirmed its 'CCC' rating with a negative outlook. The agency had expected the Superintendencia to address Emcali's financial crisis in a timely manner after taking control. After one year, however, no plan to address the situation had been made public. The agency's negative outlook reflected the increased risk that bondholders would face as the process of resolving Emcali's financial problems dragged on.

Up to this time Emcali had honoured its payment obligations under the PPA, albeit by making late payments. Under the PPA Emcali had 60 days from the receipt of an invoice to pay. Then TermoEmcali's notice of default triggered another 30 days to remedy the overdue payment. Emcali had been paying invoices just before the full 90-day term ever since the beginning of the plant's commercial operations. Standard & Poor's noted that TermoEmcali had sufficient liquidity in the short term based on an undrawn, six-month debt-service reserve, a pledged US\$11.3 million letter of credit required by the *fiducia* and certain bank accounts pledged by Emcali, representing slightly less than two months of capacity and energy payments. Under the *fiducia* Emcali was required to maintain a standby letter of credit equal to three months of capacity and energy payments. TermoEmcali could draw on this account three months after an invoice had become 90 days past due. The required amount of the letter of credit had recently increased from US\$11.3 million to US\$12.4 million because of an increase in the amount of the capacity payments. Emcali had not yet increased the letter of credit but TermoEmcali had granted a waiver that could be extended or, if Emcali was out of compliance with other obligations, revoked. Standard & Poor's concluded that the granting of this waiver would not have a material effect on the economics of the project or on TermoEmcali's 'CCC' credit rating.

At this point the continuing delay in resolution of Emcali's financial difficulty was caused primarily by the opposing views of the federal government of Colombia and the city government of Cali. The federal government, through the Superintendencia, favoured privatising a portion of the company. The city government wanted the federal government to provide additional capital to Emcali but leave the company under the city's control. The two sides had been trying to reach an amicable solution over the previous 13 months, with little success. The problem was compounded by the fact that 14 other, smaller electric distribution companies were under the Superintendencia's control because of problems similar to Emcali's: therefore a decision made in Emcali's case could set a precedent for the others. Standard & Poor's noted that TermoEmcali bondholders benefited from their ability to preclude transfer of any of Emcali's substantial assets and the requirement that they agree, before the sale of any of Emcali's assets, that the purchasing entity was not materially less creditworthy than Emcali — a moot point, of course, now that Emcali was rated 'CCC'. Nonetheless, the agency warned that the longer the status quo continued, the greater the likelihood that Emcali would default on its payments under the PPA.

In mid-2001 EPM began to explore how it could expand its distribution network to the southern Valle del Cauca province through some type of long-term relationship with Cali. Possibilities included a strategic alliance, concession contracts for EPM to operate Emcali's services, joint administrative agreements or other types of joint ventures. If EPM were to control Emcali's power distribution network, its market share of Colombia's electricity distribution would increase from 18 per cent to 24 per cent, just below the 25 per cent regulatory limit for one company. EPM was continuing to talk to the federal government about buying some of the other 13 troubled utilities, but some kind of working relationship with Emcali was its first priority. However, officials of Emcali and the city of Cali opposed the sale of Emcali to EPM or the transfer of Emcali to the Medellín utility through a share issue because the city of Cali wanted to maintain ownership of its municipal services.

In April 2002, the Colombian government extended the Superintendencia's control over Emcali, originally imposed when the utility was declared bankrupt in April 2000, for an additional year. In the following months, the Superintendencia attempted, unsuccessfully, to work with Emcali and its commercial creditors, bank creditors, customers, employees and pensioners to develop a financial restructuring plan.

In August, the new government of President Alvaro Uribe Velez assumed the Emcali problem from the outgoing Pastrana administration. In October, the government indicated that it was willing to provide funds to help Emcali with its pension liabilities if other parties, such as the municipality, the unions and the utility's customers, also participated in the restructuring effort. In January 2003, President Uribe said that Emcali must reduce its labour costs to be viable and that it also needed to create a system of 'social capitalisation' for customers and other stakeholders to invest in the company's stock and bonds. President Uribe said that if Emcali did not comply with these requirements, the government would replace it with another state company backed by a social capitalisation fund.³ Later in January, the Superintendencia said that it would recommend that Emcali be liquidated if it did not accept President Uribe's social capitalisation approach.

According to Fitch Ratings, to forestall liquidation the Superintendencia said Emcali would have to:

POWER PLANT

- restructure the terms of its PPA with TermoEmcali;
- renegotiate union agreements;
- restructure its debt with local financial institutions, and local and international suppliers;
- negotiate a new agreement with the City of Cali for approximately US\$121 million owed to Emcali; and
- negotiate with debt holders, including the federal government, local banks and suppliers, to convert a portion of their outstanding debt to capital.

Local politicians and unions continued to oppose this approach because the municipality would lose control of the utility.

Fitch Ratings noted that TermoEmcali was still receiving monthly PPA payments from Emcali within the 30-day cure period that is allowed once the project issues a notice of default. The agency also noted that TermoEmcali continued to benefit from two reserve funds that were backed by letters of credit, one providing for three monthly payments under the PPA and the other providing for six months of debt service. According to Fitch, TermoEmcali's management believed in February that it could make a US\$5 million principal and interest payment due in March without resorting to the debt service reserve. Based on the government's possible decision to liquidate Emcali and the possible renegotiation of the PPA, Fitch placed a Rating Watch Negative on its 'CCC' rating for TermoEmcali.

Lessons learned as of 2003

In a developing country, the political and economic situation as well as the creditworthiness of an offtaker can change considerably in just a few years, not to mention over the term of a PPA or bond.

¹ This case study is based on the prospectus for the project bonds, the offering memorandum for the syndicated bank loan, credit rating agency press releases, articles in the financial press, and interviews with Thomas E. Lake, then Vice President, Project Finance, Energy/Natural Resources/Infrastructure, Dresdner Kleinwort Benson, New York; and D West Griffin, Vice President, Finance – Latin America, InterGen Energy.

² Much of the information in this section was derived from articles in the Survey of Colombia published in *The Economist*, 21 April 2001.

³ 'Uribe Committed to Save Emcali', *Business News America*, 10 January 2003.

Azito, Côte d'Ivoire

Type of project

288 MW power plant and 225 kV transmission system.

Country

Côte d'Ivoire.

Distinctive features

- First major private infrastructure project in sub-Saharan Africa (South Africa excluded) to be financed with private commercial bank term loans.
- First power project in the region financed on a non-recourse basis.
- Model for similar projects in the region.
- First project financing with a guarantee from the International Development Agency (IDA).
- Largest thermal power plant in West Africa.
- Second largest independent power project in Côte d'Ivoire.
- Successful project financing requiring involvement of multilateral agencies.

Description of financing

The total project cost of US\$223 million was financed in 1999 from the following sources:

- US\$44 million in sponsors' equity;
- US\$32 million as an A loan from the International Finance Corporation (IFC);
- US\$30 million as a B loan from the IFC;
- US\$30 million from commercial banks with an IDA guarantee;
- US\$47 million from the Commonwealth Development and bilateral agencies;
- US\$22 million in subordinated debt; and
- US\$18 million in cash from operations.

Debt is repayable over 12 years. Pricing on the commercial bank portion, not made public, was reportedly about 300 basis points (bps) over the London interbank offered rate (Libor). To protect part of the project debt against interest rate volatility, the IFC provided a US\$32 million interest rate swap to convert its exposure from a floating rate to a fixed rate.

Project summary¹

Azito, the largest thermal power plant in West Africa, was financed partly through A and B loans from the International Finance Corporation (IFC), which is part of the World Bank Group. It was the first major private infrastructure project in sub-Saharan Africa (South Africa excluded) to be financed with private commercial bank term loans. The International Development Association's (IDA's) partial risk guarantee was critical in attracting commercial lenders to Côte d'Ivoire, a country that was not yet an established international borrower. The IDA is also part of the World Bank Group.

In 1990, after a state-owned corporation responsible for the electricity sector ran into difficulty, the government had signed its first concession for the generation, transmission, distribution, export and import of electricity. Success with that concession led the government to increase private-sector participation. Legal issues in the course of the Azito project negotiations included:

- the use of project assets for collateral;
- the availability of international arbitration in the event of a project dispute;
- structuring power sector revenues through a cash-flow waterfall; and
- preventing dilution of Azito project cash flows as a result of subsequent project approvals.

The government acknowledged the need to develop concession contract laws to cover Azito and future projects. The project is a model for future infrastructure projects in the region. It will be a test of the government's credibility, and of its willingness to comply with its obligations to the sponsors and lenders.

The power sector in Côte d'Ivoire

History since 1952

Starting in 1952, Énergie Électrique de Côte d'Ivoire (EECI), a government corporation overseen by a unit of the Ministry of Economic Infrastructure, was responsible for generation, transmission, and distribution of electricity. In the 1980s, however, EECI ran into financial difficulty as a result of overexpansion, droughts, financial mismanagement, the deterioration in the country's economy and problems with collecting bills from other government agencies. The company accumulated significant debt despite levying some of the highest electricity tariffs in the world. At the same time, the poor performance of many other public enterprises, the increasingly competitive international economic environment, and successful experience with a water and sewerage concession granted to a private Ivorian/French consortium led the government to formulate a privatisation program in 1990. It focused first on large enterprises in the infrastructure and agroindustry sectors that would have the biggest impact on the economy.²

Faced with a national emergency in the electricity sector, the government of President Félix Houphouët-Boigny sought the advice of international power companies and French multinationals operating in Côte d'Ivoire on a private solution. In October 1990 the government signed a 15-year concession for generation, transmission, distribution, export and import of electricity with Compagnie Ivoirienne d'Électricité (CIE), which is owned by a consortium consisting of Bouygues, a major French construction and engineering company

that had also been involved in the water and sewer concession; Électricité de France (EDF), the French national utility; the government of Côte d'Ivoire; and other Ivorian shareholders.

While EECI was to have a continuing and important role as the owner of the assets, directing new investments, overseeing CIE and managing the financial flows of the electricity sector, CIE assumed responsibility for the operation, maintenance and necessary upgrades of the country's generation, transmission and distribution facilities, in return for an exclusive franchise with the ultimate consumers of electricity. The government retained ownership of the gas fields and guaranteed the power sector's take-or-pay contracts with gas producers. It continued to set all fuel and electricity tariffs. It also established a 'waterfall' system of priority for the allocation of electric power revenues. CIE's remuneration, about 35 per cent of total receipts, came first, followed in order of priority by payment of fuel and energy expenses, other sector operating expenses, debt service requirements, required reinvestment by EECI or CIE and rural electrification. This would set an important precedent for future management of the power sector.³

CIE was able to turn the system around quickly, improving billing, collections and overall financial management, and starting to earn a profit within two years. Earnings from the electricity sector in turn helped the government to make overdue payments on its own international debt. Meanwhile, EECI, many of whose staff were transferred to CIE, did not function effectively in its supervisory role. As a result most of its responsibilities were shifted to other government organisations.

Success with the CIE concession led the government to increase private-sector participation. In 1994 it granted a build-own-operate-transfer (BOOT) concession to Compagnie Ivoirienne du Production d'Électricité (CIPREL), the first independent power project in sub-Saharan Africa (South Africa excluded.) CIPREL is owned by Valener, a local holding company that in turn is owned by subsidiaries of Bouygues and EDF, Agence Française de Développement (AFD), the IFC, and the West African Development Bank (BOAD). The project is financed with 25 per cent equity and 75 per cent debt, with the debt provided by the IFC, the AFD and the BOAD. External financing accelerated construction of the project's first phase, commissioned in March 1995, to meet urgent demand for electricity. The second phase, commissioned in June 1997, was financed under less time pressure by the state with proceeds from an IDA loan. CIPREL sells its energy to the state under a 19-year take-or-pay power purchase agreement (PPA) and operation of the facility is contracted out to CIE. The CIPREL concession contains an indexation formula that adjusts the local-currency electricity tariff for inflation and changes in taxes. There is no explicit allowance for changes in the exchange rate, but the consortium believes that the government would agree to renegotiate the tariff in the event of a devaluation.⁴

During the 1990s several new regulatory commissions were established to oversee the electricity sector, with responsibilities including investment planning, financial controls, asset rehabilitation, rural electrification, debt service and monitoring the CIPREL contract. Their success was mixed. In an article in the *Journal of Project Finance* (Fall 2000), John S. Strong described them as *ad hoc* structures put in place in response to specific problems and opportunities, with no clear overall sectoral or regulatory framework.

After a study commissioned by the World Bank, EECI and the other commissions were replaced by three new *sociétés d'état* (state entities):

- a state holding company in charge of managing state assets and overseeing financial flows;

POWER PLANT

- an independent operator that initially has responsibility for new public works in the electricity sector but eventually is slated to be in charge of buying, selling and transmitting all electricity in the network; and
- an autonomous regulatory body in charge of existing concessions, dispute resolution and protection of consumer interests.⁵

Current situation

Over the past decade electricity demand in Côte d'Ivoire has been increasing at an annual rate of about 12 per cent. The Azito power plant addresses a power supply shortage in Côte d'Ivoire and allows power exports to neighbouring countries such as Ghana, Togo, Benin and Burkina Faso. Before 1994 Côte d'Ivoire was a net importer of electricity from Ghana. The project also reduces the country's reliance on hydroelectric power in the event of a drought. Whether a given country in the region is an importer or exporter of electricity is partly determined by the amount of its rainfall and resulting hydroelectric power generation.⁶

Côte d'Ivoire's power grid supplies more than 500,000 customers, about two thirds being in urban areas. While the country's power infrastructure compares favourably with those of its neighbours, only 25 per cent of the population has access to electricity and many rural communities are not linked to the national grid. Growth of the transmission and distribution network has lagged behind increases in generation capacity in recent years, and there are substantial transmission losses from theft and electromechanical deficiencies. Nonetheless, quality and reliability improved substantially over the 1990s, with a decrease in the average outage time per year from 50 hours in 1990 to 12 hours in 1998. Tariffs are the responsibility of the Council of Ministers. They have fallen significantly in real terms over the past decade.⁷

Project description

The Azito BOOT project consists of the installation of two 144 MW generators and the construction of a transmission line from the plant site to the Côte d'Ivoire national grid. The plant is located in the Youpougou industrial zone in the village of Azito, 10 kilometres from the capital city, Abidjan. It was constructed in two 144 MW phases, the first being completed in January 1999 and the second in January 2000.

Project sponsor

The project sponsor is Cinergy, a company owned by ABB Energy Ventures, a subsidiary of the ABB Group; Industrial Promotion Services, the local arm of the Aga Khan Fund for Economic Development; and Électricité de France Internationale.

The ABB Group operates worldwide in power generation, transmission and distribution; automation; oil, gas and petrochemicals; industrial products and contracting; financial services; and rail transport.

EDF joined the partnership at a late stage of concession negotiations. It was expected to benefit the project through its prior experience in Côte d'Ivoire, including ownership interest and participation in the management of CIE and CIPREL.

Government's objectives

The government wanted to build on the success of the CIE and CIPREL concessions, increase the number of electricity producers, and encourage greater private participation. Accordingly, the Azito project was designed as a competitively tendered concession from the government that would be financed in part from private commercial banks, alongside the multilateral agency banks. The government also had a number of broader objectives, such as increasing generation capacity, extending access to more rural areas and benefiting the environment through the use of a clean-burning fuel such as natural gas. Finally, Azito was one of 12 private projects designated by President Henri Konan Bedie's government in the late 1990s to upgrade the country's infrastructure without adding a burden to the government budget.⁸

Bidding and concession process

The government launched an international competitive bidding process in November 1996. There were four bidders: AES, Cinergy, Enron and Tractebel. Cinergy won primarily by proposing the lowest electricity tariff. Because of conflicts among the Ivorian regulatory agencies concerned, the concession agreement was not signed until September 1998 and the financing was not structured until early 1999. Among the issues that caused the delay were the lack of a formal legal structure for build-operate-transfer (BOT) contracts and the routing and financing of the transmission line.

Throughout the world contractors negotiating to become the first independent power producer (IPP) in a given country have introduced legal issues neither covered by local law nor even seen before by local government authorities. In the course of the Azito project negotiations, the issues included the use of project assets for collateral and the availability of international arbitration in the event of a project dispute.

Legal issues related to the concession included structuring power sector revenues and preventing dilution of Azito project cash flows as a result of subsequent project approvals. Proper allocation of sector revenues required modification of the cash-flow waterfall established for CIE in 1990. The new priority ranking gave IPPs and gas suppliers equal *pro rata* treatment, and gave private participants in the sector priority over government agencies, in order to allay investors' and lenders' payment risk concerns. To protect the interests of existing power projects the government pledged not to approve new projects unless they met the following coverage ratio: total power sector revenues less fees paid by the government to CIE were to be no less than 1.3 times payments to fuel suppliers and IPPs. If the power sector did not meet this ratio, payments to new entrants would be subordinated to amounts due to existing power plants and fuel suppliers.

The government modified the tariff structure to improve the financial viability of the power sector. In doing so, it tightened the eligibility requirements for subsidised power, making sure that the subsidies were restricted to low-income users. Such a compromise required delicate political balancing.

Under the original plan, the transmission line was to cross heavily populated areas. After objections from the IFC and others, it was rerouted. The government originally planned to finance the transmission line but could not find a source of funding. As a result, the transmission line was financed along with the power plant by the public/private international banking syndicate.

How the financing was arranged

Prior to the Azito financing, the government and the IFC had worked together on private sector ventures, but not with private commercial bank financing. ABB brought in Société Générale as joint arranger of the financing, so that its commercial lending skills would complement the IFC's emerging-market financing skills. Société Générale helped the government and the IFC to define what would make a project financing bankable in terms of phasing project construction, defining the tariff structure, designing a cash-flow capture structure and controlling the investment of project funds.

After the concession contract was signed in 1998, the joint arrangers started to work on a financing for just the power project. Then the government expanded the scope of the financing to include the transmission line. At financial closing Cinergy would on-lend funds for the transmission line to the government, which would be responsible for the construction of the transmission line. This required the bankers to do more due diligence and other work to prepare the financing documents, and, as a result, delayed the financial closing. Also, from a lender's perspective, it increased the government's obligations and therefore the project's political risk. As a result, the lenders asked for additional multilateral agency protection and were able to negotiate a political risk guarantee from the IDA. The political risk guarantee covers only 15 per cent of the project cost, but 50 per cent of the commercial bank funding. It was a critical element in the loan syndication process because Côte d'Ivoire did not have an established international borrowing record, sub-Saharan Africa was a new frontier for project lending, and banks were generally cautious about emerging-market exposure immediately after the Asian financial crisis.

In early 1999, the government, seeing a continuing delay in the financial closing, became concerned about a possible power shortage and asked ABB to begin construction. After some difficult negotiations, ABB agreed to start with bridge financing provided by Société Générale, secured with assets on ABB's own balance sheet, and based on assurances that the World Bank would participate in the financing through an IDA partial risk guarantee.⁹

The CDC was the lead arranger of a US\$60 million club loan along with the African Development Bank, Deutsche Investitions und Entwicklungsgesellschaft mbH (DEG) and Nederlandse Financierings-Maatschappij Voor Ontwikkelingslanden NV (FMO), including US\$47 million senior debt and US\$13 million partially convertible subordinated loans. The CDC is a leading investor in emerging markets. It invests in, manages and supports commercially viable private-sector businesses while working closely with host governments. Based in London, with 30 overseas offices, the CDC concentrates on pre-emerging and emerging economies, and those carrying out economic reform programmes.

Project contracts

A fixed-price, date-certain turnkey engineering, procurement and construction (EPC) contract was awarded to ABB Energy Ventures and Industrial Promotion Services, the local arm of the Aga Khan Fund for Economic Development, for construction of the power plant in two phases. A separate EPC contract covered construction of the transmission line.

The project company signed a 20-year take-or-pay PPA with the government that provides for capacity payments and energy payments. If the government does not dispatch the plant, it makes a capacity payment but not an energy payment. Electricity is delivered to consumers by CIE, which, as noted above, is a private-sector distributor.

The project buys natural gas, the primary fuel for the project, under a fuel supply contract with the government. The government in turn buys the gas from Ocean Energy (United Meridian International Corporation at the time of the project financing) and Apache, both producers in Côte d'Ivoire's offshore gas fields. Two separate pipelines were built from the Vridi gas terminal in Abidjan to the Azito plant. Wibros built Apache's pipeline and Michael Curran, a smaller US contractor, built United Meridien's pipeline.

ABB is participating in a joint venture to fulfil the operating and maintenance contract.

Project risk factors

Construction, operating, gas supply and commercial risks

Construction risk is mitigated by a fixed-price, date-certain EPC contract.

Operating risk is mitigated by an all-in operations and maintenance (O&M) contract.

Gas supply risk pertains to the adequacy of supplies in the offshore fields. All parties agreed that these would be sufficient to supply the Azito project but would have to be re-evaluated in the event of another power project after Azito.

Commercial risk, in terms of the respective prices of fuel and electricity, known as the 'spark spread', is assumed by the government. The government has made a commitment to set electricity tariffs at a level that ensures the financial viability of the sector, but it may be politically constrained as to the level of tariffs that it can charge to the ultimate consumers.

Country risk

Côte d'Ivoire, located on Africa's Atlantic coast, gained independence from France in 1960. The country's original president, Félix Houphouët-Boigny, served until his death in 1993. His constitutional successor, Henri Konan Bedie, was elected in his own right in 1995 and served until Robert Guei staged a military coup in 1999. The country was once known for its political stability, which since 1999 has deteriorated. The election of President Laurent Gbagbo, in October 2000, was marred by violence in part because the main opposition leader, former Prime Minister Alassane Ouattara, was excluded. Reflecting the country's regional and religious divisions, Ouattara, a Muslim from the north, had also been an opponent of Bedie, a Christian from the south. In September 2002 an attempted mutiny by a group of soldiers facing demobilisation developed into a failed coup attempt that claimed the lives of Robert Guei and the Interior Minister. Since then, rebels have held Bouaké, Côte d'Ivoire's second largest city, and a large part of the country's northern region. France, the former colonial power, with between 20,000 and 25,000 citizens resident in the country, and significant economic interests, has provided military and transport support to the Gbagbo government, and the 15-member Economic Community of West African States (Ecowas), has attempted to mediate.

Although it is classified by the World Bank as a 'low-income country', a per-capita income of US\$700 in 2000 defines Côte d'Ivoire as the second most developed economy in sub-Saharan Africa, behind South Africa. Despite its dependence on traditional exports, the country has one of Africa's most diversified economies. Coffee and cocoa exports comprise 40 per cent of GDP. Other agricultural exports include sugar, rubber, bananas and cotton. Industry consists mainly of processing agricultural produce and import substitution of consumer goods. A growing financial services sector and tourism also have contributed to the

economy in recent years. The mining and hydrocarbon sectors are considered to hold strong potential for the future. Côte d'Ivoire also has emerged as Francophone Africa's main refinery centre.

Côte d'Ivoire is a member of the CFA franc zone. After the country's economy was hurt by the overvaluation of the CFA franc in the 1980s, it was helped by a devaluation in 1994. With rising exports, GDP growth reached 6 to 7 per cent in the mid-1990s, but then fell to 4.5 per cent in 1998, 2.8 per cent in 1999 and -2 per cent in 2000. The country's previously consistent trade surplus was severely reduced by falling international commodity prices, particularly those for coffee and cocoa. During the 1990s, even before the balance of trade deteriorated, increasing debt service obligations and a suspension of international aid were reflected in a widening current account deficit. Other recent factors contributing to the deficit have included excessive tax exemptions, weak expenditure control and off-budget spending. The AFD, the IMF and the World Bank suspended aid and reform-linked loans in 1999 and 2000 because of concerns about corruption, mismanagement and failure to meet debt service obligations. In conclusion, country economic risk as it relates to the Azito power project is a more troubling factor than when the project financing was arranged in 1999, but it is, of course, mitigated by multilateral agency participation.

Critical success factors and lessons learned

In his article in the *Journal of Project Finance* (Fall 2000), mentioned above, John S. Strong concluded that the Azito project was a model for future infrastructure projects in the region. Some of the reasons Strong cited for the project's success are listed below.

- Côte d'Ivoire's economic policies and growth after its 1994 devaluation and its debt restructuring initiatives gave project sponsors and lenders confidence in the success of a private project in the power sector.
- Power needs sufficient to justify a project of Azito's size were clearly demonstrated.
- The government, Société Générale and the IFC were able to demonstrate to the financial markets that the Ivorian power sector had established economic viability through sound tariffs and financial management.
- Lenders could see a precedent in the CIE and CIPREL concessions, which were working well.
- The government was willing to acknowledge the need to develop concession contract laws to cover Azito and future projects.
- As a result of its recent work in power sector reform, the government had clear notions concerning the role of private participants and social goals such as rural electrification.
- The government put together a strong team with good technical, financial, managerial and negotiating skills.
- The IDA partial risk guarantee was critical in attracting commercial lenders to a country that was not yet an established international borrower, but the project financing would have taken less time if the guarantee had been introduced earlier in the negotiating process.
- The joint arrangers, the IFC and Société Générale, had to bridge cultural gaps, but teamwork and the complementary skills of the two organisations were essential in designing a loan structure that could be syndicated successfully in the commercial bank market.
- Among other strengths, the three sponsors brought technical skills, previous experience

with similar projects, experience in Côte d'Ivoire, risk-bearing capacity and insurance relationships to the project.

- The new sectoral cash-flow waterfall was the major structural innovation, establishing a system for power concessions that provides clear risk allocation and sound financial management.

Strong also noted several outstanding issues whose resolution over the next few years will influence future participation in power and other infrastructure sectors in Côte d'Ivoire.

- Political pressure for lower retail electricity prices may make the project's covenants with respect to the price of electricity difficult to enforce.
- While the gas supply currently appears to be adequate for the Ciprel and Azito projects, continued public management of the gas sector and improved coordination between the Ministry of Hydrocarbons and the Ministry of Energy will be important to ensure that it is adequate in the future and not compromised by the needs of other future projects.
- Azito is a test of the government's credibility, and its ability and willingness to comply with its obligations to the sponsors and lenders, including the proper management of gas reserves and electricity tariffs.
- The lenders see the IDA's political risk guarantee as not just political risk cover, but a commitment by the World Bank Group to monitor the project and encourage the government of Côte d'Ivoire to meet its commitments; and Azito will test the agency's leverage in fulfilling that role.

¹ This case study is based on an article by John S. Strong, 'Azito: Operating a New Era of Power in Africa', *Journal of Project Finance*, Fall 2000; follow-up discussions with Mr Strong; and various other articles in the financial press.

² Strong op. cit., p. 39.

³ Ibid., p. 40.

⁴ Ibid., p. 42.

⁵ Ibid., p. 43.

⁶ Ibid., p. 43.

⁷ Ibid., p. 44.

⁸ 'Cote d'Ivoire Awards Second BOT Power Contract', *International Trade Finance*, 20 June 1997, p. 10.

⁹ Denes, Marco, 'Azito: A Benchmark for Africa', *Project Finance*, March 1999, p. 16.

Dabhol Power Company, India

Type of project

Power station, port facilities for the importing of liquefied natural gas (LNG), and an LNG regasification facility.

Country

India.

Distinctive features

- Largest foreign investment in India.
- Largest energy infrastructure project financing in India.
- First financing to close after foreign companies allowed into Indian power sector.
- First Indian government guarantee of a foreign corporation's liabilities.
- Wilful default by main offtaker.
- Defaults by both federal and state governments on guarantees.
- Bankruptcy of principal project developer.
- Limited effectiveness of international arbitration process.

Description of financing

The financing for Phase I (June 1995) comprised:

- US\$270 million equity from the three sponsors;
- US\$100 million in loans from the Overseas Private Investment Corporation (OPIC);
- US\$300 million in US Eximbank-guaranteed loans from Indian banks;
- US\$100 million in rupee-denominated Indian bank loans; and
- US\$150 million in a 10-year syndicated commercial bank loan, lead-managed by Bank of America and ABN AMRO, and priced at 300 basis points (bps) over the London interbank offered rate (Libor), with commitment fees of 100 bps and participation fees ranging from 75 bps for a US\$10 million participation to 87.5 bps for a US\$15 million participation.

The last-mentioned loan, which carried a counter-guarantee from the central government, was 64 per cent oversubscribed.

The refinancing (December 1996) comprised:

- US\$298 million provided by US Eximbank;
- US\$150 million from a syndicated commercial bank loan led by ABN AMRO and Bank of America;
- US\$100 million from OPIC; and
- US\$96 million funded by the Industrial Development Bank of India (IDBI).

The financing for Phase II (May 1999) comprised:

- US\$452 million in sponsors' equity;
- US\$333 million equivalent in rupee-denominated loans from an Indian bank consortium;
- US\$497 million as a commercial bank syndicated loan;
- US\$433 million as an export credit loan arranged by Japanese Export Credit Agency; and
- US\$90.8 million as an export credit loan provided by commercial banks and insured by Office Nationale du Dueroire (ONG) of Belgium.

Project summary¹

The Dabhol power project consists of the development, construction and operation of a power station, port facilities for the importing of LNG, and an LNG regasification facility. It is located near the village of Dabhol in the state of Maharashtra, 170 kilometres south of Mumbai (formerly known in the West as Bombay). The project has been constructed in two phases. The first phase is a single power block and ancillary facilities. The second phase entails construction of two additional power blocks; an adjacent regasification facility; and a fuel jetty, breakwater, dredged channel and turning basin for an LNG tanker. Each power block is a combined-cycle unit comprising two combustion-turbine generators, two heat-recovery steam generators and one steam-turbine generator.

The project represents the largest foreign investment and the largest energy infrastructure project financing in India. Financing for the first phase of the project in 1995 was the first to close after foreign companies were allowed into the Indian power sector. It was facilitated by the first Indian government guarantee of a foreign corporation's liabilities.

The project has been plagued by wilful default by the Maharashtra State Electricity Board (MSEB), the main offtaker; defaults by both federal and state governments on their guarantees; and the bankruptcy of Enron, the principal project developer. Among the underlying problems have been that:

- the price of power supplied by Dabhol under the Power Purchase Agreement (PPA) was more than the MSEB could afford;
- the State of Maharashtra had more power than it needed; and
- the project was not allowed to sell power to other parties without state and federal government permission.

The project is now under the control of the lenders.

Background

India's power sector

Under the Indian Energy Supply Act 1948, the Central Electricity Authority was created to develop a national power policy and coordinate power development at the national level. State electricity boards were set up to promote the development of the power sector in each state. The Industrial Policy of 1956 explicitly placed responsibility for generation, transmission and distribution of power in the public sector. In theory, that responsibility was shared jointly by the federal and state governments.

In recent decades power projects have been developed mostly by government utilities, and financed through the government budget and credit facilities from commercial banks, suppliers, and bilateral and multilateral agencies. During that period India has lived with consistent power shortages because generation capacity has trailed behind demand. At the same time the state electricity boards in the aggregate have earned a negative rate of return and received poor credit ratings because of mismanagement, subsidised electricity rates and electricity theft.

Faced with both a shortage of generating capacity and inadequate resources to finance new power plants, the Government of India opened the power sector to foreign as well as domestic private investors through the Electricity Laws (Amendment) Act 1991. To meet existing shortages and demand, expected to grow at 9 per cent per year, the government's central planners set a target of 45,000 MW of new generating capacity by 1997, which would be impossible to meet without the help of foreign capital. There would be no limit on foreign equity ownership. Private-sector participation was intended both to provide needed resources, and to promote efficiency and competition in the electricity sector.²

Because India had no experience in private power development, the government did not consider itself qualified to draft detailed tender documents. Further, the government wanted to increase generating capacity as quickly as possible. It concluded that competitive tendering was impossible at this early stage, particularly given the time pressures, and that the first few 'fast track' independent power projects would have to be negotiated. In October 1991 the government issued policy guidelines that were relatively thin in detail to allow flexibility as it worked with investors and learned about the independent power business. In March 1992 the Ministry of Power announced a cost-plus approach to tariff formulation under which developers would earn a set return on equity (ROE) invested and be reimbursed for fuel costs separately.

In an article in the *Journal of Structured and Project Finance* (Spring 2002), an Indian lawyer, Piyush Joshi, provided an overview of the legal framework governing independent power producers (IPPs) in India. He explained that an IPP is allowed to sell electricity only to the state electricity board in the state where its power plant is located, unless it is granted permission to do otherwise, which is not easily obtained. To sell power to a different entity within the same state, it must receive permission from the state government. To sell power to an entity in another state, it needs permission from its own state government, the receiving state government and the federal power ministry. Another important aspect of the legal framework is that the IPP has no way to manage its credit exposure to the state electricity board. An IPP is in effect a captive supplier, with nowhere to turn if the credit fundamentals of the state electricity board deteriorate.

Negotiations with Enron

International power developers did not respond immediately to the new opportunities in the electricity sector in the early 1990s because India had suffered recent balance-of-payments problems and banks had cut back their credit facilities. As a result, the government had to seek out developers. Delegates from the Ministry of Power visited various IPPs to solicit their interest. When they reached Houston, Texas, they found Enron to be particularly committed and focused. Their discussions would lead to agreement on the first of eight fast-track independent power projects.

Maharashtra, on India's west coast, was appealing to Enron for at least two reasons. First, the state and Mumbai, its capital, were enjoying a period of political stability and economic growth as industry relocated from the traditional industrial heartlands in eastern India surrounding Calcutta, whose economy had declined under successive communist administrations. Second, Maharashtra was just across the Arabian Sea from the Persian Gulf states, which Enron saw as a source of natural gas. The Indian government had discussed the possibility of natural-gas pipelines under the Arabian Sea with the governments of Oman and Iran. Most of India's power plants at the time were fuelled by coal. Although natural gas was more expensive, it was cleaner and more efficient. Further, coal would have to be transported from eastern India. It was subject to theft and delivery was unreliable, putting a power plant's contractual output commitments at risk.³

Enron, formed in 1985 through a merger between a natural gas company and a pipeline company, had achieved close to 30 per cent compound annual earnings growth during the past several years, and was looking for projects outside the United States to sustain that growth. Responsibility for negotiating the Dabhol project was entrusted to Rebecca Mark, the CEO of an Enron subsidiary, Enron Development Corporation.

In June 1992, after preliminary negotiations, Enron signed a memorandum of understanding with the Congress Party's chief minister in Maharashtra. Enron and the State of Maharashtra agreed to a project that was considered highly ambitious: a 2,105 MW, gas-fired power plant with an estimated cost of more than US\$2 billion. At a time when international bankers were not lending to India on terms longer than one year, US\$1.75 billion of that cost would have to be raised in the debt markets.⁴

Enron's first six months of negotiations after signing the memorandum were at the federal level in Delhi, primarily with the Foreign Investment Promotion Board, which coordinates approvals and clearances for foreign investment projects. In early 1993 Enron began to negotiate a PPA with the Maharashtra State Government and the MSEB.

When the Indian government developed its cost-plus approach to tariff formulation in 1992, it set guidelines that allowed power developers to earn 16 per cent ROE if the plants they built operated at 68.5 per cent of capacity. Above that level state electricity boards could grant incentive payments up to an additional 0.7 per cent ROE for every percentage point increase in output achieved. Because gas-fired plants are very efficient, Enron was willing to commit itself to a high level of generation in the PPA, and in return the MSEB committed itself to purchasing 90 per cent of the plant's capacity. Some interpreted these terms as guaranteeing Dabhol a minimum 31 per cent ROE. That was not exactly the case, because the PPA also required Dabhol to assume some risks that were not envisaged in the government's ROE guidelines: the company would incur big penalties if it missed its construction deadlines or failed to build or operate at the specified capacity.

In March 1993 the Mumbai hotel where the Enron team was staying was severely damaged by a bomb blast — an early indication of the political difficulties that the project would face. In April the Indian central government commissioned a World Bank report on the feasibility of the Dabhol project. Three months later the World Bank concluded that the project was too large and not the least-cost choice for power generation in Maharashtra. The World Bank was therefore unwilling to participate in financing the project. Dabhol was intended to be a baseload generator, producing electricity 24 hours a day rather than just at peak periods, and the MSEB was committing itself to purchasing a high proportion of the plant's capacity. The report concluded that the MSEB would be forced to use more expensive power from Dabhol in place of cheaper existing supplies during periods of low demand. The World Bank argued that LNG should not be used for baseload power generation because coal, despite transport problems, was more affordable.

In August 1993 Enron agreed to split the Dabhol project into two phases and, for the time being, move ahead with just the first phase, a 695 MW plant fired by oil distillate or naphtha, both of which could be sourced within India. The second phase, a 1,320 MW gas-fired expansion of the plant with LNG loading and regasification facilities, might or might not follow later at the discretion of the state government.

In November 1993 Dabhol Power Company (DPC) and the MSEB signed a PPA for 20 years, extendible for a further period of five or ten years by mutual consent. DPC guaranteed an average availability of 90 per cent and also guaranteed a specified heat rate for 20 years, subject to significant penalties for not meeting these performance targets. DPC committed itself to commissioning the project within 33 months (1,005 days) from the date of financial closure, subject to a large penalty for delay. The MSEB's obligations were guaranteed by the Government of Maharashtra. DPC thus became the first project to be implemented under the Indian power sector privatisation programme.⁵

In September 1994 representatives of the Indian federal government and DPC signed a counter-guarantee agreement for the first 695 MW phase of the project. This was the first time that the Indian government had underwritten the liabilities of a foreign company. The counter-guarantee was to be valid for just 12 years, even though the PPA had a 20-year term, and it limited the government's liability to US\$300 million in the event that the MSEB defaulted. To protect the government exposure, the counter-guarantee has a provision that allows the government to redirect power from the plant to alternative buyers. While providing for mutually accepted dispute-resolution mechanisms, the counter-guarantee allows a dispute that cannot be settled in 60 days to be taken to London courts under the Unictral Arbitration Rules. London was mutually agreed to be a neutral venue with a reputation for concluding arbitration proceedings quickly.⁶

In 1993 and 1994, as Enron solidified its relationship with Congress Party officials at the state level, Shiv Sena, a local militant Hindu nationalist party, became increasingly visible — for example by inciting anti-Muslim riots in Mumbai. By early 1995 Shiv Sena had formed an alliance with the Bharatiya Janata Party (BJP), a more moderate Hindu nationalist party that was active throughout India. In anticipation of nationwide parliamentary elections in 1996 Shiv Sena and the BJP were looking for political issues to use in their campaign to wrest power from the Congress Party in Maharashtra. The Dabhol project, championed by the Congress Party, was an easy and visible target that they could use in an information campaign, appealing to cultural and economic nationalism, distrust of foreign companies and fear of competition from them.

In March 1996 the Congress Party fell from power in Maharashtra and a new Shiv Sena chief minister wasted little time in setting up a committee to review the Dabhol project. As Shiv Sena pursued the investigation and the BJP pursued the politically motivated information campaign, the two allied parties looked for both evidence of corruption and ways to challenge the project on technical grounds. Enron considered itself on solid ground, being backed by contracts at the state level and a counter-guarantee at the federal level, and embarked on its own information campaign. The Shiv Sena ministers in Maharashtra came to realise, with the concurrence of officials at the MSEB, that cancelling the project could be very costly for the state unless clear evidence of corruption could be found. Rebecca Mark of Enron was confident that no such evidence could be found. Nevertheless, the BJP wanted to pursue its information campaign so as to be seen as representing the people's interests by cutting the costs or improving the terms of the MSEB's contract with DPC. The local review committee found no evidence of corruption or other legal grounds for cancelling the contract. Its report, only parts of which were released to the public, reiterated charges already made:

- the project was negotiated rather than open to competitive tender;
- the tariff was too favourable to Enron;
- LNG was the wrong fuel because it was too expensive;
- Enron had padded its costs; and
- the deal was 'obsessively secret'.

Rebecca Mark later commented that whether costs were padded or not was immaterial, because the only thing that really mattered was the tariff.

Financing for Phase I

The sponsors and their bankers closed on a US\$920 million project financing in June 1995 (as detailed in the section 'Description of financing' above).

Enron originally planned a Rule 144A private placement rather than a syndicated commercial bank loan, but as a result of the recent Mexican peso crisis institutional investors were not receptive to long-maturity, emerging-market bonds.

Contractual framework

As a prerequisite for the financial closing, the entire contractual framework for both phases of the project was put in place. In addition to the PPA the contracts included:

- engineering, procurement and construction (EPC) contracts for both phases, including the power station, the regasification facility and the marine facility;
- operations and maintenance (O&M) contracts, also for both phases;
- LNG supply and purchase agreements; and
- a time charter for an LNG tanker to be dedicated to transporting LNG to the project.⁷

The Dabhol project documents are governed by English law and provide for ICC arbitration in London.

DPC's credit risk related to the PPA was mitigated in several ways:

POWER PLANT

- DPC and the MSEB established escrow arrangements to capture revenues from selected MSEB customers to support the MSEB's payment obligations under the PPA;
- the PPA required the MSEB to open a letter of credit;
- the Government of Maharashtra provided an unconditional and irrevocable guarantee; and
- the Government of India provided a limited counter-guarantee.

Contract cancelled

The chief minister of Maharashtra, under continued pressure from the BJP, announced on 3 August 1995 that the MSEB was cancelling its PPA with DPC because of padded costs, excessive rates for electricity, environmental hazards and lack of open negotiations. Two days later Enron served the state government with legal notice that it would pursue arbitration in London. Under UN jurisdiction three selected international arbiters have the authority to evaluate all relevant information pertaining to the project before coming to a decision about contract enforceability and possible compensation, which is legally binding through Indian courts.

On 12 August Little & Co. declined to represent the MSEB after serving as its solicitors for 20 years. The firm considered the state's decision indefensible because the MSEB had been unable to show any corruption or breach of contract by the developers. By the next month it had become apparent that the Maharashtra state government was willing to renegotiate and even had persuaded the BJP to back down because of the huge penalties that the state could face for cancelling the contract.

By this time the first phase of the project was 20 per cent complete and Bechtel and its largely Indian subcontractors had 2,300 workers on site. An estimated US\$130 million of the US\$150 million loan syndicated by Bank of America and ABN AMRO had been drawn down, and approximately the same amount of equity had been invested in the project. DPC had signed about 150 contracts with local suppliers. Meanwhile, arrangements to finance the other seven fast-track projects were underway, and sponsors and bankers wondered whether their contracts could be cancelled in a similar manner.

Revised project agreement

In January 1996 the MSEB offered DPC the opportunity to resume construction on the project under revised terms:

- the MSEB would become a 30 per cent owner of the project;
- the capital cost would be reduced from US\$2.6 billion to US\$1.8 billion;
- plant capacity would be increased from 2,015 MW to 2,450 MW, because of upgraded turbines;
- the plant would be converted to accommodate domestically available oil distillate or naphtha as well as imported LNG; and
- the electricity rate would drop from 7 US cents to 5.4 cents per KW hour over the 20-year PPA period.

In addition, the LNG terminal, which could supply LNG to other customers as well, would become a stand-alone project.

As a result of the renegotiation Enron had to cancel an agreement to sell a 20 per cent

stake in the project to Entergy Corp., a utility based in New Orleans. The cost of the cancellation to Enron was about US\$75 million. The reduction in electricity rates was partly offset by a drop in turbine prices and other anticipated savings in equipment costs over the second phase of the project. Enron had a strong incentive to make concessions and reach agreement with the MSEB, so that it would not appear that its global power strategy could easily be derailed by local politics. By this time Enron had 29 power and pipeline projects pending or underway in Bolivia, Brazil, China and Turkey. At the same time India needed to reassure the international business community that disputes with foreign investors could be resolved fairly.⁸

In August 1996 the Indian lenders' consortium led by the IDBI said that it would not negotiate revised financing terms with DPC until all domestic court cases were settled and DPC withdrew its arbitration case in London. A case filed by the leftwing Confederation of Indian Trade Unions, challenging the project's approval by various federal and state agencies, was still pending and threatened to delay the project further. The lenders also refused to increase their original commitment, equivalent to US\$95 million, saying that the sponsors should cover all cost overruns resulting from the interruption of work on the site, estimated at US\$160 million.⁹

In December 1996, after a 16-month stalemate, the Indian high court dismissed the last of the many lawsuits attempting to block the project. The sponsors resumed construction work and completed financing for the first phase, which was expected to be up and running by December 1998.

Refinancing and further litigation

At that time project refinancing was closed (again as detailed in the section 'Basic information' above). By February 1997 50 per cent of the project's first phase was completed. In March preparatory work began for the second phase.

In May the Indian supreme court rejected a public-interest petition from an environmental activist and the Centre for Indian Trade Unions alleging that the Central Electricity Authority had cleared the project without complying with various provisions of the Electricity Supply Act 1948, and that the Maharashtra state administration had subverted several statutory processes in granting the most recent approval. They challenged the notion that the country had achieved a better deal in the renegotiation and called for a review of the entire project. The court noted that the project and its PPA had been adequately examined by the Mumbai high court and did not need a review at this stage. After the project had weathered more than a dozen court cases at local, state and national levels, power industry analysts and legal experts thought that the supreme court's decision finally might have brought the litigation to an end.¹⁰

Financing for Phase II and completion of Phase I

Financial arrangements for the US\$1.87 billion second phase of the project, including the LNG terminal and regasification plant, were completed on 6 May 1999 (again as detailed above). The first phase of the project began commercial power production on 13 May 1999, having been completed at a cost of US\$1.08 billion. The MSEB began to purchase all the power generated by the unit under the 20-year PPA at a price of 3.01 rupees (7.04 US cents)

per unit. According to its chairman, the MSEB would be paying DPC 1.4 billion rupees (US\$32.8 million) per month.

The MSEB fails to pay

During 2000 it became increasingly apparent that the MSEB could not afford its obligations under the PPA. DPC tried to persuade both the state and federal governments to make the policy changes that would allow it to sell electricity to more than one state electricity board and to any third party, but government officials seemed unwilling to focus on the problem. In December the Maharashtra state government announced that it would review the PPA because it believed that the power rates that DPC was charging were exorbitant.

In February 2001 DPC invoked a federal guarantee to pay a November 2000 bill for 790 million rupees (US\$17 million) owed by the MSEB. Once again DPC began the arbitration process with the International Court of Arbitration in London. By April the MSEB's unpaid bills had risen to US\$22 million and DPC had notified the federal government again. The MSEB said that the power bill should be offset against a 4 billion rupee (US\$86 million) fine that it had levied against DPC for what it claimed had been non-supply of power for intermittent periods between October 2000 and January 2001. The Indian federal government asked the two sides to sort out their argument before it would consider making any payment under the counter-guarantee. In April DPC sent the MSEB a notice of political *force majeure* to enforce its rights under the 1995 PPA and to protect itself from being penalised by the MSEB if political uncertainties interrupted its delivery of electricity.

In May DPC sent the MSEB a preliminary termination notice, which was required under the PPA to precede a final termination notice by six months. A final termination notice would cancel the PPA and transfer ownership of the power plant to the MSEB. DPC said that it had continued to meet its contractual obligations, enforce its rights under contracts and take various disputes to the dispute resolution process, but it was forced to issue the preliminary termination notice because of the failure of the MSEB, the Maharashtra state government and the Indian federal government to meet their contractual obligations. DPC also said that the Indian federal government had clearly communicated its unwillingness to assist the MSEB and the state government in either buying power or providing credit support behind other buyers. DPC noted that the federal government had not sent a representative to a recent renegotiation committee meeting, despite several days advance notice, and had failed to respond to requests from lenders to the project for assurances of its guarantee obligations. DPC said that a lasting and feasible solution would require the contractually bound parties either to purchase power or to find other creditworthy parties to purchase baseload capacity when the plant was fully constructed. Work on the second phase of the project, which was 90 per cent complete, had been stopped recently because lenders had suspended disbursements, and the Maharashtra state government and the MSEB had not implemented the escrow account that was intended to secure payments from the MSEB.¹¹

The MSEB cancels the PPA

The MSEB notified DPC on 24 May 2001 that it was cancelling the 1995 PPA and it stopped buying power from the plant on 29 May. DPC shut down the plant shortly afterwards. Over the previous few months the MSEB's defaults, and the failure of the state and federal gov-

ernments to honour their guarantees, had caused DPC to default on all its contracts. By this time most of the contracts had been cancelled.

In early June the Indian lenders asked DPC to start renegotiating the PPA with a specially convened expert panel formed to arbitrate in a tariff dispute between the two parties. Later in June, acting on a plea from the MSEB, the newly established Maharashtra Electricity Regulatory Commission (MERC) ruled that DPC could not proceed with arbitration in London. DPC replied that it was proceeding with such arbitration in accordance with the PPA. It also requested that the Mumbai high court reverse the Commission's decision, but the court ruled that the Commission was the expert body empowered to decide on the issue.

In early July Daniel Pearl reported in the *Wall Street Journal* that even though Enron and Maharashtra officials were meeting regularly, their dispute had fallen into a 'slow-motion stalemate', with Enron saying that it had not agreed to renegotiate the contract and the MSEB saying that it had already rescinded it. Vinay Bansal, the MSEB's chairman, said that completing the second phase was not a priority because the utility, required to pay for most of the plant's generating capacity, could not afford the power. Maharashtra's recent electricity consumption had been far below projections. Bansal said that he had approached the central government to help to buy excess power, but that they continually had said no. He noted that other states would be willing to buy DPC's power if rates could be lowered to 2.5 rupees (5.3 US cents), but he doubted that DPC would be willing to reduce its prices that far. Pearl noted that if construction did not resume by the end of the summer, suppliers of LNG from Abu Dhabi and Oman under 20-year contracts would become increasingly nervous. As for the Indian lenders' consortium, led by the state-controlled IDBI, they had more to lose than the foreign banks because they were guarantors of a large portion of the project's foreign debt.¹²

Later in July Enron indicated a willingness to sell its interest in the project at cost and the Indian federal government directed the Indian lenders' consortium to work out a package to save the project. By that point the sponsors had invested US\$875 million in the 1,444 MW second phase and an additional investment of US\$230 million was needed to complete the project. Enron was willing to provide technical and other assistance to help the buyer complete the project. Jawanti Mehta, India's junior power minister, said in early August that the government was not interested in buying the project, but that it was coordinating a negotiating committee, including Enron and the other investors, to find a way out of the disagreement. Later in August the Indian lenders' consortium offered to reschedule DPC's project debt.

Enron's chairman, Kenneth L. Lay, wrote a letter to the Indian prime minister in September questioning the Indian government's willingness to honour its contracts and its ability to attract foreign investment. Lay threatened to take legal action in pursuit of claims up to US\$5 billion. Enron's proposals to the Indian government included the sale of its equity investment at cost, for approximately US\$1.2 billion, and the purchase of its debt, for approximately US\$1.1 billion, amounting to a total cost of US\$2.3 billion. Lay's letter indicated that a proposal by Indian financial institutions that equity held by foreigners be sold for about US\$400 million, about one third of their actual investment in the project, was unacceptable. If Enron received anything less than its full investment, it would consider that the Indian government had committed an act of expropriation. Lay warned that it would be difficult for DPC to complete the second phase of the project unless the government reached an amicable solution with the sponsors.

Lenders stop advances

By this point the foreign lenders were so unhappy with the lack of progress in project construction that they were not advancing any additional funds. Because the physical assets were not being maintained, there was a possibility that the plant would never reach its specified performance levels. Suspension of construction already had increased the cost of the project by several hundred million dollars and the longer it was delayed, the greater the increase in construction costs would be.

On 10 September 2001 DPC requested payment of US\$80 million from the Indian federal government for electricity that it had provided to the MSEB in April, May and June. The MSEB in turn sought to force this dispute into Indian regulatory channels rather than arbitration. The MSEB appealed to the Indian supreme court to prevent the federal government from paying DPC until the Mumbai high court had rendered an opinion. DPC sent the MSEB another preliminary termination notice for nonpayment of electricity fees and abrogation of the PPA, and, once again, the MSEB claimed damages from DPC for failing to deliver at 90 per cent of capacity. The Maharashtra state government asked the MERC to set the power plant's tariff. DPC then appealed to the Indian supreme court to free it from the MERC's jurisdiction, but the court ruled that the MERC could decide on the scope of its own jurisdiction. DPC appealed against the ruling and the supreme court responded by transferring all DPC-related cases, including the appeal, to a single branch of the Mumbai high court.¹³ The latter court affirmed that the MERC has exclusive jurisdiction over ongoing disputes between the MSEB and DPC.

In an article in the *Journal of Structured and Project Finance* (Fall 2002) Mark Kantor, retired partner of Milbank, Tweed, Hadley & McCloy, observed that the Mumbai high court reached this conclusion despite mandatory arbitration clauses in project documents signed by the MSEB, the Maharashtra state government and the Indian federal government. Although the project documents were originally executed in 1993 and 1994, and the statute creating the MERC was not passed until almost five years later, the effect of the court's ruling was to afford the MERC sole competence over the MSEB's claim that the project documents were invalid because of material misrepresentations by DPC. The court's decision thus had the effect of enabling state parties to override arbitration clauses by relying on legislation enacted later.¹⁴

On 11 October 2001 the Commercial Court in London gave DPC an *ex parte* order (that is, an order undertaken on behalf of only one of the parties) restraining the Maharashtra government from filing a suit in London to challenge the arbitration proceedings that DPC had initiated there. The order made a distinction between the Maharashtra state government and the MSEB, which is owned by the state government. The order was intended to stop the state government from renegeing on its obligations even if the MSEB did so.

Mark Kantor noted that the Mumbai high court's ruling did not directly address the question of separate claims by DPC against the State of Maharashtra and the Government of India, both of which signed documents with mandatory arbitration clauses. DPC later obtained an English court injunction prohibiting the Maharashtra state government from filing suit in Indian courts to contest separate ongoing ICC arbitration in London against Maharashtra under one of the project agreements.¹⁵

In early November 2001 the Indian lenders' consortium filed a petition to try to prevent DPC from pulling out of the project. Following procedures outlined in the PPA, DPC recently had taken an additional step toward a final termination notice by issuing a notice of trans-

fer of assets to the MSEB, which allowed the assets of the power plant to be valued. Enron said that it intended to sell its stake in DPC to either the Indian government or Indian lenders and two Indian power utilities had indicated an interest. At this point Enron's own problems with unexplained off-balance-sheet transactions were beginning to escalate following a US\$1 billion charge to earnings and a US\$1.2 billion writedown of shareholders' equity disclosed on 16 October.

In December the Indian government asked local financial institutions to help it to find bidders for the Dabhol project. Two private Indian utilities, BSES Ltd. and Tata Power Company, met DPC and the lenders to discuss ways to resurrect the project. They agreed to study the project further and inspect its books over the next couple of months. Indian newspapers reported that Enron and its co-sponsors were looking for US\$1.2 billion and the Indian bidders were prepared to pay only half that amount. Later in the month the project's bank lenders agreed to release US\$20 million from various restricted accounts for urgent care and maintenance of the power plant, which was deteriorating while not in operation. By this time most of DPC's employees had been laid off, apart from a skeleton staff for security and minimal maintenance.

Fundamental problems unresolved

At this point there were still two principal problems unresolved. First, the price of power supplied by DPC under the PPA was more than the MSEB could afford and more than the price charged by other power plants in Maharashtra.

Second, Maharashtra had more power than it needed. In the early 1990s, when the original PPA was negotiated, it had been projected that Maharashtra would need all the power that the Dabhol project could produce and more. However, even though the Indian economy grew at more than 7 per cent for several years in the late 1990s, Maharashtra's economy had not grown as fast since then. The state had a total installed generation capacity well above the highest peak demand ever recorded and therefore power was needed from DPC only during peak demand periods or when other plants were shut down for maintenance.¹⁶

A review committee commissioned by the Maharashtra government and chaired by Madhav Godbole, a former home minister in the federal government, proposed that:

- DPC's shareholders should write off three quarters of their US\$1 billion in equity;
- the Indian government should forgo duties on imports of capital equipment and LNG fuel for the project;
- the federal government should borrow 25 billion rupees and make that amount available to Dabhol as an interest-free loan; and
- the government should pay Enron a contract termination penalty of US\$300 million.

In the committee's opinion, this combination of sacrifices would allow DPC to sell power at a price that Maharashtra could afford.¹⁷

The consortium of Indian bank lenders led by the IDBI had other ideas. They proposed investing an additional US\$250 million to convert the plant to run on LNG rather than naphtha, allowing the Gas Authority of India (GAIL) to take over the LNG terminal and the National Thermal Power Company (NTPC) to take over the power plant. However, GAIL and NTPC, both state-owned, were reluctant to be drawn in.¹⁸

In early December 2001 Enron filed for Chapter 11 bankruptcy protection in the United States. Later that month DPC filed a US\$180 million claim with OPIC, arguing that the MSEB's failure to pay its electricity bills was tantamount to expropriation by the state, an act that should be covered by its OPIC political risk insurance policy. After the claim was filed OPIC began to work with the IDBI on finding a buyer for the power plant. DPC issued its final termination notice to the MSEB on 27 December.

In January 2002 the IDBI invited formal expressions of interest from potential buyers of DPC. Six companies already had indicated a possible interest. There were three Indian companies – BSES Ltd, GAIL and Tata Power Company – and three foreign companies: TotalFinaElf, Royal Dutch/Shell Group and Gaz de France. The creditors' preference was to sell the facility as a whole rather than to accept separate bids for the power plant, the landing jetty and the LNG storage facilities. DPC announced that it was willing to settle any dispute arising with potential buyers under English law, as provided in the original project documents; its discussions with BSES Ltd and Tata Power had hit a roadblock the month before over whether a proposed deal would fall under Indian or international law.

While the IDBI and OPIC were continuing to work together, by February 2002 OPIC appeared to be more in control of the sale process, defining the terms of sale and setting a mid-March deadline for the submission of bids. OPIC planned to set up a data room in London where each qualified bidder would have three days to carry out due diligence, followed by a two-day visit to the plant. Operating data, information on the status of the second phase and historical construction records would be provided in the data room, and OPIC planned to have a pre-bid conference in late February.¹⁹

At this point the search for a buyer was becoming increasingly urgent because DPC, with fewer than 100 employees, no longer had enough cash to maintain the plant. NTPC turned down an offer by the MSEB to take over the plant because it found the price too high but offered to operate the plant in the national interest if it was purchased by financial institutions or the MSEB.

In March a dispute between DPC's lenders and foreign equity holders began to jeopardise the sale of the project. The lenders proposed that proceeds from the sale of the project be deposited into the Trust and Retention Account operated by Bank of America, and that money in that account be used for debt service, guarantee payments, and bank charges and defaults before distribution to the equity holders. The lenders, including OPIC, estimated that a few hundred million dollars would be needed for these payments. The equity holders protested against the transfer of the sale proceeds to the Trust and Retention Account because they thought that they would probably receive only a few million dollars after all the other distributions.²⁰ Later in March the equity holders took their argument a step further and said that they would not proceed with a sale unless they received an advance payment of US\$500 million, about half their asking price.²¹ Meanwhile some of the bidders announced that they regarded the lenders' due diligence time frame as too short and that they needed at least six months to scrutinise DPC's financial records.²²

In April Enron refused to sign a cooperation agreement with DPC's creditors because of the dispute over the Trust and Retention Account. Disgruntled bidders began to ask for a refund of the US\$100,000 'good faith' payments that they had been required to make when they submitted their expressions of interest. The Indian and foreign lenders, and their lawyers, began to discuss a foreclosure on DPC's assets if Enron did not cooperate in an equity sale, although such a foreclosure was complicated by an obscure US legal provision.

A payout under an OPIC insurance policy in these circumstances could trigger the Hickenlooper Amendment, which prevents the United States from giving development aid to countries that have nationalised the property of its citizens and have not taken appropriate steps to pay for it. The amendment, named after Senator Bourke Hickenlooper, a conservative Republican from Iowa, had been passed in 1962 in response to the nationalisation of US property in Brazil.²³

Bechtel and General Electric (GE), joint EPC contractors and both 10 per cent shareholders in DPC, were in a different position than Enron was on the issue of fair compensation. They held smaller amounts of shares than Enron did, but, more importantly, Enron had been required to pledge its DPC shares as security for the commercial bank loans, whereas Bechtel and GE had not. Therefore Bechtel and GE thought that they had a stronger argument for receiving fair compensation for their investments up front, not after all the debt holders' claims were settled. Both companies indicated that they were willing to negotiate with the creditors to try to meet them halfway, but they would not be willing to help restart the plant if they were not treated fairly. A consortium of Indian engineering and power companies conceivably could have restored and operated the plant, but clearly they would not have had Bechtel's and GE's expertise. GE had designed the plant and Bechtel had built it.

Like the foreign shareholders, OPIC preferred an equity sale to an asset sale. OPIC's US\$400 million burden under the political risk cover that it had provided would be reduced to the extent that those shareholders received part of the sale proceeds.

Despite disputes with the shareholders, the MSEB and the lenders looked for ways to restart the plant because they thought that an operating plant would be more appealing to a buyer. Once again the parties could not agree on a price. In July the MSEB offered to buy power for 2.25 rupees per unit, but the lenders were not willing to sell it for less than 2.85 rupees per unit.

In September 2002 the Indian federal power ministry convened a meeting of all stakeholders, and encouraged the Maharashtra state government and the IDBI to continue their efforts to reach a compromise. At a subsequent meeting convened by the ministry, GE agreed to support NTPC in assessing the condition of the power plant and restarting generation. By this time the plant had been exposed to two monsoon seasons without major maintenance. GE and Bechtel estimated that 8 to 12 months of repair and maintenance work would be required before Phase I of the project could be restarted. In October a Maharashtra state government committee approved the purchase of power at 2.80 rupees, essentially meeting the bank lenders' offer and raising hopes that steps to restart the idle plant could begin soon. Yet even restarting Phase I was just a short-term measure, and a comprehensive, long-term solution for Phases I and II was nowhere in sight.

Roots of the crisis

Piyush Joshi (in his article cited above) believes that the roots of the crisis lie in the legal framework that governs the project. As an IPP, DPC has been allowed to sell power only to the MSEB so long as it lacks permission to do otherwise, permission that it has not been successful in obtaining. In Joshi's opinion the issues that DPC has faced are partly a reflection of what ails the Indian electricity sector: low levels of tariff collection, high subsidies, high transmission losses, poor transmission and distribution infrastructure, and political unwillingness to make necessary reforms in the electricity distribution system. The MSEB currently does not

have the capacity either to offtake or to pay for the capacity of the Dabhol project and that problem is the result of political rather than economic factors. According to Joshi, since the project was initiated in 1993 successive governments have reduced the MSEB from being one of the best-run state electricity boards to being a debt-riddled entity having very low levels of tariff collection and high levels of transmission losses (read as theft). The MSEB has had to bear the burden of extensive subsidies granted to farmers, specific industries and other groups of electricity consumers. Meanwhile, demand for electricity has not increased as forecast because of the low growth in industries established by the state.²⁴

Necessary elements of restructuring

Joshi notes that the Dabhol project structure collapsed at a time when a huge amount of resources had been invested and there were physical project assets to reflect the investments. Given the growing power needs across the country, the Government of India cannot ignore these assets. Now the lenders are in control and trying to minimise their losses, while the original sponsors are looking for a way to exit because their original basis for participating in the project has changed irreversibly. Enron, under bankruptcy proceedings, would not be in a position to continue to develop the project even if it were interested in doing so. Joshi believes that any feasible restructuring of the project must address at least the following basic issues:

- creating a feasible structure to enable regular offtake of electricity;
- allowing multiple uses of the LNG facility; and
- finding new owners.

Joshi believes that it is clear that the project cannot go forward with the MSEB as the sole offtaker. The project needs state and federal government permission to sell electricity to consumers other than the MSEB, and even to parties outside Maharashtra. Selling to a wider market would also require suitable wheeling arrangements between DPC and various transmission entities. Wheeling is the movement of electricity from one system to another over the transmission facilities of intervening systems. Wheeling is required to offer customers a choice of electricity suppliers.

The Dabhol project has two distinct but interdependent facilities: the power plant, and the LNG regasification and storage facilities. Joshi recommends separating the project into two entities, so that the LNG facility could deal in LNG for commercial purposes, not just for the project. He notes that the Government of India would have to approve the demerger, that an arrangement would be required for the power plant and the LNG facility to share infrastructure facilities, and that a pipeline would be needed to transport the LNG to other customers.

Joshi sees a possibility that none of the potential buyers identified so far will want the entire project. Different buyers may be appropriate for the power plant and the LNG facility. Because of the project's size, several large companies may want to form a consortium to buy the project.

Lessons learned

The MSEB's failure to honour its contract obligations indicates that contract parties may fail to honour their contractual commitments when it is beyond their ability or not in their eco-

conomic interest to do so. By not honouring their guarantee and counter-guarantee obligations, the Government of Maharashtra and the Government of India undermined the foundations of the project. Such political decisions could be considered forms of ‘creeping’ expropriation.²⁵

The unwillingness of the two governments to make policy changes that would allow DPC to sell electricity to other entities illustrates a painful principle of project restructuring: preventive restructuring is rare. Contract parties usually do not make concessions until there is a crisis.²⁶

The international arbitration process does not shield project participants from unpredictable local courts, as shown in this case and, to take another example, the Paiton case in Indonesia (discussed in the following chapter).

¹ This case study is based on articles in the financial press, as well as reviews by Barry P. Gold, Managing Director, Citigroup, and Piyush Joshi, formerly an attorney with Enron/Dabhol Power Company and now Deputy Legal Counsel, British Gas India.

² Gupta, Jyoti P., and Anil I. Sravat, ‘Development and Project Financing of Private Power Projects in Developing Countries: A Case Study of India’, *International Journal of Project Management*, 16:2, 1998.

³ Edwards, Ben, and Mulul Shukla, ‘The Mugging of Enron’, *Euromoney*, October 1995, p. 30.

⁴ Ibid.

⁵ Gupta and Sravat, op. cit., p. 103.

⁶ ‘India Inks Guarantee for First Phase of Enron’s 2,015 MW Dabhol Project’, *Independent Power Report*, 23 September 1994, p. 12.

⁷ Joshi, Piyush, ‘Dabhol: A Case Study of Restructuring Infrastructure Projects’, *Journal of Structured and Project Finance*, Spring 2002, p. 28.

⁸ McWilliams, Gary, and Sharon Moshavi, ‘More Power to India: Why Enron Renegotiated Its Deal – on Maharashtra’s Terms’, *Business Week*, 22 January 1996, p. 62.

⁹ Hattangadi, Shekhar, ‘Lenders Applying New Terms to Dabhol; Concern Over Court Cases Linked to India Project’, *Platt’s Oilgram News*, 21 August 1996, p. 3.

¹⁰ ‘Supreme Court of India Rejects Suit Against 2,450 MW Dabhol Power Project’, *Independent Power Report*, 16 May 1997.

¹¹ ‘Dabhol Power Issues Notice of Termination for 2,184 MW Project’, *Global Power Report*, 25 May 2001.

¹² Pearl, Daniel, ‘Dabhol Project Vexes Foreign Firms’, *Asian Wall Street Journal*, 6 July 2001, p. 3.

¹³ ‘India Industry – The Dabhol Power Company Saga’, *EIR Viewswire*, 27 December 2001.

¹⁴ Kantor, Mark, ‘The Limits of Arbitration’, *Journal of Structured and Project Finance*, Fall 2002, p. 50.

¹⁵ Ibid.

¹⁶ Elsham, Robin, ‘Dabhol – Enron’s US\$2.9 Billion White Elephant in India’, *Reuters News*, 23 December 2001.

¹⁷ Ibid.

¹⁸ Ibid.

¹⁹ ‘Insurer Sets Terms of Sale to Bidders for India’s 2,184 MW Dabhol Power Co.’, *Global Power Report*, 1 February 2002.

²⁰ ‘Payment Dispute May Jeopardize Sale of 2,184 MW Dabhol Project in India’, *Global Power Report*, 7 March 2002.

²¹ ‘Enron, Partners Demand Advance from Sale of Dabhol Power in India’, *Global Power Report*, 21 March 2002.

²² Jegarajah, Sri, and Himendra Kumar, ‘India Dabhol Sale Stalls; Row Erupts over Equity Proceeds’, *Dow Jones Energy Service*, 8 March 2002.

²³ Lane, Ed, ‘US Could Stop India Aid Due to Dabhol Problems’, *Dow Jones International News*, 8 April 2002.

²⁴ Joshi, op. cit., p. 31.

²⁵ Ibid., p. 31.

²⁶ Ibid., p. 30.

PT Paiton Energy (Paiton I), Indonesia

Type of project

1,230 MW coal-fired power plant.

Country

Indonesia.

Distinctive features

- One of the largest independent power projects in Asia.
- The first of 27 independent power projects that signed Power Purchase Agreements (PPAs) with the Indonesian state utility in the early 1990s.
- Indonesia's first build-own-operate (BOO) electrical generating facility – a model for large private power programmes.
- Contract awarded without competitive bidding.
- Bank underwriting before syndication.
- Government support letter, but no government guarantee.
- Single commercial source of coal.
- Tight government-imposed deadline for financial closing.
- Bondholders committed to 18-year risk prior to construction.
- Export-Import Bank of Japan (Jexim) assumes construction risk.
- First investment-grade credit rating for a greenfield international power project.

Description of financing

The 1995 financing comprised:

- a US\$900 million facility from Jexim;
- a US\$540 million facility from the Export-Import Bank of the United States (US Exim);
- a US\$200 million facility from the Overseas Private Investment Corporation (OPIC);
- US\$180 million as a funding loan, refinanced in 1996 with Rule 144A private placement of US\$180 million 9.34 per cent senior notes due 2014;
- US\$374 million subordinated debt from the sponsors; and
- US\$306 million in equity.

Project summary¹

Paiton Energy's project is one of four similar-sized units at the Paiton power generating complex on the northeast coast of Java, about 220 kilometres southeast of the city of Surabaya. Jawa Power is another. The complex is intended eventually to have four projects and eight units with 4,000 MW generating capacity.

Perusahaan Listrik Negara (PLN), the Indonesian state-owned utility, signed long-term US dollar-based Power Purchase Agreements (PPAs) with 27 independent power producers (IPPs) while President Suharto was still in power. Paiton Energy was the first and therefore took the longest time to negotiate. It was intended to become a model for large private power programmes. According to the project sponsors, being the first also explained why the US\$2.5 billion total cost of the plant was the highest of any of the Indonesian IPPs and the tariff charged to PLN was the highest.

Problems for PLN and the IPPs began with the decline of the rupiah during the Asian financial crisis, starting in 1997. As the rupiah continued to decline the IPPs' dollar-denominated electricity tariffs became increasingly unaffordable for PLN. After Suharto fell from power in 1999 PLN also argued that it had been forced to sign many of the contracts under pressure from his regime. Many of the IPPs involved relatives or associates of Suharto as local partners and none of the 27 IPP contracts had been awarded in an open bidding process.

Against this background both PLN and the new Indonesian government under President Abdurrahman Wahid refused to make payments under the PPAs and the support letters. PLN filed a lawsuit seeking to nullify its PPA with Paiton Energy and saying that the total cost of power was twice that of power from other comparable plants. President Wahid ordered PLN to drop the lawsuit and seek an out-of-court settlement. PLN and Paiton reached an interim agreement in 2000 that enabled the utility to purchase power at a reduced rate, pending a full restructuring of the PPA. After prolonged negotiations the original PPA was amended in 2002. Indonesia needed to settle its PPA disputes so that it could attract investors in additional power projects to satisfy the country's growing electricity needs.

Background

By 1994 Indonesia's economy was growing at more than 7 per cent a year and electricity demand was growing at more than 14 per cent a year. PLN had not been able to meet the demand. Over 40 per cent of the country's power was supplied by industrial power generators, largely in 'captive' plants built by industrial companies for their own consumption. It was estimated that Indonesia would require an additional 24,000 MW of capacity, an increase of 75 per cent, over the following 10 years, at a cost of US\$35–60 billion. Most of this new capacity would come from IPPs as part of the country's independent power programme.

PT Paiton Energy is an Indonesian limited liability company owned by MEC Indonesia, an indirect subsidiary of Edison Mission Energy Company, which is in turn an indirect subsidiary of Southern California Edison Company (32.5 per cent); Mitsui Paiton, a wholly owned subsidiary of Mitsui & Co. Ltd (40 per cent); GE Paiton (12.5 per cent); and PT BHP, a special-purpose limited liability company formed by the Indonesian sponsors of the project.

The project originated in 1991 when the Indonesian Ministry of Mines and Energy invited competitive proposals for the private development of two 600 MW units in the Paiton complex. The sponsors retained Chase Manhattan Bank and the Industrial Bank of

Japan (IBJ) as financial advisers in February 1992. In August 1992, after several clarification sessions with each bidding group, the Government of Indonesia awarded the sponsors the exclusive right to conduct further negotiations on the project. From the end of 1992 until March 1994 the sponsors negotiated the power purchase agreement with the Government of Indonesia.

The sponsors retained RW Beck as their technical advisers. PLN retained Lahmeyer of Germany as technical and financial advisers, as well as SBC Warburg, Lazard Frères and Lehman Brothers as financial advisers.

Principal project contracts

The principal project contracts are the PPA, the construction contract, the operation and maintenance (O&M) agreement, the fuel supply agreement, the coal purchase agreement, the mining and barging contract, the coal terminal services agreement, the contract of affreightment, and the Kelanis Facility agreement.

The PPA defines the rights and obligations of Paiton Energy and PLN relating to development, financing, construction, testing and commissioning of the project, and operation and maintenance of the plant; the making of capacity and energy payments, risk allocation in the event of *force majeure* and changes in the regulatory environment; events of default; rights of termination and consequences thereof; insurance, liability and indemnity obligations; and dispute resolution.

The construction contract provides for the contractor, a consortium of Mitsui, Toyo and Duke/Fluor Daniel, to provide design, engineering, procurement, construction, startup, testing and commissioning services, and the equipment and materials necessary for construction of the plant on a fixed-price, turnkey basis. If the plant is not in compliance with defined emissions limits, the contractor pays US\$750,000 per MW for each MW by which the net electrical output has to be reduced in order to comply with emissions limits. If each unit does not achieve a minimum electrical output of 615 MW, the contractor pays US\$5 million per MW for each MW by which the net electrical output falls below 615 MW.

The O&M agreement defines the terms under which Edison Mission Energy's Indonesian affiliate provides operations, maintenance and repair services necessary for the production and delivery of electricity.

The fuel supply agreement provides that BHP is to be the exclusive supplier of coal to the project and defines BHP's obligations under the coal supply plan.

The coal purchase agreement defines the obligations of PT Adaro Indonesia, owners of the Adaro mine in the southern part of the island of Kalimantan (also known as Borneo), across the Java Sea from the Paiton complex, to sell to BHP all of the coal that BHP is obliged to deliver under the fuel supply agreement.

The mining contract between Adaro and PT Pamapersada defines PT Pamapersada's obligations to mine coal, transport it to the Kelanis terminal, strip overburden and provide routine maintenance services on the roads between the mine and the terminal.

The barging contract between Adaro and PT Rig Tenders Indonesia describes the latter's agreement to transport coal from Kelanis to the terminal.

The coal terminal services agreement is PT Indonesia Bulk Terminal's agreement with BHP to store coal in a terminal, blend coal located at the terminal, unload coal from barges and load coal onto vessels.

The contract of affreightment defines Louis Dreyfus et Cie's obligation to transport coal from the Kelanis terminal to the Paiton plant.

The Kelanis facility agreement, signed by each of the sponsors, Paiton Energy and Adaro, defines Adaro's obligation to construct and operate a crushing and loadout facility and a coal stockpile.

The coal supply plan, required under the PPA, is a plan for the reliable supply of coal submitted to PLN by Paiton Energy.

From the beginning, both the lenders and the sponsors were concerned about the dependability of the fuel supply. Each hired separate coal advisers. They did a great deal of due diligence to verify the coal reserves, and to make sure that it could be produced at a reasonable cost and delivered to the plant. When the financing was being arranged the Adaro mine was producing about 2 million tons per year. For this project, however, 4.3 million tons per year would be required. The lenders wanted to see proof of the Adaro mine's coal reserves, and they wanted to make sure that the required infrastructure would be in place four years on, when construction of the power plant was expected to be completed. Interim milestones and backup plans were developed. A team of sponsors and bankers devoted itself to the fuel supply contract until it was signed.

Negotiating the Power Purchase Agreement

Despite experience with private investors in other industries, the Indonesian government was just beginning to learn about private power project financing. It explored the possibility of a corporate commitment, but found that the sponsors were willing to do a project financing only on a limited recourse basis. The Indonesian government was accustomed to purchasing plants on a cost-plus basis and needed to learn why a fixed-price, turnkey contract was required for a limited-recourse financing.

According to Jeffrey T. Wood, a vice president of Chase during the first project financing, the first draft of the PPA proposed by PLN looked more like an engineering, procurement and construction (EPC) contract, with approval rights concerning how the plant would be constructed. The sponsors persuaded PLN that the PPA should be more oriented towards defining the amount of power to be delivered and giving the sponsors appropriate economic incentives. Still, Wood recalled, an unusual amount of detail about plant design was provided to PLN.

Tariff structure

Discussions on the tariff were particularly time-consuming. First, the sponsors and the bank advisers for the sponsors and PLN outlined the philosophy of tariff design and the different ways in which PLN could structure the tariffs: held level, escalating over time or declining over time. In the end the sponsors and PLN agreed on a tariff that declines over time. It was calculated to provide a reasonable cost to PLN over the full 30 years on a discounted cash-flow basis, but also to provide a cash-flow cushion in the early years when debt-service requirements would be particularly heavy. The bankers thought that such a structure would help to attract the debt that was required. The problem with the structure was the public perception that the tariff was high in the earlier years, even though it was lower in the final 18 years of the contract. This is the main reason that tariffs in subsequent Indonesian PPAs have

been level. Another factor that increased the Paiton Energy tariff was the cost of connection lines and other infrastructure facilities borne by this plant that would be shared with the other units at the Paiton complex.

The PPA defined four tariff components, tariffs A, B, C and D. Tariffs A and B were capacity payments that PLN had to make if the plant was ready to produce electricity, whether or not PLN was taking it, and tariffs C and D were energy payments that PLN would pay only when the plant was generating electricity. Tariff A was a fixed-price tariff that was stepped down. It was designed to cover capital costs, to pay principal and interest on the project's debt, to pay taxes and to provide a return to the equity investors. Tariff B covered fixed operating and maintenance expenses; it was designed directly to offset the estimates for fixed operating and maintenance costs. Those costs were estimated to be 50 per cent in US dollars and 50 per cent in Indonesian rupiahs, and therefore 50 per cent was indexed to the US inflation rate and 50 per cent was indexed to the Indonesian inflation rate. Tariff C was designed to cover fuel costs. It was designed to pass the cost of coal directly through to PLN at a guaranteed heat rate, that is, at a guaranteed level of efficiency of the power plant. The project company guaranteed that it would convert coal to electricity at a certain efficiency rate. Then the price per ton of coal would be renegotiated annually among Paiton Energy, the coal supplier and PLN.

In interviews, Jeffrey T. Wood said that the link between the fuel cost and the electricity sale price is critical. It is difficult for an IPP to assume the risk of revenue-cost mismatch caused by fluctuating energy prices. Jonathan D. Bram, Managing Director of CS First Boston, added that the link between fuel cost and electricity price was unusually tight in the PPA for this project. Tariff D provided compensation for all variable operating and maintenance costs other than fuel. Under the four-part tariff schedule, PLN's estimated total cost for electricity was 8.47 US cents per KW hour for the first 6 years of operation, 8.47 cents for years 7 to 12 and 5.45 cents from year 13 to year 30. The average price over 30 years was 6.6 cents.

Force majeure events

The PPA provides that if a *force majeure* event prevents PLN from receiving electricity, or is the result of government action that affects the company's ability to produce electricity, the plant will be 'deemed dispatched' and PLN will remain obliged to make capacity payments as if the *force majeure* event had not occurred. The plant also will be deemed dispatched if a coal supply *force majeure* event prevents the Adaro mine from delivering coal and requires the company to limit output as a result of using qualifying alternative coal to meet environmental requirements.

Events of default and termination

The PPA divides events of default into remediable events and nonremediable events on the part of both the project company and PLN. Company-remediable events include not achieving commercial operation by the target date, suspension of construction or operation and various other obligations under the PPA. PLN-remediable events include failure to make required payments. Nonremediable events include the company's bankruptcy or failure to rectify remediable events; PLN's dissolution, privatisation or failure to rectify remediable

events; and failure of the Indonesian government support letter to remain in full force and effect. Nonremediable events that remain uncured can lead to termination of the PPA. A party receiving notice of a remediable event has 30 days to furnish the other party with a plan to cure the event.

PLN can buy the plant at any time, whether or not a nonremediable event has occurred. If PLN elects to buy the plant in the absence of a nonremediable event, or if the company elects to sell the plant to PLN because of a nonremediable event, the purchase price before full commercial operation is equal to principal and interest on senior debt facilities other than the commercial bank facility, funded sponsor commitments and an agreed equity return. After the beginning of commercial operations the purchase price is equal to debt obligations as described above, plus the net present value of capacity payments attributable to the sponsors' equity investment. PLN has the option, but not the obligation, to purchase the plant when there has been a company-nonremediable event, for an amount equal to principal and interest under senior debt facilities minus unfunded sponsor commitments.

Foreign exchange protection

PLN started with the position that there should be no foreign exchange protection in the PPA. Then it indicated its willingness to provide rupiah-US dollar protection because most of the country's export earnings are in dollars, but resisted rupiah-yen protection because Indonesia already had heavy yen exposure and the yen was strengthening. Under the PPA, Paiton Energy enters into foreign exchange contracts on PLN's behalf. If PLN does not like the rates it can deliver dollars to Paiton. If Paiton for some reason is unable to convert its rupiah revenues to dollars PLN has the responsibility to ensure that Paiton eventually gets the appropriate amount in dollars.

Environmental requirements

Environmental laws in Indonesia specified a maximum of ground-level sulphur concentration for all eight units at the Paiton site. The sponsors had to persuade PLN to establish specific environmental requirements for Paiton Energy's two units. Otherwise Paiton Energy could be penalised for emissions of the other units. This was a risk that lenders would be unwilling to accept. The emission level that PLN defined was so strict that it gave Paiton Energy just two alternatives: installing flue gas desulphurisation scrubbers at a high capital cost or using coal with a very low sulphur content. The sponsors decided on the low-sulphur coal because they knew that it could be supplied by the Adaro mine. However, in making that decision they were aware of a risk; there was no other mine that could supply coal with similar quality. This became an issue for the lending banks and the export credit agencies (ECAs), which were used to seeing government-guaranteed fuel supplies. Because it would have been difficult to finance the project if it were dependent on just one mine, the PPA provided environmental relief in case *force majeure* prevented the Adaro mine from shipping coal to Paiton Energy.

Negotiating other contracts

The sponsors were reluctant to spend a lot of time negotiating the EPC, O&M, and fuel supply contracts, and requesting competitive bids for equipment, before the PPA was finalised.

The coordinating banks had to try to move both the project contracts and the financing ahead at the same time. Some decisions on financing documents could not be made because the credit structure was not yet defined by the project documents. For example, the bankers did not know where the equipment would be coming from and how much ECA financing would be available. They were concerned that, even though the PPA would be signed, the project would not yet be structured enough to take to the lending community.

The bank underwriting

Even though a great deal of work remained to be done on negotiating and finalising the other project contracts, the sponsors wanted some kind of underwriting commitment from Chase and IBJ. Given the amount of financing required, Chase and IBJ had to start by estimating the total amount that could be raised and the longest maturity available from each market, such as the ECAs, the multilaterals and the commercial banks. The ECAs were offering a maximum maturity of 10 years for power plants, although there was some indication that they might go out as far as 12 years in a competitive bidding situation. The commercial banks appeared to have a capacity of about US\$300–400 million for uncovered Indonesian risk, and were willing to go out as far as eight years, with a four-year construction period and four years of amortisation.

The two coordinating banks sought internal approval to underwrite the deal before syndication with as much flexibility as possible. To be safe, they got internal approval assuming a minimum amount of ECA cover, hoping that the ECAs would provide a lot more, and negotiated a term sheet with the sponsors. Then the coordinating banks talked to six additional commercial banks, hoping that at least four would be willing to match Chase and IBJ's US\$250 million underwriting commitments. They all accepted, so all eight banks were ratcheted down to US\$187.5 million.

With commercial banks on board, attention turned to the official lenders. Although the commercial banks were used to working in a fluid environment, the ECAs were not so flexible. When first approached they replied with long lists of issues. On most of these issues they said that they did not have enough information to analyse the credit because they did not have all of the project documents. Another delay was caused by US Exim's creation of a new project finance group in the summer of 1994. While such a commitment by US Exim boded well for project finance, the new group needed time to get started, and to redefine policies and procedures, before making major new commitments.

US Exim said right from the beginning that it would not assume construction risk, but after a lot of time and effort the coordinating banks were able to persuade Jexim to take construction risk. Looking back, Wood considers the bank group fortunate, in that all the ECAs were willing to commit themselves to 12 years post-completion, and while the financing was being arranged OPIC increased its maximum coverage for a single project from US\$50 to US\$200 million. This minimised the final retention of uncovered debt and improved the debt-coverage ratios.

An underwriting of this size before syndication was a real milestone for the Asian market. Another related milestone was getting the Japanese Ministry of International Trade and Industry (MITI) to commit itself to political risk coverage before all the banks were signed up. MITI made an exception to its normal policy, giving the banks a time window to syndicate the loan and reassign the political risk coverage to the participating banks.

Structure of the financing

The US\$900 million Jexim facility finances up to 85 per cent of the amounts payable by Paiton Energy to Mitsui for Japanese goods and services pursuant to the construction contract, and for Indonesian goods and services as long as they do not exceed 15 per cent of the amount exported from Japan. The facility has two tranches. Tranche A is a US\$540 million loan at a fixed rate of 9.44 per cent. Tranche B is a financing based on the London interbank offered rate (Libor) swapped to provide all-in fixed rates ranging from 4.875 per cent to 11.375 per cent. Tranche B lenders have the benefit of political risk insurance from MITI for 97.5 per cent of the principal amount and commercial risk coverage related to PLN's payment obligations for 95 per cent of the principal amount. The MITI insurance is denominated in yen, but Tranche B holders have an indemnity covering exchange risk in converting yen to US dollars.

The US\$540 million US Exim facility is a four-year commercial bank construction loan at an interest rate of 9.382 per cent with US Exim political risk coverage, which will be taken out by a US Exim term loan over eleven-and-a-half-years at a rate of 11.5 per cent on the US Exim project completion date, when Paiton Energy is to satisfy various terms in US Exim's credit agreement. These terms include its own certification that the plant is capable of operating in accordance with the technical requirements of the PPA and a technical adviser's certification that all work under the construction contract is complete.

The US\$200 million OPIC facility is a 12-year loan with Libor-based rates that have been swapped to provide for all-in fixed rates, ranging from 6.18 per cent to 12.288 per cent per annum.

The commercial bank facility has two tranches. Tranche A is a US\$180 million uncovered four-year construction loan at Libor plus 2.25 per cent, with a four-year amortisation period. Tranche B is a US\$93,750,000 uncovered standby contingent facility available for funding project cost overruns after the US\$175 million sponsors' overrun equity is fully used.

Tranche A of the commercial bank facility was refunded by US\$180 million of 9.75 per cent bonds due in 2014 under Rule 144A. The bank group gave Paiton a year to refinance Tranche A, and agreed to relinquish their upfront fees when and if the refinancing was done. This gave the investment bankers a firm deadline to get the bond deal done.

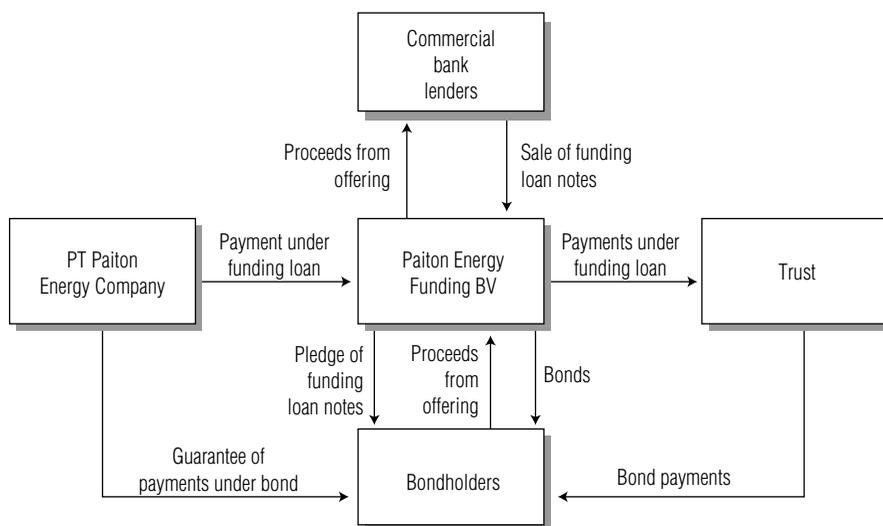
The issuer of the bonds was a Netherlands Antilles company. Because of a tax treaty between the Netherlands Antilles and Indonesia, itself a former Dutch colony, this domicile offered a withholding tax saving.

The structure of the bond offering is illustrated in Exhibit 6.1.

The government support letter

In November 1994 representatives from the coordinating banks and the ECAs met in Indonesia to discuss the form of support that the government would give to the project. The ECAs were pressing for a guarantee, but the government had already agreed with the sponsors on a support letter. The government was not willing to change a condition that it had already agreed to, and thus increase its risk, without a price reduction or some other concession in return. The support letter issued by the ministry of finance (MOF) says that the government will cause PLN to discharge its payment obligations. Lenders at the time considered it adequate, because it provided a statement of support for the project at the highest level of the government, but it was not a guarantee.

Exhibit 6.1

Structure of the bond offering**Meeting the financial closing deadline**

When project negotiations began the coordinating banks told the government that a minimum of a year, but usually longer, is required for arranging a project financing after a PPA has been signed. The word ‘minimum’ seems not to have made any impact. When the PPA was signed, on 12 February 1994, the government set a one-year deadline for both signing loan agreements and advancing funds. If the deadline was not met the government could reopen negotiations on the price defined in the PPA.

In January 1995 a team representing the underwriting banks and the sponsors convened in New York to work full time on the project contracts and financing documents, in an effort to meet the 12 February deadline. As that deadline began to appear unrealistic the team kept PLN informed of each milestone so that PLN could at least see evidence that work on the contracts was moving ahead. Wood recalls working 36 hours straight at one point in February, in an effort to deliver as many completed documents as possible to PLN in Jakarta by 12 February. When the documents were delivered the government decided to extend the final deadline for closing the deal to 21 April.

During the entire period from the original to the revised deadline, work on the EPC and fuel contracts also continued. Two issues that remained outstanding until the very end related to real estate security and interpretation of the government support letter. On the first issue the lenders had to settle for a provision in the PPA that indemnified the project against any claims against the site. They were not able to persuade the government to change its position. On both issues government officials said that they were unwilling to make any further changes to terms that had already been negotiated. They reiterated that if the deal was not closed by midnight on 21 April they would have the right to terminate the PPA.

Intercreditor issues

Some people say that because of intercreditor disputes it is difficult to arrange a deal with banks, bondholders and ECAs at the same time. While admitting that hard work was required, Jonathan D. Bram of CS First Boston recalls that his firm, Chase, OPIC and the ECAs were able to reach agreement simply by sitting down together and patiently working out each issue. First Boston developed a covenant package for the bondholders that is typical of a bond deal and not as rigorous as in many commercial loans. The indenture events of default are major events such as nonpayment of principal or interest, or bankruptcy. If there is a default under the bank or the ECA agreements the bondholders can rely on cross-acceleration.

Credit rating

Standard & Poor's gave the US\$180 million of 9.75 per cent bonds privately placed under Rule 144A a 'BBB' rating, the same as Indonesia's sovereign rating at that time. The primary risk factors cited by Standard & Poor's were as listed below.

- Three years of construction remained before commercial operation of the project began; the project's coal supply involved a succession of transport modes and transfers, with the possibility of fuel supply disruption.
- Creditor rights and enforcement were subject to uncertainty, a lack of precedent and interpretative differences under Indonesian law.
- With the bond principal representing only 10 per cent of the US\$1.8 billion debt outstanding, bondholders' rights, remedies and abilities to take action would be controlled primarily by the project's bank and agency lenders, not the bondholders themselves.

Offsetting these risks, the rating agency cited a substantial number of strengths.

- The project helped to fulfil a strategic need for increased generating capacity in Indonesia.
- The plant design incorporated proven, pulverised coal-fired, steam turbine and coal-handling technologies.
- Project construction was to be under a turnkey, lump-sum contract with a highly qualified consortium.
- The PPA with PLN appeared at the time to be well-structured to hedge inflation, fuel price and regulatory risks; it contained provisions that allocate currency risk to PLN; and it provided for the full recovery of project capital and operating costs, including debt service.
- PLN's PPA obligations benefited from a letter of support issued by the Government of the Republic of Indonesia.
- Established project sponsors were contributing US\$680 million of equity and subordinated debt, 27 per cent of the project's capital, and were obliged to provide up to US\$300 million in overrun commitments.

Lessons learned as of 1996

Dealing across cultures, across time zones and under time pressures made this project a par-

ticular challenge. People from the United States, Japan and Indonesia had very different approaches to business when they started to work together, but over time they grew to understand each other. People were locked up in conference rooms and spent months in hotel rooms. There were times when it seemed that the deal was not going to get done. Wood gives a lot of the credit to the personality and perseverance of Bob Edgell, Executive Vice President and Asia Pacific Division President of Edison Mission Energy.

The original deadline for closing the financing – 12 months from the time that the PPA was signed – was unrealistic, given the precedent-setting nature of this transaction in Indonesia. The time required for financial closing on most independent power projects in the United States averages close to 18 months and the parties involved have the benefit of prior experience with similar deals. Most PPAs in the United States have sunset dates between 24 and 36 months from PPA signing. The deadline would have been easier to meet if negotiations for more of the contracts had been started while the PPA negotiations were under way.

Developments since 1996

Indonesia's economy and credit rating

During most of 1997 Standard & Poor's maintained a 'BBB' credit rating for the Republic of Indonesia, based on the government's long-term commitment to prudent fiscal management, a political consensus in favour of market-oriented economic policies rooted in decades of steady GDP growth, savings and investment rates of more than 30 per cent of GDP, and steadily rising non-oil exports. The rating was constrained by heavy infrastructure needs; a heavy, though favourably structured and declining net external debt burden of 140 per cent of exports; a risk that eventual political transition from Suharto to his successor could slow an ongoing economic reform process and an uneven trend toward increased transparency; and weakness in the banking system.

In December 1997 Moody's downgraded Indonesia's foreign currency rating from 'Baa3' to 'Ba1' as a result of a greater than 50 per cent drop in the value of the rupiah and a loss of investor confidence. The agency said that the depreciation of the rupiah put considerable stress on the corporate sector to meet its overseas debt payments and was likely to create considerable stress on the banking system as well.

In January 1998 Standard & Poor's downgraded Indonesia's long-term foreign currency rating from 'BB' to 'B' because of Indonesia's deepening financial crisis and diminished external payments flexibility, as a result of the government's recent suspension of foreign currency debt servicing for troubled corporations. The agency said that Suharto's credibility was crumbling and that a clear plan for transfer of power was vital. The agency predicted that the Indonesian economy would contract by more than 5 per cent in 1998 and that some 40 per cent of bank loans would be nonperforming by the end of the year. It said that a comprehensive solution to the private external debt overhang was essential for reviving economic activity and moderating social unrest.

In May 1998 Standard & Poor's reduced Indonesia's long-term foreign currency credit rating from 'B-' to 'C+', reflecting the country's deepening political crisis, which in turn was eroding its ability to service its public-sector obligations, the increasing likelihood that Suharto would leave office, and lack of clarity as to how a change of administration might play out. At the same time, in downgrading several structured finance transactions Duff & Phelps (now Fitch) noted the deteriorating creditworthiness of the Indonesian government as

a result of the increasingly unstable political situation. The agency observed that social unrest in the capital city and elsewhere in the country, sparked by economic decline and rising prices, had put the viability of Suharto's government into question. In November Duff & Phelps issued a special report stating that, without strong new government leadership and a properly implemented bank recapitalisation plan, Indonesia was unlikely to emerge from its economic and political crisis.

In March 1999 Standard & Poor's reduced its long-term foreign currency sovereign credit rating for Indonesia from 'CCC+' to 'SD' (selective default), reflecting its distressed rescheduling of US\$210 million principal on a US\$350 million commercial loan disbursed in 1994 by a syndicate of 70 banks led by Bank of Tokyo Mitsubishi. The 'SD' rating is applied when a country has selectively defaulted on an issue or class of obligations, but continues to make timely payments on its other obligations. Bank Indonesia said that there was no default, only a rescheduling that met all the conditions required by the Paris Club, a group of government creditors that rescheduled debt to developing countries, loosely based around the Group of 10. After further review of the rescheduling Standard & Poor's restored Indonesia's foreign currency rating to 'CCC+'.

In June 1999 Indonesia conducted its freest and most peaceful general election in four decades. At the same time Standard & Poor's observed that Indonesia was undergoing the worst banking crisis since the 1970s and might have to spend as much as US\$87 billion to revive the sector. It estimated that nonperforming loans would reach 75–85 per cent by the end of 1999, and that the cost of recapitalising the system and paying out creditors of distressed banks would be about 82 per cent of GDP. In comparison, the agency estimated the likely cost of banking recovery at 35 per cent of GDP in Thailand, 29 per cent in South Korea and 22 per cent in Malaysia. The agency noted that one of the reasons for the severity of the crisis was the economy's over-reliance on the domestic banking system as a result of the underdeveloped local equity and debt markets.

In reaffirming its 'CCC' rating for Indonesia in September 1999, Duff & Phelps pointed to the need for resumed multilateral loans from institutions such as the IMF, the World Bank and the Asian Development Bank, which would depend partly on the government's willingness to allow UN peacekeepers into East Timor and satisfactory resolution of a corruption investigation regarding Bank Bali. In October, Standard & Poor's declared that, while it was encouraged by the election of Abdurrahman Wahid as Indonesia's fourth president, it also noted that the government's debt had grown to 110 per cent of GDP, from just 26 per cent three years before, and that the end of a current Paris Club consolidation period could lead to a spike in debt service requirements. It also pointed to the need for another round of Paris Club debt restructuring.

In November 1999 the IMF agreed in principle to resume lending after the Indonesian legislature published the findings of an international audit team investigating the Bank Bali corruption scandal. Moody's vice president and senior analyst Stephen Hess remarked that Indonesia was critically reliant on external finance and that anything that could help to restart private sector capital flows would be good for the country's external liquidity.²

In April 2000 Standard & Poor's once again downgraded Indonesia's long-term foreign currency rating to 'SD' because it was effectively in default on US\$850 million of foreign-currency-denominated commercial bank loans. The loans would be restructured on terms that were disadvantageous to creditors, reflecting Indonesia's commitment to seek debt relief from the private sector similar to that sought by a Paris Club of 19 bilateral creditor governments.

One positive aspect that the agency noted was that, by agreeing to a generous rescheduling of about US\$5.8 billion of principal on bilateral debt coming due between April 2000 and March 2002, Indonesia had strengthened external finances and reduced the likelihood that its sovereign debt would have to be restructured annually.

In August 2000 David Beers, Standard & Poor's Managing Director for Sovereign Ratings, said that Indonesia's political turmoil, weak currency and lagging reform made its sovereign debt the weakest credit story in Asia.³ The country also was suffering from uncertainties regarding legal reform, the quality of bank lending and the sale of assets by the government-run Indonesia Bank Restructuring Agency. However, he also noted the completion of a debt restructuring agreement with Indonesia's commercial creditors, which could lead to an upgrade from the 'SD' long-term foreign currency rating. The agency raised that rating to 'B-' in November, based on a reduction of general government debt to 65 per cent of GDP, increasing revenues as a result of high world oil prices and sustained government budget surpluses.

In March 2001 Moody's removed the positive outlook on its 'B3' rating and Standard & Poor's put its 'B-' rating for Indonesia on a negative outlook, citing President Wahid's faltering grip on power and interethnic violence across the archipelago. The IMF was delaying a US\$400 million tranche of loans to the country because of the government's failure to push key economic reforms through the legislature. However, it seemed unlikely that the ratings would fall again to the 'SD' level because the country had US\$29 billion in foreign exchange reserves.

Project developments

In October 1997 Standard & Poor's lowered its rating on Paiton Energy Funding's senior secured bonds due 2014 from 'BBB' to 'BBB-', in line with a similar downgrade of its rating on Indonesia's long-term foreign currency obligations, because a 32 per cent decline in the rupiah's value over the past four months and resulting weakness in the financial sector had increased repayment risk for lenders to Indonesian IPPs. The agency noted that dollar-denominated debt financed about 73 per cent of Paiton Energy's financing costs. While electricity tariffs were payable in rupiahs, PLN was required to pay the rupiah equivalent of the agreed dollar-based tariff. PLN also assumed convertibility risk by agreeing to remit electricity payments in dollars if the sponsors could not secure their own foreign exchange contracts. Thus, at least in theory, the project sponsors and lenders were hedged for devaluation of the rupiah. However, the fundamental problem affecting PLN was that, as a result of recent depreciation of the rupiah, the cost to PLN of electricity from dollar-financed IPPs had become 40 per cent higher than originally anticipated in local-currency terms. Also, as new IPPs came on line over the next few years PLN's hard-currency needs would increase while Indonesia's reserves were declining.

Later in October 1997 Standard & Poor's began to investigate reports that PLN was seeking to reopen the negotiation of PPAs for projects such as Paiton Energy. The agency's original assessment of offtaker creditworthiness was based partly on the government's general support for PLN and a letter of support from the MOF. When a team from Standard & Poor's visited Jakarta in November, the MOF was not willing to affirm its support arrangements for the IPPs and PLN. Based on the potential weakening of government support and the reopening of PPA negotiations, the agency put its 'BBB-' rating for Paiton Energy and its ratings for two other IPPs on CreditWatch. Later in the year it downgraded the ratings to 'B'.

In December 1997 Moody's downgraded three Indonesian IPPs – Paiton Energy, CE Indonesia (owned by affiliates of California Energy) and DSPL (owned by affiliates of Unocal and PT Nusamba Geothermal) – from 'Baa3' to 'Ba1', and in January 1998 it further downgraded them to 'B2' following similar downgrades of the Indonesia foreign currency ceiling. The agency noted that the electricity tariffs that PLN was paying to the IPPs had become significantly higher than the tariffs that it charged to consumers. Whereas there would be increased regulatory pressure for the IPPs to reduce their tariffs to levels closer to PLN's retail tariffs, Moody's thought that PLN's willingness to adjust those tariffs to a level that more accurately reflected the cost of new generating capacity would be a critical component in the long-term success of Indonesia's IPP programme.

In March 1998 Standard & Poor's downgraded its ratings on Paiton Energy and three other IPPs from 'B' to 'CCC', following a downgrade in Indonesia's foreign currency rating to 'B-'. The agency noted that PLN did not have the liquidity to pay electricity invoices in full and in US dollars, as required in the PPAs for currently operating IPP projects as well as those scheduled to start operating in the near future. With inflation running close to 40 per cent, the government was unlikely to allow PLN to raise its retail electricity rates high enough to help the utility honour its hard-currency obligations. Further, as the Indonesian economy continued to contract, possibly by as much as 5 per cent in 1998, unemployment would rise, real incomes would fall and demand for electricity would fall, creating increased revenue pressure for PLN. The agency was sceptical about the ability of a new cabinet appointed by President Suharto to implement reforms in the financial, electricity and energy sectors, and noted that projects under construction could face completion difficulties as a result of the country's macroeconomic problems and deteriorating social environment. Offsetting these risk factors, Standard & Poor's noted that construction of the Paiton project remained on schedule; no disruptions in drawdowns for the construction loans were expected; capitalised interest would protect Paiton Energy's lenders during construction; and the debt-service reserve fund would provide another six months' protection during operations.

In June 1998 Suzanne Smith, director of infrastructure ratings at Standard & Poor's in Hong Kong, noted that while no IPP yet had missed a payment from PLN: 'we think there is mounting pressure on these projects to get renegotiated because the economic fundamentals have shifted and have put the government and PLN in an impossible situation'.⁴

She continued to assume that Paiton Energy's two 660 MW generators would start operations in early 1999. In the opinion of a lawyer interviewed by Dow Jones, neither side had an interest in seeking arbitration because the result would be damage to Indonesia's reputation among foreign investors and lower dollar returns for the IPPs than they could achieve through negotiation. He therefore concluded that the renegotiation of contracts was inevitable and thought that the project sponsors might seek extensions in the terms of their contracts in return for reduced electricity tariffs.⁵

Later in June 1998 PLN unilaterally cancelled its power purchase contract with PT Cikarang Listrindo, an IPP owned by a cousin of Suharto. PLN's president, Djiteng Marsudi, said that he was ready to face a lawsuit as a result of this action and might take similar actions against other IPPs that refused to renegotiate contracts to ease the financial pressure on his company.⁶

In September 1998 Moody's downgraded its rating on Paiton Energy to 'Caa2', and its ratings on DSPL and CE Indonesia to 'Ca'. The agency was prompted to review the ratings of these three Indonesian IPPs by the failure of PLN and Pertamina, the state-owned oil and

gas company, to make payment in full for electricity delivered by DSPL and CE Indonesia. Moody's noted that each failure represented a breach of contract and a failure by the government of Indonesia to abide by its support obligations. Therefore the renegotiation of the PPAs for most Indonesian IPPs appeared certain and the risk of default to bondholders was significantly increased. Because DSPL was receiving partial payments, it seemed likely to be able to continue paying bondholders until the first quarter of 1999. Paiton Energy still had some breathing space because it was not scheduled to come on stream until the following year. CE Indonesia, however, had received no payments for the electricity that its Dieng geothermal plant had delivered since it began operating in March. PLN had asked that CE Indonesia shut down the Dieng plant and halt construction on its Patuha geothermal plant. Therefore its principal sponsor, California Energy, a unit of MidAmerican Energy Holdings, Inc., had begun arbitration proceedings against the government. Also during September, former US Secretary of State Warren Christopher, then Chairman of the Executive Committee of Edison International, Paiton Energy's parent, met then President B.J. Habibie in Jakarta to discuss the growing problem. Christopher was accompanied by John E. Bryson, CEO of Edison, Edward R. Muller, President of Edison, and Ronald P. Landry, President of Paiton Energy.

Paiton Energy's power plant came on stream in May 1999, at a final project cost of US\$2.5 billion. For the remainder of the year PLN refused to buy power and paid Paiton Energy only for the cost of fuel. The plant submitted its first monthly bill in August and PLN defaulted on that payment. Also in May 1999, an arbitration panel ruled that the Indonesian government was obliged to pay US\$572 million in breach-of-contract damages to MidAmerican, the parent of CE Indonesia and CalEnergy. When PLN failed to pay the damages within 30 days, CalEnergy filed a claim under its political risk insurance policy with the US OPIC. Because the Indonesian government refused to honour the decision, MidAmerican sought a second arbitration panel under the rules of the UN Commission on International Trade Law, which also ruled in MidAmerican's favour. OPIC paid the claim and, in line with normal practice, sought reimbursement from the government of Indonesia.

In October 1999 PLN filed a lawsuit seeking to nullify its PPA with Paiton Energy. The utility said that the total cost of the power project was twice the cost of other comparable plants and that the unit price at which PLN had agreed to buy power was twice the price paid to other power stations. PLN, according to its new President, Adhi Satriya, would seek to prove that the Paiton Energy contract was negotiated on corrupt grounds by the regime of former President Suharto and had no basis in Indonesian law. This was the first case brought by the Indonesian government against an IPP since Suharto had left office and the first attempt to prove in court that corruption had influenced commercial agreements during his decades in power.

In a press release Paiton Energy expressed its disappointment that PLN had filed a lawsuit when the two parties were meeting almost daily. Paiton Energy noted that it had offered significant concessions in an effort to reach an interim agreement, including reducing the cost of coal, the C component of its electricity tariff, to match PLN's price and accepting payments from PLN for outstanding invoices at a then-preferable rate of 2,450 rupiahs to the dollar, resulting in an interim price of 3.3 cents per KW hour. The company also said that it was unaware of any improper actions taken to influence the contract award or any terms of its agreement with the government of Indonesia. It also noted that one of the reasons that the cost of the plant was so high was that it included infrastructure that would be

used by the other Paiton units. A few days later Paiton Energy offered to renegotiate the PPA with PLN.

On 13 October US Exim announced that it would delay making a refinancing loan that would have replaced the US\$540 million construction loan facility that was to have been disbursed upon the satisfaction of a number of conditions when construction was completed, and no later than 15 October. This was not a surprise at a time when the World Bank and IMF had already suspended loans to Indonesia because of the Bank Bali scandal. With Paiton Energy receiving no payments from PLN, and therefore having no source of income to make payments on its loans, the commercial lenders had been negotiating an interim agreement with Paiton Energy under which debt repayments would be waived for a certain period of time or until Paiton Energy restructured its PPA with PLN.

In December 1999 the newly elected President Wahid ordered PLN to drop the lawsuit against Paiton Energy and seek an out-of-court settlement, renegotiating all the electricity tariffs in the original agreements. In response Adhi Satriya resigned from his post at PLN. His successor, Kuntoro Mangkusugroto, a former Minister of Mines and Energy, asked Paiton Energy to revoke its arbitration claims in response to the Indonesian government's demonstration of goodwill in dropping the lawsuit. The government set up a ministerial team for the renegotiation of PPAs headed by the State Enterprises Minister and also including the Finance Minister, the Mining and Energy Minister, and the Foreign Affairs Minister. Shortly afterwards US Exim extended its commitment to take out the US\$540 million loan by one year. A spokesperson said that US Exim's decision was not a direct result of any specific decision by the Indonesian government, but was designed to provide the principals with an opportunity to work out an adequate restructuring.

In February 2000 PLN and Paiton Energy reached an interim agreement that enabled the utility to purchase power at a reduced rate pending a full restructuring of the PPA.

In August Standard & Poor's reaffirmed its 'CC' rating for Paiton Energy Funding with a continued negative outlook. The agency explained that Paiton Energy was continuing to operate under an interim agreement whereby PLN purchased power at a far lower rate than in the original agreement. As a result, Paiton Energy Funding had not been able to make principal payments on its bank loans since December 1999. Lenders had agreed to defer principal payments until 31 December 2000, when the company expected to conclude negotiations with creditors on a revised agreement. The agency noted that principal payments on the senior secured bonds were not scheduled to begin until May 2008, and that operating costs and interest payments were being covered by power plant revenues and contributions from shareholders. Because the interim agreement and negotiations with PLN were confidential, it was impossible to estimate project revenues, but the agency did not expect that shareholders would continue to provide funds for bond interest payments much longer. On the positive side, electricity demand on the main national grid was rising, leading to an increase in PLN's demand for electricity from Paiton Energy. However, the agency concluded that, even with increased electricity demand and the possibility of a settlement within the next six months, the combination of PLN's weak financial position and its high debt service obligations made a default on the bonds a possibility.

Later in 2000 Paiton Energy and PLN reached a tentative agreement on a three-phase rate scheme through which Paiton Power would gradually raise its rates, starting at 2.6 cents per KW hour in 2001. In May 2001 Landry of Paiton Energy said that the two sides were close to reaching agreement on the actual long-term rates. Among the factors that Paiton Energy

was considering as it negotiated were the opportunity to extend the 30-year term of the contract; an opportunity to build another plant at the Paiton site; and the increased electricity sales that would be possible after completion of the Java–Bali transmission grid. By that time Paiton Energy's shareholders had advanced additional US\$300 million equity into the project to cover debt payments and other expenses.⁷

In May 2001 the Indonesian government decided to pay US\$260 million to settle OPIC's claim in connection with PLN's refusal to pay CE Indonesia after it was awarded US\$572 million by an arbitration panel in 1999. While some lawmakers still felt that the Indonesian government should not bail out overpriced power projects commissioned under Suharto, others were more concerned about Indonesia's image in the eyes of foreign investors, whom the country badly needed for power and other infrastructure projects.

At a power seminar in June 2001 David Newell of Unocal Indonesia said that projections of supply and demand indicated a power shortage by late 2002 or 2003. He explained that neither the government nor local banks had the capacity to raise the necessary funding, while foreign investors were still holding out because of concerns about their legal protection and the slow pace at which the country's power sector was being restructured. Unocal, for example, was unwilling to commit additional capital to the Indonesian power sector until it reached a fair and reasonable resolution of the contracts for its own Salak and Sarulla power projects. Newell cited data from the Asian Development Bank indicating that a power shortage in the Philippines during the late 1980s had reduced GDP growth by 6 per cent. He said that, according to Indonesian government data, a total investment of US\$28.5 billion would be needed to restructure the country's battered power sector over the following 10 years. At the same seminar Citibank's country corporate officer, Michael Zink, said that Indonesia would have to compete with its neighbours in attracting capital and that, according to the Asean Energy Centre, Southeast Asian countries would need a total of US\$69.5 billion to meet growing power demand between then and 2010.⁸

In July 2001 PLN's finance director, Parno Isworo, said that his company needed US\$2 billion to revive suspended power generation projects in order to prevent an energy crisis, but before it could attract the investment that it needed to finance those projects, it would have to agree on lower purchase prices from Paiton Energy and Jawa Power (Paiton I and II). He said that resolution of the PPAs for these two projects would serve as a showcase to investors that Indonesia could provide a conducive environment for new power projects. In June PLN had finalised an agreement with PT Energi Sengkang to purchase power at 4.286 cents per kilowatt hour, representing a 36 per cent reduction from the original contract or a US\$200 million saving to PLN. Parno said that PLN was concluding negotiations with other IPPs and intended to take over some abandoned projects, such as the Tanjung Jati-B power plant in central Java. He estimated that PLN's installed capacity in the Java–Bali grid would remain stagnant at 18,608 MW until 2003, while peak load would rise by 18 per cent to 15,608 MW. A PLN study had indicated that the Java–Bali electricity grid would need an additional 1,776 MW of power capacity by 2003 and another 2,432 MW by 2004 to maintain a minimum power reserve margin of 30 per cent. However, if new capacity did not come on stream, that margin could drop to 16 per cent by 2004, putting parts of the country in darkness during periods of peak demand. Parno added that Indonesia's current transmission capacity was inadequate and would need an investment of US\$600 million over the following three years. He said that PLN would rely on 'captive power' from industrial power generators as a short-term solution to meet potential shortfalls. Captive power capacity had increased in the early 1990s,

when industrial growth outpaced development of the power infrastructure, and now represented about 40 per cent of installed capacity in the Java–Bali grid.⁹ However, Indonesia was gradually reducing its fuel subsidies and, as fuel prices began to rise, industrial companies were becoming less interested in generating their own power.

In a subsequent interview Parno said that PLN had warned 24 critical systems outside the Java–Bali grid that they would experience power shortages in 2002 because of insufficient funds. He said that PLN expected to hook up 1.3 new customers in 2002, just half the rate of new connections before the Asian financial crisis.

In October 2001 PLN signed an agreement with Paiton Energy to make three fixed monthly payments totalling US\$69 million during the fourth quarter. This amounted to 3–4 cents per KW hour, a rate that PLN was hoping to achieve in its renegotiated PPAs with both Paiton Energy and Jawa Power (Paiton I and II). The parties were expecting to conclude their negotiations by the end of the year.

In December 2001 PLN reached agreement with both of the Paiton projects. For Paiton Energy it agreed to pay 4.93 cents per KW hour for 40 years and to pay arrears of US\$450 million. The final negotiated amount for arrears fell considerably short of the US\$1 billion that Edison Mission Energy was asking for, but from Edison's point of view the losses would be mitigated by the extended term of the contract and the opportunity to build new generating capacity on the Paiton site.¹⁰

By January 2002 PLN had concluded new long-term agreements with seven of Indonesia's 27 IPPs, including the two Paitons, Daragat, Sengkang, Tanjung Jati B, Pare-Pare and Unocal's Salak geothermal plant, mentioned above. The rate for Salak was 4.45 cents per KW hour. Dorodjatun Kuntjoro-Jakti, Coordinating Minister for the Economy, said that the government was in no position to pursue a better deal than it had because the country was in dire need of investment in new power facilities and was hampered by its 'CCC' credit rating. He added that the government could have let PLN seek international arbitration for the disputes, but its electricity cost could have been much higher if it had lost in the proceedings.¹¹

In February 2002 PLN's latest President, Eddie Widiono, said in an interview with *Dow Jones Newswires* that the appetite from existing IPP investors was not strong but allowed for some additional generating capacity. He expected capital from these investors to be supplemented by power project loans from the World Bank, the Asian Development Bank and the Japan Bank for International Cooperation. Widiono noted that the peak load recorded in November 2001 was 12,577 MW, compared to an estimated installed capacity of 15,000 MW. He thought that the Java–Bali grid could survive until 2004 or 2005, but noted that electricity demand was expected to keep growing at an annual rate of 8 per cent and that by 2010 demand would be twice the current installed capacity.¹²

In March 2002 Paiton Energy began to negotiate with several international lenders to arrange financing for Units 3 and 4 on the Paiton power plant site. The planned capacity was 800 MW and the estimated cost of the facility was US\$1,000 per KW, or US\$800 million. In April the Indonesian government approved four new power projects to be developed by IPPs already involved in projects in the country.

In July 2002 the original PPA signed in 1994 was amended to reflect the terms that Paiton Energy and PLN had agreed on in December 2001. Energy consumption continued to grow rapidly as Indonesia began to recover from the Asian financial crisis, and the Paiton I plant was operating at or near capacity.

In early October 2002, the project sponsors signed a term sheet for debt restructuring

with the four major agencies involved in the power plant financing US Exim; OPIC; Japan Bank for International Cooperation (JBIC), which had replaced Jexim; and Nippon Export and Investment Insurance (Nexi), which had replaced MITI. US Exim reportedly agreed to take up to 75 per cent of the debt in its US\$540 million term-loan tranche before the end of the year. As explained above, US Exim originally had committed to that term loan as a take-out for its construction loan. As a result of US Exim's commitment, the commercial banks participating in the Paiton 1 financing reportedly expected not to suffer any extension of maturity or other 'haircut' (adverse changes in terms) to their original lending commitments. Paiton 1 was expected to resume its principal and interest payments in early 2003.

Lessons learned as of 2003

In an economic crisis the value of a government support letter is diminished. Nonetheless, the Indonesian government considered its support letter to be an important moral obligation that it did not want to breach.

Contracts are of diminished value when a project participant can no longer afford to abide by their terms. Nonetheless, the PPA provided a framework and set the boundaries for several years of negotiations. The strength of that agreement, and the likelihood of litigation and arbitration ultimately favouring Paiton Energy, were important restraints for PLN.

The involvement and active support of government lenders and ECAs was of significant value in achieving consensual resolutions.

In the future, a lack of competitive bidding, and involvement by relatives and other close associates of the head of state, should be viewed as danger signals.

One of the main factors in the sponsors' ability to salvage a difficult situation was their persistence, including their consistent, steadfast denial of corruption charges and their willingness to explore other choices, such as extending the term of the contract, building new power capacity and extending equity funding.

¹ This case study is based on interviews with Jeffrey T. Wood, then Vice President in Chase Manhattan Bank's global power and environmental group (now Managing Director of Global Project Finance at CS First Boston), as well as a prospectus for the bonds, articles in the financial press and follow-up interviews on events since 1996, when the original case study was written.

² 'Moody's: Need Indonesian Economic Results Before Ratings Change', *Dow Jones International News*, 9 November 1999.

³ *Dow Jones International News*, 7 August 2000.

⁴ *Dow Jones Energy Service*, 8 June 1998.

⁵ *Dow Jones Energy Service*, 8 June 1998.

⁶ *Dow Jones Energy Service*, 9 June 1998.

⁷ 'PLN and Paiton Close to Reaching Long-term Accord', *Jakarta Post*, 31 May 2001.

⁸ 'Indonesia to Face Power Shortage in Two Years', *Jakarta Post*, 20 June 2001.

⁹ Lim, Sharon, 'Interview: Indonesia PLN to Fight Darkness with New Rates', *Dow Jones International News*, 2 July 2001.

¹⁰ 'Indonesia's Paiton Energy to Expand Generating Capacity', *Dow Jones International News*, 5 February 2002.

¹¹ Kurniawan, Moch N., 'No Better Deal With Power Supplier: Minister', *Jakarta Post*, 31 January 2002.

¹² Lim, Sharon, 'Interview: Indonesia to Raise Existing IPP Power Capacity', *Dow Jones Energy Service*, 7 February 2002.

Samalayuca II, Mexico

Type of project

Power plant.

Country

Mexico.

Distinctive features

- First quasi-independent power producer (IPP) venture in Mexico, paving the way for future IPPs.
- First private-sector financing for the Inter-American Development Bank (IDB).
- Build-lease-transfer (BLT) project structure.
- Hybrid between project financing and structured on-balance-sheet financing, with equity holders earning equity rate of return during construction phase and subordinated-debt rate of return during lease phase.
- Trust structure developed to provide lenders with protection not available with leases under then-current Mexican law.
- Political risk coverage from the Export-Import Bank of the United States (US Eximbank) and the IDB.
- Contract documents in Spanish, governed by Mexican law; financing documents in English, governed by New York law.

Description of financing

The US\$650 million project cost was financed in 1996 as follows:

- US\$132 million in sponsors' equity;
- US\$442 million as a commercial bank construction loan, with a term of 10 years, taken out by US Eximbank; and
- US\$76.9 million in construction and term financing from the IDB.

The financing was structured as a build-lease-transfer (BLT) under a Mexican business trust.

Introduction

The case studies in this Chapter and Chapters 8 and 9 examine five power projects in Mexico.

Samalayuca II was Mexico's first quasi-IPP, and the project sponsors and the Mexican government had to resolve many legal issues related to the contract structure and project financing never previously raised in Mexico. Merida III, discussed in Chapter 8, was Mexico's first true IPP; it is the first build-own-operate (BOO) power plant and has a conventional 25-year power purchase agreement (PPA) to sell power to the Comision Federal de Electricidad (CFE) and a 25-year fuel supply contract to purchase natural gas from Pemex through the CFE. In the past, the CFE provided virtually all the specifications for a power project and the developer bid a price as well as qualifications to do the job. More recently, IPPs negotiated with the CFE have allowed their sponsors increasing flexibility with regard to site selection, fuel supply, and sale of excess power. InterGen's Bajio and La Rosita plants, discussed in Chapter 9, were deliberately oversized so as to be able to offer a lower price to the CFE and to export power to the United States. One of the most important trends with recent IPPs in Mexico has been delinking PPAs and fuel supply agreements. With Samalayuca II and Merida III, the CFE not only bought the plant's electricity under the PPA, but also acted as the intermediary for the purchase of fuel from Pemex. Now developers are concluding PPAs and fuel supply agreements separately, thereby assuming both fuel-supply and fuel-price risk. As IPPs take on more of those risks, lenders tend to require lower project leverage and more sponsor support. A long-standing question has been whether the CFE may be privatised some day, an event that would put IPP loans into default, but that is unlikely to occur in the near future. The Fox Administration has concentrated on efforts to make the IPP programme more attractive to developers. Recent initiatives have included efforts to develop a private bilateral contract market and a methodology for private plants to place excess power on the national grid at prices that are competitive with the CFE's power plants.

Project summary¹

Samalayuca II is a 700-MW power plant just south of Ciudad Juarez in the state of Chihuahua, directly across the border from El Paso, Texas. Construction of the plant was completed in the autumn of 1998. Samalayuca II was structured as a BLT project because, until December 1992, build-own-operate (BOO) projects were not permitted under Mexican law. The plant will be leased for 20 years and then owned by the CFE. It is adjacent to Samalayuca I, a 320-MW plant. (Samalayuca I used both oil and natural gas until the new Samalayuca gas pipeline was completed in early 1998, and is now expected to use mostly gas.) The new plant employs three state-of-the-art GE Frame 7FA gas turbine/steam turbine, combined-cycle machines and is equipped with state-of-the-art environmental equipment to meet current Texas air-quality standards. The shortage of water in the area is reflected in the plant's design. Although the plant was designed to run on natural gas, it is also capable of running on diesel oil.

The plant supplies power not only for Ciudad Juarez, a city of 1 million residents and more than 300 factories, but also for US customers under US-Mexican electricity interchange agreements. The project has brought benefits to the local economy through the local purchase of goods and services, and through the creation, at the plant site, of 1,800 jobs at the peak of construction and 100 permanent jobs.

The 45-mile Samalayuca pipeline carries natural gas from El Paso Energy's Hueco com-

pressor station, near El Paso, to the Samalayuca site. The US\$35 million pipeline project, carried out in 1997, involved the construction of 22 miles of pipeline in the United States and 23 miles in Mexico. It is a 50/50 joint venture between two business units of El Paso Energy Corporation – El Paso Natural Gas and El Paso Energy International Company – and Pemex.

Background

The project sponsors and the Mexican government had to resolve many legal issues related to the contract structure and financing of the Samalayuca II project, issues that had never previously been raised in Mexico.

Evolution of IPPs in Mexico

In the early 1990s, before the creation of the North American Free Trade Area, there was growing interest among Mexican authorities and US developers in creating an independent power industry in Mexico. To meet expected power needs, the Comisión Federal de Electricidad (CFE) planned for an increase in installed power-plant capacity from 33,000 MW, projected for 1995, to 45,000 MW in 2005. About half of the new capacity and one quarter of total capacity was expected to come from IPPs. The government of President Carlos Salinas started to negotiate two projects, the Carbon Dos coal-fired project with Mission Energy, and the Rosarito project with a US-Canadian-Mexican group. A Mexican law authorising IPPs was passed in 1993. It seemed to be a ‘win-win’ situation, since Mexico needed the power and the US developers, right next door, had the skills to make it happen.

Late in 1993 regulations to interpret and implement the enabling IPP legislation were issued. Power projects larger than 30 MW would be required to go through a competitive bidding process. Additional rules were spelled out for projects smaller than 30 MW. The Samalayuca II project, which was competitively bid and awarded in March 1992, was not affected by the legislation, but some other large project proposals had to be scrapped. The Carbon Dos and Rosarito projects kept moving during this period.

Also in 1993 the *pacto* among government, business groups and labour unions was renegotiated. The price of power was reduced to help businesses become more competitive. As a result, the Carbon Dos and Rosarito projects, and many proposals for small ‘inside the fence’ power projects, became uneconomical and were cancelled. A power project ‘inside the fence’ is located within a company’s industrial plant or complex, is owned by the company and is intended to serve mainly the needs of that plant or complex. Sometimes excess power is sold to other users. Developers that had been interested in Mexico diverted their attention to other countries with brighter prospects, such as Argentina. Prospects for new IPP ventures were further dimmed by the economic slowdown after the devaluation of the Mexican peso in December 1994.

Throughout this period negotiations between the sponsors and the Mexican government on the Samalayuca II project kept moving along, albeit at a delayed pace. The industry was watching the progress of this project to determine whether IPPs could become viable in Mexico. After the Samalayuca II project financing closed in May 1996, perceptions were generally favourable. The energy minister, the head of the CFE and President Ernesto Zedillo made reinforcing statements to the effect that the country was committed to IPPs. Developers became excited about Mexico again. The request for proposal (RFP) for the natural-gas-fired

Merida III project in Yucatan drew six qualified world-class bidders. Additional power and pipeline projects were begun shortly afterwards. Even though the project structure moved from build-lease-transfer (BLT), as used with Samalayuca II, to build-operate-transfer (BOT), as used with Merida III, and build-own-operate-transfer (BOOT), Samalayuca was the first quasi-IPP venture in Mexico and blazed the trail for future IPP ventures.

Award of the project

The Mexican government issued tender documents to the bidders for the Samalayuca II project in May 1991. Bids were submitted in March 1992 by three groups, one led by General Electric (GE), another by ABB and the third by Westinghouse. GE was joined in the winning consortium by Bechtel, El Paso Natural Gas, Grupo ICA and Coastal Corporation, a pipeline company. Later, Bechtel established its InterGen subsidiary and participated through it, while El Paso Natural Gas participated through El Paso Energy International.

Grupo ICA was an investor and ICA Fluor Daniel was a contractor with Bechtel and GE Power Systems. The publicly traded Grupo ICA is the largest construction company in Mexico and one of the largest in Latin America. It sold a 50 per cent interest in ICA Industrial, a subsidiary that constructs power plants and similar projects, to Fluor Daniel.

Coastal was the fifth partner at the time that the contract was awarded. Coastal had intended to build a pipeline to supply natural gas to the project, but this plan was modified to a joint venture with El Paso Energy and Pemex Gas y Petroquímica Básica (Pemex), the Mexican state-owned energy company, to accommodate the Pemex monopoly on pipelines in Mexico.

Structure of financing

The project financing for the Samalayuca II power plant was a BLT arrangement under a Mexican business trust. Commercial banks provided funds and assumed construction risk during the construction period. US Eximbank provided political risk coverage to the commercial banks during the construction period and replaced the commercial banks with a term loan for the 20-year lease period. The IDB provided a loan throughout the construction and lease periods, but is covered for construction risk by a letter of credit from the commercial banks. The lessee is the CFE, the state-owned electricity utility. A Mexican business trust was used because, under Mexican law, a lessee cannot undertake an unconditional lease-payment obligation.

Citibank was retained as financial adviser before the project was awarded to the sponsors and stayed on as lead manager of the syndicated commercial-bank term loan. Additional funding and political risk coverage were provided by US Eximbank and the IDB. This was the IDB's first private-sector deal, helped by the experience and guidance of US Eximbank.

The equity investors made a US\$132 million investment, representing 20 per cent of the project's capital structure. The remaining 80 per cent of the financing was provided by a consortium of commercial banks, US Eximbank and the IDB. Citibank was the lead manager in the US\$442 million construction loan, joined by ABN AMRO, Dresdner and Union Bank of Switzerland as co-managers. The loan was syndicated to 38 banks. US Eximbank provided US\$410 million of political risk coverage to the construction lenders for the term of their loan in the event of political violence, expropriation or currency inconvertibility, and took out the

construction lenders with a 10-year term loan. (The amount of US Eximbank's political risk coverage was less than the amount of the construction loan because the latter includes capitalised interest during construction, which US Eximbank does not cover.) The IDB provided an additional US\$76.9 million in construction and term financing, covered for construction risk during the construction period by a letter of credit by the commercial bank group. US Eximbank's board of directors approved the loan not as a pure project financing but as a passthrough credit obligation of the CFE.

At the end of the construction period the construction lenders are taken out in two ways. Their US\$76 million standby letter of credit in favour of the IDB, covering construction risk, expires, and US Eximbank takes them out of their construction loan with a 10-year term loan.

Alternative sources of finance considered

US Eximbank has restrictions on the amounts that it can lend based on the percentage of US content, percentage of local content and interest capitalised during construction. The sponsors originally had planned a Rule 144A bond offering through Salomon Brothers for the amount of funding still required after the commercial banks and US Eximbank had made their commitments. However, after the devaluation of the peso in December 1994 the bond market became unavailable to Mexico. The sponsors approached the IDB, which was willing to lend money but was not willing to incur construction risk. The market reopened a surprisingly short six months later, when the Mexican government did a US\$1 billion bond issue, but by that time the IDB had already committed itself to filling the gap that the 144A tranche would have filled.

Guarantees and other third-party sources of support

There is no explicit Mexican government guarantee. However, the CFE is viewed as an implied sovereign credit risk. The CFE runs the electricity business for the entire country just as Pemex runs the oil business.

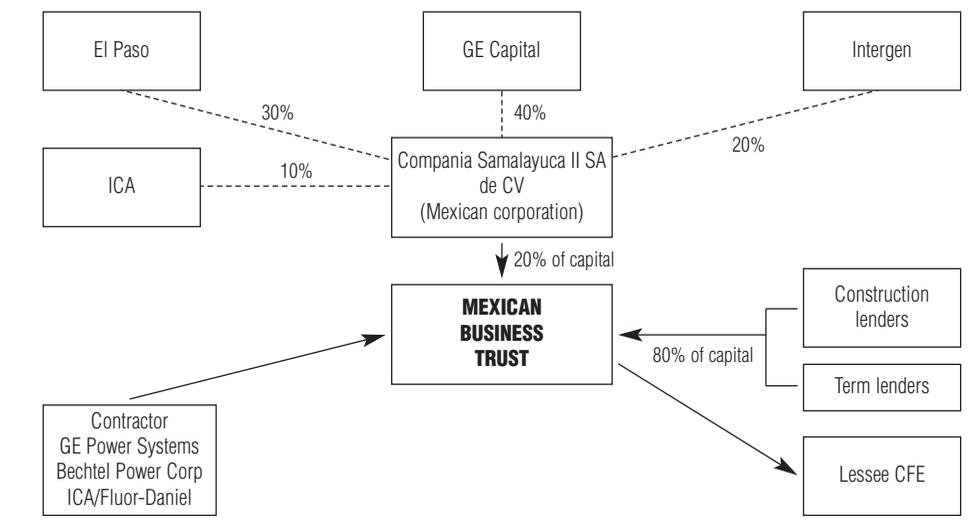
Ownership structure

The project was an opportunity for GE Power Systems to sell turbines, for GE Capital to make an attractive equity investment and support an affiliate's large-ticket sale, for Bechtel to provide design and engineering, for ICA Fluor Daniel to construct a power plant, and for El Paso Energy to sell natural gas. All the sponsors considered this project to be an important step in developing further business in Mexico and other Latin American countries.

The sponsor team

The project company, Compania Samalayuca II SA de CV, was formed in August 1994 with four equity partners and co-developers, the Structured Finance Group of GE Capital Services (GECC) owning 40 per cent, El Paso Energy International owning 30 per cent, InterGen owning 20 per cent and Grupo ICA owning 10 per cent. GE Power Systems and GE Capital acted together as the lead developer and project manager, and GE Power Systems was the equipment supplier. The construction partners were GE Power Systems; Bechtel Power, an

Exhibit 7.1

Project participant structure

InterGen affiliate; and ICA Fluor Daniel. ICA was responsible for local content. The GECC Capital Markets Group co-arranged the debt financing with InterGen. The CFE becomes the lessee of the plant after construction and testing.

Legal structure of project entity

Samalayuca II was structured as a BLT project because, until December 1992, build-own-operate (BOO) projects were not permitted under Mexican law. The project's BLT structure accommodates a construction period, similar to most project financings, and a 20-year lease period that is comparable to a highly structured, on-balance-sheet corporate financing rather than a project financing. The CFE has an unconditional obligation to make lease payments, whether or not the plant is operating. At the end of the lease period the ownership of the project is transferred to the Mexican utility. A Mexican business trust is the owner of the plant, the lessor of the plant to the CFE and the obligor of the project debt. The project structure is illustrated in Exhibit 7.1.

All the financing documents involving the trust, the commercial banks, US Eximbank and the IDB are in English, and were negotiated in New York. On the other hand, the lease, the trust and annexes to the trust are governed by Mexican law. The CFE would not accept having them governed under New York law. Negotiations to create these documents were conducted in Spanish at the CFE's offices in Mexico City. Although there have been English translations, the original enforceable versions of lease and trust documents are in Spanish. This presented problems, because a number of legal terms in the Spanish-language documents are less than exact translations of English-language terms that exist in the context of English and US law, but that do not exist in Spanish or in Mexican law. An example concerns the English adjective 'material': the Spanish words *importante* and *substantiale* do not have the same meaning in the context of Mexican law.

Risk analysis

In principle the project risks were allocated as follows:

- the commercial banks assumed construction and commercial risk throughout the construction phase;
- US Eximbank and the IDB assumed political risk; and
- the sponsors assumed all other residual risks.

The sponsors developed a risk-allocation matrix similar to the one shown in Exhibit 7.2. For construction risk, the first layer of defence was liquidated damages payable by the contractor, the consortium of GE Power Systems, InterGen and ICA Fluor-Daniel. The second layer was the equity invested, 20 per cent of the capital structure. The final layer comprised the construction lenders.

Because the commercial banks bore all the construction risk, while US Eximbank and the IDB bore all the political risk, the allocation of risks among the lenders did not coincide with the amount of funding that each institution provided. The construction lenders took on construction risk in two ways: through direct lending and through standby letters of credit, issued by the lending banks, indemnifying the IDB during the construction phase in the event of construction problems. As a multilateral agency, the IDB was comfortable with Mexican political risk but not with construction risk.

The banks were accustomed to taking on construction risk but not completely comfortable with Mexican political risk. They arranged a political-risk insurance policy from US Eximbank for the amount that they lent during the construction phase. The IDB does not give guarantees. Instead, it extended a loan and retained its political risk, but covered its construction risk with a standby letter of credit in its favour issued by the lending banks. If some event caused US Eximbank's political risk guarantee to be terminated, the same event would trigger payment to take out the IDB under the letters of credit. In effect the IDB provided the same political-risk coverage as US Eximbank, but the documents were completely different. As with many aspects of this financing, developing the structure and the required documentation to dovetail US Eximbank and the IDB's political coverage required many hours of legal work.

Among the residual risks that the CFE originally did not foresee was privatisation risk. If it was to be privatised, the CFE would become a far different credit risk than it was as part of the Mexican government. This was neither a political risk that US Eximbank would cover nor a commercial risk that the com-

Exhibit 7.2

Risk-allocation matrix

| | <i>CFE</i> | <i>Project sponsors</i> | <i>Commercial banks US Eximbank and IDB</i> |
|---------------------------|------------|-------------------------|---|
| <i>Construction phase</i> | | | |
| Construction risk | | X | |
| Political risk | | | X |
| Residual risks | X | | |
| <i>Lease phase</i> | | | |
| CFE credit risk | | | X |
| Political risk | | | X |
| Residual risks | X | | |

Source: Offering Memorandum.

mercial lending banks would cover. Therefore privatisation was defined as an event of default by the CFE in the trust agreement throughout the construction and lease periods.

Gas-supply risk was another difficult issue. Because the CFE was undertaking an unconditional lease-payment obligation, whether or not the plant was operating, it could not readily see why it should be required to commit itself to supplying gas to the plant as part of the trust agreement. US Eximbank's representatives reiterated that they could not be seen to be financing a 'white elephant' power plant that was not operating even if the required lease payments were being made.

A number of other 'pinhole' risks also had to be negotiated. For example, US Eximbank wanted a standard loan-agreement provision that the borrower pays for enforcement costs. The CFE objected to the inclusion of the provision to meet legal fees as indicating a presumption by some that there may be a default.

The equity holders, the ultimate bearers of both political and construction risk, earn two rates of return that are fixed in the agreements with the CFE and incorporated on a present-value basis in the amount of the CFE's monthly lease payments to the trust. They earn an equity rate of return during the construction period and a lower, subordinated-debt rate of return during the lease period. The sponsors found the equity rate of return difficult to negotiate. They had to persuade the CFE and the Mexican Ministry of Finance that the contractor and the equity holders bore just as much construction risk with this project as they would with any other power project. However, after the power plant was constructed and running, the nature of the equity holders' risk changed. The subordinated-debt rate of return throughout the term of the lease was based on the 20-year 'hell or high water' lease-payment obligation of the CFE. During this period the creditworthiness of the CFE is the equity holders' principal risk. Because the CFE is both the lessee and the operator of the plant, the equity holders do not have the opportunity to increase or decrease their return based on their own operating performance. In the unlikely event that the CFE decides not to operate the plant, it still must make lease payments to the lessor, the trust.

Credit analysis

Because market conditions changed and bonds never were issued, the sponsors had no reason to have the project credit rated. If a 144A bond programme had been implemented, they would have expected to achieve a credit rating at or slightly below Mexico's sovereign rating.

Principal problems encountered

The bid was awarded to the sponsors in December 1992, but the project did not close until May 1996, after more than three years of hard work and uncertainty. Negotiations for the project financing took a long time for several reasons, including:

- the lack of precedents in Mexico for similar projects;
- the transition from Salinas's presidency to Zedillo's;
- the devaluation of the peso in December 1994; and
- the temporary shutdown of the US Federal Government.

These will be discussed in turn in the following paragraphs.

The recent introduction of IPPs into less developed countries, such as Mexico, was mak-

ing cautious progress. Even in the United States at that time, utilities were just becoming comfortable with risk-allocation issues related to IPPs. At about the same time sponsors were negotiating terms for the Chabei power project in China, the Termobarranquilla project in Colombia, the Dabhol project in India and the Paiton I project in Indonesia. The issues between the sponsors and the host countries were similar. Specifications in the host countries' RFPs were not precise. The host countries did not have a clear understanding of how ownership relationships would work, how risks would be allocated among contract parties or other legal issues. Progress required trust to be developed on both sides of the negotiating table. The sponsors had to maintain the fundamentals of project contracts and project finance, while recognising that the host countries' authorities had to protect their own countries' assets and to be seen by their peers as negotiating smart deals.

When President Zedillo assumed power the top officials at the CFE were replaced and the new officials had to be brought up to speed. Continuity of many officials at lower levels aided this process.

The economic crisis following the devaluation of the peso in December 1994 temporarily rocked confidence in Mexico, which had restructured its foreign debt in the early 1990s and recently had come to be seen as one of the more stable economies in Latin America. With the bond markets unavailable, the sponsors looked for other sources of financing. This came in the form of loan commitments from US Eximbank and the IDB, and a syndicated commercial bank loan, as discussed above.

Political risk was evident in the United States as well. The US government was shut down for two short periods in late 1995 as a result of domestic disagreements between the Republican-dominated Congress and the Democratic administration of President Bill Clinton. This delayed negotiations between the project sponsors and one of the principal lenders, US Eximbank. Later, however, the debate over US Eximbank's own reauthorisation did not put the project at risk because US Eximbank had already made a binding commitment to finance it.

Legal issues

The CFE's original bid specifications included a model lease agreement that was about three pages long. Brandon A. Blaylock, Managing Director, International Business and Venture Development, GE Capital Services Structured Finance Group, noted at the time that even a normal car lease in the United States is longer. The sponsors and their lawyers had to negotiate a more detailed comprehensive agreement.

The principal problem that the sponsors faced was a provision in Mexican law that a lessee that suffers *force majeure* can abrogate a lease. For example, if half of an apartment is destroyed by fire, the lessee has a right to reduce the rent paid by one half. If the problem is not corrected within a reasonable time, the lessee has the right to terminate the lease. This right cannot be waived by a lessee. It applies to all types of leases, from apartments to power plants. A lease that gave the CFE a right to terminate in the event of a problem could not have been financed. Financial leases generally have 'hell or high water' payment provisions. The challenge for the sponsors was to arrange a BLT project structure that would satisfy Mexican law but could also be financed.

Negotiations had a couple of false starts. One structure developed in detail, with some precedent in Mexico, was called a split lease. Some of the assets, principally movable assets, would have been leased under New York law, which does not allow the lessee to abrogate the

lease because of *force majeure*. Other immovable assets would have been leased under Mexican law. The Mexican authorities rejected this structure in early 1994 because of its complexity, sending the sponsors and their lawyers back to the drawing board.

The sponsors' principal Mexican law firm, Ritch, Heather y Mueller, and the CFE's lawyer developed the concept of a Mexican business trust combined with a lease. Obligations under trust agreements can be made 'come hell or high water' and these obligations cannot be abrogated because of *force majeure* as they can under leases. If the lessee were subject to *force majeure*, the value due under the trust would turn out to be equal to the remaining lease payments. This was the fundamental legal cornerstone that allowed the project to be financed.

The trust structure also provided benefits to the CFE, such as the right to interact with the developers in the construction process, seeing drawings, approving designs and inspecting progress. (The original bid specifications would have handicapped the CFE, the user of the plant, by not providing for it to interact with the developers.) As a result, lawyers for both sides believed that there was a sufficient two-way flow of benefits and consideration to make the agreement enforceable.

An unusual aspect of the trust structure, as applied to a project financing, is that the CFE contracted with the owner, which in turn contracted with the engineering, procurement and construction (EPC) contractor. The obligations that the owner undertook in favour of the CFE in many respects had to be identical to obligations undertaken by the EPC contractor in favour of the owner.

The CFE is a party to the trust as well as to the lease agreement. It is the third beneficiary of the trust, the first being the senior lenders and the second being the equity holders. As a result, when the transfer of the trust's assets, the power plant, is made at the end of the lease period, the CFE will have third priority in receiving the assets.

Lessons learned

Blaylock believes that the lessons learned from this long process can be applied to any potential project participant in developing international markets: be prepared to learn a lot and be prepared to teach as well. A successful project requires close teamwork among all the project participants, and sensitivity to each other's issues and needs. As those involved in concurrent IPP ventures in other less developed countries would agree, financing takes longer than usual with any first-of-a-kind project, especially when there are difficult risk-allocation issues. Often the process is just as important as the substance.

Miguel Rubio, a lawyer with US Eximbank, believed at that time that the Mexican government had learned about the need to develop project-financing and risk-allocation structures that are in line with the world market.

Ana Demel, partner of Cleary, Gottlieb, Steen & Hamilton, believes that the most important lesson concerns the need to have rational, well-thought-out bid specifications, with careful consideration of local-law constraints and a realistic approach to meeting market requirements. When there are flaws in the specifications, a lot of time and money is required to work around the problems. Demel notes that delay is not only expensive and frustrating for all parties, but also brings with it a host of other risks such as the uncertain policies of a new government.

Because this was Mexico's first quasi-IPP venture, the CFE encountered many problems that it should, perhaps, have foreseen but did not when drawing up the rather simple bid specifications and draft lease agreement. Examples include the Pemex monopoly on pipelines and

the inability of a commercial lease under Mexican law to be used as a basis for project financing. Part of the problem was that the CFE is a large enterprise, and in the past the people responsible for planning power projects were not the same as those responsible for financing. As a result of what the CFE learned from the Samalayuca II project, bid specifications for later projects were better thought out and more attuned to the requirements of international project financing.

The Samalayuca II project financing illustrates how the Latin American region is a substantially different kind of a place to do business in than it had been 10 to 15 years before. Blaylock noted that the whole region is moving toward private capital rather than government financing for power, water systems, ports and other types of infrastructure projects.

¹ This case study is based on interviews with Brandon A. Blaylock, Managing Director, International Business and Venture Development, GE Capital Services Structured Finance Group, Inc.; and Ana Demel, Partner, Cleary, Gottlieb, Steen & Hamilton.

Merida III, Mexico

Type of project

Power plant.

Country

Mexico.

Distinctive features

This was the first venture by an independent power producer (IPP) in Mexico.

Description of financing

The total project cost of US\$231 million was financed in 1998 as follows:

- US\$58 million sponsors' equity;
- US\$104 million A loan from the International Finance Corporation, with 20-year maturity and mortgage-style repayments priced at 225 basis points (bps) over the London interbank offered rate (Libor); and
- US\$74 million IFC B loan, with 16.5-year maturity and mortgage-style repayments priced at 135 bps over Libor.

Introduction

The case studies in this Chapter and Chapters 7 and 9 examine five power projects in Mexico. Please refer to the 'Introduction' in Chapter 7 for a brief overview of the projects.

Project summary¹

Merida III, Mexico's first true IPP venture, is a 440 MW electric power plant in the city of Merida on the Yucatan peninsula. The plant is powered by a Westinghouse 501F gas turbine.

Background

Power demand in Mexico

As of 1994 Mexico had about 27,000 MW in its electricity grid. Power needs were expected

to grow at 5 per cent per year over the following decade, requiring 17,000 MW of new capacity by the year 2000. An estimated US\$11 billion of investment over the following six years would be required to keep up with growing national demands for energy. The energy ministry had a list of 21 power plants that needed to be built to satisfy this growing electricity demand. Merida III was the first of these projects to be put to tender.

Concession award

The Comision Federal de Electricidad (CFE) originally asked for bids in 1994. Plans to go ahead with the project were delayed because of uncertainty over arrangements to supply natural gas to the project. The concession was awarded in January 1997 to a consortium comprising AES of Arlington, Virginia (55 per cent); Nichimen of Japan (25 per cent); and Grupo Hermes, a Mexican industrial company (20 per cent). Competing groups were led by, among others, Mitsubishi, Enron, General Electric, Siemens and Westinghouse. AES bid the lowest KW hour price for selling power to the CFE. As of 1997 AES had assets of US\$3.5 billion and more than US\$5 billion of projects in construction or late stages of development. The company owned or had an interest in 33 power facilities totalling over 11,000 MW, in Argentina, Brazil, China, Hungary, Kazakhstan, Pakistan, the United Kingdom and the United States.

AES had a right to negotiate to keep the assets at the end of the 30-year concession. This was, however, a minor financial consideration, taken on a present-value basis, because the gas turbines were not expected to have much useful life remaining at that time and the power plant technology would probably have made significant advances.

Contractual relationships

IPP ventures in developing countries are often, in effect, caught between two government utilities, having to buy fuel from a hydrocarbon utility and sell electricity to a power utility. In this case the project company has a 25-year power purchase agreement (PPA) to sell electricity to the CFE and a 25-year fuel supply contract to purchase natural gas from Pemex Gas y Petroquimica Basica (Pemex), the Mexican state-owned energy company, through the CFE. At the time that Merida III was financed there were no plans to create a free electricity market in Mexico. Subsidiaries of Westinghouse Power Generation, then a division of CBS Corporation and now part of Siemens, were the engineering, procurement and construction (EPC) contractors, and a subsidiary of AES and Nichimen operates the plant.

Natural gas pipeline

To supply fuel to the plant a 700-kilometre natural gas pipeline, to carry 370 million cubic feet per day, was built from Ciudad Pemex in the state of Tabasco to the Yucatan peninsula. A US\$250 million, 26-year contract to build, own and operate the pipeline was awarded in 1997 to a consortium consisting of InterGen, TransCanada and Gutsa Construcciones, a Mexican construction company. The pipeline was completed in early 2000, about the same time as the power plant was finished.

The project contracts allowed AES to run the plant on distillate fuel for up to two years in the event of construction of the pipeline being delayed. Pemex had plenty of storage facil-

ities to supply fuel to four older plants on the site. There was a technical risk in making this concession, because liquid fuels, if not properly treated, can cause gas turbines to deteriorate.

Financial structure

The project is financed 25 per cent with equity and 75 per cent with debt. The Japanese Export-Import Bank provided 40 per cent of the debt financing, and the IFC's A and B loans provided the remaining 60 per cent. IFC loans are not subject to local withholding taxes. This gives the IFC and the commercial banks that participate in its loans a competitive advantage.

How the financing was arranged

The IFC can foresee being a leading lender to merchant power plants where commercial lenders are not yet ready to go independently. The IFC and the Inter-American Development Bank (IDB) competed with each other to undertake the financing. The IFC was aware that the IDB was well-established in its territory. The IFC also realised that it had a reputation for stringent enforcement of technical and environmental requirements, and that it could drive away potential project sponsors if its standards seemed unreasonable. In meetings with AES, the IFC sought to demonstrate the institution's competence. The IFC was awarded the mandate in April 1997. The project appraisal took about five months and the IFC's board of directors approved the project financing in October. Financial closing, which took longer than expected, occurred in June 1998.

Sanwa Bank, which worked with AES on the bid for the contract, had the largest single commercial bank stake in the financing, but because the financing was already thinly priced there were no bank underwriters and no agents' fees. The IFC had the freedom to choose the other commercial banks apart from Sanwa. The opportunity to work with AES and the IFC on a Mexican deal attracted a large number of prominent international banks, despite the record-setting sixteen-and-a-half-year maturity and a spread over Libor that was considered aggressive at that time.

The Asian financial crisis that began in the spring of 1997 had a somewhat positive effect on the syndication of the loan. Lenders were looking for opportunities outside Asia but anxiety had not yet spread to markets such as Latin America.

IFC due diligence

The IFC's objective when working with AES was to ensure that sound project contracts were executed and that Mexico's first IPP venture was financed in a way that could easily be replicated with other developers and financial institutions. There were no precedents for IPP ventures. (The IFC does not consider a build-lease-transfer (BLT) arrangement such as that for Samalayuca II, discussed in the previous chapter, to be an IPP venture.) Finding the right audience in the government and sorting through the issues was time-consuming for the IFC and AES, but ultimately resulted in a deal satisfactory to both organisations.

The IFC performed due diligence on Pemex's ability to deliver fuel and the CFE's ability to offtake electricity and make payments. It also performed due diligence with the IDB to assess the likelihood that the pipeline would be constructed and ready to deliver fuel by the time that the power plant was completed.

One of the scenarios that the IFC considered in its due diligence and credit analysis was the privatisation of the CFE. This seemed a remote possibility in 1997, but as of 1999 the privatisation of the CFE, the establishment of a deregulated electricity market and the introduction of merchant power plants appeared to be strong possibilities within the next five years. In February 1999 President Ernesto Zedillo introduced legislation into the Mexican Congress that would provide for an extensive restructuring of the Mexican power industry, making it more attractive to private investment. The bill would have allowed IPPs to sell power directly to consumers and, in the future, energy marketers; split the CFE into generation, transmission and distribution assets, to be sold off to private companies; create a new state-owned company to oversee the electricity transmission grid; and establish a wholesale spot electricity market. The objective of these reforms would have been not just to allow private participation in the electricity sector, but also to attract foreign investment to build the capacity necessary to satisfy Mexico's growing electricity needs. The legislation was not passed, however, and Zedillo's government later decided to pass the power industry restructuring issue on to the government of Zedillo's successor, Vicente Fox.

Credit analysis

The credit risk of the CFE was considered to be almost the same as that of the sovereign. The government has provided financing to the CFE from time to time when it has run into financial difficulties.

The commercial banks participating in the loan were concerned with the soundness of project fundamentals, such as power demand, and the relationships between the project, Pemex and the CFE. They were also concerned about the experience and reputation of the developer, and whether the pricing on the deal was sufficient to compensate for the risk. AES's strong international reputation, and the structure of the IFC's A and B loans, were both strong selling points for the commercial banks that participated in the loan.

The IFC is the lender of record for both the A and the B loans, even though commercial banks are the actual lenders for the B loan. Principal and interest payments for both loans are sent to the IFC through a trustee. Although the borrower is naturally aware of the commercial banks' participation, it makes no payments directly to them. The commercial banks are not protected by any guarantees, but, in their perception, lending alongside the IFC mitigates their risk. If a US\$10 million loan repayment is expected, but the borrower pays only US\$5 million, the IFC splits the payment *pro rata* among itself and the commercial banks. If the borrower runs into financial difficulties, or if there are political or regulatory problems, the IFC is in an advantageous position to enlist the help of other multilateral agencies, such as the World Bank or the IMF, to pursue possible solutions.

Lessons learned

The IFC played a pivotal role, ensuring that sound project contracts were executed so as to facilitate the future financing of independent power projects in Mexico.

¹ This case study is based on an interview with Haran Sivam, Investment Officer, Power Department, International Finance Corporation.

Bajio, La Rosita and TEG, Mexico

Type of project

Natural-gas-fired power plants.

Country

Mexico.

Distinctive features

- Oversizing for sales to industrial customers (Bajio, La Rosita I & II).
- Site selection by project sponsors (La Rosita I & II).
- Fuel supply risk assumed by project sponsors (La Rosita I & II).
- ‘Inside the fence’ project financed under Mexican self-supply legislation (TEG I & II).
- Commercial paper facility to reduce financing cost (Bajio).

Description of financing

Bajio

- US\$22.5 million Inter-American Development Bank (IDB) A loan.
- US\$113 million B loan syndicated by BNP Paribas, Citibank, Deutsche Bank and Dresdner.
- US\$215 million commercial paper facility provided by Citibank.

La Rosita I & II

- US\$625 million commercial bank financing, US\$425 million covered by political risk insurance from Export Development Corporation of Canada.

TEG I

- US\$75 million IDB A loan.
- US\$102 million IDB B loan.

Introduction

The case studies in this chapter and Chapters 7 and 8 examine five power projects in Mexico. Please refer to the ‘Introduction’ in Chapter 7 for a brief overview of the projects.

Mexican power projects following Samalayuca II and Merida III

After AES was awarded the mandate for Merida III in March 1997 (see Chapter 8), three power project concession awards followed the build-lease-transfer (BLT) model of Samalayuca II (see Chapter 7): the 450 MW Rosarito III project, the 100 MW Cerro Preto project and the 435 MW Encino project. Subsequently, budget cuts made the Comision Federal de Electricidad (CFE) more receptive to the private sector and several more independent power producer (IPP) ventures were approved. The structure for the Merida III loan from the International Finance Corporation (IFC) was sufficiently sound to be essentially replicated in two recent loans from the IFC to Mexican IPP ventures, the Rio Bravo and Saltillo projects, and a loan from the Inter-American Development Bank (IDB) to another such venture, the Hermesillo project.

In all these power projects the CFE provided virtually all the specifications and the developer bid a price as well as qualifications to do the job. More recently, as Jonathan Lindenberg, Managing Director of Citibank, observes, IPP ventures negotiated with the CFE have allowed their sponsors increasing flexibility with regard to site selection, fuel supply and the sale of excess power. For example, when InterGen, a Shell/Bechtel venture, submitted bids to the CFE for the Bajio and La Rosita projects, described below, it deliberately specified larger plants than were necessary to satisfy the CFE's needs so as to be able to offer a lower price to the CFE, to start exporting power to the United States and to develop a bilateral market for power sales to Mexican industrial customers. In the bankers' view, the ability of border-region plants to sell power in either country enhances their creditworthiness. Mexico now has investment-grade ratings from Moody's, Standard & Poor's and other agencies. As a result, there should be less requirement than before for support from the multilateral and bilateral agencies, such as export credit agencies, whose country capacities are strained.

Lindenberg of Citibank observes that project oversizing adds a new credit wrinkle from the CFE's perspective. The CFE has always agreed that if it defaults, or following certain events of *force majeure*, it would have to buy out the project, and make debt and equity holders whole. That is reasonable when the size of the power purchase agreement (PPA) and the project size are the same, but different issues arise when the project is bigger than the PPA because it is selling additional power to industrial or export customers. Recently, the CFE has indicated that, in the event of default, it might be willing to bear the risk of having to buy out projects larger than the related PPAs just so that it can stay in control of the situation.

The following sections describe the financing of the Bajio and La Rosita projects, and of Termoelectrico del Golfo I and II, two 'inside the fence' power projects financed under Mexican self-supply energy legislation. A power project 'inside the fence' is located within a company's industrial plant or complex, is owned by the company and is intended to serve mainly the needs of that plant or complex. Sometimes excess power is sold to other users.

Bajio

InterGen's 600 MW Bajio project in San Luis de la Paz, 160 miles northwest of Mexico City, shows some new directions for IPPs in Mexico. The project sponsors are InterGen and AEP Resources, a subsidiary of American Electric Power. The project will use 495 MW of its capacity for sale of electricity to CFE under a 25-year PPA and the remaining 105 MW for sales to third-party industrial customers. A Mexican IPP with a 'self-supply permit' is

allowed to sell electricity to industrial customers that hold a nominal 2 per cent share in the project. This is just a legal requirement; these companies have no shareholders' rights. InterGen deliberately oversized the project so as to be able to offer the CFE a lower electricity tariff. This helped the developer win the bid from the CFE against heavy competition and establish a position in the nascent Mexican wholesale power market.

Financing for the Bajio project, which closed in June 2000, came from:

- a US\$22.5 million IDB A loan;
- a US\$113 million B loan syndicated by BNP Paribas, Citibank, Deutsche Bank and Dresdner; and
- a US\$215 million commercial paper facility provided by Citibank.

Commercial paper offers the project lower-cost financing than a loan based on the London interbank offered rate (Libor) would have. Citibank will sell the commercial paper through a conduit vehicle called Govco, which it developed several years ago for government-guaranteed financings. This is the first time that this vehicle has been used for a non-recourse project financing.

The commercial paper is backed by a comprehensive guarantee from the Export-Import Bank of the United States (US Eximbank), which further reduces the cost. US exports include gas and steam turbines from General Electric Power Systems. US Eximbank set a precedent with this financing as well. Bajio is the first project for which its comprehensive guarantee covers both the construction and the operating period.

Bankers based their credit decisions primarily on the PPA with the CFE, considering that the risk related to industrial sales would be borne by the sponsors. In an unlikely worst-case scenario, the sponsors would bear the cost of a 600 MW plant but only receive the revenue from a 495 MW PPA. From a business perspective, some see InterGen as breaking even on the PPA and making its profit on the industrial sales.

La Rosita I and II

In December 2001 InterGen closed a US\$625 million commercial bank financing for La Rosita I and II (formerly called Rosarito but renamed because of confusion with other projects), in Baja California, about six miles south of the US border. Of the total amount, US\$420 million is covered by political risk insurance from the Export Development Corporation of Canada. The covered portion has a tenor of 15 years and the uncovered portion 11 years. Guillermo Espiga, Director – Finance, Latin America, for InterGen Energy, Inc., in Coral Gables, Florida, noted that the successful syndication of the Bajio project helped with this financing. As with Bajio, InterGen oversized La Rosita I in order to achieve economies of scale and to be able to offer a better rate to the CFE. InterGen will use 500 MW of the plant's capacity to sell to the CFE and 250 MW to export to the California market.

La Rosita I and II is the first Mexican IPP in which the developer rather than the CFE has selected the site, which in this case was based on serving both the Mexican and the Californian markets. Also, instead of buying fuel from Pemex Gas y Petroquímica Básica (Pemex), the Mexican state-owned energy company, as previously established IPPs have, La Rosita I and II has the flexibility to arrange its own fuel supply from either the US or the Mexican market.

The plant's natural gas fuel supplier is Coral Energy, which has a tolling arrangement for the 250 MW of its power sold in the US market. Coral Energy is the AAA-rated trading arm of Shell, InterGen's 68-per-cent owner. The fuel will be supplied through the North Baja pipeline, a joint venture between two potential customers of the plant, PG&E Corporation and Sempra Energy.

The 310 MW La Rosita II plant is an entirely merchant facility that will sell power through Coral Energy into the Californian market. It therefore has a considerably higher risk profile than La Rosita I, with its CFE contract. The bank financing addresses the varying level of merchant risk through an innovative borrowing base approach that limits leverage and distributions (after the plants begin to operate), based on proportions of contracted power and forecast power prices. Leverage will be 75 per cent for La Rosita I but just 50 per cent for La Rosita II. Thus US\$625 million is the maximum commercial bank commitment. The amount of loans that can be drawn at a given time is calculated according to a borrowing base determined by the respective leverage of the two power plants.

InterGen's long-term strategy is to build a national energy company in Mexico, continuing to bid on CFE projects but always adding value through factors such as industrial and export sales.

TEG I

Termoelectrico del Golfo I (TEG I) is an 'inside the fence' project costing about US\$370 million. The plant is located in Tamuin in the central Mexican state of San Luis Potosi.

The project is sponsored by Sithe Energies, Inc., ABB Alstom Power and Cemex. The sponsors have put in place wheeling arrangements with the CFE so that the project can transmit power to 12 Cemex cement plants. Wheeling is the movement of electricity from one system to another over the transmission facilities of intervening systems. Wheeling is required to offer customers a choice of electricity suppliers. The project will sell surplus power to the CFE.

Sithe is the largest non-utility IPP in the United States. The company has no political risk insurance on its equity. Robert Kartheiser, Sithe's senior vice president for Latin America, believes that political risk in Mexico today is manageable, based on recent structural and economic changes, increasing integration with the US economy as a result of membership of the North American Free Trade Area, and Vicente Fox's victory in the presidential election in July 2000. In the past Sithe has followed an opportunistic worldwide IPP strategy. More recently, its shareholders have decided to focus on Canada, Mexico, and the United States.

ABB Alstom is a turbine manufacturer based in Belgium. The banks lending to this project were concerned that the clean-burning, fluidised bed technology that ABB Alstom planned to use in the boilers was, although not completely new, an extension of an existing technology. Further, this technology had never been employed in such a large plant. To allay their concerns the lenders became comfortable with ABB Alstom's reputation and negotiated an acceptable level of liquidated damages under the engineering, construction and procurement contract.

Cemex, the power offtaker, is one of the largest industrial companies in Mexico and the third largest cement maker in the world. TEG I represents a strategic measure for Cemex to manage its long-term cost of electricity, which accounts for about 20 per cent of

POWER PLANT

its manufacturing cost. The company wanted a secure, predictable and competitive source of power.

For fuel, the TEG I plant uses petroleum coke, which costs less than natural gas. Whereas the price of natural gas has doubled in the past two years and there is considerable uncertainty as to where it will go in the future, the price of petroleum coke has been stable over the past 20 years and recently has been dropping as Pemex produces it in increasing volume. Pemex has converted its Cadareyta and Madero refineries and will soon convert other refineries as well to produce lighter, lower-sulphur fuels. In producing those fuels, Pemex also produces what Robert Kartheiser describes as ‘literally mountains’ of petroleum coke as a byproduct.

TEG I is the first project financed under Mexico’s self-supply energy legislation. Current law in Mexico permits three types of privately financed IPPs:

- CFE-sponsored projects;
- cogeneration facilities; and
- self-generating facilities.

TEG I fits into the last of these three categories. Under Mexican law Cemex cannot simply take the initiative to build a plant to supply its own power, but must structure the offtake and ownership of the generating plant to comply with Mexican self-generation regulations.

In addition to 25 per cent equity from the sponsors, financing for TEG I comes from a US\$75 million IDB A loan and a US\$102 million, 14-year B loan priced at the following spreads over Libor: 225 basis points (bps) for years one to three, 262.5 bps for years four to six, 300 bps for years seven to 10, and 337.5 bps to maturity. ABN AMRO and Deutsche Bank arranged and syndicated the B loan. TEG is the first ‘inside the fence’ project supported by the IDB. Half of the debt is covered by a comprehensive political and commercial guarantee from Compagnie Française d’Assurance pour le Commerce Extérieur (Coface).

Miguel Pachicano, Group Vice President of ABN AMRO in Chicago, reports that the B loan was syndicated quickly and oversubscribed. Four of the issues that lenders focused on were:

- the credit of Cemex, the offtaker;
- the technology;
- the project structure; and
- a default scenario.

As one of the fastest growing and most innovative cement companies in the world, Cemex made a positive impression in a presentation to the lenders.

The lenders required a little extra time to understand the rather complicated legal structure of the project, in which the actual borrower and holder of the assets is a Mexican business trust, supervised by a master trust. That structure is dictated by the Mexican self-supply law and tax considerations.

Finally, the lenders were concerned about what would happen if Cemex defaulted and the CFE at the same time was partially or fully privatised. They did a dispatch study and concluded that the low fuel price would enable the plant to be competitive in a wholesale market.

TEG II

TEG I was followed later in 2001 by TEG II, a sister plant also sponsored by Sithe on the same site, at an estimated cost of US\$330 million, less than the first plant because of economies of scale. The offtaker is Pinales, a Mexican mining and metals company with a similarly heavy need for electricity in its manufacturing process.

According to Robert Kartheiser, Sithe's objectives are to replicate a good project with another blue-chip offtaker for which electricity is a strategic input; to capitalise on economies of scale; and to achieve a similarly successful loan syndication. Coface will provide comprehensive commercial and political risk insurance, and the British agency, the Export Credit Guarantee Department, will also provide political risk insurance.

Fuel supply issues

One of the most important trends with recent IPPs in Mexico has been delinking PPAs and fuel supply agreements. With Samalayuca II and Merida III, the CFE not only bought the plant's electricity under the PPA but acted as the intermediary for the purchase of fuel from Pemex. Dino Barajas, an attorney with Milbank, Tweed, Hadley & McCloy in Los Angeles, explains that, even if the CFE did not supply the fuel, the power plant would receive its capacity payment to cover debt and capital costs.

Developers are now concluding PPAs and fuel supply agreements separately. The majority of their fuel supply agreements are with Pemex, but some plants near the northern border have US-based fuel suppliers. Further, with recent IPP ventures developers have been required to submit bids before concluding fuel supply agreements. Bidders win largely on the basis of the prices quoted in their PPAs, which are based on their best estimates of fuel prices. Therefore a developer risks fuel price arrangements that turn out to be higher than anticipated when the electricity price bid was submitted. In addition, an IPP venture now bears the risk that the CFE will dispatch tomorrow but Pemex or another supplier will not deliver the fuel.

In an article in the *Journal of Structured and Project Finance* (Fall 2002), John Schuster, a senior project finance credit director, and Bob Marcum, a project finance loan officer, explain that as IPPs take on increasing natural gas procurement risk, lenders tend to require lower project leverage and more sponsor support. IPPs' fuel-supply agreements with Pemex are divided between variable or 'swing' supply and firm supply on a take-or-pay basis. A higher proportion of firm supply results in a lower fuel price, which helps the developer to quote a lower electricity price and win the bid, but also exposes the developer to a higher risk that the IPP will have to pay for natural gas that it cannot use. Marcum and Schuster recommend that Pemex consider two possible remedies to help IPPs with take-or-pay risks:

- offering different levels of take or pay for different commitment periods, for example, a 30 per cent minimum take on a weekly basis but a higher 60 per cent take on an annual basis – allowing an averaging process to work over the course of a year to the IPP's benefit; or
- allowing IPPs, in their ongoing efforts to match fuel nomination with electricity dispatch, to be relieved of a certain portion of their take-or-pay obligations with sufficient advance notice.

Marcum and Schuster also note that natural gas suppliers typically offer two forms of contractual remedies to mitigate delivery performance risks: penalties to cover lost capacity pay-

ments; and ‘in kind’ replacement of supply, in the form of either natural gas from another source at market prices or delivery of electricity. However, according to these authors, Pemex appears to be leaning towards a third option: to provide for penalties that are equal to a percentage of the cost of the minimum take-or-pay level of the fuel that was not delivered, based on the current fuel price. They see a potential mismatch problem with this approach. Penalties equal to a percentage of gas commodity costs may be either more or less than the plant’s lost capacity revenue resulting from a lack of fuel and failure to generate. The CFE, if willing, could help solve this problem by curtailing the plant’s dispatch when it has insufficient fuel supply. Exactly how IPPs will deal with their fuel price risk and how lenders will respond through the terms of their loans are still being determined.

Future structure of the Mexican power industry¹

Since the Samalayuca II financing, one of the future contingencies that IPP project sponsors and their bankers have kept in mind has been the possible eventual privatisation of the CFE. If the CFE was privatised and the resulting successor entity had a credit standing less than the CFE’s, a default would be triggered in most IPP loan agreements. Today, however, while bankers do not ignore the possibility that the CFE could be privatised some day, it appears to be unlikely, at least over the next few years. Since 1960 the Mexican constitution has defined public electricity services as the sole responsibility of the state power utilities. Therefore a major change such as the privatisation of the CFE would require a constitutional amendment, which would have to be approved by at least two thirds of Congress, and would be opposed by labour unions and the two opposition parties, the Institutional Revolutionary Party (PRI) and the Democratic Revolution Party (PRD), because of concerns including possible job losses.

After he was elected President in July 2000 Vicente Fox took up the power sector reform proposals put forward by his predecessor, Ernesto Zedillo, in February 1999 (described in the Merida III case study in Chapter 8), but with the caveat that he would not sell any state-owned electricity assets. Fox said that Mexico needed a competitive electricity market, grounded in the most advanced technology, to meet the needs of its economy. He called for reforms that would allow Mexico to guarantee its energy supply in the coming years with the greatest efficiency and competitive prices. He was motivated by projections showing that Mexico’s demand for electricity would grow at 6 per cent per year and that the country would need an additional 28,000 MW of installed capacity by 2010. In response, the PRI and PRD argued that there was no need to change the constitution, because under the Mexican IPP law of 1993, private companies already can generate electricity as IPPs, generate electric power for industrial use and build cogeneration plants.

Rather than fight a difficult and possibly losing battle to privatise the CFE, Fox’s government has concentrated on efforts to make the IPP programme more attractive to developers. Its recent initiatives have included efforts to develop a private bilateral contract market and a methodology for private plants to place excess power on the national grid at prices that are competitive with those of the CFE’s power plants.

Lessons learned

The case studies on Samalayuca II, Merida III, Bajio, La Rosita I and II, and TEG I and II in

Chapters 7 through 9 show a continuum. It ranges from the financing of the first quasi-IPP on a BLT basis (Samalayuca II); to the financing of the first true IPP (Merida III); to Bajio, which was deliberately oversized to sell power to industrial customers; to La Rosita I and II, which was similarly oversized, built on a site selected by the developer rather than CFE, located to serve both the Mexican and the US markets, and had the flexibility to arrange its own fuel supply in either the Mexican or the US market; and finally to TEG I and II, inside-the-fence projects that can sell power to other users in addition to serving their own industrial sponsors under the rules of Mexican self-supply energy legislation. Until recently, PPAs and fuel supply agreements were linked; now generally they are not, requiring IPPs to take on increased fuel-procurement risk. Although Mexico gradually has introduced many of the features of a deregulated, private electricity market, that market is still largely government-owned and controlled and will be until CFE is privatised—and there is no telling if or when that will happen.

¹ This final section is based on interviews with the individuals quoted and articles in the financial press, including Harrup, Anthony, 'Mexico's Electricity Hikes Seen Tied to Reform Agenda', *Dow Jones International News*, 11 February 2002.

CBK, the Philippines

Type of project

Rehabilitation and expansion of hydroelectric power plant and pumped storage facility.

Country

The Philippines.

Distinctive features

- Largest private, political-risk-covered project financing ever completed.
- First syndicated project financing for a sub-investment-grade country after Asian financial crisis.
- Syndication accomplished at a time when market conditions for the Philippines were deteriorating because of economic and political uncertainty.

Description of financing

The total project cost of approximately US\$488 million was financed in 2000 by:

- a US\$351 million 12.5-year term loan at 215 basis points (bps) over the London interbank offered rate (Libor), covered by private political risk insurance priced at 175 bps for the relevant principal amount plus six months of applicable interest cover; and
- US\$137 million of equity.

The debt financing package also includes:

- US\$20 million as an uncovered 6.5-year revolving credit debt service reserve facility at 300 bps over Libor; and
- US\$12 million as an uncovered 4.5-year performance security facility at 350 bps over Libor.

Project summary¹

The CBK project entails a 25-year build, rehabilitate, operate and transfer (BROT) contract for the rehabilitation and upgrading of three Philippine hydroelectric power stations –

Caliraya, Botocan and Kalyaan I (hence ‘CBK’) – and the construction of a new pumped-storage power station, Kalayaan II, adjacent to the existing Kalayaan I pumped-storage power station. The company undertaking the project is CBK Power Corporation Company Limited, a limited partnership between Industrial Metalurgicas Pescarmona SA (Impsa) of Argentina and Edison Mission Energy in the United States.

Accomplished at a time when market conditions in the Philippines were deteriorating because of economic and political uncertainty, this was the first syndicated project financing for a sub-investment-grade country after the Asian financial crisis. There were significant delays in contract negotiations because of the need for scrutiny by multiple government agencies, a lack of deal experience on the part of the Philippine Department of Finance’s personnel and political sensitivity over awarding the concession to a foreign contractor rather than a competing local bidder.

Background

The Kalayaan I and II power stations, which represent approximately 94 per cent of the total project capacity, are the only pumped-storage hydroelectric facilities in the Philippines. They use power from the Luzon grid during offpeak hours to pump water from Lake Laguna de Bay into the Caliraya Reservoir, released to flow through the turbines and thus generate electricity for the grid. The Luzon grid serves the metropolitan Manila area.

In addition to their energy-storage capabilities, the CBK stations provide critical ancillary facilities to support the stability of the Luzon grid, such as frequency regulation, ‘load following’, ‘load shedding’, ‘spinning reserve’ and ‘standby reserve’. Load following consists of small increases or reductions in pressure on the turbines to adjust the plant’s output in response to fluctuations in the load on the grid. Load shedding is the process of shutting off the CBK facility when it is in pumping mode, taking power from the grid, at a time when that power is needed elsewhere. When a plant is in spinning reserve status it is running and ready to be connected to the grid with minimal notice. When a plant is on standby reserve it is not running and must be started before it sends power to the grid. The need for additional grid-stabilisation support in the Philippines was demonstrated in 1999, when the ingestion of a large number of jellyfish at the Sual II 540-megawatt power station caused the unit to fail, leading to the tripping of Sual I and subsequently all generating stations in the Luzon grid. Restoration of power took approximately 18 hours.

As mentioned above, CBK Power Company Limited, which is undertaking the project, is now a limited partnership between Impsa of Argentina and Edison Mission Energy of the United States. However, it began as a company set up by Impsa Asia Ltd, a subsidiary of Impsa. The Argentine parent company is an industrial conglomerate with experience in the development and operation of hydroelectric power projects. It has designed and manufactured turbines and generators to a total power load of more than 7,000 MW. It has a presence in 20 countries and has been in Asia for more than 15 years.

Impsa Asia Ltd established CBK Power Corporation to pursue the CBK power project.

CBK Power began preparation for the project in 1993 and won a contract with the state-owned National Power Corporation (NPC) in 1997, after a lengthy approval process that included scrutiny by the Philippine Central Bank, the Board of Investments, the National Economic and Development Authority, and the Departments of Justice, Energy, and Environment and Natural Resources. Other delaying factors included lack of deal experience

on the part of the Department of Finance's personnel, who were not familiar with documents considered routine in international project finance, and political sensitivity. There was a competing local bid for the project that Impsa was able to match on the basis of both price and technical qualifications, despite several court challenges. The government was reluctant to push the decision in favour of Impsa too quickly, for fear that it would be perceived as favouring a foreign contractor over a local contractor.

In November 1999 Impsa Asia sold a 50 per cent interest in CBK Power to the Philippine subsidiary of Edison Mission Energy Corporation, itself a subsidiary of Edison International, which specialises in the development, acquisition, construction, management and operation of global power production facilities. With assets of US\$36 billion, Edison International at that time owned nearly 23,000 MW of generating capacity, including interests in more than 75 projects in Australia, Indonesia, Italy, New Zealand, Spain, Thailand, Turkey, the United Kingdom and the United States.

In the first phase of the project, completed in late 2000, CBK Power rehabilitated Kalayaan I, restoring its capacity to 172 MW. Impsa committed itself to delivering an additional 225 MW of capacity by the end of 2001 and the final 350 MW (Kalayaan II) by the beginning of 2003. The construction phase was expected to employ about 1,200 Filipinos.

In 1999 CBK Power secured enough bank lending commitments for half of the project's US\$360 million debt component and planned a bond offering for the other half. Towards the end of the year, however, the company began to consider bank debt for the entire financing, fearing that the time required for a bond offering might prevent it from meeting a 14 December financing deadline set by the NPC.

In early December Federico Puno, President of the NPC, said that the NPC would turn over land titles to the facility and other required documents to CBK Power by the following month, January 2000. His statement turned out to be too optimistic, however, because both sides still needed to fulfil numerous conditions in the contract. In late June 2000 Puno announced that the contract had automatically been cancelled because Impsa had failed to meet several contract requirements, which included closing on the US\$360 million financing for the project and paying the NPC the required US\$70.8 million security deposit. Ruben Valenti, CBK's President, disputed the contract cancellation and predicted resolution of remaining issues in a few weeks, noting that the NPC still had its own list of unfulfilled responsibilities. Among them were the issuance of a Department of Justice confirmation of the contract, acquisition of all necessary sites for the expanded project, Department of Justice approval for Impsa Asia's partnership with Edison Mission for the project and Central Bank approval for the security deposit. Puno acknowledged that a provision for conflict resolution in the contract required the chief executives to work together to negotiate a settlement when necessary.

By this time Impsa had already invested US\$80 million in the project to rehabilitate Kalayaan I, which it had almost completed, and to procure equipment for the rest of the contract. The NPC had requested that CBK Power undertake some work in advance, because deterioration in the Kalayaan I transformer posed a risk to the integrity of the Luzon grid. CBK Power's willingness to take a risk by continuing to work without an effective contract impressed the NPC as a demonstration of good faith and helped in the process of settling remaining disputes.

Under its contract with the NPC, CBK Power will operate the power complex for 25 years for a fee, but will have to shoulder the cost of repairing the existing 230 MW complex and upgrading its capacity from 300 to 750 MW. Other project contracts include:

- a relatively standard concession agreement embodied in the BROT agreement;
- a turnkey construction contract with Impsa Construction Corporation; and
- an operations and maintenance (O&M) agreement between CBK Power and the two sponsors, Impsa and Edison Mission Energy.

Arrangement of financing

In August 2000 CBK Power took the most important step toward finalising the contract by reaching agreement on a US\$383 million loan with four major international financial institutions: Société Générale (SG), Banque Nationale de Paris (subsequently BNP Paribas), Dai-ichi Kangyo Bank and the Industrial Bank of Japan (IBJ). Impsa and Edison Mission Energy planned to provide US\$120 million equity for the project. By that time the NPC had made progress on the outstanding right-of-way issues for the project, but had not completely resolved them.

The Debt Service Reserve Facility provides liquidity for a debt service reserve once the project has begun operation. It works in tandem with the requirement for the borrower to maintain an amount in a debt service reserve account. If the account balance is insufficient, the borrower is able to show the committed amount of the facility as evidence of funds available to meet the debt service reserve requirement. If the borrower cannot meet a payment due, the lenders have the discretion to be paid under the Debt Service Reserve Facility, thereby keeping the project out of default. All of the lenders have *pro rata* shares in this facility. The advantage of the facility for the borrower is that it allows cash that would otherwise be sitting in the Debt Service Reserve Account to be used to pay dividends, thus improving the project's return on a net-present-value basis.

Syndication, launched on 28 August 2000 and closed on 5 October, was 30 per cent over-subscribed, with 14 participating banks. SG and the IBJ served as joint bookrunners, BNP as technical and insurance bank, DKB as agent and modelling bank, and SG as documentation bank and political risk insurance coordinator.

The next step, at the request of CBK Power and the lenders, was for the Philippine Department of Finance to issue a government acknowledgement and consent agreement (GACA), which was to acknowledge the government's pledge to fulfil the NPC's obligations under the 25-year BROT contract. Issuance of the GACA would clear the way for CBK Power to provide the required security deposit, a US\$70.8 million, 15-year, interest-free loan to the Philippine government, and for the rest of the project to proceed. The final documentation, allowing the facility to be turned over to CBK Power, was not completed until early 2001, primarily because of local political turbulence. The first loan drawdown was on 7 February 2001.

Project debt service coverage ratios

The projected base case debt service coverage ratio was an average of 1.47 times and a minimum of 1.34 times. A sensitivity analysis was conducted to estimate the effect of various unexpected events on the project's debt service coverage, as summarised in Exhibit 10.1.

The base case assumed that all units were completed in accordance with the turnkey construction contract.

The 'delay' case assumed that the completion of Caliraya Units 1 and 2, and Kalayaan

Units 1 and 2, would also be delayed by six months, with liquidated damages payable by the contractor under the turnkey construction contract.

The ‘performance’ case assumed that the Net Contracted Capacity of the units was 97 per cent of the Guaranteed Net Contracted Capacity and that the pumping efficiency was 98.5 per cent of the Contracted Efficiency. Below these levels, the units were assumed to have been rejected by the project company as provided under the turnkey construction contract. Therefore this represented a worst-case scenario.

The ‘EAF’ case assumed a 97 per cent equivalent availability factor. This meant that the annual allowable planned and/or forced outage downtimes specified in the BROT Agreement were exceeded for approximately 1,000 hours, or approximately 12 per cent of the number of hours per year.

Compared to the base case, the ‘economic variables’ case assumed higher inflation rates – 4 per cent in the United States and 12 per cent in the Philippines – and a higher devaluation rate of the Philippine peso, at 2 per cent per year in excess of the forecast.

Finally, the ‘interest rate sensitivity’ case assumed a 1 per cent increase in Libor and a 0.5 per cent increase in the swap rate.

Political risk insurance

In an article in *Project Finance International*² and subsequent interviews, David Gore, Director, Project Finance and Advisory, SG Asia, and Ken Hawkes, Senior Associate, Milbank, Tweed, Hadley & McCloy LLP, pointed out that, until recently, the sponsor of an emerging-market project could not source nonrecourse international bank financing without securing risk cover from ECAs or other bilateral or multilateral agencies. Negotiations with these agencies are time-consuming, however, and that often prolongs the time required to close a project financing. Just like banks, the agencies have country credit limits, and most ECAs lend primarily in order to support exports from their own countries.

When the lead banks reached their agreement with CBK Power in August 2000, they were under time pressure to syndicate the loan as soon as possible. Most equipment would be sourced from Argentina, where little if any ECA support was available, and the size of the loan posed a challenge for securing full political risk coverage. At the same time the lenders were also aware of the growing private political risk insurance market, which tended to take a more flexible approach.

Gore and Hawkes pointed out that private political risk insurance is now increasingly available for emerging markets as an alternative to the coverage commonly provided by ECAs and other agencies. One of the reasons why it has become more attractive is that some private insurers have extended their available tenor to 15 years and more in recent years, often reinsuring some of their earlier-year coverage with underwriters not willing to go out as far.

Exhibit 10.1

Sensitivity analysis of debt service coverage ratios (DSCRs)

| | Average DSCR | Minimum DSCR |
|--------------------------------------|-----------------|-----------------|
| Base case | 1.47 | 1.34 |
| Delay | 1.54 | 1.37 |
| Performance | 1.41 | 1.28 |
| Equivalent availability factor (EAF) | 1.42 | 1.30 |
| O&M | 1.45 | 1.33 |
| Economic variables | 1.44 | 1.31 |
| Interest rate sensitivity | 1.44 | 1.31 |

Source: Loan Information Memorandum.

Exhibit 10.2

Insurable political risks*Asset-based risks*

| | |
|--|--|
| Confiscation, expropriation, nationalisation, deprivation (CEND) | Selective and discriminatory acts by the host government causing permanent loss of benefit of a venture without fair compensation |
| Forced divestiture | Permanent divestiture of a shareholding in a foreign enterprise by the investor's own government or by a foreign government |
| Forced abandonment | Abandonment of a foreign enterprise arising from a deteriorating security situation |
| Arbitration award default | Default by a government on an obligation arising from an arbitration award |
| Import/export licence cancellation, embargo | The prevention of import or export of goods or technology from any country due to the cancellation of previously obtained import/export licenses or prohibition due to embargo |
| War and political violence | Physical damage to the assets of a foreign operation or inability to continue debt service due to strikes, riots, civil commotion, malicious damage, international war, civil war or terrorism |

Trade-related risks

| | |
|---|---|
| Currency inconvertibility | The inability of the country/central bank to exchange deposits of local currency representing principal, interest, earnings, dividends, management fees, etc., deposited by a foreign enterprise for exchange into a designated foreign currency |
| Exchange transfer risk | The host government/central bank blocking or refusing to transfer deposited funds in the host country to a designated foreign location |
| Contract frustration | The nonfulfilment of a contract due to 'political events', including import/export licence cancellation, embargo, government buyer's nonpayment or repudiation, CEND (see above), currency inconvertibility, war, or not honouring a letter of credit |
| Unfair calling of guarantee/wrongful calling of guarantee | The unfair drawing down of an on-demand, standby letter of credit posed as a bid, advance payment, warranty or performance guarantee by a government entity; or a fair drawing where the contract terms are unfulfilled due to a political risk |

Source: Galvao, Daniel, 'Political Risk Insurance: Project Finance Perspectives and New Developments', *Journal of Project Finance*, Summer 2001, p. 35.

Rates for private political risk insurance are generally higher, but are justified by greater speed, flexibility and capacity. The risks that can be covered in today's market by political risk insurance are summarised in Exhibit 10.2.

Gore and Hawkes also explained that a lender takes out private political risk insurance to cover a stream of payments due from a borrower. If an insured event prevents the borrower from making a scheduled payment, the insurer indemnifies the lender for the agreed percentage of the loss caused by that event. Often, in a syndicated bank financing, one bank acts as the insured and participates out its beneficial interest in the insurance policy to a trustee or agent that is appointed as loss payee to collect insurance proceeds. For this purpose the loss

payee is a beneficiary of an insurance policy, but does not have an insurable interest in its own right. In other cases all lenders are insured for their own interests and insurance proceeds are paid either directly to each lender or through a designated loss payee.

As they began to source political risk insurance for the CBK project, the coordinating lead arrangers had four principal concerns:

- market capacity for the required tenor – it appeared that this transaction would have to tap the entire market capacity for Philippine political risk insurance;
- acceptance of private political risk insurance by the bank syndication market;
- structuring the policy to accommodate multiple insurers and lenders; and
- complete and understandable policy coverage without unnecessary or uncontrollable exclusions.

Specific policy issues included:

- terms of cover – finalising the essential terms laid out in the political risk insurance policy;
- nonviolation – ensuring that acts of any one insured party, in this case one of the banks, do not lead to disruption of cover for all insured parties;
- exclusions – providing for events that the insurer expressly declines to cover; and
- the willingness of private insurers to cover the impact on principal and interest payments, on a present-value basis, of a loan acceleration stemming from an insured event.

SG, working with Milbank Tweed, represented the coordinating lead arrangers for political risk insurance matters. Given the complexity, the required speed of execution and the number of ‘firsts’ that they would be attempting with this transaction, they appointed JLT Risk Solutions to assist in the structuring and placement of the insurance. To ensure the acceptance of the package by the syndicated bank loan market, JLT set out to develop a single policy exposing the lenders to the risk of the smallest possible number of insurers. Three insurers, AIG, Zurich Insurance Company, and ACE Global Markets at Lloyds of London, acted as counterparts to the lenders under the policy, while Sovereign and XL Brockbank acted as leaders for the placement of reinsurance. In all, 13 insurance underwriters participated in the policy.

Ultimately the insurers did not agree unconditionally to cover the present-value impact of a loan acceleration covered by an insurable event. However, the nominal value of the principal and interest payments was covered, and the insurers at least retained the right to make the lenders completely whole on a present-value basis as well.

Lessons learned

Gore and Hawkes attributed the success of the CBK syndication to the strong underlying rationale for the project, a natural mitigant to many forms of risk; the complementary experience that Impsa and Edison Mission Energy brought to the project; and the strength and comprehensiveness of the political risk insurance package. They believe that this project is a milestone that has demonstrated how private political risk insurance can serve as a very real alternative to more traditional cover from ECAs and other agencies. Private political risk insurance tends to be more expensive, but it also tends to be more flexible, and it can be

arranged more quickly. In their opinion, the CBK financing also demonstrates that the international bank lending market is receptive to projects that make commercial sense where political and other important risks are allocated to the parties best suited to bear them.

¹ This case study is based on articles in the financial press, as well as interviews with David Gore, Director, Project Finance and Advisory, Société Générale Asia; and Ken Hawkes, Senior Associate, Milbank, Tweed, Hadley & McCloy LLP.

² Gore, David, 'Private Political Risk Insurance Comes of Age on CBK', *Project Finance International* 4 April 2001, p. 53.

Quezon Power, the Philippines

Type of project

440 MW pulverised-coal-fired power plant.

Country

The Philippines.

Distinctive features

- First private-sector generation facility selling power to a privately owned, unrated utility in a non-investment-grade emerging-market country.
- First large-scale independent power project in the Philippines to be financed, built, owned and operated by a private entity without the sovereign backing of the Philippine government.
- Longest term (25 years) of Power Purchase Agreement (PPA) with private counterparty in Asia.
- Longest term and thinnest spread for a power project financing in Southeast Asia.
- First project finance loan for Private Export Funding Corporation (PEFCO).
- First emerging-market project financing with a bond initially registered with the US Securities and Exchange Commission (SEC).

(Previous deals that have begun with the issuance of unregistered Rule 144A bonds have later been refinanced with bonds registered with the SEC. The sale of Rule 144A bonds is limited to qualified institutional buyers. Upfront SEC registration allows immediate sale to a broader range of investors and minimises any possible illiquidity premium in bond pricing.)

Description of financing

The Quezon Power project was financed in 1997 with US\$830 million of debt and equity, including fees payable to the Export–Import Bank of the United States (US Eximbank) at project completion. The sponsors' equity contribution was US\$204.2 million. The US\$662.5 million bank financing comprised the following elements:

- US\$405 million as a 60-month construction loan priced at 137.5 basis points (bps) over the London interbank offered rate (Libor) with principal and interest insured

against political risk by US Eximbank, 25 bps front-end fee and 35 bps commitment fee on undrawn amounts;

- US\$100 million as a trustee loan facility supported by the US Overseas Private Investment Corporation (OPIC);
- US\$115 million as an uninsured construction loan;
- US\$30 million as an uninsured cost overrun loan; and
- US\$12.5 million as a coal supply and PPA IC facility.

Six months after financial closing, the OPIC-guaranteed tranche was replaced with a US\$215 million bond offering with 19-year, 11-month final maturity, 14.5-year average life, issue price of par, and yield of 8.959 per cent, or 245 bps over US treasuries.

Project summary¹

Quezon Power is a bond-financed independent power producer (IPP) that sells electricity to the Manila Electric Company (Meralco), an investor-owned utility with a monopoly on electricity distribution for Metropolitan Manila and surrounding provinces. The plant is coal-fired, taking advantage of abundant local coal supplies and helping the Philippines to diversify away from oil-fired power generation. It is the first large-scale IPP in the Philippines to be financed, built, owned, and operated by a private entity without the sovereign backing of the government.

Until 1987 the state-owned National Power Corporation (NPC) had a monopoly on power generation and distribution. In that year the government authorised private-sector development of the power generation infrastructure. In 1996, after several years of power shortages, it authorised the private development of priority infrastructure projects on build-operate-transfer (BOT) and build-transfer (BT) bases. The NPC is now being privatised, with generation assets being sold to private investors.

The project developed a plan for sustainable development that took economic development, environmental protection and social responsibility into account. Among the project's risks are that Meralco's franchise will not be renewed or that Meralco, mandated to reduce its costs by the Electric Power Industry Reform Law of 2001, will put pressure on Quezon Power to reduce its rates.

Background

The Philippine power industry

Because electricity demand is forecast to outpace rapid economic growth, and much of the current capacity is old and unreliable, there is a significant need for additional, competitively priced baseload generating capacity in the Philippines. The Quezon power project has provided the Luzon grid with much needed additional generating capacity, as well as diversification away from oil- and hydro-based power plants.

There are three separate major grid systems in the Philippines: Luzon, Mindanao and the Visayas. The Luzon grid is by far the largest, accounting for 75 per cent of the national market and serving the metropolitan Manila area. In recent years the low reliability of the grid's generation and transmission facilities has led to frequent 'brownouts'. Through a series of

projects connecting the grid systems and their components, the Philippine Department of Energy, the principal policy-making body in the energy sector, aims to maximise the use of indigenous energy, improve overall system reliability and reduce capacity requirements through pooling reserves.

Imported oil was required for about 47 per cent of Philippine electricity generation in 1995. The government wants to replace a large portion of oil-fired generation with coal-fired capacity, because coal is readily available in the region and more suitable for large baseload capacity.

The overall objectives of the Philippine electricity sector were set forth in a Presidential decree issued in 1972 that called for hastening electrification, particularly in rural areas, and mandated the NPC to set up generation facilities and transmission grids throughout the country. Until power reform legislation was enacted in 2001, the Philippine electric power industry consisted of three sectors:

- power generation, in which the NPC was the dominant player;
- the transmission grids, operated and maintained by the NPC; and
- the distribution companies, which included both private companies and independent non-profit electricity cooperatives.²

In the early 1990s the Philippine Congress began to explore proposals for a partial privatisation of the NPC, and its division into separate generation, transmission and distribution entities. By 1996, the NPC was operating 77 power plants in the three grids, accounting for 78 per cent of electricity generated in the country and 81 per cent of the country's 9,925 MW generating capacity. The remainder of the nation's power was coming from IPPs through BOT arrangements with the NPC.

In December 1998 the Asian Development Bank committed itself to making a US\$300 million loan to finance some of the adjustment costs of the government's proposed power industry restructuring programme, including improvement in the transmission sector. In June 2000 Federico Puno, President of the NPC, estimated that the country's electricity requirements would require an investment of 40 billion pesos (US\$940 million) over the following 10 years. One of the problems preventing the NPC from building more generating capacity was a heavy debt load – a burden shared by the Philippine government in its capacity as guarantor.

In May 2001, after three years of debate, the Philippine Congress passed the Electric Power Industry Reform Law, which divided the power industry into four sectors: generation, transmission, distribution and supply. The law expressly provides that power generation is not a public utility operation.³ Most of the NPC's generation assets will be sold to private interests. The proceeds will be used to reduce the NPC's US\$6.7 billion debt. The government will absorb the NPC's remaining liabilities, estimated to be as high as US\$4 billion. The NPC's role will be reduced to operating generation facilities that have not been sold off, and generating and delivering power to rural areas not connected to the grids. The transmission sector will continue to be a regulated common electricity carrier business, subject to the rate-making power of the Energy Regulatory Commission (ERC).

As part of the privatisation process two new government corporations were created.

- TRANSCO will assume the NPC's transmission function, provide all electricity users with open and nondiscriminatory access, ensure the reliability and integrity of the nation-

al grid, improve and expand transmission facilities, and, subject to technical constraints, provide the central dispatch of all generation facilities.

- The Power Sector Assets and Liabilities Management (PSALM) Corporation will manage the disposition and privatisation of the NPC's assets, and the liquidation of its financial obligations and stranded contract costs (the excess of the contracted cost of electricity under eligible contracts over the actual selling price of the contracted energy output).

The distribution sector, including Meralco, was essentially left unchanged by the new legislation. Distributors will retain a monopoly on small customers – those with annual usage of no more than 1 MW, accounting for three quarters of all customers – and a monopoly on power lines, although it will be required to grant access to rivals at rates determined by the government.

A new supply sector system subjects sellers of electricity, other than generators and distributors in their franchised areas, to the authority of the ERC. The law provides for the establishment of a wholesale electricity spot market within a year, and for retail competition and open access within three years.

Finally, the new law will end a system of cross-subsidies under which customers in the Luzon region subsidised those in the Mindanao and Visayas regions and, within the Luzon region, industrial customers subsidised commercial and residential customers.

Project description

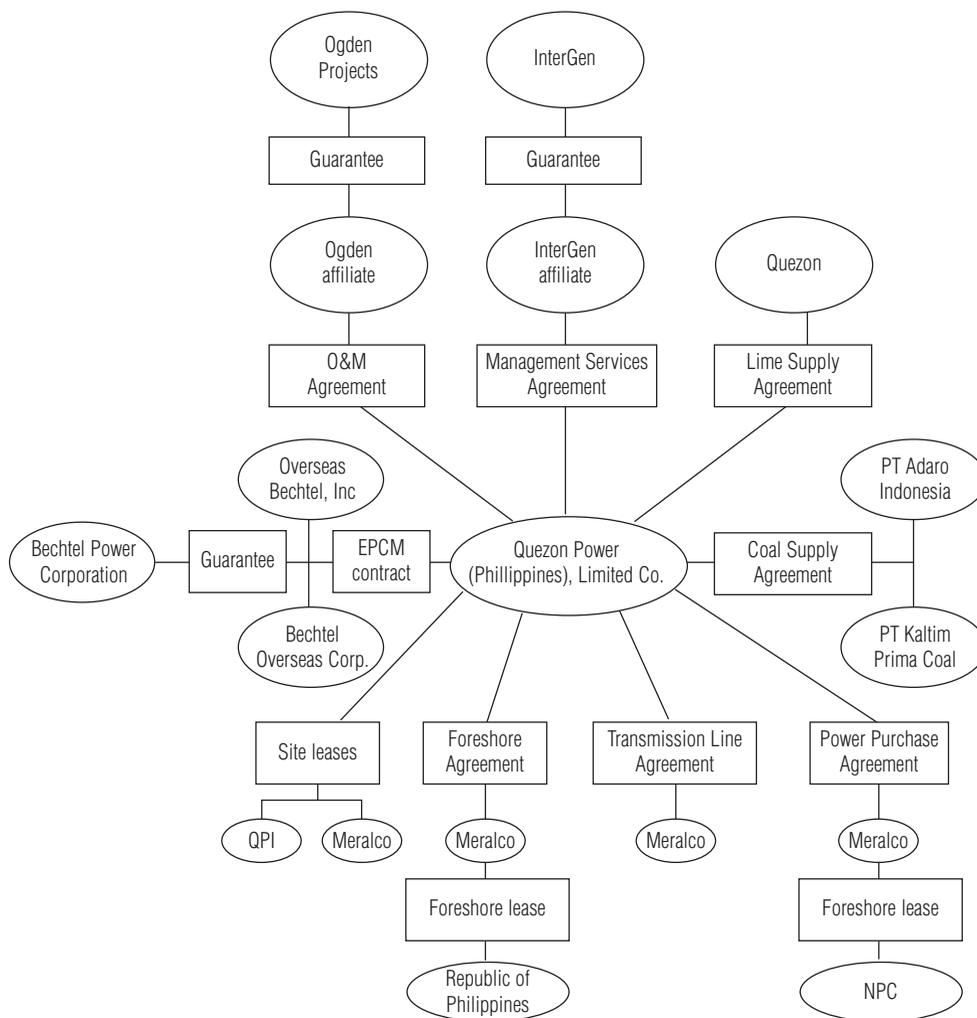
The Quezon Power project consists of a 440 MW baseload, pulverised-coal-fired electric generation facility, a 31-kilometre, 230 kV double-circuit transmission line and related facilities. The generation facility is located on a 100-hectare coastal site near the municipality of Mauban in Quezon province on the island of Luzon, about a four-hour drive southwest of Manila. The transmission line runs through a 40-metre-wide corridor from the generation facility to the NPC's power-grid substation at Tayabas in Quezon province. The generation facility includes an offshore construction pier, a coal-handling pier, coal-storage and ash-disposal facilities, sewage and wastewater treatment plants, desalinisation equipment, a switchyard, housing facilities and an administrative office. It is equipped with semidry flue scrubbers and an electrostatic precipitator for emissions control, as well as low-nitrous oxide (NOX) burners. The PPA requires that Meralco receive the generation facility's electrical output at Tayabas, the point of interconnection with the transmission line, which connects the generation facility with the NPC's transmission system. The NPC takes responsibility for wheeling the power produced from the generation facility to Meralco. The commercial structure of the project is shown in Exhibit 11.1. Wheeling is the movement of electricity from one system to another over the transmission facilities of intervening systems. Wheeling is required to offer customers a choice of electricity suppliers.

Project origins

In 1993 PMR Power, a local developer, reached a preliminary agreement to develop an independent power project to sell power to Meralco. PMR Power selected Ogden Energy, Inc. and Bechtel Enterprises as co-developers in 1994. The three project sponsors worked together to complete the PPA; structure the technical, commercial and financial aspects of the project; and

Exhibit 11.1

Project commercial structure

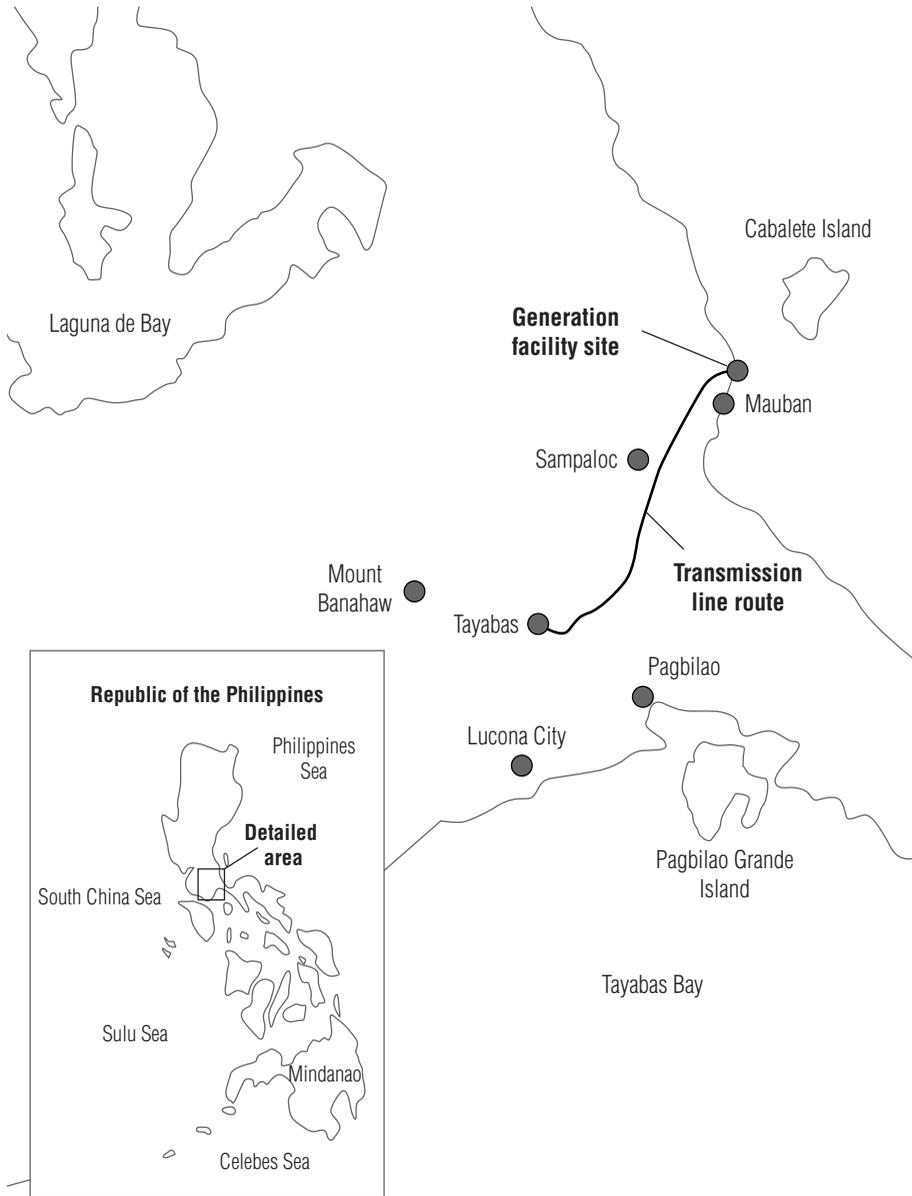


develop an international financing plan. Preparation for the project included acquisition of both a site for the power plant and a right of way for a 31-kilometre transmission line. A site map for the project is shown in Exhibit 11.2. The project company was formed in 1996 and financing was completed in February 1997. To meet schedule requirements, the sponsors began construction two months before the financial closing. The plant began commercial operation in May 2000.⁴

As part of its diversified fuel strategy, the government mandated coal as the source of fuel for the project. At that time an indigenous gas supply had not yet been developed. The sponsors selected coal from Indonesia because of its competitive cost, low sulphur content and burn characteristics. They modelled the plant on the cleanest-burning coal plant in the United States. Pollution control equipment incorporated into the plant’s design surpassed legal requirements, reducing particulates to one half of the accepted international standard, and virtually eliminating NOX and sulphur oxides from air emissions.

Exhibit 11.2

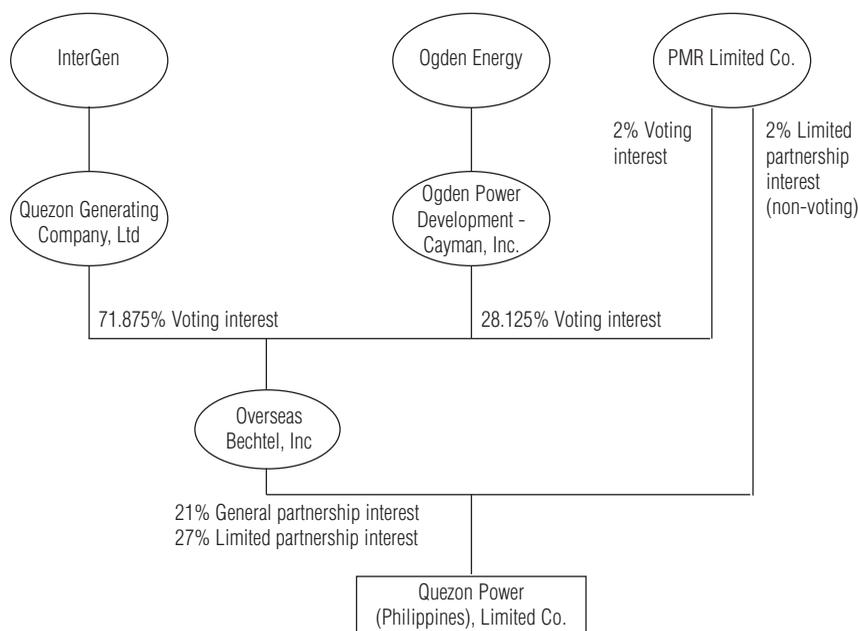
Site map



Project ownership

As shown in Exhibit 11.3, Quezon Power, Inc., a Cayman Islands corporation, was owned at the time of financing by Quezon Generating Company, Ltd, a wholly owned subsidiary of International Generating Company, Ltd (InterGen); Ogden Power Development Cayman, Inc., a wholly owned subsidiary of Ogden Energy Group, Inc. (now Covanta Corporation); and PMR Limited Co. (PMRL), a Philippine limited partnership.

Exhibit 11.3

Project ownership structure

InterGen was formed in 1995 by subsidiaries of Bechtel Enterprises and Pacific Gas & Electric (PG&E) to develop, own and operate power projects outside the United States. In 1996, because of a change in business strategy, PG&E sold its interest to Bechtel. Bechtel later sold an interest in InterGen to Shell Generating Company.

At the time of the financing Ogden Energy designed, built, owned, acquired, operated, maintained and managed independent power and cogeneration projects throughout the world. It was a subsidiary of Ogden Corporation, a New York-based global services company with revenues of US\$2 billion. Ogden changed its name to Covanta in 2000, when it decided to sell units in the entertainment and aviation business, and become a pure-play energy company.

PMRL is a Philippine limited partnership formed by PMR Holdings. Both PMRL and PMR Power were formed when, in response to severe power shortages in 1992 and 1993, the Philippine government began to encourage third-party participation in power plant development.

How the financing was arranged

Union Bank of Switzerland (UBS) was mandated to underwrite the entire US\$662.5 million bank debt portion of the financing in September 1996, thereby assuming Philippine country risk for that entire amount during the presyndication period, and reached financial closing in February 1997.

US Eximbank insured the US\$405 million, 60-month construction loans against political risks and agreed to take out that loan with a direct loan when construction was completed.

Nations Bank (now Bank of America) underwrote 50.1 per cent of the US\$100 million trustee loan facility, thereby satisfying the requirement for OPIC coverage that the majority of

financing be provided by US banks. Nations Bank also underwrote 25 per cent of the US Eximbank-guaranteed construction loan. Other lead managers were ABN AMRO, which absorbed US\$35.3 million; and Banque Paribas (now BNP Paribas), ING Bank and Fuji Bank, each of which underwrote US\$28.3 million. In all, 36 banks participated in the financing.

In August 1997, six months after the initial financial closing, InterGen and Ogden Energy Group, Inc., arranged an offering for US\$203 million in senior secured bonds to take out the US\$100 million trustee loan insured by OPIC. Because of strong investor demand, the offering was increased to US\$215 million. Salomon Brothers arranged the deal.

The estimated sources and uses of funds for the Quezon Power project are shown in Exhibit 11.4.

When construction was completed and the plant began to operate, PEFCO took out the construction loan by extending a US\$424.6 million, 12-year loan at a fixed rate of 6.013 per cent. The loan was covered by a comprehensive US Eximbank guarantee.

PEFCO was created in 1970 to assist in the financing of US exports through the mobilisation of private capital as a supplement to the financing available from commercial banks and other lenders. It acts as a direct lender and as a secondary market buyer of export loans originated by lenders. PEFCO's programmes cover the range of the export finance continuum: short-term, medium-term and long-term. Headquartered in New York City, PEFCO is a private-sec-

Exhibit 11.4

Estimated sources and uses of funds

| <i>Sources of funds</i> | <i>Construction period (US\$)</i> | <i>Operations period(US\$)</i> |
|---|-----------------------------------|---------------------------------|
| Eximbank-supported construction | | |
| credit facility | 375,202,000 | 0 |
| Eximbank term loan | 0 | 409,533,000 |
| Total bank loan commitments | 375,202,000 | 409,533,000 |
| Senior secured bonds due 2017 | 203,000,000 | 203,000,000 |
| Total credit facilities | 578,202,000 | 612,533,000 |
| Base equity contributions | 204,178,000 | 204,178,000 |
| Total equity contributions | 204,178,000 | 204,178,000 |
| Total sources | 782,380,000 | 816,711,000 |
| <i>Uses of funds</i> | <i>Construction period (US\$)</i> | <i>Operations period(US\$)</i> |
| Generation facility | 419,560,000 | 419,560,000 |
| Transmission line | 23,306,000 | 23,306,000 |
| VAT, insurance | 21,878,000 | 21,878,000 |
| Total EPCM costs | 464,744,000 | 464,744,000 |
| Start-up and other owner costs | 50,487,000 | 50,487,000 |
| Development costs | 37,951,000 | 37,951,000 |
| Development fee | 8,000,000 | 8,000,000 |
| Eximbank term exposure fee | 8,000,000 | 34,331,000 |
| Interest during construction | 87,425,000 | 87,425,000 |
| Other financing fees | 62,719,000 | 62,719,000 |
| Contingency | 35,000,000 | 35,000,000 |
| Other | 36,054,000 | 36,054,000 |
| Total uses | 782,380,000 | 816,711,000 |
| <i>Funding commitments</i> | <i>Construction period (US\$)</i> | <i>Operations period (US\$)</i> |
| Eximbank-supported construction | | |
| credit facility | 405,000,000 | 0 |
| Eximbank term loan | 0 | 442,057,500 |
| Uninsured alternative credit facility (except cost overrun) | 50,000,000 | 50,000,000 |
| Cost overrun loan commitment | 30,000,000 | 30,000,000 |
| Total bank and Eximbank loan commitments | 485,000,000 | 522,057,500 |
| PPA letter of credit facility | 6,505,500 | 6,505,500 |
| Coal supply letter of credit facility | 6,000,000 | 6,000,000 |
| Total bank facility commitments | 497,505,500 | 534,563,000 |
| Senior secured bonds due 2017 | 203,000,000 | 203,000,000 |
| Total credit facility commitments | 700,505,500 | 737,563,000 |
| Base equity commitments | 207,709,000 | 207,709,000 |
| Contingent equity commitments | 20,000,000 | 20,000,000 |
| Total equity commitments | 227,709,000 | 227,709,000 |
| Total commitments | 928,214,500 | 965,272,000 |

tor, taxpaying entity whose shareholders include commercial banks, industrial companies, and financial service companies. Its staff has significant experience in export finance and the programmes of the US Eximbank. PEFCO's board of directors and its advisory board include senior managers from international lending institutions and major exporting companies.

Principal project contracts

Power Purchase Agreement

In 1996 Quezon Power signed a PPA with Meralco that extends 25 years from the 'Commercial Operations Date', the date that the project company certified that the generation facility has been completed, inspected and tested, and is ready to begin operation. That date was certified as 30 May 2000.

The PPA was structured so as to provide for stable operating cash flows throughout the life of the project. Under its terms Meralco is obliged to make monthly capacity payments, operating payments and energy payments. Its obligations to make monthly capacity payments and the fixed portion of monthly operating payments are unconditional. However, if Quezon Power fails to meet its delivery obligations under the PPA, it is obliged to make certain payments to compensate Meralco.

Components of the operating payments are subject to escalation under the Philippine or US consumer price index (CPI), providing linkage between revenues and operating expenses. Energy payments, including related transport and insurance charges, are a passthrough of the cost of fuel, subject to the power plant's achieving a specified heat rate, and fuel handling and degradation losses not exceeding a specified percentage.

All payments under the PPA are made in Philippine pesos, but the capacity payments, energy payments and portions of operating payments are denominated in US dollars. The number of pesos required to make the dollar payments specified in the PPA is determined by the market exchange rate at the time of the payment.

Transmission Line Agreement

Under the Transmission Line Agreement between Quezon Power and Meralco, signed in June 1996, the project company is obliged to secure all necessary rights of way, and to design, construct, operate and maintain the transmission line. Meralco compensates Quezon Power for all expenses related to the transmission line through periodic transmission charges throughout the life of the PPA. Like the PPA, the term of the Transmission Line Agreement began on the Commercial Operations Date and runs for 25 years. If the Commercial Operations Date had been delayed because of either disputes over property acquired for the transmission site or the NPC's failure to provide wheeling service for reasons other than *force majeure*, Meralco would have been obliged to pay for Quezon Power's interest during construction until the plant was ready to be operated.

Engineering, Procurement, Construction and Management (EPCM) Contracts

In August 1996 the project company entered into two related contracts known collectively as the EPCM contracts:

- an Engineering and Procurement Contract with Overseas Bechtel Incorporated (OBI), covering engineering, equipment procurement and performance guarantees for the project; and
- a Project Management Agreement with Bechtel Overseas Corporation (BOC), covering construction management and project testing.

OBI and BOC are together known as the EPCM contractors. At the same time Quezon Power entered into a contract guarantee agreement under which Bechtel Power Corporation guaranteed the obligations of CBI and BOC.

Coal Supply Agreements

The project company entered into Coal Supply Agreements with two Indonesian suppliers. The agreement with PT Adaro Indonesia terminates in 2022 and the agreement with PT Kaltim Prima Coal terminates 15 years after the Commercial Operations Date. Under certain circumstances the project company may extend the term of each Coal Supply Agreement beyond its scheduled termination date. The agreements specify the price, quality and quantity of coal to be supplied to the project. The coal suppliers are responsible for inland and ocean transportation of coal delivered to the project's coal handling pier. The project company operates a dedicated coal handling pier, capable of offloading coal in all weather conditions.

Limestone Supply Agreement

Successful operation of the project depends on a constant, dependable supply of lime, which is used for flue gas desulphurisation. Limestone, the raw material for lime, is abundant throughout the Philippines, with more than 19 billion tonnes being available for development. The project company entered into a Limestone Supply Agreement with Guanzon Lime Development, Inc., the largest lime supplier in the Philippines, for a minimum term of five years.

Plant Operation and Maintenance Agreement

Under the Plant Operation and Maintenance (O&M) Agreement, signed in December 1995, Ogden Philippines Operating, Inc., the project operator, is responsible for the operation and maintenance of the generating facility. The agreement is a cost-reimbursable contract starting on the Commercial Operations Date with an initial term of 25 years, and provisions for extension or earlier termination under mutually acceptable terms and conditions. The project operator's obligations are guaranteed by Ogden Projects, Inc., a subsidiary of Ogden Energy.

Management Services Agreement

In September 1996 Quezon Power entered into a Project Management Services Agreement with InterGen Management Services (Philippines), Ltd, an affiliate of InterGen, for day-to-day management of the project. The initial term of the agreement extends 25 years from the Commercial Operations Date, with provisions for extension or early termination. Under the

POWER PLANT

Management Services Agreement Guarantee, InterGen guaranteed the obligations of its Philippine affiliate.

Description of additional agreements

Common Agreement

The Common Agreement in connection with the bond offering establishes:

- certain uniform conditions precedent, covenants, events of default and remedies available to the lenders; and
- certain uniform terms applicable to the borrower's obligations, including representations and warranties, prepayments and commitment reductions, limitations on recourse, indemnification, payment of expenses, the relationship among financing parties, miscellaneous provisions, and defined terms.

Credit Agreements

The credit agreements for the project financing include the following.

- An Eximbank-Supported Credit Agreement, provided for a US\$405 million construction loan commitment guaranteed against political risk by US Eximbank with a term of 52 months.
- An Eximbank Term Loan Agreement, provided for a 12-year, US\$442.1 million direct-term loan from US Eximbank to refinance the Eximbank-Supported Credit Agreement; subject to the following conditions precedent: receipt by Eximbank of a completion certificate declaring that Final Acceptance and Commercial Operations have been achieved, completion of satisfactory wheeling arrangements between Meralco and NPC, signing by project company of satisfactory lime-supply contracts, confirmation to Eximbank of adequate fuel supply for the power plant, a maximum debt-equity ratio of 3:1, security documents and liens in full force and effect, insurance policies in full force and effect, all representation and warranties continuing to be true, the continuing occurrence of no Default or Event of Default, payment of all required fees, no modification of Power Purchase Agreement, Transmission Line Agreement, or the EPCM Contracts without US Eximbank's consent, the borrower continuing to have Acceptable Rights to the Generation Facility Site, and no other events having occurred that would be likely to effect the borrower's ability to service its loan obligations. (When construction was completed, the term loan was provided by PEFCO rather than US Eximbank.)
- An Uninsured Alternative Credit Agreement, provided for the US\$115 million uninsured commercial bank construction loan.
- A Trustee Loan Agreement, covering US\$100 million of commercial-bank construction loans supported by political risk insurance from Overseas Private Investment Corporation (OPIC).

Intercreditor Agreement

The Administrative Agent, Eximbank, the Certificate Trustee, the Collateral Trustee, the

Onshore Trustee and the Intercreditor Agent entered into the Intercreditor Agreement to govern the relationships among the lenders in respect of the borrower's obligations. Upon issuance of the bonds, the Bond Trustee also became a party to the Intercreditor Agreement. Union Bank of Switzerland was appointed Administrative Agent and Chase Manhattan Bank was appointed Certificate Trustee, Collateral Trustee and Onshore Trustee.

Trust and Retention Agreement

The Trust and Retention Agreement provides for, among other things:

- the establishment, maintenance and operation of US dollar and Philippine peso accounts into which power sale revenues and project-related, and other, cash receipts of the project company are deposited and from which all operating and maintenance disbursements, debt service payments and equity distributions will be made; and
- the sharing among the lenders of certain parts of the collateral on a *pari passu* basis.

The Agreement provides for the following accounts to be established at the Collateral Trustee's New York office.

- An Equity Proceeds Account, for equity contributions from the sponsors.
- A Bond Proceeds Account, for deposit of proceeds from the bond offering.
- A Capitalised Interest Account, which is a sub-account of the Bond Proceeds Account for interest payments on the bonds before the Eximbank Conversion Date, the date on which conditions precedent to the conversion described in the Eximbank Term Loan Agreement were to be satisfied and the Eximbank Supported Construction Credit Facility was to be repaid using the proceeds of the Eximbank Term Loan Facility. (As mentioned above, the term loan was provided by PEFCO rather than US Eximbank.)
- A Construction Period Loan Proceeds Account, into which amounts disbursed pursuant to the Eximbank Supported Credit Agreement, Uninsured Alternative Credit Agreement and/or the Trustee Loan Agreement are deposited.
- A Completion Account, into which, on the Eximbank Conversion Date, funds from the Equity Proceeds Account and Bond Proceeds are deposited.
- A Dollar Retention Account, which consists of the following sub-accounts: a Dollar Revenue Account, into which all revenues are deposited; a Debt Service Reserve Account, into which amounts in satisfaction of scheduled debt service requirements are deposited; a Maintenance Reserve Account, for amounts to satisfy required maintenance reserve requirements; an Extraordinary Proceeds Account, if applicable, for liquidated damages proceeds, insurance proceeds, expropriation proceeds, and proceeds from Meralco upon and Event of Default under the Power Purchase Agreement; and an Eximbank Disbursement Account, into which all US Eximbank disbursements are deposited.
- Peso Retention Account, an account established at the Manila office of the onshore trustee (Chase Manhattan Bank) with the following sub-accounts: a Peso Revenue Account, for all peso-denominated revenues; a Peso Conversion Holding Account, for deposit, pending conversion to dollars, of the amounts required for the dollar portion of operating costs, not including taxes; and a Peso Disbursement Account, for deposit of amounts required for peso operating costs, not including taxes.

Other project documentation

Environmental compliance

An Environmental Impact Statement was submitted to the Department of Environment and Natural Resources in June 1995 and an Environmental Compliance Certificate for the project was issued in April 1996. The project is designed to meet the most restrictive Philippine environmental standards and US Eximbank guidelines for air emissions, water discharge, noise levels and protection against natural disasters (earthquake, wind and flood). The project company developed a comprehensive monitoring plan to ensure compliance during construction and operation.

Plan for sustainable development

In an article in *Project Finance* (February 2001) Jeffrey E. Goldstein and Michael B. Selvin of Bechtel Enterprises Holdings, Inc., described how the project sponsors designed and implemented a programme for sustainable development.⁵ They cite the following definition of sustainable development from the report of the UN Commission on Environment and Development, published in 1987: 'development that meets the needs of the present without compromising the ability of future generations to meet their own needs'. For a project such as Quezon Power, this meant creating an integrated approach to development, design, construction, operation and decommissioning, taking three principal elements into consideration: economic development, environmental protection and social responsibility.

Despite the advantages of the plant site, including deepwater access for coal importation and a sheltered harbour, the sponsors realised that the construction and operation of a large power plant would impose substantial burdens on the local community. They wanted to make sure that there were offsetting benefits as well.

The plant, coal storage facility and ash disposal area required land from 50 separately owned parcels, and the acquisition of rights of way for the 31-kilometre transmission line had an impact on 400 additional properties. Residents directly affected were offered relocation and compensation packages. Vocational training programmes were developed for people from local farms and commercial enterprises whose livelihoods were affected.

The project sponsors drew up a memorandum of understanding with all the stakeholders, including the municipality, the province and the Philippine Department of Environment and Natural Resources. The memorandum defined legal, communication and other obligations on both sides. The sponsors agreed to provide:

- an electrification fund to provide power to local residents;
- a development and livelihood fund to be used for a microlending programme;
- environmental funds to ensure plant compliance with environmental regulations, and to provide for protective measure such as reforestation, watershed management and monitoring offshore ecology; and
- additional financial support for schools, roads, an irrigation dam and improvement of the water supply.

Before the plant was constructed there were frequent 'brownouts' and 'blackouts' in the vicinity of the project. Now, because Philippine Department of Energy rules require that 25 per cent

of the power output be distributed locally, the plant has made a contribution to the quality of life in the local community. At the peak of construction the plant employed 3,000 people. Now, in routine commercial operation, it employs 175, half of them from the local community.

Independent Engineer's Report

In June 1997 R.W. Beck, Inc. presented the Independent Engineer's Report. The principal conclusions were as follows.

- The construction, operation and maintenance, and management contractors had previously demonstrated their capacities to discharge their respective responsibilities.
- Provided that the construction contractors followed the design criteria set out in the construction contracts concerning site development, subsurface conditions and foundations, the proposed site should be adequate for the construction and operation of the generation facility. Also, on the basis of the Independent Engineer's site assessment, there were no significant contamination issues that required additional investigation or allocation of funds.
- The coal-fired steam electric power plant technology proposed for the generation facility was a sound, proven method for electricity production.
- The proposed methods of design, construction and operation of the project were in accordance with generally accepted engineering and industry practices.
- Assuming that the project would be designed, constructed, operated and maintained as proposed, the power plant should be capable of operating at a long-term average net capacity of 440 MW, with a net plant heat rate of 10,040 Btu/KWh (including allowance for degradation), and would have a useful life of at least 25 years.
- The project would be capable of achieving annual average equivalent availability factors of 80 per cent during the first year of operation, 83 per cent in the second year and 86 per cent in subsequent years.
- The performance tests and guarantees in the EPCM contracts were typical of those for similar projects and should be adequate to estimate future performance of the power plant.
- In the absence of events such as delays in the delivery of material and equipment, labour difficulties, unusually adverse weather, *force majeure* events or untimely equipment failure, 36 months was a realistic estimate for construction time.
- The company had obtained the necessary environmental approvals and there should be no technical circumstances that would delay the issuance of remaining construction and operating permits.
- The EPCM contract price of US\$442,866,000 and the total project construction cost of US\$563,075,000 were developed in accordance with generally accepted engineering practices and estimation methods.
- Based on the project company's estimated total use of funds, and Salomon Brothers' estimates of interest rates, reinvestment rates, and US and Philippine exchange rates, the proposed credit facilities and equity contribution should be sufficient for the project construction cost and interest during construction.
- Operation and maintenance costs had been estimated by the project company and the operator using a reasonable methodology, and were comparable to those of other coal-fired plants of similar size.

POWER PLANT

- For the Base Case Projected Operating Results (see Exhibit 11.5), revenues from the sale of electricity, transmission line payments and interest income should be adequate to pay the power plant's annual operating and maintenance expenses (excluding major maintenance), fuel and fuel transport costs, lime costs, ash disposal costs, and Philippine corporate taxes, providing a minimum annual debt service coverage ratio of 1.55 times the annual debt service requirement and a weighted average debt service coverage of 2.22 over the life of the contract. Under an increased-heat-rate sensitivity analysis, minimum coverage was estimated to be 1.51 and average coverage 2.17; under a reduced availability sensitivity, minimum coverage was 1.55 and average coverage 2.18; under an increased operating and maintenance expense sensitivity, minimum coverage was 1.48 and average coverage 2.13; under a reduced inflation sensitivity, minimum coverage was 1.42 and average coverage 1.95; under a combination of increased O&M and reduced availability, minimum coverage was 1.48 and average coverage 2.08; and, finally, under zero availability, minimum coverage was estimated to be 1.0 and average coverage 1.48.

Fuel Adviser's Report

In March 1997 Norwest Mine Services, Inc., prepared the Fuel Adviser's Report, with three principal conclusions:

- the coal supply plan for the project had a high degree of security;
- by using a combination of two high-quality coal suppliers, the project was unlikely to face material fuel supply disruptions; and
- even if fuel supply disruptions did occur, the project could easily find alternatives supplies in a timely manner from other suppliers in Indonesia or Australia.

Risk factors

The prospectus for the bond offering and other sources summarised project risk factors for lenders and bond investors under a number of headings.

Construction risks

Despite the experience of the EPCM contractors and their use of proven technologies, the construction of any major power plant involves many risks, including shortages of materials and labour; work stoppages and other labour disputes; weather interference; disputes with landowners; catastrophic events such as floods, volcanic eruptions, earthquakes or fires; sabotage, including guerrilla attacks; and engineering, archaeological, environmental and geological problems. Any of these could cause delays and/or cost overruns. Mitigating these risks on this particular project were insurance against specific construction risks, the obligation of the EPCM contractors to pay liquidated damages resulting from unexcused delay in achieving provisional acceptance by the Guaranteed Completion Date and a US\$35 million contingency in the construction budget. However, there was no guarantee that these risk-mitigation measures would completely cover expenses that the project company could have incurred in the event of construction delay.

Exhibit 11.5

Base case projections

| <i>Year ending</i> <i>31 December</i> | <i>2000</i> | <i>2001</i> | <i>2002</i> | <i>2003</i> | <i>2004</i> | <i>2005</i> | <i>2008</i> | <i>2007</i> | <i>2008</i> |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| Net capacity (kW) | 440,000 | 440,000 | 440,000 | 440,000 | 440,000 | 440,000 | 440,000 | 440,000 | 440,000 |
| Equivalent availability factor (%) ⁽¹⁾ | 80 | 83 | 86 | 86 | 86 | 86 | 86 | 86 | 86 |
| Annual energy sales (MWh) ⁽²⁾ | 3,029,558 | 3,143,167 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 |
| MGEQ (MWh) ⁽³⁾ | 2,991,690 | 3,105,297 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 | 3,256,775 |
| Heat rate (Btu/kWh) ⁽⁴⁾ | 10,040 | 10,040 | 10,040 | 10,040 | 10,040 | 10,040 | 10,040 | 10,040 | 10,040 |
| Average heat content (Btu/lb HHV) ⁽⁵⁾ | 9,900 | 9,900 | 9,900 | 9,900 | 9,900 | 9,900 | 9,900 | 9,900 | 9,900 |
| Fuel consumption (tonnes) | 1,421,300 | 1,474,700 | 1,528,000 | 1,528,000 | 1,528,000 | 1,528,000 | 1,528,000 | 1,528,000 | 1,528,000 |
| Fuel purchases (tonnes) ⁽⁶⁾ | 1,446,200 | 1,500,500 | 1,554,700 | 1,554,700 | 1,554,700 | 1,554,700 | 1,554,700 | 1,554,700 | 1,554,700 |
| Lime (tonnes) ⁽⁷⁾ | 2,100 | 2,200 | 2,300 | 2,300 | 2,300 | 2,300 | 2,300 | 2,300 | 2,300 |
| Ash (tonnes) ⁽⁸⁾ | 37,000 | 38,300 | 39,700 | 39,700 | 39,700 | 39,700 | 39,700 | 39,700 | 39,700 |
| <i>Commodity prices</i> | | | | | | | | | |
| US general inflation (%) ⁽⁹⁾ | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 | 3.1 |
| Philippine general inflation (%) ⁽¹⁰⁾ | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 | 8.5 |
| Philippine exchange rate (pesos/US\$) ⁽¹¹⁾ | 30.87 | 32.48 | 34.18 | 35.97 | 37.86 | 39.84 | 41.93 | 44.12 | 46.43 |
| <i>Electricity</i> | | | | | | | | | |
| Capacity (US\$/MWh) ⁽¹²⁾ | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 | 29.98 |
| Energy (US\$/MWh) ⁽¹³⁾ | 20.20 | 20.71 | 21.24 | 21.78 | 22.77 | 23.35 | 23.95 | 24.57 | 25.21 |
| O&M (US\$/MWh) ⁽¹⁴⁾ | 20.61 | 21.25 | 21.92 | 22.58 | 23.29 | 24.01 | 24.76 | 25.53 | 26.31 |
| Lime (US\$/tonne) ⁽¹⁵⁾ | 156.97 | 161.83 | 166.85 | 172.02 | 177.35 | 182.85 | 188.52 | 194.36 | 200.39 |
| Fuel (US\$/tonne) ⁽¹⁶⁾ | 35.82 | 36.71 | 37.62 | 38.56 | 40.42 | 41.44 | 42.49 | 43.56 | 44.67 |
| Fuel transport (US\$/tonne) ⁽¹⁷⁾ | 5.80 | 5.96 | 6.13 | 6.30 | 6.48 | 6.66 | 6.85 | 7.05 | 7.25 |
| Ash (US\$/tonne) ⁽¹⁸⁾ | 10.27 | 10.59 | 10.92 | 11.26 | 11.61 | 11.97 | 12.34 | 12.72 | 13.12 |
| <i>Operating revenues (US\$ thousand)</i> | | | | | | | | | |
| <i>Electricity revenues</i> | | | | | | | | | |
| Capacity revenues | 89,691 | 93,097 | 97,638 | 97,638 | 97,638 | 97,638 | 97,638 | 97,638 | 97,638 |
| Energy revenues | 60,438 | 64,319 | 69,168 | 70,931 | 74,151 | 76,044 | 78,005 | 80,020 | 82,092 |
| O&M revenues | 61,659 | 65,987 | 71,389 | 73,538 | 75,851 | 78,196 | 80,638 | 83,145 | 85,686 |
| Transmission line ⁽¹⁹⁾ | 8,288 | 8,601 | 9,017 | 9,026 | 9,036 | 9,046 | 9,057 | 9,069 | 9,080 |
| Shortfall payments ⁽²⁰⁾ | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Excess payments ⁽²¹⁾ | 2,340 | 2,384 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Franchise tax ⁽²²⁾ | 4,448 | 4,688 | 4,944 | 5,023 | 5,134 | 5,218 | 5,307 | 5,397 | 5,490 |
| Interest income ⁽²³⁾ | 0 | 58 | 144 | 297 | 294 | 147 | 181 | 338 | 551 |
| Total operating revenues | 226,864 | 239,134 | 252,300 | 256,453 | 262,104 | 266,289 | 270,826 | 275,607 | 280,537 |

POWER PLANT

Exhibit 11.5 continued – Base case projections

| <i>Year ending 31 December</i> | <i>2000</i> | <i>2001</i> | <i>2002</i> | <i>2003</i> | <i>2004</i> | <i>2005</i> | <i>2008</i> | <i>2007</i> | <i>2008</i> |
|---|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|
| <i>Operating expenses (US\$ thousand)(24)</i> | | | | | | | | | |
| Fuel | 60,185 | 64,021 | 68,018 | 69,752 | 72,918 | 74,780 | 76,708 | 78,689 | 80,727 |
| Auxiliary fuel | 713 | 736 | 758 | 782 | 806 | 831 | 857 | 883 | 911 |
| Lime | 330 | 356 | 384 | 396 | 408 | 421 | 434 | 447 | 461 |
| Ash disposal | 380 | 406 | 434 | 447 | 461 | 475 | 490 | 505 | 521 |
| Deposits to major maintenance reserve (25) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Wages and benefits | 3,763 | 3,888 | 4,017 | 4,141 | 4,270 | 4,403 | 4,539 | 4,679 | 4,824 |
| Operator fees | 2,202 | 2,270 | 2,340 | 2,413 | 2,488 | 2,565 | 2,644 | 2,726 | 2,811 |
| Parts | 2,675 | 2,837 | 3,005 | 3,099 | 3,194 | 3,294 | 3,396 | 3,502 | 3,610 |
| Plant supplies | 1,120 | 1,180 | 1,243 | 1,281 | 1,321 | 1,361 | 1,404 | 1,448 | 1,493 |
| Subcontracting | 1,359 | 1,440 | 1,524 | 1,573 | 1,621 | 1,671 | 1,722 | 1,777 | 1,831 |
| Plant equipment rental | 86 | 92 | 99 | 101 | 105 | 108 | 112 | 115 | 119 |
| Additional O&M | 2,083 | 1,074 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Water treatment | 1,596 | 1,707 | 1,824 | 1,881 | 1,938 | 1,999 | 2,061 | 2,125 | 2,190 |
| Administrative and general (26) | 4,738 | 4,314 | 4,453 | 4,591 | 4,731 | 4,879 | 5,030 | 5,186 | 5,348 |
| Fuel unloading (27) | 1,285 | 1,325 | 1,366 | 1,409 | 1,452 | 1,498 | 1,544 | 1,592 | 1,641 |
| Renewals and replacements | 572 | 590 | 608 | 627 | 647 | 667 | 687 | 709 | 730 |
| Insurance and taxes (28) | 7,339 | 7,503 | 7,601 | 7,961 | 8,736 | 8,536 | 8,681 | 9,291 | 9,178 |
| Transmission line maintenance | 166 | 171 | 176 | 181 | 187 | 193 | 199 | 205 | 211 |
| Other (29) | 948 | 978 | 1,009 | 1,040 | 1,072 | 1,105 | 1,139 | 1,174 | 1,210 |
| Letter-of-credit fees | 285 | 288 | 290 | 293 | 296 | 299 | 302 | 305 | 308 |
| Contingency | 169 | 174 | 179 | 185 | 191 | 197 | 203 | 209 | 216 |
| Franchise taxes (22) | 4,448 | 4,688 | 4,944 | 5,023 | 5,134 | 5,218 | 5,307 | 5,397 | 5,490 |
| Total operating expenses | 96,442 | 100,038 | 104,272 | 107,176 | 111,976 | 114,500 | 117,458 | 120,964 | 123,830 |
| Net operating revenues | 130,422 | 139,097 | 148,028 | 149,277 | 150,128 | 151,789 | 153,368 | 154,643 | 156,708 |

Operating risks

Although the plant was to use proven technology, and would be operated and maintained by companies with significant experience and high reputations, any major power plant is subject to many risks, including the breakdown or failure of equipment or processes, and plant performance below expected levels of output and efficiency. These problems may be caused by wear and tear, misuse, labour disputes, weather, catastrophic events or sabotage. Although the project company was to maintain insurance and reserves to protect against these risks, there could be no assurance that these measures would cover all possible financial losses.

Fuel supply risks

In order to protect against possible fuel supply problems the project company designed the

generation facility to take all forms of pulverised coal and signed contracts with two Indonesian coal suppliers.

PPA counterparty risk

Because Meralco was to be the principal source of revenues for the project company, any failure by Meralco to meet its financial obligations under the PPA could severely affect the company's ability to service its debt obligations. At the time that the PPA was signed, Meralco's franchise area covered a population of 15.5 million, about 23 per cent of the Philippine population, and accounted for about half of the country's GDP. Between 1992 and 1996 Meralco's sales and operating income grew at compounded annual rates of 8.3 per cent and 27 per cent respectively. In 1996 the company had operating cash flow of US\$265.6 million. (Meralco's consolidated financial statements for 1999–2001 are summarised in Exhibit 11.6 and 11.7. Selected operating statistics are summarised in Exhibits 11.8 and 11.9.)

Meralco's franchise to provide electricity to the City of Manila, which accounts for 75 per cent of its sales, expires in 2003. The franchise was first granted in 1903, then renewed in 1947 and 1964. When the prospectus was issued Meralco expected it to be renewed, but it could not guarantee that it would be renewed, or that it would not be modified in some adverse way.

In a report published in August 1996 Hagler Bailly, a consulting firm specialising in the power industry that was later acquired by PA Consulting Group, expressed its opinion that the prospects for the renewal of Meralco's franchise were excellent because of the company's technical and financial strength; the forecast increase in demand for electricity in Manila and surrounding areas, requiring a strong utility provider; the absence of a credible rival; restrictions on foreign ownership that would discourage unfriendly takeover attempts; and the impracticality of a competitor's building redundant facilities. Also, because Philippine law prohibits foreign-controlled corporations from owning Philippine land, Meralco is the owner and lessor of the land on which the power plant is built. Under the Philippine constitution the government could condemn any of Meralco's land at any time with fair compensation.

Exhibit 11.6

Manilla Electric Company and subsidiaries consolidated income statement, thousands of Philippine pesos

| | 2001 | 2000 | 1999 |
|--|-------------|-------------|------------|
| Revenues | 132,587,606 | 106,615,600 | 88,159,125 |
| Operating expenses | | | |
| Purchased power | 106,278,460 | 82,718,886 | 65,158,633 |
| Operations and maintenance | 10,390,260 | 8,566,209 | 6,996,891 |
| Depreciation and amortisation | 5,059,055 | 4,369,932 | 3,997,958 |
| Taxes other than income tax | 2,981,410 | 2,404,111 | 1,889,868 |
| Provision for income tax - operating | 2,024,689 | 2,408,300 | 2,869,845 |
| Cost of real estate | 1,612,382 | 1,353,055 | 1,486,263 |
| Cost of contracts and services | 865,905 | 981,657 | 866,747 |
| Total revenues | 129,212,161 | 102,802,150 | 83,266,205 |
| Operating income | 3,375,445 | 3,813,450 | 4,892,920 |
| Other income (charges) | | | |
| Interest and other financial charges - net | -3,101,246 | -2,048,339 | -1,456,707 |
| Purchased power | -953,488 | -583,497 | -1,285,331 |
| Benefit from income tax - nonoperating | 1,186,765 | 854,025 | 945,909 |
| Equity in net earnings of investee companies | 605,644 | 338,827 | 345,696 |
| Total other income (charges) | -2,262,325 | -1,438,984 | -1,450,433 |
| Income before minority interest | 1,113,120 | 2,374,466 | 3,442,487 |
| Minority interest | -367,426 | -115,264 | 132,593 |
| Net income | 1,480,546 | 2,489,730 | 3,309,894 |

Note: US\$1 = Ps54.

Power industry restructuring risk

The ongoing restructuring of the Philippine energy and power sector, discussed above, was not expected to change Meralco's status as a privately owned regulated monopoly within its service territory. However, increased competition in the power generation sector as a result of restructuring and privatisation could reduce the cost of electricity in other parts of the Philippines, and lead to political and regulatory pressure for Meralco to lower its own electricity prices.

Financial projection risk

As in any other financial projections, the project company made economic and technical assumptions that it believed to be reasonable, but there were many uncertainties and contingencies that could cause actual results to vary from forecasts.

Date-certain risk

The obligation of US Eximbank to make the term loan at the end of the construction period was subject to construction completion, the satisfaction of certain performance criteria by the generation facility and numerous other conditions precedent by a defined Date Certain. If those conditions had not been satisfied or waived by US Eximbank, resulting in its refusal to make the loan, and the company had not been able to arrange alternative financing, an event of default under the Common Agreement could have been triggered and all of the credit

Exhibit 11.7

Manila Electric Company and subsidiaries consolidated balance sheet, thousands of Philippine pesos

| | 2001 | 2000 | 1999 |
|---|-------------|-------------|-------------|
| Assets | | | |
| Utility plants | 77,680,674 | 71,935,103 | 66,443,812 |
| Other property and equipment | 12,523,605 | 12,204,999 | 7,822,128 |
| Investments and advances | 1,387,888 | 1,208,876 | 1,291,608 |
| Land and development | 1,583,679 | 1,482,602 | 6,263,097 |
| Current assets | | | |
| Cash and cash equivalents | 2,965,904 | 5,374,345 | 2,131,081 |
| Net receivables | 30,384,321 | 23,196,452 | 16,565,589 |
| Inventories | 2,390,203 | 4,560,513 | 2,706,890 |
| Other current assets | 1,453,432 | 980,487 | 855,938 |
| Total current assets | 37,193,860 | 34,111,797 | 22,259,498 |
| Other assets | 14,329,556 | 15,798,545 | 8,561,852 |
| Total assets | 144,699,262 | 136,741,922 | 112,641,995 |
| Stockholders' equity and liabilities | | | |
| Stockholders' equity | | | |
| Preferred stock | 863,175 | 830,189 | 804,121 |
| Common stock | 10,663,113 | 10,663,113 | 8,385,927 |
| Capital in excess of par value | 3,445,417 | 3,445,417 | 3,445,417 |
| Subscriptions receivable - common stock | -170,570 | -245,219 | -574,175 |
| Deposits on subscriptions to preferred stock | 155,235 | 211,132 | 220,681 |
| Appraisal increase in utility plant and others | 25,577,873 | 24,075,364 | 21,727,718 |
| Unappropriated retained earnings | 15,350,745 | 19,387,242 | 18,578,223 |
| Appropriated retained earnings | 12,600,000 | 6,000,000 | 6,000,000 |
| Total stockholders' equity | 67,884,988 | 63,767,238 | 58,587,912 |
| Minority interest | 3,039,258 | 3,806,803 | 3,497,538 |
| Long-term debt, net of current portion | | | |
| | 26,707,827 | 28,738,480 | 17,951,993 |
| Current liabilities | | | |
| Notes payable | 9,604,936 | 8,235,558 | 5,384,358 |
| Accounts payable and other liabilities | 17,059,101 | 14,774,167 | 10,697,072 |
| Income tax payable | 24,339 | 83,642 | 191,328 |
| Current portion of long-term debt | 2,516,456 | 1,177,330 | 1,100,604 |
| Total current liabilities | 29,204,832 | 24,270,697 | 17,273,362 |
| Deferred income tax | 3,639,572 | 3,817,044 | 3,704,469 |
| Customers' deposits - net of current portion | | | |
| | 12,472,174 | 10,327,783 | 9,286,640 |
| Operating reserves | 1,750,611 | 2,013,877 | 2,240,081 |
| Total stockholders' equity and liabilities | 144,699,262 | 136,741,922 | 112,641,995 |

Exhibit 11.8

Manila Electric Company (Meralco) selected operating statistics

| Year | Number of customers | | | | Total | Change (%) |
|------|---------------------|------------|------------|--------|-----------|------------|
| | Residential | Commercial | Industrial | Others | | |
| 1990 | 1,728,820 | 185,245 | 10,439 | 3,395 | 1,927,899 | 4.8 |
| 1991 | 1,818,553 | 192,525 | 11,144 | 3,097 | 2,025,319 | 5.1 |
| 1992 | 1,935,736 | 201,384 | 11,099 | 3,362 | 2,151,581 | 6.2 |
| 1993 | 2,072,642 | 209,159 | 11,719 | 3,562 | 2,297,082 | 6.8 |
| 1994 | 2,234,052 | 226,889 | 12,246 | 3,789 | 2,476,976 | 7.8 |
| 1995 | 2,406,959 | 237,576 | 12,936 | 4,044 | 2,661,515 | 7.5 |
| 1996 | 2,596,687 | 255,640 | 13,073 | 4,132 | 2,869,532 | 7.8 |
| 1997 | 2,787,974 | 269,382 | 13,287 | 3,999 | 3,074,642 | 7.1 |
| 1998 | 3,010,868 | 286,581 | 13,453 | 3,845 | 3,314,757 | 7.8 |
| 1999 | 3,181,751 | 298,846 | 12,553 | 3,834 | 3,496,984 | 5.5 |
| 2000 | 3,341,738 | 314,383 | 12,291 | 4,008 | 3,672,420 | 5.0 |

Compounded growth rates (%)

| | | | | | |
|----------|-----|-----|------|------|-----|
| 10 years | 6.8 | 5.4 | 1.6 | 1.7 | 6.7 |
| 5 years | 6.8 | 5.8 | -1.0 | -0.2 | 6.7 |

| Year | Energy sales (millions of kilowatt hours) | | | | Total | Change (%) |
|------|---|------------|------------|--------|----------|------------|
| | Residential | Commercial | Industrial | Others | | |
| 1990 | 3,593.1 | 3,813.3 | 4,069.0 | 90.0 | 11,565.4 | 4.6 |
| 1991 | 3,753.6 | 3,750.8 | 4,335.1 | 91.9 | 11,931.4 | 3.2 |
| 1992 | 3,781.8 | 3,815.8 | 4,430.4 | 92.3 | 12,279.3 | 2.9 |
| 1993 | 4,747.0 | 3,781.8 | 4,333.0 | 106.8 | 12,250.7 | -0.2 |
| 1994 | 4,652.4 | 4,747.0 | 5,048.2 | 107.4 | 14,555.1 | 18.85 |
| 1995 | 5,293.6 | 5,140.3 | 5,327.2 | 115.3 | 15,876.4 | 9.1 |
| 1996 | 5,975.8 | 5,805.1 | 5,909.2 | 120.4 | 17,810.4 | 12.2 |
| 1997 | 6,526.2 | 6,313.6 | 6,213.4 | 126.6 | 19,179.8 | 7.7 |
| 1998 | 7,348.4 | 6,870.4 | 5,952.6 | 134.7 | 20,306.1 | 5.9 |
| 1999 | 7,284.3 | 7,038.1 | 5,974.4 | 136.6 | 20,433.4 | 0.6 |
| 2000 | 7,880.4 | 7,507.2 | 6,359.9 | 133.2 | 21,880.7 | 7.1 |

Compounded growth rates (%)

| | | | | | |
|----------|-----|-----|-----|-----|-----|
| 10 years | 8.2 | 7.0 | 4.6 | 4.0 | 6.6 |
| 5 years | 8.3 | 7.9 | 3.6 | 2.9 | 6.6 |

Source: Meralco website.

facilities could have been accelerated. There was no assurance that the exercise of remedies, including foreclosure on collateral, would have completely repaid the debtholders.

Collateral and enforcement risk

The liens granted were to be shared by all the lenders on a *pro rata* basis. The ability to foreclose on the collateral upon an event of default was made subject to the usual problems asso-

Exhibit 11.9

Manila Electric Company (Meralco) selected operating statistics*Aggregate substation MVA capacity versus peak demand in MW*

| <i>Year</i> | <i>Total number of substations</i> | <i>Total number of banks</i> | <i>230kV, 115kV, and 69kV</i> | <i>3.4kV and below</i> | <i>Total</i> | <i>Meralco peak demand (in MW)</i> |
|-------------|------------------------------------|------------------------------|-------------------------------|------------------------|--------------|------------------------------------|
| 1991 | 88 | 152 | 3,338 | 1,782 | 5,120 | 2350 |
| 1992 | 95 | 159 | 4,205 | 1,129 | 5,334 | 2386 |
| 1993 | 94 | 166 | 5,146 | 1,146 | 6,292 | 2398 |
| 1994 | 103 | 172 | 5,626 | 1,148 | 6,774 | 2695 |
| 1995 | 106 | 178 | 6,106 | 1,149 | 7,255 | 2901 |
| 1996 | 108 | 183 | 6,740 | 1,116 | 7,856 | 3222 |
| 1997 | 114 | 195 | 8,137 | 1,105 | 9,242 | 3550 |
| 1998 | 111 | 188 | 8,080 | 1,057 | 9,138 | 3834 |
| 1999 | 110 | 182 | 8,634 | 975 9,609 | 3838 | |
| 2000 | 112 | 192 | 9,435 | 963 10,39 | 4153 | |

Meralco system load factor

| <i>Year</i> | <i>Load factor</i> |
|-------------|--------------------|
| 1991 | 0.6803 |
| 1992 | 0.6908 |
| 1993 | 0.6936 |
| 1994 | 0.7258 |
| 1995 | 0.7202 |
| 1996 | 0.7183 |
| 1997 | 0.7059 |
| 1998 | 0.6875 |
| 1999 | 0.6893 |
| 2000 | 0.6696 |

Source: Meralco website.

ciated with the realisation of security interests, which may be compounded in countries with insufficient creditor legislation. The ability of bondholders or bank lenders to take action in response to an event of default was limited by the terms of the Common Agreement and the Intercreditor Agreement. Finally, any sale of the project upon foreclosure could result in peso-denominated proceeds, subjecting the creditors to foreign exchange rate risk.

Additional indebtedness

The bond indenture and the credit agreements permit the project company to incur certain types of indebtedness in addition to the credit facilities, including:

- not more than US\$15 million in unsecured debt for ordinary business purposes;
- subordinated debt;
- a working capital facility not to exceed US\$15 million;

- senior debt for required project modifications;
- other debt, subject to satisfaction of debt-service-coverage-ratio tests; and
- further refinancing of the credit facilities.

Such additional indebtedness could adversely affect the project company's overall debt-service capability.

Environmental compliance

The project was subject to numerous environmental regulations governing construction; operation; transport, storage and disposal of fuel; and air, water and noise emissions. Additional expenditures could be required of the project company because of new laws or regulations, or changes in the interpretation of existing laws and regulations. Partially mitigating this risk to the project company, the PPA required Meralco to pay increased costs caused by changes in government laws, regulations, judgements, ordinances, permits or other conditions.

Force majeure event risk

Although Meralco was required to continue making payments under the PPA even if *force majeure* events occurred, there could be no assurance that it would ultimately make such payments.

Cross-default risk

An event of default under the bond indenture or the bank credit agreement also would be an event of default under the other credit facilities. There could be no assurance that, upon an event of default, the exercise of remedies, including foreclosure on the collateral, would make all the creditors whole.

Land lease risk

Under Philippine law only Philippine citizens, corporations or associations at least 60-percent owned by Philippine citizens may own land or leasehold interests in foreshore land (seashore land between the high and low water mark) or hold permits to build or operate piers on such land. Therefore Meralco became the owner of the land on which the power plant was to be built, and the holder of a foreshore lease from the Philippine Department of Environment and Natural Resources, and in turn it was to lease this property to the project company. Any material failure of Meralco to perform its obligations under the site leases could affect the project company's ability to operate and service its debt.

Bond market risk

Neither liquidity nor an active trading market could be assured for the bonds. The bond prospectus noted that Salmon Brothers, as the representative for all the bond underwriters, intended to make a market in the bonds but was not obliged to do so and could discontinue market making at any time without notice.

Bond transfer risk

Ownership and transfer of the bonds was to occur only on the books of the Depository Trust Company in New York. As a result any investors legally required to take physical delivery of such securities could be precluded from buying the bonds.

Currency risks

Because it was to receive revenues in local currency and pay debt obligations in foreign currency, the project company would be subject to foreign exchange rate risk and availability risk. The foreign exchange rate risk was covered by the US dollar indexation of Meralco's peso-denominated payments under the PPA, but the project would still have foreign exchange availability risk because there was no assurance that the Onshore Trustee would be able to obtain dollars at a given time. The Monetary Board of the Central Bank has the power, with the approval of the President of the Republic, temporarily to suspend or restrict foreign exchange transactions during a national emergency or a foreign exchange crisis.

Country risk

The bond prospectus noted that any future political instability, low economic growth or government action concerning facilities vital to the nation, such as power plants, could have a materially adverse impact on the project or on Meralco, the offtaker. In the past the Philippines has experienced periods of significant political instability, slow or negative growth, high inflation, significant currency devaluations, the imposition of exchange controls, the restructuring of official and commercial indebtedness, and electricity shortages affecting the industrial and service sectors of the economy.

Since the end of the regime of Ferdinand Marcos, in 1986, the political and economic situation has improved considerably. From 1987 to 1989 real GDP growth averaged 5.8 per cent. Then, after a slower period of 1.2 per cent average real GDP growth from 1990 to 1993, the economy picked up again, growing at a 5.0 per cent rate from 1994 to 1997 under the pro-business administration of President Fidel Ramos, who was credited with lifting the country to 'little tiger' status through measures such as deregulation, privatisation and liberalisation of rules on foreign direct investment. Among the growing sectors was the assembly of electronic products, which now accounts for 60 per cent of the country's exports. Because its economic growth was not as overstretched, the Philippines suffered less than nearby Indonesia and Thailand during the Asian currency crisis. Also, its banking sector was in better shape, with stricter regulation and accounting standards. Nonetheless, real GDP declined by 0.6 per cent in 1998 before recovering to a growth rate in the range of 3.5–4.0 per cent in 1999 and 2000.

After assuming office in June 1998, President Joseph Estrada got off to a reasonable start, addressing the need to cut government spending, reduce the extraordinarily high levels of foreign debt (US\$45 billion) and public-sector debt (US\$55 billion), quickly resolve cases against associates of former president Marcos, and improve the lot of the poor. In his first 'state of the union' address, in July 1998, Estrada called upon Congress to pass the long-delayed legislation to privatise the NPC and said that the sale of government stakes in companies such as the Philippine National Bank and Petron, the country's largest petroleum company, would start the following year.

In January 1999 the Philippines issued US\$1 billion in sovereign bonds, the first non-

investment grade government issue in Southeast Asia since the Philippine issue in April 1998. The bonds, with a spread of 4.35 per cent above US treasuries, carried a 'BB+' foreign currency rating from Standard & Poor's.

The performance of the Estrada administration did not live up to its promise. Foreign direct investment was slow to recover from the regional economic crisis, partly because of the perception that Estrada was surrounding himself with advisers and friends, and allowing a return to the kind of cronyism seen in the days of Marcos. The anticipated sales of government corporations did not occur.

Estrada was forced out of office in January 2001 as a result of a scandal involving illegal gambling receipts and the acceptance of diverted taxes. He was replaced by Gloria Macapagal Arroyo, the independently elected vice president and daughter of a former president. Among the problems Arroyo had to address were the reduction in electronic product exports because of falling imports of electronic components from other Asian countries; reduced demand for exports from principal markets, such as the United States; the growing budget deficit inherited from Estrada; and chronic problems such as a feeble tax collection system and a poor infrastructure in areas such as roads, ports and railways. The successful passage of the Electric Power Industry Reform Act of 2001 enhanced the reputation of Arroyo's government for getting things done.

The New People's Army (NPA), a paramilitary revolutionary group, has long been active in parts of Quezon province, including the region where the project is located. During project construction persons who identified themselves as representatives of the NPA contacted the company to demand 'revolutionary taxes'. Believing that similar demands had been made of other development projects in the region, Quezon Power's management coordinated its reaction to these demands with the Philippine authorities, the US Embassy in Manila and private security consultants. In general problems with the NPA are far less serious than those that the Philippine government faces with Muslim secessionist and terrorist elements in the country's southernmost island of Mindanao.

Country credit ratings

In May 1997, shortly before the Quezon Power bonds were issued, Moody's upgraded its sovereign credit rating for Philippine foreign currency debt and bank deposits from 'Ba2' to 'Ba1', one notch below investment grade, based on continued implementation of structural reforms, considerable adjustment in fiscal accounts, a five-year expansion of economic activity and a relatively sound banking system. The agency noted that favourable economic growth in the medium term would depend on the country's ability to complete the final stage of a tax reform programme, increase domestic savings, maintain an appropriate tight monetary policy, and contain trade and current account deficits. Standard & Poor's upgraded the country's foreign currency rating from 'BB' to 'BB+' at about the same time.

During the period of instability under Estrada Moody's had downgraded the Philippines to a foreign currency rating of 'Ba2', while Standard & Poor's downgraded it to 'BB'. In 2001, with positive signs from Arroyo's government, these were upgraded to 'Ba1' and 'BB+', respectively.

Project credit ratings

In July 1997, when the financing closed, the senior secured bonds were rated 'Ba1' by

Moody's. In its rating analysis Moody's cited contracts providing for strong cash flow in support of debt-service coverage ratios, a fuel-cost passthrough, and minimum firm capacity payments to cover operations and maintenance. Other strengths that the agency cited were the turnkey construction contract with Bechtel Power Corporation and the 25 per cent equity contribution from the sponsors. Moody's also noted that the project was expected to provide power to the offtaker at a competitive cost for the term of the contract. In 2002 Meralco was expected to pay Quezon Power 8.2 cents per KW hour compared to a long-term marginal cost of power of 9 cents starting in 2000.

In the same month Standard & Poor's rated the senior secured bonds at 'BB+'. It cited the following project risks:

- construction could be hindered because the project was sited in a remote area;
- the project sponsors were obliged to pay Meralco, the project offtaker, liquidated damages if the plant failed to maintain a load factor between 79 per cent and 88 per cent; and
- the enforceability of the 25-year PPA was threatened by uncertainties in the Philippine judicial and political systems.

Offsetting these risks, the agency noted that the project economics were strong and that Meralco's capacity payments alone would service the debt. The project was strategically important to Meralco, which wanted to diversify its power supplies away from the NPC. The forecast debt-service coverage ratio was a minimum of 1.54 and an average of 2.18. Other strengths included the plant's simple and proven technology, the experience of the EPC contractors – units of Bechtel Corporation – and the fact that the project had reached financial closing when the ratings were issued.

In August 1997 Standard & Poor's reaffirmed its 'BB+' foreign currency rating and its 'BBB-' local currency rating in response to the company's proposal to senior lenders and bondholders to eliminate the Capitalised Interest Account through an amendment to the Trust and Retention Agreement Account. The elimination of this account ended the requirement that the Collateral Trustee segregate certain bond proceeds allocated to bond interest payments prior to construction completion. As a result those funds could be used solely for construction. The agency noted that, even though the Capitalised Interest Account provided bondholders with assurances of interest payments until December 1999, the project's targeted completion date, the rating horizon looked past construction to the project's operating phase, when that account would already have been depleted. In addition, the agency made the following points to support its rating affirmation.

- There were sufficient funds to pay bondholder interest during the construction of approximately US\$50 million from other sources, including the partners' equity contribution, the commercial bank facilities other than the US Eximbank facility and unexpended development funds.
- The partners' equity contributions were already secured by a standby letter of credit from a single-A-rated company for the base equity amount of US\$207.7 million, and in addition there was another standby letter of credit for contingent equity contributions for cost overruns up to US\$20 million.
- Eliminating the Capitalised Interest Account reduced negative arbitrage and made better economic use of funding sources, saving the project an estimated US\$2.5 million.

In February 1998 Standard & Poor's reaffirmed its existing ratings for Quezon Power, but revised its outlook from stable to negative. The revision was in response to deteriorating economic conditions in the Philippines, not to any significant change in the risk profile of the project. The agency noted that progress on the transmission line was somewhat slower than had originally been forecast because the project's access to the right of way was blocked by about 3 per cent of the landowners concerned. However, it also noted that, as of January 1998, progress on construction of the power plant supported the 36-month guaranteed construction schedule. The plant was 51 per cent complete, compared to a target level of 57 per cent and a guaranteed level of 42 per cent.

Standard & Poor's once again affirmed its 'BB+' foreign currency rating and its 'BBB-' local currency rating in December 1999, this time with a stable outlook. By then the project was 99 per cent complete. The agency noted that the target completion date had been delayed from January 2000 to March 2000 because, during the autumn of 1999, the NPC had restricted grid access for Quezon Power's testing and commissioning. Another IPP venture was being tested and commissioned at the time, and the NPC had been concerned that testing both plants at the same time would subject the grid to undue risk. In the agency's opinion there were adequate funds to support the project under the revised construction schedule and to support further significant delays if they occurred. A total of US\$58 million was available to support the project beyond the funds already required to reach commercial operation. The additional funds included a development fee of US\$8 million, US\$20 million sponsors' contingent equity in the form of a direct-draw letter of credit and US\$30 million of contingent equity in the form of loan notes. However, the agency noted that, under the revised construction schedule, the project would not need to rely on any of this US\$58 million to meet debt service or complete project construction.

In March 2000, in a periodic review of construction progress, Standard & Poor's reaffirmed its ratings and the stable outlook, observing that the project had fallen four months behind its original construction schedule and was now expected to be operational by May 2000. By this time the project had completed a 240-hour provisional acceptance performance test.

In early 2001 Standard & Poor's placed the project on CreditWatch because of the possibility that it could face refinancing risk if it did not meet the conditions precedent for converting US Eximbank's construction loan into a long-term financing by the deadline date of 30 April. On 27 April, after the project met the conditions, the agency removed it from CreditWatch and reaffirmed its existing ratings. It noted that the project was complete, that the Commercial Operations Date under the PPA had been declared to be 30 May 2000 and that the final acceptance date under the EPCM contracts was likely to be declared, retroactively, to be during July 2000. The agency's rating outlook for the project at that time was negative, reflecting the negative outlook for the sovereign rating of the Philippines, which was 'BB+' foreign currency and 'BB-' local currency.

On 20 July 2001 Standard & Poor's reaffirmed the project's ratings with a negative outlook because of a possibility that the project's returns would be reduced as a result of renegotiation of the PPA. The recently passed Electric Power Industry Reform Law 2001 had required Meralco, the project offtaker, to make a reasonable best effort to reduce the costs of existing contracts with IPPs to levels not exceeding the average buying price of other land-based electric power generators, as a condition for Meralco to recover its stranded contract costs. Meralco had sought what it considered to be a more equitable risk-sharing agreement with Quezon Power, proposing that Quezon Power take a higher share of plant availability

POWER PLANT

risk and that Meralco take a higher share of commercial risk. Meralco currently was required to make an almost full capacity payment even when the power plant was unavailable.

Lessons learned

For the Quezon Power sub-investment-grade project bonds, up-front, full SEC registration broadened distribution and helped to create the impression of a mainstream, liquid, corporate type of deal.

¹ This case study is based on the prospectus for the project bonds, articles in the financial press and an interview with Barry P. Gold, Managing Director, Salomon Smith Barney.

² Reyes, Rocky L., 'Power Industry Reform in the Philippines', *IFLR Guide to Energy and Power*, Euromoney Institutional Investor, 2001, p. 69.

³ *Ibid.*, p. 72.

⁴ Goldstein, Jeffrey E., and Michael B. Selvin, 'Wider Environment', *Project Finance*, February 2001, p. 46.

⁵ *Ibid.*

Drax, United Kingdom

Type of project

3,960 MW coal-fired power plant.

Country

United Kingdom.

Distinctive features

- One of the largest and most complex power project financings ever done.
- Largest power project financing to date in London market.
- First high-yield project bonds issued in Europe.
- High leverage justified partly by hedging contract that covered 60 per cent of the plant's output.
- Difficulty of adjusting to terminated hedging contract and increased proportion of merchant sales because of declining wholesale electricity prices and high leverage.
- Standstill agreement with creditors to allow debt restructuring.

Description of financing

The original bank financing in 1999 comprised a £1.3 billion, 15-year, amortising term loan repayable in semiannual instalments from June 2000 to June 2015. Pricing, based on a grid tied to the borrower's credit rating, ranges from 150 basis points (bps) over the London interbank offered rate (Libor) to 300 bps over Libor.

The subsequent bond financing in 2000 comprised £400 million in equivalent senior secured notes due 2020 and 2025, and £250 million in deeply subordinated, 10-year-bullet, high-yield bonds.

Project summary¹

Drax, a coal-fired power station located in North Yorkshire in England, is one of the largest coal-fired plants in western Europe and generates about 8 per cent of the United Kingdom's electricity. Its owner, National Power, was required to divest some of its generation capacity when it purchased the distribution/supply business of Midlands Electricity, one of the country's 14 Regional Electricity Companies. AES Corporation, based in the United States, purchased the

plant for US\$3 billion, which was more than was expected, and financed it with substantial leverage. One of the factors that was said to justify the leverage was electricity price protection from a hedging contract with the UK subsidiary of TXU, a diversified energy company based in Dallas, Texas, that covered 60 per cent of the plant's output. The remainder of the plant's output was subject to merchant risk. The senior bonds received investment-grade ratings in 1999.

Since the project financing in 1999 AES and its Drax power plant investment have been affected primarily by two important developments with far-reaching ripple effects: first, the combination of the UK's New Electricity Trading Arrangements (NETA) and an oversupply of generating capacity reduced wholesale electricity prices by far more than had been expected, and consequently reduced the earnings and value of power plants such as Drax. Secondly, the bankruptcy of Enron caused investors and lenders to take a more conservative stance towards the entire power industry, requiring companies such as AES and TXU to deleverage and sell off assets. When TXU, facing its own financial problems, terminated the hedging contract, it was clear that Drax would not be able to service its debt on an ongoing basis. In November 2002 Drax reached a six-month standstill agreement with its lending banks and bondholders to give it time to restructure.

Power plant description

The plant was commissioned in two 1,980 MW stages, in 1974 and 1986. It consists of six 660 MW (gross) coal-fired steam turbine generating units and three 25 MW gas-oil-fired, open-cycle gas turbine generating units. Each of the 660 MW units is designed to operate wholly independently and thus can be dispatched, ramped up or down or put on or off line without affecting the operating capabilities of the other units. Drax is designed to operate as a base-load generating facility, being on line and operating at close to full capacity most of the time. However, the power station also has the capacity to be started up or shut down daily and therefore to be run when prices are high and not run when they are low. This is known as the ability to operate on a two-shift basis.

In 1996 Drax was retrofitted with a flue gas desulphurisation unit designed to dispose of 250,000 tons of sulphur emissions each year, representing about 90 per cent of the sulphur dioxide from boiler gases contained in coal that has sulphur content of up to 2.8 per cent by weight. As a result Drax is able to burn coal from a variety of sources and remain in compliance with current environmental standards.

The 1,850-acre plant site is located close to supplies of coal, cooling water and limestone, and an ash disposal site. It has good connections with the road and rail infrastructure. The plant's significant project parties are illustrated in Exhibit 12.1.

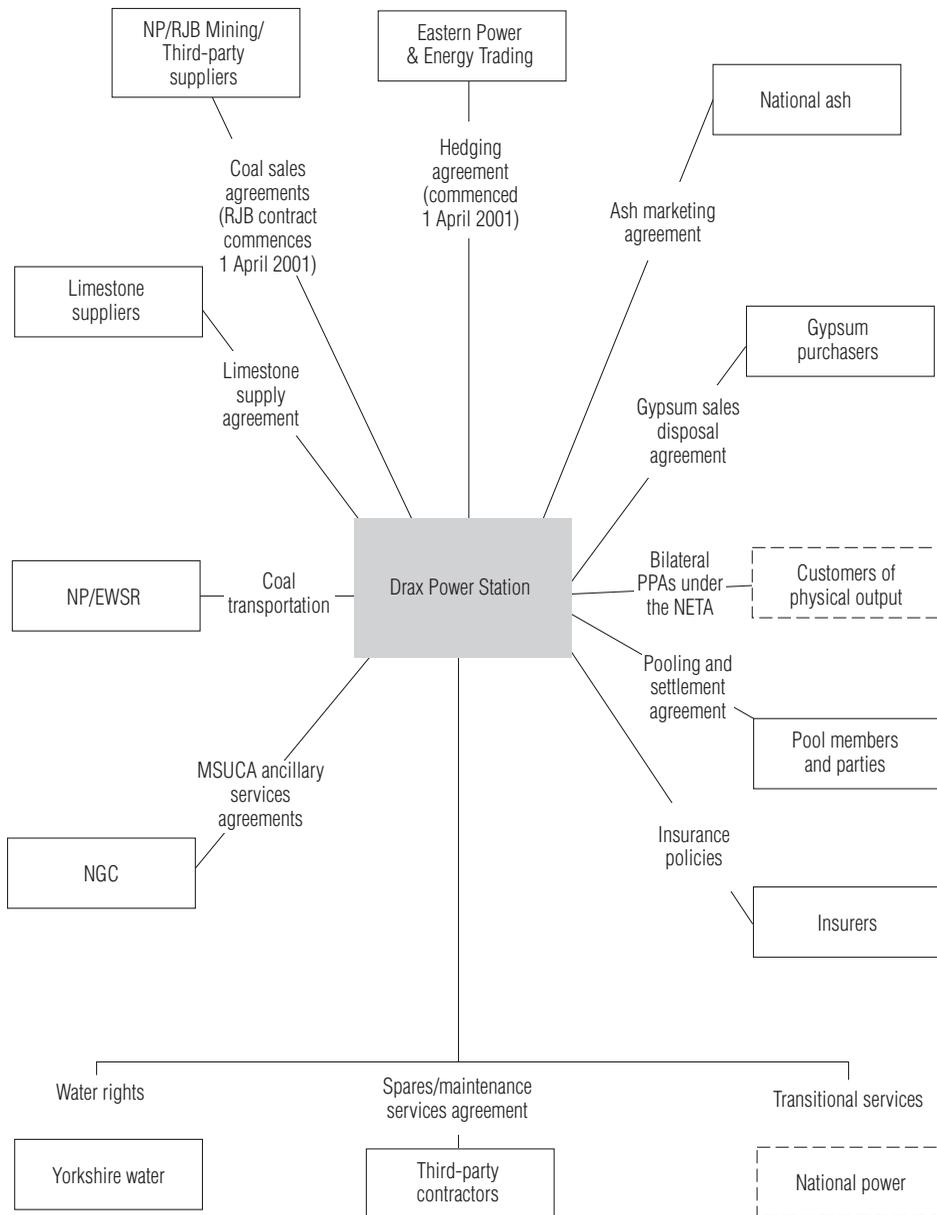
Background

The British power industry

As in most countries, firm fuel supply and electricity offtake contracts were the norm for most British independent power producers (IPPs) until the mid-1990s, when the energy market became deregulated and IPPs started to assume greater fuel-supply and electricity-sale risks. Before March 2001 electricity in England and Wales (as distinct from Scotland and Northern Ireland, the other parts of the United Kingdom) was traded between generators and suppliers through a day-ahead market known as the Pool, administered by the National Grid Company plc. The Pool was used to determine which generators were dispatched to satisfy demand and

Exhibit 12.1

Significant project parties²



the price of electricity at any particular time. The price for all generating units was the marginal price, determined by the cost of the least efficient unit dispatched. IPPs could use swap arrangements, known as ‘contracts for difference’, to hedge their exposures to the pool prices. If the pool price were lower than the contract or index price, the counterparty would pay the difference to the IPP; if the pool price were higher than the contract price, the IPP would pay

the counterparty. The Pool system was criticised by some who claimed that it frequently resulted in unnecessarily high power prices and was subject to gaming by the largest generators, which could withdraw capacity to keep prices high.

The NETA system, implemented in March 2001, was intended to replace the Pool and create a more competitive market for electricity. Rather than just selling into the Pool, generators would be required to find customers and arrange bilateral contracts with them. The new system exposed generators to dispatch risk to the extent that they generated power they could not sell or sold power they could not generate. Under the Pool arrangement this risk had been assumed by the system operator. Under the new system a short-term balancing mechanism called the UK Power Exchange sets the price for electricity sold from four hours ahead to two days ahead. Participation in this mechanism is voluntary. Under the Pool system generators and offtake counterparties could hedge against volatility in the Pool price with contracts for difference. Under the new system these arrangements effectively became invalid and had to be renegotiated, because there was no longer a Pool price.

In April 2002 the National Grid Group announced that as of July power trading would continue until one hour before physical delivery, rather than the then current three-and-a-half hours before. As a result companies that put more or less power into the system than their contracts require will have more time to trade off the imbalance. However, if the grid has to correct the imbalance and pass the cost on to the company, the cost undoubtedly will be higher. Because of the shorter period the grid is likely to call on the most flexible and hence the most expensive plants to balance the system.

Reason for plant sale

In 1999 National Power plc, then the largest electricity generator in England and Wales, was required to divest approximately 4,000 MW of generation capacity in order to comply with regulatory conditions imposed when it purchased the distribution/supply business of Midlands Electricity. In the view of Stephen Byers, then Secretary of State for Trade and Industry, the merger created horizontal overlaps in electricity supply/distribution, as well as vertical integration issues. While he did not consider vertical integration in itself objectionable, he saw competition concerns as a result of integration where there was existing market power on both ends of the supply chain, namely National Power's market power in the price-setting part of the generating market and Midlands Electricity's market power in the market for the supply of electricity to retail customers in its own authorised area. He saw an opportunity for National Power to disadvantage competitors to the detriment of end-customers.³

National Power invited bids for the power station and received approaches from 30 potential buyers. The company did not reveal how many bids it had received. The US-based AES Corporation was the winner. The £1.875 billion it paid was higher than had been expected and considerably above the £1.25 billion that Mission Energy had recently paid PowerGen for two plants with a similar power level of 4,000 MW. In November 1999 InPower, a UK subsidiary of AES, purchased the plant for US\$3 billion from National Power Drax Ltd, a special purpose vehicle set up by National Power plc.

Sponsor profile

AES Corporation is a global power company headquartered in Arlington, Virginia, across the

Potomac River from Washington, DC. The company was started in 1981 by Roger Sant and Dennis W. Bakke, who had been colleagues in the administration of Gerald R. Ford. It was one of the first companies to adopt a strategy of buying power plants and electricity distribution facilities, and selling in competitive markets, as the electricity utility business around the world gradually began to be deregulated. In 1993 AES made its first acquisition outside the United States, a power plant in Argentina.

When it acquired Drax, in 1999, AES had assets in excess of US\$20 billion and employed approximately 54,000 people around the world. The company had grown rapidly from nine power plants with 2,479 MW generating capacity in 1994 to 111 plants with 36,675 MW capacity in 1999. In addition, it had acquired majority and minority ownership interests in 15 distribution companies around the world. As a result AES's revenues had grown at a compound annual rate of 44 per cent from US\$533 million in 1994 to US\$3.25 billion in 1999. AES had broad experience of working in liberalised power markets and of operating coal-fired plants.

Before acquiring Drax AES already owned six other power stations in the United Kingdom. The Drax power station represented AES's largest acquisition to date and its largest equity contribution to a single project. In order to maximise its return AES wanted to structure the project financing with the highest possible leverage, subject to debt placement and risk management constraints.

How the financing was arranged

The financing was arranged in two phases:

- an original £1.3 billion bank financing at the time of purchase in 1999; and
- a subsequent bond financing in 2000.

Bank financing

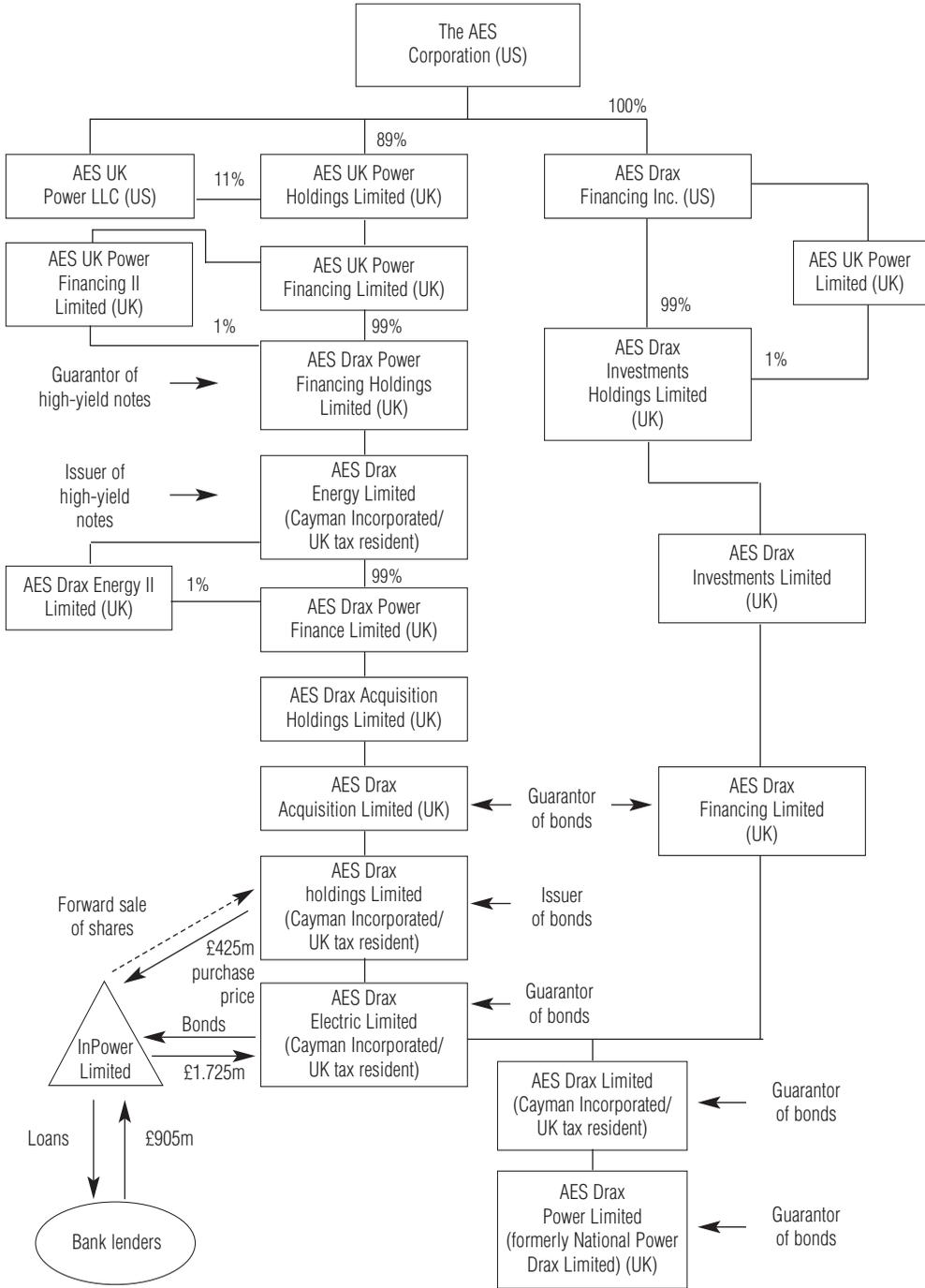
The lead arrangers for the original bank financing were Chase Manhattan, acting as book manager, ratings adviser and financial modelling bank; Deutsche Bank, as loan documentation bank, technical bank and facility agent; and the Industrial Bank of Japan, the project documentation and insurance bank. The lead arrangers faced three main challenges: the size of the financing was unprecedented; the plant was partially subject to merchant power risk; and the project had high leverage. Co-arrangers, earning underwriting fees of 35 bps for commitments of US\$50 million or more, were Abbey National, Bank of Scotland, Bank of Tokyo Mitsubishi, Bankgesellschaft Berlin, Fortis Bank, HSBC, MeesPierson, National Australia Bank and Rabobank.

One of the factors that justified Drax's high leverage was a 15-year hedging contract, a financial instrument that had the effect of a power purchase agreement (PPA) and provided for a fixed stream of capacity payments. The contract protects approximately 60 per cent of the power plant's forecasted revenues until 2007 and then the proportion of revenues protected was to decrease over time, such that over the life of the contract about 40 per cent of the plant's revenues would be protected.

Drax signed the hedging contract with Texas Utilities (TXU), the owner of Eastern Electric. Before it was purchased by TXU, Eastern had been one of the country's 14 regional electricity companies. At this point TXU was one of the major power distributors on the eastern side of England, a large generator through its PowerGen subsidiary and a rising player in power trad-

Exhibit 12.2

Structure of the acquisition and refinancing



ing. When the management of AES negotiated the agreement, it was aware that TXU would have liked to own Drax, but was subject to regulatory constraints because it already had a large share of the power generation market. Both parties might have considered raising the percentage of output covered by the agreement, but they feared that if the percentage were too high the agreement would appear to the regulators to be a *de facto* purchase of the plant by TXU.

The resulting hedging contract strengthened the credit of the project by providing on the one hand a steady revenue stream, while, on the other hand, leaving a substantial amount of forecast revenues subject to merchant risk. AES was confident about its ability to trade and manage this risk, but merchant risk would be an important issue for many of the banks that considered participating in the loan. Given the risks and the size of the deal, the bank underwriters sought a credit rating for the loan and worked with AES to make sure that the rating would be investment grade.

Bond financing

In July 2000 AES Drax Holdings Ltd issued £400 million equivalent senior secured bonds due in 2020 and 2025 to repay part of the £1.3 billion bank financing for InPower Ltd. At the same time AES Drax Energy Ltd issued £250 million equivalent high-yield, deeply subordinated notes to refinance a bridge loan of a similar amount made to AES at the time of the plant purchase. InPower Ltd is a special-purpose vehicle, while AES Drax Holdings Ltd and AES Drax Energy Ltd are indirect subsidiaries of AES Corporation. Exhibit 12.2 shows the structure established by AES in connection with the acquisition of the Drax power station and refinancing of the project.

The subordinated debt is serviced by dividend distributions after operating expenses, senior debt service and full funding of required reserve accounts. The distributions are subject to various tests and come before distributions to the parent company, which are subject to a 1.5 times semi-annual debt-service-coverage-ratio test on both a one-year-historic and a two-year forward-looking basis.

The high-yield debt increased the average life of Drax's entire debt financing from about 11 years to 17 years and provided an uplift to the sponsors' returns. However, it potentially increased the risk of the senior debt and could not have been issued without agreement by the senior lenders to weaken their protections against junior debt. The senior lenders were particularly concerned that the high-yield debt be deeply subordinated, so as not to jeopardise the investment-grade credit rating on the senior debt.

Sources and uses of funds

The capitalisation of the project after the bond financing is reflected in the sources and uses of funds (see Exhibit 12.3).

Exhibit 12.3

Sources and uses of funds

| <i>Sources</i> | <i>Amount (£ millions)</i> | <i>Proportion (%)</i> |
|--------------------------|--------------------------------|---------------------------|
| Senior secured bank loan | 905 | 46 |
| Senior secured bonds | 400 | 20 |
| Equity | 413 | 21 |
| Subordinated debt | 250 | 13 |
| Total | 1,968 | 100 |

| <i>Uses</i> | <i>Amount (£ millions)</i> | <i>Proportion (%)</i> |
|-------------------------------|--------------------------------|---------------------------|
| Shares of AES Drax Ltd | 1,807 | 92 |
| Fuel stock | 45 | 2 |
| Intellectual property license | 11 | 1 |
| Acquisition costs | 105 | 5 |
| Total | 1,968 | 100 |

Intercreditor Agreements

Under the Intercreditor Deed the senior bondholders share security with the bank lenders, including security and guarantees from various AES-related entities, assets and intellectual property related to the Drax power station, bank accounts, and hedging agreements.

Group Account Agreement

The Group Account Agreement defines the Cash Flow Waterfall, described below, and requires all of Drax's revenues be paid into a Proceeds Account except for physical damage and expropriation compensation.

Cash Flow Waterfall

The order of payments according to the Cash Flow Waterfall is as follows:

- payment of administrative costs, fees, expenses and taxes;
- payments under interest rate and currency hedging arrangements and interest due on Original Bonds;
- deposits required to maintain Debt Service Reserve Account at Required Balance;
- deposits required to cover exposure to balancing charges under new balancing and settlement code to take effect under NETA;
- deposits required to maintain required Liquidity Account balances; and
- assuming all ratio requirements have been satisfied, transfers to Distributions Account.

Payments are made from the Distributions Account in the following order:

- distributions required to cover interest, principal or any expenses related to the bonds or notes;
- required payments to the Currency Collateral Account; and
- distributions to the sponsors.

Reserve Accounts

The initial Senior Debt Service Reserve Account was required to be the greater of six months' debt service or £50 million. That amount increases in equal semiannual steps to the greater of 12 months' debt service or £100 million on the 15th semiannual repayment date. It is then reduced in equal steps to the original balance on the 20th repayment date, provided that the adjusted debt service coverage ratio over the next 10 repayment dates is greater than a ratio between 1.4 and 1.75 times, the exact level depending on the level of hedged capacity. The absolute levels of the Debt Service Reserve Account are reduced by any voluntary prepayments of the senior debt. The account can be applied immediately to any debt service obligations that become due and payable.

There are no maintenance reserve accounts. In its initial credit rating analysis Standard & Poor's noted that the operations and maintenance (O&M) budget includes £18 million in capital expenditures for 2000–04 and £5 million per year after that.

Distribution test

The project must pass a distribution test, calculated on each interest payment date, before distributions are made to the sponsor. The level of distributions permitted depends on the level of capacity that is hedged. As merchant risk increases, the distribution test becomes more

demanding, leaving a greater cash cushion in the project and providing more protection for senior lenders. As shown in Exhibit 12.4, the distribution test consists of three ratio thresholds: the one-year historic average debt service coverage ratio (ADSCR), the two-year projected ADSCR and the five-year projected ADSCR. These thresholds are set at different levels depending on the amount of capacity hedged. Where ranges are indicated, the thresholds increase on a straight-line basis in direct proportion to the decrease in hedged capacity.

Exhibit 12.4

Average hedged capacity

| | $\geq 1,890MW$ | $< 1,890MW$ | |
|------------------------|----------------|---------------------------|-------------|
| | | <i>but</i> $\geq 1,260MW$ | $< 1,260MW$ |
| 1-year historic ADSCR | >1.25x | 1.25–1.50x | 1.50–1.60x |
| 2-year projected ADSCR | >1.25x | 1.25–1.50x | 1.50–1.60x |
| 5-year projected ADSCR | >1.25x | >1.35x | >1.60x |

Cash flow sweep mechanism

A cash sweep of the liquidity account for prepayment of bank debt occurs if historic, two-year projected, or five-year project DSCRs are less than 1.2 times on two consecutive test dates.

Independent consultants' reports

The prospectus for the £400 million bond issue contained reports from three independent consultants: Stone & Webster Management Consultants Ltd, the Independent Engineer; Caminus Ltd, the Power Market Consultant; and Coal Ink Consultancy, the Fuel Consultant.

Independent Engineer's Report

Among the opinions expressed by the Independent Engineer were the following.

- The Drax power station, as National Power's flagship representing 20 per cent of its generating capacity, had been operated and maintained to the highest standards.
- An availability factor of 89.75 per cent, one of the assumptions in the Power Market Consultant's model, was reasonable and achievable, reflecting the plant's high standards of design, construction, operation and maintenance.
- Historically, the plant had achieved a net efficiency, derived from total fuel consumption and total net power exported, of 38 per cent. The Independent Engineer estimated that the net efficiency would gradually decline from that level to 37 per cent at the end of year 30.
- If the plant were maintained at the level assumed in the maintenance budget, it would be capable of operating for another 30 years.
- The Drax power station achieved comparable efficiencies with the flue gas desulphurisation system as other stations without such systems and therefore was in a strong posi-

tion to produce electricity as cheaply as its contemporaries, but without any emission constraints. The plant appeared to have no deficiencies in environmental compliance.

- The power plant had demonstrated the ability to burn coal from numerous sources while maintaining emissions within legal limits.
- The plant's technology was well-proven and there appeared to be no problem with obtaining replacement parts during its expected operating life.
- The Drax power station was connected to the 400 kV grid, the principal power distribution grid for the United Kingdom, and benefited from a good rail and road infrastructure.
- AES was well-qualified to operate the Drax power station through its considerable experience in operating other coal-fired power plants and had demonstrated the ability to improve the operations of plants that it had acquired from others.
- Transformers in Unit 3 of the power station had been damaged by fire in December 1999, after which replacement transformers had been acquired and similar transformers in other units had been inspected, with no generic equipment faults identified. The company received about £20 million business interruption and damage insurance. Unit 3 was brought back to full load in May 2000.

Power Market Consultant's Report

A bank base-case scenario and sensitivity analysis indicated average and minimum projected debt service coverage ratios (DSCRs) over the life of the bonds, as shown in Exhibit 12.5.

Based on several different price models, the Power Market Consultant developed a wholesale price forecast to support a base-case scenario, a bank base-case scenario and a low-price scenario. As shown in Exhibit 12.6, prices in the base-case scenario decline from £23 per MWh to about £21 by about 2010; in the bank base case prices decline to £19.50 by 2005; and in the low-price scenario they fall to £17.50 by 2003.

The consultant predicted that there was a 50 per cent probability that actual prices would exceed those in the base-case model, a 70 per cent probability that they would exceed those in the bank base case and an 80–85 per cent probability that they would exceed those in the low-price scenario.

The report also reviewed the implications of NETA, including the aims of the regulator, and the ways in which the forward market, the balancing mechanism and the settlement process were expected to operate. The consultant noted that, historically, 70–80 per cent of the market had been covered by contracts with terms of one to five years and that it was reasonable to expect a similarly high level of forward contracting activity under NETA. Therefore Drax was expected to have ample opportunities to arrange contracts for the plant output that was still uncontracted. The report also contained a marginal cost curve (see Exhibit 12.7) predicting the order in which plants would be dispatched, depending on the amount of power needed in the grid.

Exhibit 12.5

Bank base-case scenario and sensitivity analysis

| | <i>Average DSCR</i> | <i>Minimum DSCR</i> |
|---|-------------------------|-------------------------|
| Bank base case | 3.04 x | 1.42 x |
| Availability reduced from 89% to 83% | 2.78 | 1.19 |
| Efficiency reduced from 38% to 37% | 2.95 | 1.36 |
| Coal price increase of 9% | 2.80 | 1.36 |
| 10% increase in fixed O&M expense | 2.93 | 1.38 |
| 25% sterling devaluation 2000–04 | 3.04 | 1.42 |
| Power Market Consultant's low-price scenario | 2.56 | 1.27 |

Exhibit 12.6

Wholesale price forecast

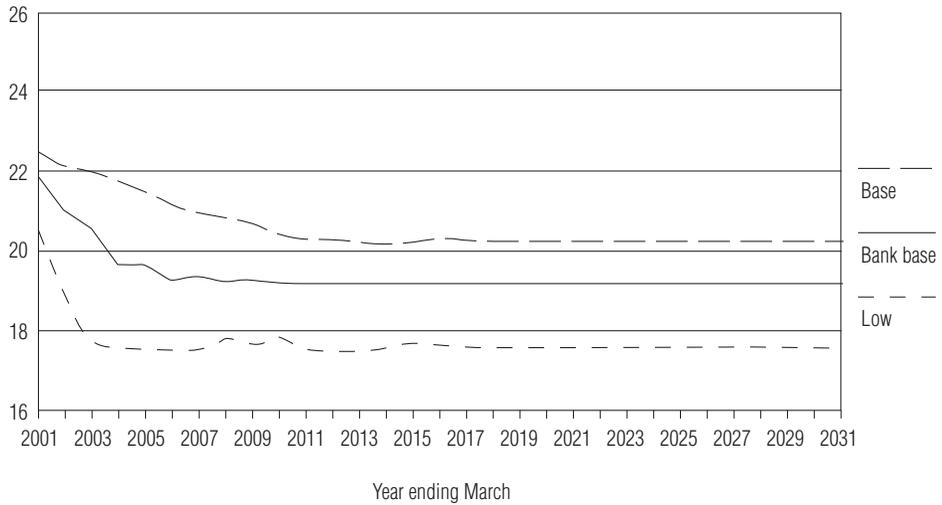
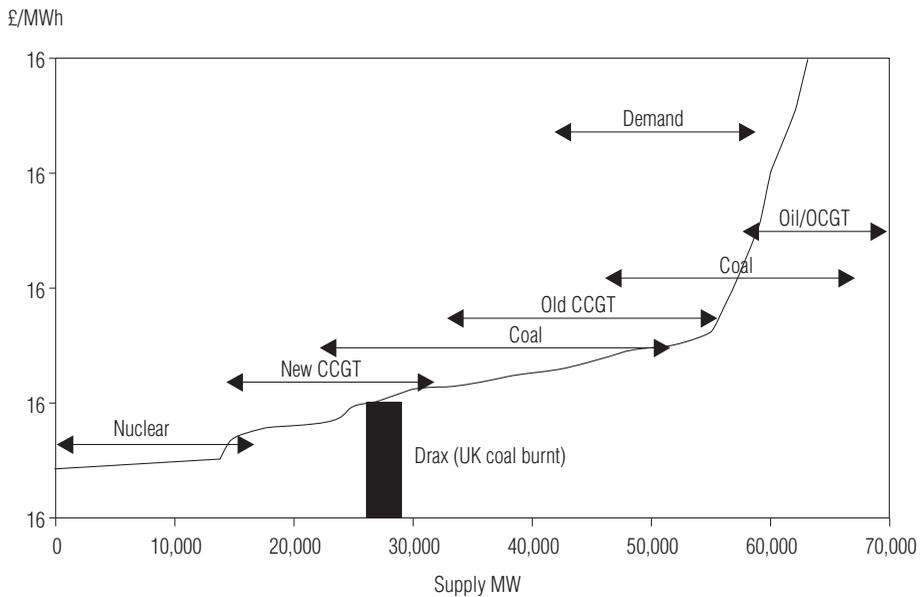


Exhibit 12.7

Marginal cost curve



Drax's costs were above those for nuclear plants and the newest combined-cycle gas-turbine (CCGT) plants, but below those of older CCGT plants and other coal-fired plants. The consultant concluded that Drax's cost structure fell well below the typical range of demand and

therefore that there was a high probability that the plant would be dispatched virtually all of the time. Finally, the consultant concluded that the hedging contract with TXU was a well-structured agreement that reduced risks for both parties.

Fuel Consultant's Report

The Fuel Consultant expressed the opinion that:

- there were sufficient coal reserves, either developed or capable of being developed, to supply UK coal-fired power plants for the life of the project debt;
- the Drax power station was capable of burning a wide variety of coals traded on the international market with sulphur contents up to 2.8 per cent; and
- coal prices were likely to fall by an average of 1 per cent per annum in real terms until 2010, because of the worldwide abundance of coal supplies.

The report noted that, although there was no longer a political mandate to support the UK coal industry through electricity pricing, the government had indicated that it would provide subsidies to some mines that were operating at a loss.

Finally, the Fuel Consultant said that:

- the Drax power station was served by a well-developed road and rail infrastructure capable of handling more than the required coal tonnages;
- the company's fuel supply strategy balanced long-term supply security with some ability to take advantage of market opportunities; and
- the recent coal-supply contract with RJB Mining was consistent with the company's strategy of providing secure supplies over an extended period at favourable prices.

Initial credit ratings

In 1999 Duff & Phelps issued a preliminary 'BBB' credit rating for the original bank financing, and Standard & Poor's issued a preliminary 'BBB-' rating. In July 2000 Standard & Poor's rated the £400 million senior secured bond issue that would repay part of the bank loan 'BBB-' and the £250 million deeply subordinated bond 'BB-', both with a stable outlook.

After the issuance of the senior bonds and subordinated notes, Standard & Poor's said that lenders and bondholders would be subject to the following risks:

- volatile and possibly lower electricity prices;
- regulatory and politically driven changes in the generation market, such as changes in the current preferences given to coal-generating units, which could distort the balance among various fuel sources and adversely affect generation prices;
- uncertainty concerning the effect of NETA, which could adversely affect Drax's competitive position; and
- merchant risk, particularly after 2007.

Offsetting those risks, Standard & Poor's noted the following points.

- The hedging arrangement with investment-grade-rated TXU reduced merchant risk substantially by supporting most of debt service until 2007.
- Drax's high efficiency rate of 38 per cent and its low marginal costs gave it a competitive position in the UK electricity market.
- AES had experience of operating older, coal-fired plants and of operating in the UK merchant power market.
- The company had retained highly qualified personnel, minimising its O&M risk.
- The plant's assets had been well-maintained, and significant capital expenditure and operating expenses were budgeted to improve operations on an ongoing basis.
- Fuel procurement and fuel price risk were expected to be minimal.
- Environmental risk was minimised by the flue-gas desulphurisation system.
- The financing benefited from adequate projected debt-service-coverage ratios in the bank base case, which also held up under stress scenarios such as continued decreasing electricity prices, new capacity entering the generation market at a low cost and lower load factors.

The stable outlook in the rating from Standard & Poor's reflected the support for debt service in the first seven years provided by the hedging contract, under which Drax would have relatively low exposure to fluctuating electricity prices and a reasonably predictable level of cash flow. Nonetheless, the agency explained that regulatory and price uncertainty limited an upgrade of the ratings. Finally, the agency pointed to the cash flow sweep mechanism that supported the payment of senior debt.

Subsequent developments

Since the project financing in 1999 AES and its Drax power plant investment have been affected primarily by two important developments with far-reaching ripple effects. First, the combination of NETA and an oversupply of generating capacity reduced wholesale electricity prices in the United Kingdom by far more than expected, and consequently reduced the earnings and value of power plants such as Drax. Second, the Enron bankruptcy caused investors and lenders to take a more conservative stance towards companies throughout the power industry, requiring companies such as AES to deleverage and sell off assets.

When the NETA system was implemented, in March 2001, Drax's hedging contract with TXU Europe had to be renegotiated because the Pool price that had been used as an index price no longer existed. The two parties had difficulty agreeing on a new index price. Consequently the hedging contract was changed to a physical delivery contract. The parties also agreed that Drax would pay 75 per cent and TXU Europe 25 per cent of transmission charges; and the call notice for TXU Europe to dispatch power from the Drax plant was changed from one day ahead to periods ranging from four hours to six months. Drax's revenues would come from the new physical delivery contract with TXU Europe, the sale of excess power through the balancing mechanism run by the system operator and the sale of ancillary services.

In April 2001 Moody's reaffirmed its 'Baa3' rating of the senior secured bonds and its 'Ba2' rating of the subordinated notes. It said the impact of NETA on Drax was negligible, because the bulk of its contract revenues remained the same, but that Drax would face higher financial risk whenever the plant was not available to meet all its contractual obligations.

The TXU Europe contract offered some mitigation of that risk. Moody's also observed that Drax would have reduced flexibility in selling power not dispatched by TXU Europe, having to sell through the balancing mechanism in relatively illiquid markets rather than through the Pool system, which had had virtually unlimited liquidity.

AES's high risk profile began to work adversely in 2001 before Enron's problems became apparent. On 26 September the company reduced its earnings outlook significantly, citing weakness in the value of the Brazilian real and lower wholesale energy prices, especially in the United Kingdom. The company's shares lost 49 per cent of their value in a single day.

Between March 2001, when NETA was implemented, and the end of the year, wholesale electricity prices had dropped 30 per cent. Other factors contributing to the lower prices were the ample supply of natural gas, falling prices on gas-fired plants because there were more sellers than buyers, and increasing competition from older plants that, in recent years, had been purchased and tuned up to operate at higher efficiency and lower cost by international power companies such as AES.

Enron Corporation filed for bankruptcy protection on 2 December 2001. The collapse of this enormous company caused investors and lenders to become sceptical about other companies in the power business, whether or not they were traders, and about companies with complicated accounting. AES suffered in this environment, although its problems related primarily to emerging markets and its UK merchant power exposure, and it had not been accused of any accounting or other misdeeds.

Later in December 2001 the credit ratings of two US energy trading firms active in the UK market, Dynegy Inc. and Mirant Corporation, were downgraded and a third, El Paso Corporation, held on to its credit rating only after substantially strengthening its balance sheet. Calpine Corporation, owner of the 1,200 MW Salt End power station in the United Kingdom, was the first IPP downgraded by the rating agencies.

At the end of the month Moody's downgraded the AES Drax Ltd subordinated notes two notches from 'Ba2' to 'B1', based on three factors: the prospect that counterparties would be tightening credit requirements and procedures; Drax's dependence on the hedging contract with TXU Europe; and its increased exposure to merchant risk after 2007. The agency observed that counterparties were beginning to cut their limits to some power companies by as much as 50 per cent and some were starting to settle weekly rather than monthly.

In February 2002 Standard & Poor's put its 'BB' rating for the Drax plant on CreditWatch with negative implications, but identified the hedging contract with TXU Europe as an important factor supporting the current rating. In early March Moody's put the Drax subordinated notes, rated 'B1', on review for possible downgrade, and maintained the 'Ba1' ratings on the senior secured bonds and senior secured bank debt with a negative outlook. Drax had requested that the senior secured lenders waive an event of default relating to a breach of insurance requirements, and requested a distribution to AES Drax Energy Ltd to allow payment on the subordinated notes and a dividend to AES Corporation. Because that waiver was not granted by 28 February 2002 Drax made its required interest payment from the Debt Service Reserve Account dedicated to the subordinated notes. As a result of changes in the insurance market after 11 September 2001 Drax was not as fully covered as required by the bank loan agreement. The company therefore was in technical default and needed a waiver from the bank lenders. After the interest payment the Debt Service Reserve Account no longer had sufficient funds for the scheduled interest payment on the subordinated notes

at the end of August. Moody's said that it expected to reconfirm its 'B1' rating on the subordinated notes if the banks granted the waiver and Drax was able to replenish the Debt Service Reserve Account, but otherwise it would have to downgrade the notes by at least one notch.

As of late February 2002 Drax's parent AES owned all or part of 182 power plants in 31 countries, most of them acquired in the past five years and financed with US\$22 billion debt then outstanding, US\$16.5 billion issued by subsidiaries such as Drax on non-recourse terms. It employed 60,000 people, although only 100 worked in its Arlington headquarters. The price of the company's shares had climbed from less than US\$5 in 1994 to a peak of US\$67.50 in 1999, but they were now trading below US\$5. Analysts were concerned that the company could run out of money at the end of the year as a result of two primary factors: falling worldwide wholesale electricity prices and economic difficulty in Latin America, where half the company's assets were located.⁴

The company responded with a restructuring plan to sell off US\$1.0–1.5 billion in assets to shore up its balance sheet and boost liquidity, and to reduce its capital spending on new construction by US\$500 million to US\$700 million. Company officials said that over the long term AES would sell a large part of its merchant generation business, which made it too susceptible to swings in the price of electricity. As part of the restructuring effort, AES hired a consultant to help it to reevaluate Drax and other investments in the United Kingdom.

By March 2002 electricity for the summer months in the United Kingdom was selling at £13.60 per MWh, which was below the operating costs of some plants. AES had recently said that Drax's marginal costs were just £9 per MWh, helped by low-cost coal contracts with UK Coal plc and a relatively high level of efficiency, at 38 per cent. However, industry experts believed that the fully absorbed cost for the entire plant had to be considerably higher. They questioned whether even a plant with Drax's high efficiency could operate profitably through the summer. An article in the Dow Jones Energy Service estimated that coal-fired units smaller than 200 MW could generate power for about £14 per MWh, while units around 500 MW could achieve £12.87 per MWh, assuming 35 per cent efficiency and an international coal price of £1.25 per gigajoule, including transport charges. Additional costs for imbalance charges (when the plant produces more or less than its contracted amount), connection costs and a conservative estimate of unplanned outage costs would add £1 per MWh, bringing the total estimated generating cost of a coal-fired plant to £14–15 per MWh. As a result it appeared likely that some operators of older coal-fired plants would turn them off for the summer or mothball them for longer periods.⁵

Also in March 2002 AES closed its 363 MW coal-fired Fifoots power plant in Wales and put it into receivership because wholesale electricity prices were not covering its operating costs. In addition, the company put its 230 MW gas-fired Barry plant, also in Wales, up for sale. Fifoots, built in 1963, thus became the first IPP to fail after the implementation of NETA. AES had bought the plant in 1996 after it had been mothballed for four years by its previous owner, National Power. AES had spent about US\$200 million refurbishing the plant. As part of that process, it had installed flue-gas desulphurising equipment, which had increased its operating cost by an undisclosed amount. During the spring several other power companies in the United Kingdom, including TXU Europe and PowerGen, also decided to mothball uneconomic power plants.

In May 2002 TXU Europe reportedly told its lawyers to scrutinise the terms of the hedging contract. This raised concerns because Drax had been required to renegotiate its insurance after 11 September 2001 and was not as fully covered as before, creating a technical default

in its bank loan agreements. Jan Willem Plantagie, a credit analyst for Standard & Poor's, said that the TXU contract could be terminated only under certain conditions, none of which was evident at the moment.⁶

In April AES agreed to sell Cilcorp, a gas and electric utility based in Peoria, Illinois, for US\$540 million. In June the company agreed to sell NewEnergy, a growing player in the Chicago area's modest but expanding retail energy market, for US\$240 million.⁷

Also in June Standard & Poor's reduced its rating on the company's senior unsecured debt from 'BB' to 'BB-' and its rating on the subordinated debt from 'B' to 'B-', citing the company's increasing challenges in managing its businesses in Latin America. Among the problems the agency mentioned were political instability in Venezuela and Brazil, and the weakening currency in Venezuela.

In the same month Moody's downgraded the company's senior debt from 'Ba1' to 'Ba3', its senior and junior subordinated debt to 'B2', and its preferred stock to 'Caa1'. The agency cited weakening power prices in the merchant portion of the company's business and deteriorating conditions in several of its international markets. In particular, volatile cash flows from the company's Latin American investments were likely to result in reduced dividends. Because of the combination of these factors, AES would have to rely on increased asset sales at a time when the market was becoming less favourable. Not only was there an oversupply of power assets on the market, but prospective buyers had reduced access to capital. Dennis Bakke had recently stepped down as AES's CEO and Moody's noted that his successor, Paul Hanrahan, appeared to have a strong commitment to reduce costs, debt, and capital spending while continuing to look for asset sale opportunities.

An article in the Dow Jones Energy Service (June 2002) estimated that about a dozen UK electricity generators were facing financial difficulties because they had borrowed when electricity prices were high and were now repaying their debts when prices, often unhedged, were at unforeseen low levels. Bankers had made an estimated US\$5–6 billion in power station loans since the industry was privatised in 1990 and now many of those assets were worth less than the sum of their debts. A large part of the problem was the oversupply of generating capacity, caused by two factors. First, following privatisation the regulators had told the two non-nuclear generators (National Power and PowerGen) to sell many of their power stations in order to promote competition. Independent power companies such as AES had bought plants that were on the verge of closure or infrequently operated and needed to generate electricity to service their debt. Second, new gas-fired generators had been built to take advantage of low natural gas prices in the mid-1990s.⁸

Whether or not AES would want to sell Drax because of the combination of low electricity prices in the UK market and its own balance sheet problems remained a question throughout the spring of 2002. Ironically, one of the possible buyers in the market was International Power, one of two successor companies to Drax's previous owner, National Power. (The other successor was nPower, which focused on the UK domestic market.)

In the summer of 2002 Drax continued to benefit from its above-market PPA with TXU Europe, although its overall profitability was impaired by low market prices for the remaining 40 per cent of its power, which was on a merchant basis. In late August 2002 Drax needed cash support from AES to make payments on its two series of senior secured notes due in 2010. Drax reportedly had a shortfall of £8 million on a payment of £15 million. At that time Standard & Poor's lowered the credit rating on Drax's senior debt from 'B+' to 'CCC' and also put these bonds on CreditWatch with negative implications.

In August and September TXU Europe negotiated with Drax to find possible ways to terminate the PPA. Alternatives that TXU Europe reportedly considered included paying Drax US\$700 million to restructure the offtake contract, so as to be at market prices; or buying a stake in Drax from AES. However, these possible measures became less realistic as TXU Europe began to face its own earnings problems.

In early October TXU announced plans to infuse about US\$700 million into its European operations, primarily those in the United Kingdom. However, on 14 October the company reversed these plans. After substantially reducing its earnings estimates for the year, TXU said that it planned to abandon its European wholesale and retail electricity businesses altogether. The company also announced that it would cut its dividend by 80 per cent in order to preserve cash and, if possible, maintain its US parent-level investment-grade credit rating. The credit rating for the company's European subsidiary, TXU Europe, was downgraded from 'BBB-' to 'BB' by Fitch, from 'Baa3' to 'B3' by Moody's, and from 'BBB-' to 'B+' by Standard & Poor's. The downgrade of TXU Europe's ratings to a level below investment grade potentially triggered the early repayment of bonds and collateral calls from trading counterparties. That, of course, did not have a direct bearing on its negotiations with Drax, because it was in Drax's interest to keep the above-market PPA just as it was.

AES and TXU Europe began discussions on a restructuring of the hedging contract on 14 October. TXU did not make the £20 million payment due on that day for the electricity it purchased in September. As a result AES gave notice to TXU, as of 15 October, that it must deliver a letter of credit in favour of Drax in accordance with the terms of the hedging contract. On the same day, as a result of the credit rating downgrades on AES Drax's debt, TXU gave notice to Drax to deliver a letter of credit in its favour, also under the terms of the hedging contract. If Drax failed to issue the letter of credit, TXU could terminate the contract within 20 days, although there was a 90-day cure period.

On 15 October Fitch reduced its rating on TXU Europe's senior unsecured debt and on obligations guaranteed by TXU Europe to 'CCC'. As a result the agency also downgraded the ratings for the AES Drax Holdings senior secured bond and the InPower senior secured bank loan from 'BB' to 'CCC', and for the AES Drax Energy senior notes from 'CCC' to 'CC'. At the same time Moody's reduced its rating on the InPower senior bank debt from 'Ba2' to 'Caa1' and the rating on the AES Drax Energy subordinated notes from 'Caa2' to 'Ca'. Fitch dropped its ratings for the AES Drax Holdings and InPower bank debt from 'BB' to 'CCC', and its rating for the Drax Energy subordinated notes from 'CCC' to 'CC', just above the 'D' imminent default level. Similarly, Standard & Poor's dropped the InPower and AES Drax Holdings senior debt to 'CC', and the AES Drax Energy subordinated debt to 'C'.

Both Fitch and Moody's noted that Drax would not be able to make its interest payments if it had to arrange new contracts for its power in the open market, and that it could not rely on support from AES, its parent, which was also facing financial pressures. Moody's noted that if the TXU Europe contract failed AES Drax might be able to claim up to £270 million (US\$420 million) in compensation, but those funds would go entirely toward the retirement of US\$1.4 billion in senior bank debt issued by InPower, which was linked directly to proceeds from the TXU contract. The agency also noted that if Drax went into receivership the unencumbered asset value of the power station would be considerably below book value and that the proceeds from liquidation would not cover all senior secured liabilities.

On 17 October TXU paid Drax £20 million for power purchased in September, three days late. Garry Levesley, the manager of the Drax plant, publicly called the late payment 'reckless behaviour', thus adding to concern that creditors might force TXU Europe into administration (the British equivalent of Chapter 11 bankruptcy proceedings).⁹ On the same day UK Coal, which was facing its own financial difficulties, cut off supplies to Drax. Drax, which had a two-month supply of coal, had delayed a £12 million payment due to UK Coal largely because of the delayed receipt of funds from TXU. Drax made a partial payment on 21 October and agreed to pay the rest on 25 October. Supplies from UK Coal remained temporarily suspended but were expected to be resumed in November.

On 21 October TXU agreed to sell its British retail business and power generation plants to PowerGen, Britain's third largest generator, for £1.37 billion (US\$2.1 billion). In the summer of 2002 PowerGen had been purchased by E.ON of Germany for just under £10 billion. TXU Europe's retail business had reportedly been on the verge of collapse because of unfavourable power purchase contracts and Ofgem, the power regulator, had been prepared to step in if TXU Europe had become incapable of buying or generating enough power to supply its customers. Under the Utilities Act of 2000 the regulator had the authority to direct a competitor to become a supplier of last resort to prevent blackouts. Following the sale of its British retail operations, TXU Europe still owned profitable Nordic and German electricity and gas supply businesses, a shrinking energy trading business, and several loss-making PPAs, including the contract with Drax. Because of difficulty in renegotiating those contracts, TXU Europe was reportedly moving toward administration (or bankruptcy).

TXU was the last US company to exit the British electricity supply market, following the recent departures of American Electric Power, Aquila and Mirant. At one point in the 1990s nine of the 14 regional electricity supply businesses in Great Britain had been controlled by US companies. Now the market would be controlled by continental European utilities, including RWE, Électricité de France and E.ON.

On 24 October AES's CEO, Paul Hanrahan, said during a webcast of third-quarter earnings that: 'depending on the outcome of recent events, AES might have to write off some or all of the assets of Drax'. On the same day Standard & Poor's published a research report, written by Jan Willem Plantagie, entitled 'Drax Recovery Prospects: Hope for Senior Debt but Bleak Prospects for Subordinated Debt'. Plantagie noted that after TXU Europe sold its assets to PowerGen it was likely that Drax's energy sales contract with TXU Europe Energy Trading Ltd would be ended soon, because TXU no longer had retail customers for the power purchased from Drax. If TXU Energy went into administration Drax could terminate the contract, making TXU Energy liable for a termination payment of about £270 million (US\$420 million), as mentioned above. However, the ranking of Drax's claim against TXU Energy, and eventually against TXU Europe, was difficult to ascertain at that point.

Plantagie also pointed out that the future of Drax following the termination of the energy sales contract lay somewhere in between operating as a pure merchant plant and operating with a new power sales contract. The plant was likely to be able to sell at least a portion of its power under three-to-twelve-month contracts at rates above the current low spot prices, but of course well below the rate in the TXU Energy contract. The termination of that contract would be an event of default for the senior bonds if the credit rating on those bonds was not reaffirmed within 30 days of termination, and that would give the senior bondholders the right to accelerate their debt in 90 days. However, Plantagie con-

sidered restructuring more likely because that was what the bank lenders, which held 70 per cent of the outstanding senior debt, generally preferred. Given Drax's liquidity at the time, Plantagie considered a payment default on the borrower's senior debt unlikely before June 2003, although a ratings default (to 'D') was a possibility. Even if Drax signed a new energy sales contract, the price would have to be significantly above current market prices to enable Drax to service its senior debt. As noted above, a payment from TXU Energy for contract termination would go entirely to senior lenders. However, if Drax were sold, bank lenders and senior bond lenders would share the proceeds. Plantagie also noted that the senior debt agreements provided for a cash sweep that would take all the money in the liquidity accounts, and prepay senior debt after two consecutive failures of a one-year-historic and a two-year and five-year forward-looking distribution test, and a 1.2 times debt-service coverage ratio.

Plantagie explained that subordinated note holders would have very limited ability to affect the senior debt. Once senior debt was accelerated, the subordinated debt could be accelerated as well. However, as noted above, acceleration of the senior debt appeared unlikely. A payment default on the subordinated notes in February 2003 seemed more likely. That would lead to a 90-day standstill period in which senior and subordinated lenders would try to find a solution before subordinated note holders could enforce their security. Those note holders could enforce a mortgage that they had on all of the shares of AES Drax Energy, thereby reducing AES's ownership of Drax. However, the value of shares in a distressed asset under control of senior lenders was questionable, leaving the subordinated note holders with only a claim on potential dividends after debt service. Payment of such dividends would be unlikely until a significant portion of senior debt was retired and wholesale power prices recovered. Thus prospects were very bleak for subordinated note holders.

On 4 November TXU Energy notified Drax that, following Drax's failure to post a £50 million letter of credit, TXU Energy intended to terminate its hedge contract on 3 February 2003. The contract required the company to provide 90 days notice. TXU Energy and TXU Europe had been struggling to survive since the US parent had pulled financial support in October. On 6 November TXU Europe announced that it was putting its remaining German energy assets up for sale. The company was reportedly negotiating to sell its Nordic interests as well. During the same week Innogy filed a petition with the London High Court to put TXU Europe into administration. TXU Europe was overdue on paying Innogy approximately £15 million. Innogy, now owned by RWE of Germany, was formerly National Power, the company that had sold Drax to AES for £1.9 billion (US\$3 billion) in 1999. Some industry insiders speculated that Innogy's motivation for trying to force TXU Europe into administration was in turn to force the shutdown of the Drax plant, which it then would be able to buy cheaply from the administrator.

Following TXU Energy's notice of termination Moody's downgraded Drax's senior secured bonds and bank debt from 'Caa1' to 'Caa2', and its subordinated notes from 'Ca' to 'C'. In a press release the agency said that it believed that there was sufficient cash available in Drax accounts to make the interest and principal payments due on the senior debt at the end of December, but that there was virtually no chance of cash being available for the interest payment on the subordinated notes due in February 2003. In Moody's opinion, in the absence of the hedge contract and taking into account the current conditions of the UK electricity market, Drax would not be able to service its senior secured debt on an ongoing basis. All of the agency's ratings reflected its view that there was a very high probability of default,

and therefore of losses for lenders and bondholders. The 'Caa2' rating on the senior debt reflected Moody's expectation that any realised value of the assets would not fully cover all senior secured liabilities. It expected that recovery would be based on the unencumbered value of the asset, the cash available in various Drax accounts and any sums that might be paid as a consequence of TXU's termination of the hedge contract. The 'C' rating on the subordinated notes reflected their deep subordination and the fact that there was almost no prospect that noteholders would receive any amounts.

In November TXU Energy again failed to make its monthly electricity payments to Drax on time. The two parties made additional efforts to renegotiate the hedging contract. However, on 19 November, when they could not reach agreement, Drax demanded a £267 million termination fee within three days, plus £72 million for power supplied in October and November. Drax's parent, AES Corporation, indicated that it would press to have TXU Europe wound up. On the same day, succumbing to the pressures of weak electricity prices and a £2.9 billion debt load, TXU Europe obtained a court order to place itself and its five subsidiaries into administration. The following day TXU Europe's Eurobonds fell to 12 per cent of their par value. Fitch said that TXU Europe's financial creditors were likely to recoup less than 50 per cent of their investment and trade creditors significantly less. TXU Europe's administrators, Ernst & Young and KPMG, asked the company's trading partners to halt gas and power deliveries, and froze electricity purchase contracts with four power stations, echoing moves to wind up Enron Europe just a year before. Some observers thought that TXU Europe could have survived and that Drax could have stood a chance to recover more if it had not insisted on being paid ahead of other creditors, and being paid 100 pence on the pound.¹⁰ At this point analysts from the rating agencies commented that restructuring was inevitable for Drax. Plantagie of Standard & Poor's commented that a restructured Drax with a lower debt burden could be competitive.

On 28 November Drax announced that it had reached a six-month standstill agreement with its lending banks and bondholders to give it time to restructure. It said that the lenders and bondholders would provide fresh credit of up to £30 million, to give the plant breathing space to adapt to operating in an open merchant market, and had agreed to the temporary or permanent waiver of certain defaults that had occurred or could occur during the six-month standstill period. As a result of the termination of the TXU Europe hedging contract, the bondholders could have accelerated the bonds, but in doing so they would have forced Drax into administration. Levesley of AES Drax said: 'The standstill agreement ensures financial stability and provides adequate credit support, ensuring the most effective marketing of the plant's output over the coming months. The prospects for the business now appear better than they have for some time'.¹¹

Meanwhile AES Corporation was continuing its efforts to sell off assets and strengthen its balance sheet. On 3 October the company had announced an offer to exchange a combination of cash and new senior secured notes for up to US\$500 million of senior notes due in 2002 and 2003. The offer affected US\$300 million aggregate principal amount outstanding of 8.75 per cent senior notes due in 2002 and US\$200 million aggregate principal amount of 7.375 per cent remarketable and redeemable securities (ROARs) due in 2013 but puttable in 2003. For each US\$1,000 principal amount of the 2002 notes AES offered US\$500 in cash and US\$500 principal amount of a new issue of 10 per cent senior secured notes due in 2005. For each US\$1,000 principal amount of the ROARs the company offered US\$1,000 principal amount of new 10 per cent senior secured notes due in 2005. Consummation of the ten-

der offer was subject to a number of conditions, including tenders representing 75 per cent of the 2002 notes and the ROARs on a combined basis, and AES's concurrent entry into a new multitranche senior secured credit facility that would rank *pari passu* with the new senior secured notes. The proposed bank facility would replace an US\$850 million revolving credit due in March 2003; a US\$425 million term loan due in August 2003; a US\$262.5 million term loan EDC Funding II LLC, an AES subsidiary, due in 2003; and a £52.3 million letter of credit facility.

Upon review of the new secured refinancing, Standard & Poor's downgraded AES's senior implied rating from 'Ba3' to 'B2', its senior unsecured rating from 'Ba3' to 'B3', its senior subordinated rating from 'B2' to 'Caa1', its junior subordinated rating from 'B2' to 'Caa2' and its preferred stock rating from 'Caa1' to 'Ca'.

Moody's assigned a 'B2' rating to AES's proposed US\$1.6 billion senior secured bank credit facility and to its proposed US\$500 million senior secured bond offering. The outlook for these ratings was negative. Moody's noted that AES's credit fundamentals had deteriorated because of difficult wholesale power markets in Argentina, Brazil, Venezuela, the United States and the United Kingdom. The agency's rating actions reflected weak cash flow relative to a high debt burden and diminishing financial flexibility. The negative outlook reflected the possibility of further rating downgrades if AES proved to be unable to do any of the following:

- maintaining its expected dividend stream from subsidiaries and investments;
- executing the sale of Cilcorp in the first quarter of 2003;
- completing additional asset sales on a timely basis;
- maintaining capital spending at more sustainable levels consistent with a debt reduction strategy; and
- refinancing bank credit facilities and near-term bond maturities.

Moody's said that AES's success in restructuring would be determined primarily by its success in executing asset sales sooner rather than later. In addition to Cilcorp, AES had committed itself to selling as much as US\$1 billion worth of additional assets. The agency said that the rating on the prospective senior secured bonds and bank credit facilities was assigned at the senior implied level because the collateral was primarily stock in subsidiaries, rather than a claim on underlying physical assets. The new bond and bank debt at the holding company level would be structurally subordinated to a large amount of debt at the subsidiary level, such as that of Drax.

Lessons learned

Three principal lessons can be drawn from the story of Drax. First, the effect of the introduction of NETA was underestimated. Second, Drax's leverage was too high to withstand the deterioration in wholesale electricity prices and the related upheaval in the UK electricity market. Third, as a high-growth, high-leverage company, AES was vulnerable to the combination of a worldwide drop in wholesale electricity prices, economic collapse in Latin America and ripple effects from the bankruptcy of Enron.

POWER PLANT

- ¹ This case study is based on an interview with Eric Lejous, formerly Vice President of Chase Manhattan Bank, plc, London, and analyses by, and interviews with, Richard Hunter, Managing Director of Fixed Ratings and Jan Willens Plantagie, Credit Analyst at Standard & Poor's.
- ² The source for Exhibit 12.1 and the other Exhibits in this case study, is the *Offering Memorandum*, dated 27 July 2000 for AES.
- ³ The *Regulatory News Service*, 9 April 1999, p. 1.
- ⁴ Irwin, Neil, 'Formula for Corporate Crisis: Enron, Collapsing Currencies, and Falling Energy Prices Cause Problems for AES', *Washington Post*, 25 February 2002, p. E1.
- ⁵ Spikes, Sarah, 'UK Coal-Fired Power Stations to Hibernate This Summer', *Dow Jones Energy Service*, 28 March 2002.
- ⁶ Kemeny, Lucinda, 'Threat to Drax Power Plant', *Sunday Times* (London), p. 3.
- ⁷ Miller, James P., 'AES Sells Competitive Energy Unit to Constellation Energy Group', *Chicago Tribune*, 12 June 2002.
- ⁸ Chipman, Andrea, 'UK Power Plant Crisis Could Cool Project Finance', *Dow Jones Energy Service*, 11 June 2002.
- ⁹ Piller, Dan, 'TXU Pays Bill for British Subsidiary Three Days Late', *Fort Worth Star-Telegram*, 18 October 2002.
- ¹⁰ Moore, Malcolm, 'Draxula – A Power Horror Story', *Daily Telegraph*, 21 November 2002, p. 36.
- ¹¹ 'AES Drax Reaches Restructuring Agreement with Lenders', *Dow Jones International News*, 28 November 2002.

Panda Energy–TECO Power joint venture, United States

Type of project

Two 2,200 MW combined-cycle, natural-gas-fired power plants.

Country

United States.

Distinctive features

- The two largest merchant power plants in the United States.
- Uncertain power sales picture in both project markets.
- Sponsor liquidity issues.

Description of financing

The US\$2.2 billion bank financing in 2001 to cover construction costs for the two separate power plants was structured as follows:

- a US\$500 million equity bridge loan, priced at 87.5 basis points (bps) over the London interbank offered rate (Libor), with a 'rating trigger' and full recourse to TECO Power Services, to be paid off quarterly as units of the power plants enter service; and
- a US\$1.7 billion nonrecourse five-year loan, syndicated among 40 banks, with pricing that started at 162.5 bps over Libor for construction, and increases to 175 bps over Libor for the first year of operation and 200 bps over Libor for years two and three.

Project summary¹

This project financing covers the construction costs for two 2,200 MW natural-gas-fuelled power projects, the Union Power Station (also known as the El Dorado project) in Union County, Arkansas, and the Gila River Power Station in Gila Bend, Arizona. They are the two largest merchant power plants in the United States.

The Union Power Station serves wholesale customers throughout the states of Arkansas and Louisiana, as well as portions of Mississippi and Texas. In addition, the plant is designed to produce power for sale in the surrounding states of Oklahoma, Missouri and Illinois. Construction of the Union Power Station began in the spring of 2001. The first phase of the Union facility was scheduled to begin commercial operation in the autumn of 2002 and the rest of the facility was expected to be fully operational by the summer of 2003.

The Gila River Power Station was designed to produce electricity for sale throughout Arizona, but it was also expected to sell excess energy to wholesale customers in California, Nevada and New Mexico. Initial construction and site preparation for the project began in May 2001. The project was expected to begin full commercial operation in the summer of 2003.

The projects are located in two separate and distinct power markets with minimal price correlation. The structural differences, such as in climate, weather patterns, customer demographics and load profiles, tend to minimise the possibility of similar adverse price trends affecting both plants at the same time. The project partnership has a comprehensive energy management plan for fuel purchase, power sales and risk management that uses the experience and business contacts of qualified third parties, while retaining oversight and ultimate responsibility in the hands of the project sponsors.

The project's power sales use a portfolio sales approach, negotiating contracts with a variety of terms and pricing structures. The fuel supply strategy is closely coordinated with the power sales strategy to manage the spark spread.

The original engineering, procurement and construction (EPC) contractor was the National Energy Production Corporation (NEPCO), a subsidiary of Enron. After Enron declared bankruptcy, the sponsors first helped bring stability to NEPCO to prevent it from being drawn into the Enron bankruptcy filing and later replaced NEPCO with a new EPC contractor, SNC-Lavalin of Canada.

Background

Sponsor profiles

TECO Power Services Corporation (TPS) is a wholly owned subsidiary of TECO Energy, Inc., a diversified energy-related holding company headquartered in Tampa, Florida. Other TECO Energy businesses include Tampa Electric, Peoples Gas System, TECO Transport, TECO Coal, TECO Coalbed Methane, TECO Propane Ventures and TECO Solutions. TPS builds, owns and operates electricity generation facilities with an emphasis on high-growth areas in North America. Announced domestic projects call for TPS to serve customers in 18 states, spanning the southern half of the United States. TECO Energy as a whole has net ownership interests in nearly 11,000 MW of generating capacity, either operating, in construction or in the advanced stages of development around the world. TPS's independent power operations have been a part of TECO's effort to evolve from a predominantly regulated energy company to one that operates primarily in deregulated, competitive markets.

Headquartered in Dallas, Texas, Panda Energy International, Inc. is a privately held, non-regulated electricity generation company primarily focused on the development, ownership and operation of state-of-the-art, environmentally clean, low-cost power plants. At the time of the project financing in 2001, the company had plants in Roanoke Rapids, North Carolina, and Brandywine, Maryland, and it had an ownership interest in three 1,000 MW plants that it had developed in Texas (in Guadalupe County, Paris and Odessa). Panda also had plants in

China and Nepal, and was the developer of, and a partner in, three merchant plants recently constructed in the United States. Panda had developed 9,000 MW that were either under construction or in commercial operation.

Panda typically uses nonrecourse financing at the project level and has drawn from a variety of funding sources to finance its projects, including bank loans, multilateral and bilateral agency loans, leveraged leases, and capital market transactions. The company has also attracted substantial private equity capital for its merchant projects. In addition to TECO, it has established partnerships and joint ventures with companies such as PSEG Global, FPL Energy and Calpine Corporation.

Panda and TECO developed the two power plants on a 50/50 basis. Panda, as the original developer, contributed the development assets to the partnership, and TECO provided all equity support during construction and long-term equity capital. The partnership will own the power plants directly or indirectly, and will manage their development, construction and operation.

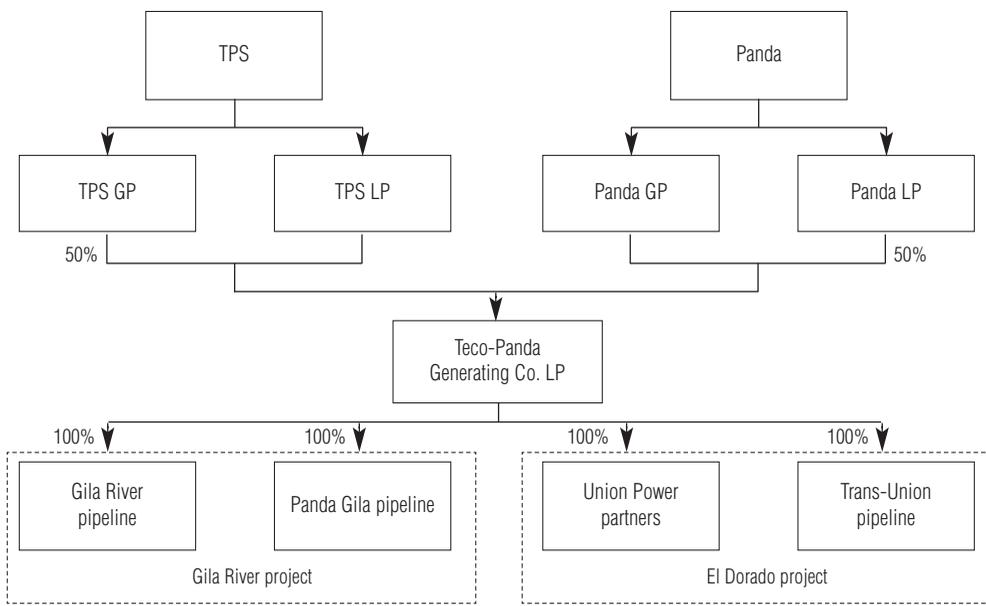
Partnership ownership structure

The partnership ownership structure is illustrated in Exhibit 13.1. The borrowers are two indirectly but wholly owned special-purpose subsidiaries of the Partnership:

- Union Power Partners (UPP), formed to construct, own, operate and maintain the Union Power (El Dorado) project; and
- Panda Gila River (PGR), formed to construct, own, operate and maintain the Gila River Project.

Exhibit 13.1

Project ownership structure²



Source: Offering Memorandum for Project Loans.

UPP and PGR guarantee each other's obligations under the credit facilities. In addition, Trans-Union Pipeline and Gila River Pipeline, indirectly but wholly owned subsidiaries of the Partnership, have constructed and own the gas pipelines for the projects, and guarantee the respective project's nonrecourse loans.

The Partnership is managed jointly through a management committee, which has four members, two representatives and two alternates, with TPS and Panda each designating one representative and one alternate. The management committee is primarily responsible for approving the strategic objectives of the Partnership and providing direct supervision to the Partnership.

Markets served

The Union Power Station will provide power to the Entergy, Tennessee Valley Authority (TVA) and Southern Company subregions within the Southern Electric Reliability Council (SERC), one of 10 electric reliability councils in the North American Electric Reliability Council (NERC) and one of the eight regional councils in the Eastern Interconnect. At the time of the project financing electricity demand in these subregions was expected to grow by 2 per cent per year up to 2009. The Entergy subregion, the power project's immediate target market, was estimated to require capacity additions of more than 10,500 MW between 2001 and 2010 if it were to cope with forecast growth and the expected retirement of older existing units, as well as to maintain a reasonable planning reserve margin of 13 per cent. In addition, with a heat rate advantage of about 30 per cent over the average existing plant the Union Power Station was expected to displace or dispatch ahead of older, less efficient generation in the target market.

The Gila River Power Station is located in the southwestern subregion of the Western Systems Coordinating Council (WSCC), also part of the NERC. The plant was intended to sell power primarily into the high-growth markets of Arizona, Nevada and southern California. In Arizona load growth was forecast to grow by 2.7 per cent per year up to 2010, and the project sponsors believed that factors such as a limited water supply and a rigorous permitting process would create high barriers to entry for additional, competing power plants. Access to the southern California electricity market is available through the Palo Verde transmission hub in Arizona, a very liquid trading point in the WSCC.

Market diversity

The Union and Gila River projects are located in two separate and distinct power markets. Not only are they geographically separated by more than 1,000 miles, but they are also located in two separate nonsynchronous power grids, commonly known as the Eastern and Western Interconnects. Each project is located within regional and local power markets that possess unique climates, weather patterns, electricity customer demographics and load profiles. In addition, each market area contains a different mix of generating resources, with different proportions of generation fuels used to serve load and with different supply sources for those fuels.

Some of the underlying factors that affect wholesale market prices, such as the installed cost of new generation, commodity or traded prices for fuels, price trends for differing fuel types and, in some cases, weather patterns, are considered likely to follow similar trends in

the two power markets. However, the project sponsors believe that structural differences between the two markets and the lack of synchronous interconnection should minimise price correlation between the markets caused by most short-term disturbances and, to a lesser extent, by longer-term trends. For instance, in general only one of the market areas at a time experiences price spikes caused by localised or short-term effects, such as severe weather or generating or fuel supply outages; seasonal effects, such as drought, affecting hydrologic conditions; or seasonal weather extremes, causing increased load and/or local or regional generating fuel supply shortages. In the sponsors' view, longer-term trends, such as expected construction cycles for generation capacity additions, electric transmission system expansion, timing of wholesale and retail deregulation, fuel supply exploration and development, or fuel storage and transport system expansions, are likely to occur at different times and proceed at different paces in the two regions.

Power plant technology

Both projects use advanced models of the General Electric (GE) 7FA turbine technology, which is the fourth operating and technology improvement in the Frame 7F series. With guaranteed heat rates of 7,064 and 7,060 Btu/kWh respectively, the Union and Gila River projects are expected to enjoy a 30 per cent efficiency advantage over the average price-setting plants in their market areas. Total capital costs of US\$534 per kWh for Union and US\$619 per kWh for Gila River compare favourably with the capital costs of other new generating facilities in the two regions.

Multiple independent generating systems

Each project contains four separate power blocks with the capability of operating completely independently of each other. This structure has two advantages:

- each project is able to serve different geographical markets at the same time; and
- generation redundancy expands the array of electricity products and pricing premiums that the projects can provide.

Natural gas supply and transportation

Each project is located in a region with abundant and diverse natural gas supplies. The Union Power project is in the South Central gas market, which has the largest base of natural gas reserves, and the most extensive production and gas pipeline infrastructure, in any region in North America. It is interconnected to the pipelines of two transportation systems, which are operated by the Texas Gas Transmission Company and the Gulf States Pipeline Corporation. The Gila River project is in the liquid Southwestern gas market, with redundant connections to the El Paso Natural Gas Company's pipeline system, and access to the Permian, San Juan, Mid-Continent, Rockies, and western Canadian supply basins at competitive market prices.

Water supply

The Union project satisfies its water supply requirement, averaging 15 million gallons per day

POWER PLANT

(MGD) from the nearby Ouachita River through an agreement with a local water agency, which has rights to 65 MGD. To satisfy the project's needs and to provide a new source of water supply to the local industrial community, a five-mile, 48-inch pipeline has been constructed between the power plant and the river.

Water for the Gila River project is drawn from an on-site aquifer through seven 700–900-foot-deep water wells. A hydrological study concluded that the aquifer could meet the project's water needs, estimated at 11 MGD, during its lifetime. This will provide the project with an advantage over other proposed projects in the region that face significant hurdles in securing sufficient water supplies.

Electrical transmission capability

The Union Power project is connected to Entergy Corporation's 500 kV El Dorado transmission substation located adjacent to the plant site, thereby gaining direct transmission access to the Entergy subregion of the SERC, which is connected to the Southwest Power Pool, part of the NERC, and to the TVA and Southern Company subregional markets. In addition, the sponsors have invested in several additional upgrades recommended by Entergy to enhance the power plant's transmission capability.

The Gila River project output is delivered to the existing Palo Verde–Kyrene transmission line via two new 19-mile 500 kV transmission lines. It is also interconnected to the existing Arizona Public Service Company 230 kV Gila Bend–Liberty transmission line, which is located adjacent to the plant site. These transmission facilities provide the project with direct access to four investor-owned utilities, the metropolitan market of Phoenix, Arizona, and the Palo Verde hub, which serves significant portions of the Southern California market.

Energy management plan

The Partnership has a comprehensive energy management plan for fuel purchase, power sales and risk management that uses the experience and business contacts of qualified third parties, while retaining oversight and ultimate responsibility in the hands of the sponsors. Responsibilities and major roles in the energy management plan are illustrated in Exhibit 13.2.

TPS planned to manage long-term transactions and divide the coordination of short-term transactions among three parties:

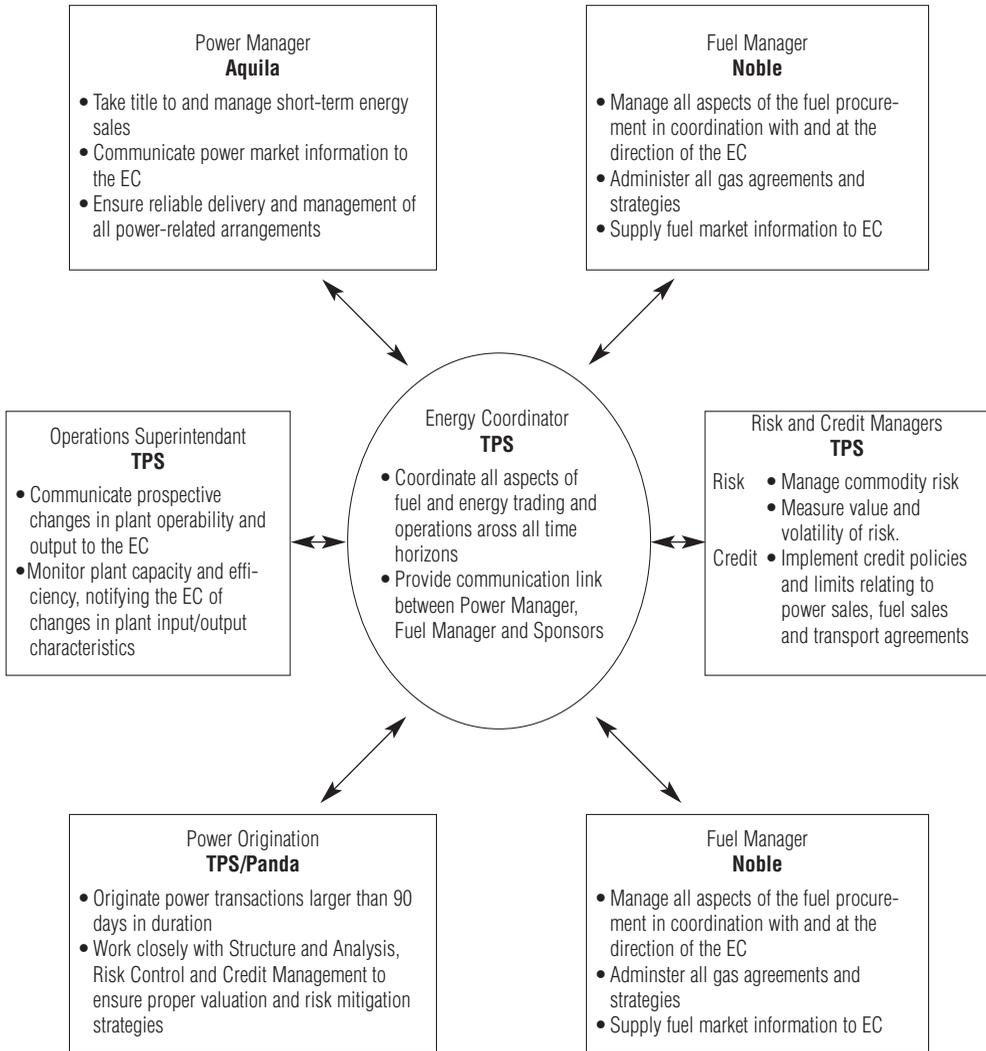
- Aquila as the Power Manager;
- Noble as the Fuel Manager; and
- TPS itself as the Energy Coordinator.

At the time of the project financing Aquila was one of the top five combined gas and power marketers in the United States. Its wholesale energy marketing business consisted of gas and power marketing, and a supply and transport network comprised relationships with gas producers, local distribution companies and end-users throughout the United States and Canada. Obligations of Aquila were guaranteed by its parent, UtiliCorp United, which was rated 'BBB' by Standard & Poor's, and 'Baa3' by Moody's.

Noble, a subsidiary of NAI, an independent exploration and development company with

Exhibit 13.2

Energy management plan



about US\$2 billion in assets, manages significant volumes in the south central region of the United States.

TPS, as Energy Coordinator, has overall responsibility for the projects’ energy strategies, managing and monitoring the physical and financial energy commodity positions on a daily basis, and providing communication links among the Power Manager, the Fuel Manager, the projects and the sponsors. Its management and staff have significant experience in power development and marketing, and have been directly responsible for marketing, negotiating and administering long-term power sales agreements for numerous other TECO projects.

Power marketing plan

To maximise the profit potential of the projects within certain risk tolerances, the Partnership planned to use a portfolio sales approach, negotiating contracts with a variety of terms and pricing structures. Over the long run it expected to implement a mixture of short-term, medium-term and long-term sales agreements, with a mixture of fuel-indexed and fixed energy pricing and tolling arrangements. Any of those arrangements could be structured as firm or non-firm sales of capacity.

Approximately 50 per cent of each project's capacity was expected to be used in long-term sales agreements (longer than one year) to provide for consistent revenues, and pay a large part of the projects' fixed expenses and debt-service obligations. Pricing would be on either a fuel-indexed basis or a fixed-energy basis with fixed monthly capacity payments, or it would be determined as part of tolling arrangements, in which a third party would assume both fuel price and electricity price risk.

Up to 25 per cent of capacity would be used in intermediate-term sales agreements (90–365 days), which would incorporate seasonal sales and purchases, and take advantage of regional situations such as generation capacity limitations. The remaining portion of the power portfolio, and any excess power released from the long-term and medium-term arrangements, were to be offered for sale to Aquila, the designated power manager for short-term transactions at the time of the project financing. (Aquila's exit from the energy trading business and TECO's intention to secure a new power manager are discussed below in the section 'Subsequent developments'.)

Fuel management

The fuel supply strategy works in conjunction with the power marketing strategy. Firm transport arrangements are maintained with supply basins for approximately 50 per cent of each project's full load requirements. The remainder of each project's transport needs is contracted on terms consistent with current power sales agreements and market opportunities. Noble, an experienced fuel manager, provides fuel management services to the project. Noble coordinates with the Energy Coordinator to take advantage of opportunities to improve cash flow through gas/power arbitrage or increased generation.

Credit and risk management

TPS has primary responsibility for risk management. The Risk Control Manager heads the risk management and reporting functions, working closely with the Credit Manager, the Fuel and Power Managers, and a position control function to ensure the effective ongoing identification, evaluation and reporting of risk. The main responsibilities of the Risk Control Manager include:

- reviewing project-specific hedging strategies in the context of the marketing and trading of power;
- assessing fuel arbitrage opportunities;
- performing risk analysis on existing and proposed transactions;
- providing daily risk reports; and
- enhancing ongoing risk mitigation and portfolio optimisation efforts through consistent stress testing, scenario analysis and simulation techniques.

Exhibit 13.3

Transaction approval limits

| <i>Authorised personnel</i> | <i>Nominal transaction value (US\$ million)</i> | <i>Nominal transaction term</i> | <i>Nominal transaction size</i> |
|-----------------------------|---|---------------------------------|--|
| Bank's administrative agent | >150 | Greater than three years | Pursuant to the terms of the EMP |
| Management committee | 150 | Three years | Pursuant to the terms of the EMP |
| General manager | 75 | 91 days to one year | One half of estimated generating plant output for a one month period |
| Energy coordinator | 10 | 90 days or less | One half of estimated generating plant output for a three month period |

Risk management includes commodity limits such as open position limits, Value at Risk (VaR) limits, and cash flow limits for all electricity and natural gas activities. The purpose of these commodity limits is to define clearly the fixed and index price positions allowable in the context of the Partnership's desired risk profile, business objectives and debt-coverage requirements. VaR limits are used to prevent excessive risk concentrations. VaR is a statistical measure that indicates the maximum probable loss over a defined period of time within a specific confidence level; that is, the value of capital that is being risked based on dynamic market price behaviour. The period of time for financial institutions is generally one day.

The Partnership's credit policy defines guidelines for contracts with power purchasers, gas suppliers and gas transporters to minimise the exposure to any counterparty that fails to fulfil its trade obligations. The Credit Manager works closely with the Energy Coordinator to ensure traders' compliance with credit policies and procedures. The Credit Manager performs stress tests on the credit characteristics of each project's portfolio of power and natural gas agreements, in order to assess the potential maximum loss over a predetermined period and to determine an estimate of aggregate portfolio credit risk for each project.

Engaging in energy commodity transactions, including power, capacity, fuel supply and natural gas transportation, requires approval at the level indicated in Exhibit 13.3.

Contracts**EPC contract**

NEPCO was originally responsible for design, procurement, construction and testing under separate but similar EPC contracts. The contracts contained schedule and performance guarantees on a per-unit basis, and liquidated damage provisions for up to 25 per cent of each plant's total contract price, in line with typical EPC contracts in the industry. The contracts also contained comprehensive warranty packages covering design, engineering, construction work and equipment for each project.

At the time of the loan syndication, in May 2001, NEPCO's obligations under the EPC contract were fully guaranteed by its parent, Enron Corporation, then rated 'BBB+' by Standard & Poor's, and 'Baa1' by Moody's. (Enron's bankruptcy in 2001 and SNC–Lavalin's assumption of NEPCO's EPC contract responsibilities are discussed below in the section 'Subsequent developments'.)

Other contracts

The Dashiell Switchyard Agreement is a contract with Dashiell Corporation for design, engineering, procurement and construction, including materials, equipment, and commissioning and testing of the switchyard transmission lines on the site of the Union Power project. A similar contract for the Gila River project was signed with GE-Hitachi HVB, Inc.

The El Dorado Willbros Gas Pipeline EPC Contracts with Willbros Engineers Inc. provide for the design, engineering, procurement, installation, construction, startup and commissioning of a pipeline to transport natural gas from the Sharon Compressor Station in Claiborne Parish, Louisiana, to the Union plant, on a lump-sum, turnkey, fixed-price basis. A similar contract with Willbros provides for the delivery of natural gas from existing El Paso Natural Gas pipelines in Maricopa County, Arizona, to the Gila River plant.

The Entergy Payment Agreement between UPP and Entergy Corporation provides for the design, ordering, purchase and construction of an electrical substation, distribution circuit, and associated facilities to supply electric service to UPP's water intake pump station near the Ouachita River and temporary power to its construction site for the Union plant.

The Raw Water EPC Contract with Milam Oil Corporation provides for the design, engineering, procurement, installation, construction, startup and commissioning of a raw water supply system on a lump-sum, turn-key, fixed price basis. That system is used to provide clarified water from the intake structure near the Ouachita River to the Union plant and to return cooling-tower blowdown water back to the river. A similar contract was signed with the Felix Raw Water System for the Gila River plant.

The Willbros Intake Structure EPC Agreement provides for the design and construction of the intake structure used in transporting water from the Ouachita River to the El Dorado plant.

Under the APS Facilities Construction Agreement, Arizona Public Service (APS) agreed to construct, own and operate various facilities to allow the Gila River plant to interconnect with the APS's transmission system.

Interconnection Agreements

UPP entered into the Entergy Interconnection Agreement to transmit electricity into the Entergy system and the Gulf States Interconnection Agreement to receive natural gas from the Trans-Union pipeline. Other agreements were made to connect the Union plant pipeline to the Tennessee Gas and Texas Gas systems.

Fuel transport agreements

UPP entered into both firm and interruptible fuel transport agreements with Gulf States, Tennessee Gas and Texas Gas; a gas storage agreement with Tennessee Gas; and balancing agreements with Gulf States and Texas. The balancing agreements provide for adjusting the flow of natural gas by up to 5 per cent on a given day to compensate for operational imbalances.

UPP also entered into the Tennessee Gas Credit Agreement, under which it was required to demonstrate its creditworthiness by meeting a debt-to-total-capitalisation ratio, a debt-service coverage ratio and a net worth requirement 90 days before commencement of service. If the defined minimum thresholds were not met, Tennessee Gas could require either a US\$750,000 letter of credit or prepayment for 90 days of service.

Gila River entered into firm transport, interruptible transport and balancing agreements with

El Paso Natural Gas Company. Under the El Paso Consent Letter Agreement Panda Gila River agreed to ensure that metering equipment was adequate for measuring the flow of gas from El Paso Natural Gas, and to demonstrate its creditworthiness to El Paso in accordance with procedures defined in standard US Federal Energy Regulatory Commission (FERC) gas tariff agreements.

Fuel supply agreements

UPP entered into fuel supply agreements with Duke Energy Field Services Marketing and with the Mexican state-owned utility Pemex. Panda Gila River entered into a similar agreement with El Paso Natural Gas.

Service agreements

UPP entered into an Operations and Maintenance (O&M) Agreement with TPS Arkansas, a wholly owned subsidiary of TPS; a power manager agreement with Aquila; a fuel manager agreement with Noble, and a pipeline O&M service agreement with Tennessee Gas. Panda Gila River entered into similar agreements with TPS Arizona, Aquila, Noble, and Hollomon Construction.

Water supply agreements

Under a water supply agreement with the Union County Water Conservation Board, UPP will receive up to 25 million gallons of clarified water for use in electricity generation and in the plant's cooling towers.

How the financing was arranged

Citigroup and Société Générale served as lead arrangers for the financing. Eighteen banks served as underwriters and 40 participated. Forty banks participated in the general syndication, which was oversubscribed by US\$1.2 billion, including a 36 per cent oversubscription on the US\$500 million equity bridge loan and a 62 per cent oversubscription on the US\$1.7 billion nonrecourse portion. The success of the syndication was credited to the relatively straightforward structure, market-based terms and pricing, and aggressive marketing by the sponsors through numerous face-to-face meetings with lenders.

The projects were expected to secure an investment-grade credit rating near the end of the construction phase, at which point the pricing was expected to drop by 12.5 bps. The increase of the spread over time was intended to be an incentive for the sponsors to refinance in the capital markets at about the time the plants begin commercial operation.

Among the terms for the equity bridge loan was a 'rating trigger'. If TECO Energy's credit rating fell below investment grade, TECO Energy would have to post a letter of credit equal to the equity bridge loan.

Union Power industrial revenue bond

The financing of the Union project involves a lease from Union County, Arkansas, that provides substantial property tax savings and is transparent to the lenders. The structure includes the issuance of 20-year, tax-free industrial revenue bonds by Union County that are purchased by

POWER PLANT

UPP Finance Company (UPP FinCo), a wholly owned special-purpose subsidiary of UPP. Lease payments equal debt service on the bonds. As a result UPP does not have legal title to the leased assets – the power plant – but has all the other typical rights of a project owner. In the event the lease is terminated and the bonds are cancelled or repaid during their term, UPP may acquire the leased assets for a nominal payment but will lose the tax benefits afforded by the lease structure from that time forward. The structure of the security package enables the lenders to foreclose on both the lessee's and the lessor's interests in the lease, thus putting the lenders in substantially the same position that they would have been without the lease structure.

Flows of funds

During the construction period:

- UPP draws under the non-recourse loan;
- UPP makes an intercompany loan to UPP FinCo using the loan proceeds;
- UPP FinCo uses the intercompany loan proceeds to purchase bonds from Union County; and
- Union County advances proceeds of the bonds to UPP for construction of the power plant (see Exhibit 13.4).

After the plant starts to operate:

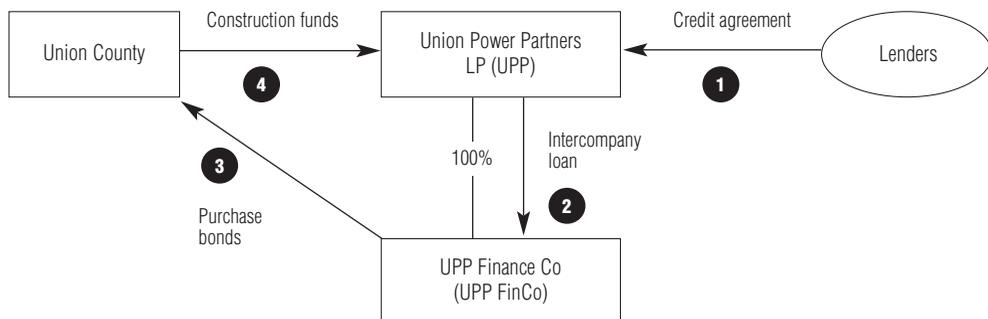
- UPP makes periodic lease payments to Union County equal to the principal and interest that the county pays on the bonds;
- UPP FinCo, as holder of the bonds, receives principal and interest from Union County;
- UPP FinCo makes loan payments to UPP equal to bond payments received from Union County; and
- UPP makes payments to service the nonrecourse project loan (see Exhibit 13.5).

Crosscollateralisation

The two projects are fully crosscollateralised, enhancing the lenders' security by diversifying

Exhibit 13.4

Flow of funds during the construction period



individual project risks related to construction, operations and market prices. The value of crosscollateralisation and the likelihood of sufficient cash flow for debt-service coverage are further enhanced by low correlation between the two project markets, as estimated in a market diversity analysis by RW Beck, Inc., an independent engineering and electricity market consulting firm.

Environmental permits

Both projects have a combined-cycle configuration. The combustion turbines use low-nitrogen-oxide (NOX) combustors along with selective catalytic reduction to reduce NOX emissions. The exclusive use of low-sulphur natural gas in the combustion turbines minimises particulate matter, sulphur dioxide and sulphuric acid mist air emissions. In addition space is provided in the heat recovery steam generator for future installation of an oxidation catalyst capable of reducing carbon monoxide emissions by 80 per cent. The air permits for the projects include short-term and annual emission limits for combustion turbines and duct burners, which operate on natural gas. They also set out testing, monitoring and record-keeping requirements.

Risk summary

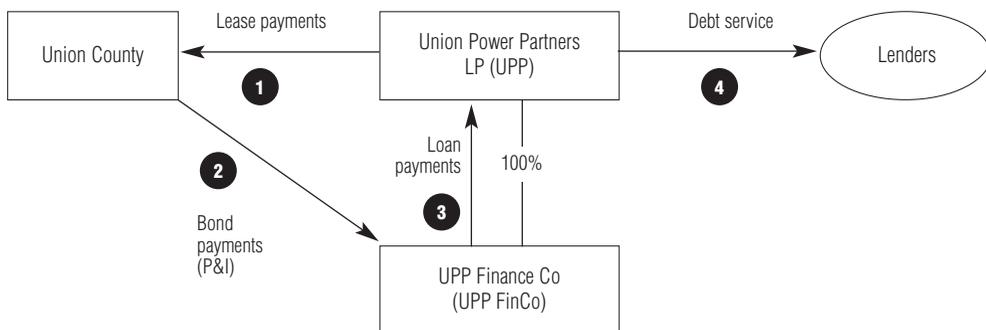
The projects are subject to typical power plant risks, including those discussed in this section.

Construction risk

SNC–Lavalin, which took over from NEPCO as the EPC contractor, is a full-service engineering and construction company with over 60 years’ experience. TECO Energy replaced Enron as the guarantor of some of NEPCO’s obligations under the EPC contracts in December 2001. Liquidated damages and retainage provide SNC–Lavalin, and more importantly their subcontractors such as GE and Alstom, with incentives to achieve guaranteed levels of performance on a timely basis. TECO Energy guarantees substantial completion of the projects on a date-certain basis and provides liquidated damage provisions

Exhibit 13.5

Flow of funds during the operations period



POWER PLANT

equal to up to 25 per cent of the contract price for each project. The EPC contracts also contain extensive warranty packages covering design, engineering, construction work and equipment. RW Beck commented that the terms and provisions of the new SNC–Lavalin EPC contract, as well as those of the gas pipeline, water supply facility and electrical connection EPC contracts, were adequate, with well-defined schedules of events from startup to completion.

Technology risk

Both projects use advanced models of the GE Frame 7FA turbine technology. R.W. Beck, Inc. concluded that the projects use sound technology, and that the proposed method of design and construction conformed to accepted industry practice for combined-cycle facilities. The firm noted that GE has an evolutionary approach to the development of its combustion turbine generator, making incremental enhancements from one model to the next. Further, the risk of part failure or unplanned part replacement is mitigated by long-term service agreements and warranty agreements.

Electricity price risk

As explained above, the projects are intended to apply a portfolio sales approach by negotiating contracts with a variety of terms and pricing structures, a mixture of short-term, medium-term and long-term sales agreements, and a mixture of fuel-indexed and fixed-energy pricing along with tolling arrangements. The sponsors believe that such a mixture should allow the projects to be flexible, and capable of adapting to changes in the fuel and electricity markets.

Fuel price risk

At the time of the project financing, approximately 27 per cent of the maximum daily fuel requirement for the Union project was under contract at an index-based price, but, because of unusually high prevailing natural gas prices in its market area, the Gila River project had not yet executed any contracts to purchase natural gas. Pace Global Energy Services, an independent fuel and energy management consultant, projected that these high prices would decline and then rise by 0.5 per cent annually during the life of the projects. Reasons for the expected decline in natural gas prices included:

- downward price pressure from increased US production;
- sufficient and growing reserves to support increased production;
- downward price pressure from increased imports, particularly from Canada;
- technological advances in production; and
- interfuel competition from advanced crude oil projects and high-grade coal.

Fuel supply risk

To reduce supply risk, long-term firm transport has been contracted for 52 per cent of the Union project's maximum daily requirements. Risks that the remainder of the project's needs

will not be met are mitigated by the project's interconnections with two different pipeline systems, Texas Gas and Gulf States, each capable of meeting the project's full requirements. Although at the time of the project financing the Gila River project had not entered into any long-term fuel-supply arrangements, Pace considered this to be the best approach, given the project's access to abundant gas supplies.

Fuel transport risk

The Union project interconnects with two large pipeline systems via its affiliate-owned pipeline, the El Dorado Project Pipeline. One of these systems, the Trans-Union Pipeline, has filed with the FERC as an open-access pipeline and may be required to provide transport services to other users in the region. However, a 'precedent agreement' that UPP signed with Trans-Union Pipeline for 419,000 million cubic feet per day (Mcf/d) is sufficient for the plant's peak daily usage. Pace believes, based on its knowledge of other recent regulatory proceedings, that the daily amount in the precedent agreement cannot be pro-rated and reduced by the addition of new customers. Furthermore, during the regulatory proceedings, only one other potential customer with a 9,000 Mcf/d need expressed any interest.

The Gila River project has minimised risks associated with reliance on the El Paso Natural Gas system by:

- establishing hot taps into two different loops of the system to reduce redundancy in the event of delivery failure;
- entering into firm transport contracts for approximately 50 per cent of the project's peak fuel transport needs and 65 per cent of average requirements; and
- using backhauls and delivered deals with other suppliers holding El Paso's capacity rights.

The project has rights of first refusal for 70,000 Mcf/d of firm capacity, or 27 per cent of its average daily consumption. Finally, Pace expects new pipeline expansions in the west to ease any current capacity shortfalls that have contributed to historically high prices.

Operator risk

A subsidiary of TPS provides O&M services for the projects. TPS and its affiliates have more than 100 years of operating experience and currently operate over 4,400 MW of generating capacity in the United States and other countries. Over the years TPS has gained experience with many technologies, including simple-cycle and combined-cycle facilities, coal-fired boilers, oil-fired boilers, and integrated gasification combined-cycle facilities. TPS affiliates own and operate several power projects using the GE Frame 7F technology.

Equity funding risk

The sponsors, guaranteed by TECO, committed themselves to making cash contributions during the construction period to supplement the equity bridge facility, in order to maintain a 60/40 debt-equity ratio.

Power marketing risk

Aquila, the former manager of short-term energy transactions for both projects, was among the top five energy marketers in North America for combined gas and electricity marketing at the time of the project financing. Following Aquila's exit from the energy trading business TPS will find a new power manager, possibly a large utility with a trading arm.

Transmission risk

A power station operates under the risk that regional transmission capacity may be insufficient to handle growing power loads and that bottlenecks may delay the transmission of electricity from a power plant to its customers, thereby reducing the plant's revenues.

Financial projections

The project loans were structured to have investment-grade credit characteristics based on crosscollateralisation of the two projects' assets, strong debt service coverage ratios, operations in diversified markets and multiple independent generating systems. The transaction structure provided strong incentives for the sponsors to obtain investment-grade ratings as soon as possible. When such ratings were realised, pricing on the loans would drop by 12 bps. Until such ratings were granted cash distributions would be prohibited and 50 per cent of excess cash would be swept to pay down the bank debt.

The Partnership developed financial models for each project and for both projects on a consolidated basis, incorporating assumptions about plant performance and future conditions in the two local markets. For the Base Case and Sensitivity Cases the sponsors used fuel price forecasts from Pace Global Energy Services and power market price forecasts from R.W. Beck, Inc. On a combined basis the Base Case estimated average and minimum debt-service coverage ratios of 3.24 times and 2.42 times, respectively, based on an estimated 18-year amortisation period. In other words, it assumed that the bank debt would be paid off and refinanced with 18-year bonds.

The Base Case and Sensitivity Cases were developed to gauge the impact of certain conditions on the two projects' financial performance, including a 25-year bond financing case, a market overbuild case, a low-fuel-price case, and a higher O&M expenses case. In all cases average debt-service coverage ratios exceeded three times on a combined basis.

Subsequent developments

In the months following the Enron bankruptcy in December 2001 the merchant power business in general, and power players such as TECO Energy and Panda Energy in particular, were affected by a combination of events described as a 'perfect storm', including:

- the economic slowdown;
- declining electricity demand;
- the resulting decline in electricity prices;
- accounting scandals;
- scepticism about power companies engaged in trading and other unregulated activities; and
- concern over power companies' ability to refinance three-to-five-year 'miniperms' project loans.

During 2002 and early 2003 the Panda–TECO joint venture replaced its EPC contractor and sought to replace its power marketer; TECO cut back its capital spending plans, and issued new debt and equity to protect its investment-grade credit rating and fulfil its obligations to the joint venture; and the power market outlook became more uncertain for both projects.

New EPC contractor

The catastrophic decline of Enron, culminating in its bankruptcy filing, created many significant challenges for the Partnership. First and foremost was the challenge of avoiding disruption to the two construction sites. Because Enron’s bankruptcy posed serious questions as to the long-term viability of NEPCO, many subcontractors and vendors, as well as much of the site labour pool, were concerned that NEPCO would not be able to meet its current and future obligations. The sponsors immediately took action to calm the fears of the site personnel, most of whom were being paid by Enron, and provided assurance to subcontractors and vendors of all their payment obligations. In addition, modifications to the EPC Contracts were quickly worked out with NEPCO management to provide some immediate stability to NEPCO, preventing the EPC contractor from being pulled directly into the Enron bankruptcy filing. The swift actions by the sponsors prevented any significant disruptions at either of the sites.

Additionally, Enron’s bankruptcy permitted the project lenders to stop funding construction costs for the two projects until the condition was cured or waived. To resolve the issue TECO Energy replaced Enron as the guarantor of certain of NEPCO’s obligations under the construction contracts, including payment by TECO Energy of any project cost overruns, which were estimated to be US\$63 million as of January 2002. That amount could be offset by unused construction contingency upon completion of construction. TECO Energy also agreed to inject an additional US\$200 million equity capital into the project by mid-2002. It would otherwise have made this capital contribution at a later stage of the project.

In late January 2002, as a result of the additional commitments that TECO made to secure the project loans and the resulting increase in TECO Energy’s project-related risk, Moody’s downgraded TECO Energy’s senior unsecured credit rating from ‘A2’ to ‘A3’.

During the first few months of 2002 the sponsors and lenders continued to express concern about the long-term viability of NEPCO. In May 2002, with the concurrence of Panda and TECO Energy, SNC–Lavalin, Canada’s largest engineering and construction company, took over construction on both project sites. SNC–Lavalin assumed all construction activities previously performed by NEPCO, and directly hired all of NEPCO’s site and management personnel. In June SNC–Lavalin acquired all of NEPCO’s assets and placed them in a new subsidiary, SNC–Lavalin Constructors, Inc., headed by John Gillis, NEPCO’s long-time president. About 5,000 NEPCO employees were retained. The new EPC contract with SNC–Lavalin provides for the projects to be completed on a cost-plus-fee basis, with the fee portion at risk until completion of the projects. Significant schedule and performance penalties provided by subcontractors remain, as does the guarantee by TECO Energy of certain SNC–Lavalin obligations for the benefit of the lenders.

Aquila’s exit from energy trading

In March 2002 UtiliCorp United, historically a traditional regulated utility, was renamed

POWER PLANT

Aquila to reflect the increased importance of its energy trading activities. During 2002, however, all energy traders came under close scrutiny as a result of the Enron bankruptcy and the deceptive trading practices that were revealed. Flat energy demand and tougher credit requirements imposed by the market kept prices low, and increased the cost of the capital that traders needed to back their portfolios. As a result the overall energy trading business contracted significantly. In August, after suffering reduced earnings and liquidity, and facing a credit-rating downgrade, Aquila decided to abandon the energy trading business, reduce its risk profile and return to its roots as a traditional utility. Aquila became the first of the leading US energy traders to exit the business. Panda-TECO plans to replace Aquila with a new power manager, possibly a large utility whose trading activities are an adjunct to its underlying power business.

Dividend increase

In April 2002 TECO Energy announced an increase in its quarterly common dividend from 34.5 cents to 35.5 cents per share. This was TECO's 43rd straight annual dividend increase, a record matched by only one other power company, WPS Resources. Despite growing cash flow problems TECO Energy's management maintained the dividend at 35.5 cents in September. Dividends had always been an important matter for such a classic example of a stable 'widows and orphans' utility share, but starting in 1989, when it founded TECO Power Services, TECO Energy had diversified from its base of regulated utility businesses in an effort to increase its earnings growth. Some of the pressure to diversify came from seeing what was happening to competitors: in 1999, for example, Florida Progress, another utility based across Tampa Bay in St Petersburg, had been acquired by Carolina Power & Light after giving up efforts to remain independent. TECO Energy's strategy to survive on its own was to invest in wholesale power businesses outside its home market. The company was encouraged by a strong economy pushing up electricity demand and the growth of the energy trading business, with Enron as its most prominent pioneer.³

Changing power sales outlook

During 2002 the power sales outlook became more uncertain for both plants. Overbuilding and limited transmission capacity were becoming increasingly apparent in both markets. The justification for building the Gila River plant and other merchant plants in Arizona had been not only that there was an attractive local market, but that there was an opportunity to export electricity to California. Now the Arizona market was heading toward overcapacity and transmission constraints were limiting generators' access to local markets as well as exports. The Entergy subregion of the SERC, the Union Power plant's immediate target market, was already overbuilt and capacity was still being added. Entergy was reportedly tending to use its own plants, even when they were less efficient, rather than buy power from the new plants in the area with heat rates above 7,000 Btu/kWh. Further, the prospects for wholesale power sales were dimming because of delayed deregulation in Arkansas.

Another rating downgrade

In September 2002 analysts at several brokerage firms placed 'sell' recommendations on

TECO Energy's stock because they anticipated an oversupply of electricity in some of the markets that the company's new wholesale power plants were intended to serve. TECO Energy's share price fell to its lowest level since 1990. TECO Energy's CEO, Robert Fagan, argued that his company should not be judged in the same category as an independent power producer without a base in regulated utilities, but it was a tough case to argue. By this time TECO Energy had an ownership interest of 50 per cent or more in 10 independent power plants with total generating capacity of 7,100 MW, compared to the 4,000 MW combined capacity of Tampa Electric's local power plants. About 5,700 MW of these plants' generating capacity was scheduled to come on line in 2003.⁴

On 6 September 2002 Moody's announced that it was reviewing TECO Energy's debt ratings for a possible downgrade. On 23 September Fitch downgraded its rating for TECO Energy's senior unsecured debt from 'A-' to 'BBB' and for Tampa Electric's senior secured debt from 'AA-' to 'A', citing continued weakness in wholesale power markets, and the expected negative impact on TECO Energy's earnings and cash flow measures. On the same day TECO Energy announced that it would postpone completion of two power plants, the Dell Power Station in Dell, Arkansas, and the McAdams Power Station in Kosciusko, Mississippi, and raise US\$400 million from the repatriation of cash from the company's power plants in Guatemala, the sale of methane gas assets in Alabama and other asset sales.

On 24 September Moody's reduced TECO Energy's senior unsecured debt rating from 'A3' to 'Baa2', and also reduced several other TECO and Tampa Electric debt ratings, following a review that was prompted by concerns about low projected wholesale power prices, excess capacity and deteriorating market conditions in the regions where TECO Power Services (TPS) was completing an aggressive merchant-generation expansion programme. The agency said that its downgrade reflected TECO Energy's large and highly concentrated exposure to merchant-generation markets, but also took into account the difficult measures that management was taking to limit the adverse effects of that exposure. While TECO Energy's action plan would mitigate some of the long-term risks related to its merchant-generation portfolio, it might affect the company's credit quality adversely in the short term. For example, the indefinite delay of the Dell and McAdams projects would save the company US\$87 million, and reduce its merchant market exposure in 2003, but raised the possibility that the company would have to write off the capital that it already had invested in those projects. TECO Energy said that it was exploring various options regarding the US\$137 million debt related to its Odessa and Guadeloupe power projects in Texas, thus introducing the possibility of writing off all or part of that investment as well.

In downgrading TECO Energy Moody's said that it expected that fully half of the company's cash flow going forward would come from businesses other than Tampa Electric and Peoples Gas, its stable, regulated utility subsidiaries. The agency viewed the quality and certainty of the cash flows coming from TECO Energy's other businesses, including TPS, TECO Coal and TECO Transport, to be lower than for its regulated utilities. Nonetheless, Moody's said that the stable outlook that it assigned to the rating indicated its view that management had taken action to limit the downside risk associated with its merchant generation portfolio, and also reflected the expectation that stable earnings from Tampa Electric and Peoples Gas would help mitigate the impact of the continued low-power-price environment in the medium term. The agency noted, however, that the management's plan still had to be executed, and that the company would be challenged to generate cash and earnings from the Gila River and Union Power projects, scheduled to come on stream in the first half of 2003.

Additional financing

In October 2002 TECO Energy issued US\$200 million in common equity. Despite this balance-sheet strengthening, in early November the company was unable to persuade banks to renew a US\$350 million line of credit, and that line was converted to a one-year term loan. To preserve medium-term liquidity and stave off a credit-rating downgrade, the company made preparations for a US\$240 million bond issue to refinance an existing issue of long-term debt. A rating downgrade was a particular issue at this point, because TECO Energy had the lowest investment-grade ratings, and a downgrade just one notch to a speculative level would have required the company to post a letter of credit equal to the equity bridge loan for the Union Power and Gila River projects. The amount of the equity bridge loan had recently been reduced from US\$500 million to US\$375 million. During a conference call arranged to market the US\$240 million bond issue, the company heard calls from prospective bond investors to strengthen its balance sheet by cutting its dividend or launching still another common share offering. During November TECO Energy's shares hit 15-year lows after UBS Warburg downgraded its stock, citing concerns about the company's ability to sell electricity from Gila River and Union Power after they went online.⁵

On 13 November Moody's confirmed its 'Baa2' rating for TECO Energy's senior unsecured debt, but changed the rating outlook from stable to negative. The agency said that the conversion of the credit line to a term loan did not have an immediate affect on TECO Energy's liquidity, but it did indicate that the company could have difficulty replacing the term loan a year from then. Moody's viewed the issuance of US\$240 million senior unsecured notes, rated 'Baa2', along with an associated release of cash collateral, as important steps towards maintaining the company's liquidity in the short term. TECO Energy's financial flexibility would be further enhanced when the company repaid its US\$375 million equity bridge loan in 2003 and freed itself from any rating triggers. On the same day Standard & Poor's made a statement that TECO Energy had sufficient liquidity, including cash on hand and US\$700 million in credit facility capacity. The agency said that TECO Energy's maturities were minimal, with US\$130 million in debt coming due in 2003 and US\$30 million per year up to 2006.

TECO Energy's 10.5 per cent notes due in 2007, originally estimated to be US\$240 million, were issued on 15 November. Market acceptance allowed the company to increase its offering to US\$380 million. In addition to refinancing US\$200 million of redeemable securities due in 2015, TECO Energy intended to use the proceeds to pay down short-term debt drawn against its credit facility and for general corporate purposes. Credit Suisse First Boston purchased all of the notes on 15 November, and registered them with the US Securities and Exchange Commission on 6 January 2003 in order to become able to sell them to individual as well as institutional investors. The notes contained some stiff provisions. TECO Energy promised to deliver a US\$50 million letter of credit if its ratings from either Moody's or Standard & Poor's fell below investment grade, if it failed to maintain a 65 per cent debt-to-capital ratio, or if it failed to maintain earnings before interest, taxes, depreciation and amortisation (EBITDA) at a level at least 2.5 times interest payments on outstanding debt. This is in addition to the US\$375 million letter of credit related to the equity bridge loan required while that rating trigger remained in effect, until the Gila River and Union plants were expected to begin operation, and the equity bridge loan would be repaid. A TECO Energy spokesman said that the company was working quickly to boost its liquidity in the short term, having recently sold assets and raised new financing, but the real test would come in the long term. Power

prices would be the key, not only in Florida, but also in all the other markets where TECO Energy was building plants, including Arizona, Arkansas, Mississippi and Texas.⁶

Lessons learned

Lower-than-expected power demand and power prices, along with lagging development of transmission facilities, highlight the risk of merchant power exposure combined with leverage. A few credit problems with prominent merchant power players, combined with scepticism concerning electricity deregulation, could begin to push power companies back toward the traditional integrated-utility business model.

¹ This case study is based on the Offering Memorandum for the Project Loans and articles in the financial press.

² The source for this and other Exhibits is the Offering Memorandum for Project Loans.

³ Hau, Louis, 'TECO Energy Shares Drop 17% on Plant Concerns', *St. Petersburg Times*, 8 November 2002, p. 6E.

⁴ Hau, Louis, 'TECO Energy Shares Drop 17% on Plant Concerns', *St. Petersburg Times*, 8 November 2002, p. 6E.

⁵ Hau, Louis, 'TECO Shares Sink to a 15-Year Low', *St. Petersburg Times*, 9 November 2002, p. 1E.

⁶ 'Looking for Cash, TECO Sells \$380 Million in Bonds, Strings Attached,' *Electric Utility Week*, 13 January 2003.

Calpine, United States

Type of project

Power plant portfolio.

Country

United States.

Distinctive features of company's approach

- Rapid growth through acquisition and new power plant development.
- First open-ended revolving-credit project finance construction facility for a portfolio of greenfield merchant plants.
- Scaling back of growth plans and capital expenditures in response to difficult market conditions; survival threatened by heavy debt load.

Description of financing for some of its projects

- The first merchant power plant financing in the United States was launched in 1996. It consisted of equity-guaranteed debt (replaced by sponsor's equity when construction was completed) and ordinary senior debt.
- The first mini-perm power plant financing, in 1998, included a two-year construction loan and a five-year term loan.
- Leverage leases financed the purchase of 15 geothermal power plants in 1999.
- An open-ended revolving-credit project finance construction facility financed a portfolio of greenfield merchant plants in 1999, as well as the advance purchase of turbines in 2000.

Summary of approach to projects¹

This case study, unlike other case studies in this book, examines a single company engaged in various projects in the power industry. Calpine is a leading independent power producer (IPP) engaged in the development, acquisition, ownership and operation of power generation facilities, and the sale of electricity, predominantly in the United States. Calpine has used a wide variety of methods to finance its growth, including equity offerings, traditional bank

project finance loans, private placements, leveraged leases and open-ended revolving credits. Calpine’s financing of a 240 MW gas-fired power project in Pasadena, Texas, in 1996 is considered to have been the first merchant power project financing in the US market. The company’s US\$170 million financing for a power plant in Tiverton, Rhode Island, in 1998 included a two-year construction loan and a five-year term loan, which made it the first application of mini-perm financing in the US domestic IPP industry. In 1999 Calpine created the first open-ended revolving-credit project finance construction facility for a portfolio of green-field merchant plants. It was worth US\$1 billion and had a term of four years. Under a similar but larger financing in 2000 Calpine was able to borrow for the advance purchase of new turbines as well as for new plant construction. This new approach to power plant construction financing was motivated by an evolving merchant power environment that made traditional project financing difficult in view of Calpine’s extraordinary growth rate.

Background

Profile of Calpine

Calpine is based in San Jose, California. The company was founded in 1984 by Peter Cartwright and Electrowatt, a Swiss engineering firm. The name is a portmanteau word based on ‘California’ and ‘Alpine’.

Calpine has grown substantially in recent years and continues to have ambitious growth targets. As of March 2001 the company owned interests in 50 power plants with a net capacity of 5,849 MW. It also had 25 gas-fired plants under construction and had announced plans to develop an additional 28 gas-fired projects, including new power plants and expansions of current facilities, with a net capacity of 15,142 MW. Upon completion of the projects under construction Calpine expected to have interests in 74 power plants in 21 states with a total net capacity of 19,877 MW. Of this total generating capacity, 96 per cent would be attributable to gas-fired facilities and 4 per cent to geothermal facilities. As a result of its expansion programme Calpine’s revenues, cash flow, earnings, and assets grew significantly in the period 1996–2000, as shown in Exhibit 14.1.

Calpine has remained profitable and its business does not resemble Enron’s. However, it has recently had to scale back its acquisition and capital spending plans, sell nonstrategic assets, and reduce debt, because of the weakness of the US economy, falling electricity prices and overall industry risk concerns stemming from the Enron bankruptcy.

Exhibit 14.1

Calpine’s growth record, 1996–2000

| | 1996 | 2000 | Compound |
|---------------|-----------|-----------|----------|
| | (US\$ | (US\$ | annual |
| | millions) | millions) | growth |
| | | | rate (%) |
| Total revenue | 214.6 | 2,282.8 | 81 |
| EBITDA | 110.7 | 825.9 | 65 |
| Net income | 18.7 | 323.5 | 104 |
| Total assets | 1,031.4 | 9,737.5 | 75 |

Source: Company Annual Report.

The US power market

The power industry is the third largest industry in the United States, with end-user electricity sales of over US\$215 billion in 2000, produced by power generation facilities with 860,000 MW of capacity. In response to increasing customer demand for access to low-cost electricity and enhanced services, new regulatory initiatives have been adopted, at both the federal and the state level, to increase competition

in the domestic US power generation industry. Historically the industry has been dominated by regulated electricity monopolies selling to captive customer bases. Many of the utilities' generating facilities have been considered old, high-cost and inefficient. Industry trends and regulatory initiatives are creating a more competitive market in which users buy electricity from a variety of suppliers, including nonutility generators, power marketers, public utilities and others.

Until recently there appeared to be a significant need for additional power generating capacity throughout the United States, both to satisfy existing demand and to replace old and inefficient generating facilities. Because of environmental and economic considerations Calpine's management believed that this new capacity would be provided primarily by gas-fired facilities. It saw significant opportunities for efficient low-cost producers that could sell power at competitive rates.

As deregulation unfolded the competitive landscape and composition of power plant ownership in the United States appeared to be changing. Numerous utilities were selling power generation facilities in order to focus their resources on transmission and distribution, while industrial companies sold plants in order to focus on their core businesses. Many IPPS, each owning just a small number of plants, were finding themselves at a competitive disadvantage and were selling to larger producers.

Calpine's strategy

Based on the significant opportunities that it saw in the US power market, Calpine's strategy was to continue its rapid growth through development and acquisition programmes. The company's goal was to have about 100 plants in the western, southern and northeastern regions of the United States with a total capacity of 70,000 MW, enough to light 70 million houses by 2005. To implement this strategy and achieve a competitive advantage, Calpine developed a fully integrated approach to the acquisition, development and operation of power plants. The company relied primarily on in-house expertise in design, engineering, procurement, finance, acquisitions, operations, construction management, power marketing, and fuel and resource production. It realised economies of scale through a standardisation model similar to those employed by McDonald's or Wal-Mart.

In order to capitalise on its integrated approach the company looked for acquisition opportunities where it could assume full responsibility for operation and maintenance, and development opportunities where it could control the entire process, and avoid the need for turnkey engineering, procurement and construction (EPC) contracts with outside parties. Many of the markets that Calpine has entered have been deregulated, but have continued to be served primarily by old and inefficient gas-, oil- or coal-fired plants. The company has therefore had opportunities to become a lower-cost IPP by building combined-cycle, clean-burning gas generation systems, which are estimated to be 40 per cent more efficient than coal-fired plants. The company has also tended to buy or construct several plants in a given region and operate them as a system, enhancing profitability through coordinated sales and operations. For example, it has reduced costs by rotating some of its staff among several plants and reduced inventory through central pools of spare parts such as rotors or blades.

Financing methods

Calpine has raised about US\$12 billion from banks, institutional investors and private equity

investors since 1994 – US\$8 billion in 2000 alone – while staying below its target ratio of 65 per cent debt to total capitalisation. Because Calpine has helped to define the ‘cutting edge’ in the industry, part of the evolution of US power project financing methods over the past few years can be traced through a history of its deals.

Merchant power financing

As mentioned above, Calpine’s financing of a 240 MW gas-fired power project in Pasadena, Texas, in 1996 is widely considered to have been the first merchant power project financing in the US market. The project’s US\$150 million cost was financed with US\$50 million of equity-guaranteed debt (replaced by sponsor’s equity when construction was completed) and US\$100 million ordinary senior debt. ING (US) Capital underwrote the deal. Ninety MW of total power generated were committed to a seven-year offtake agreement with Phillips Petroleum (now Conoco Phillips), while the remaining 150 MW were sold into the Texas power pool.

The market was surprised that Calpine did such a groundbreaking transaction in Texas rather than its home state of California, then considered to be at the forefront of electricity deregulation. At this point Calpine was still considered a small player compared to competitors such as AES or US Generating Company, but it was already steadily increasing its power assets. Texas was catching up with California in deregulating its market and had significant power needs, partly because it had lagged behind other states in the 1980s and early 1990s in allowing the construction of plants by IPPs.

Mini-perm financing

In September 1998 Calpine completed a US\$170 million financing for a power plant in Tiverton, Rhode Island. The financing included a two-year construction loan and a five-year term loan, which made it the first application of mini-perm financing in the US domestic IPP industry. The term ‘mini-perm’ applies to a project loan with a relatively short term – in this case five years. Because the term of the loan is considerably shorter term than the life of the asset, it requires refinancing. The financing was underwritten by a consortium of banks that included Helaba, CoBank and Hypo Vereinsbank.

Leveraged lease financing

In 1999 Calpine arranged two lease financings through Newcourt Capital. The first consisted of a US\$247 million 24-year lease financing to purchase 14 geothermal power plants from Pacific Gas & Electric Company. The plants are located in the Geysers region of Sonoma and Lake Counties in Northern California, the world’s most productive geothermal resource. The plants convert steam into power, which is sold on the spot market. The merchant risk is offset by the reliability of the steam supply and the relatively low cost of producing the power. Newcourt provided the entire financing, comprising US\$209 million in senior debt and US\$38 million in lease equity, but some security was provided by Calpine’s equity investment in the steamfields. A lease structure was chosen because of its accounting and tax benefits, and because it could be arranged quickly. The lease provided even payments throughout its term, helping to stabilise Calpine’s reported earnings.

When Pacific Gas & Electric Company was forced to sell the plants, Calpine had the right of first refusal, but had only 60 days to raise the financing. A Rule 144A private placement issue was considered, but it was ruled out because it could not be completed in less than four to six months. The leases, on the other hand, could become effective as soon as Calpine acquired the plants. Newcourt Capital had leasing experience and was able to provide Calpine with quick access to long-term financing through the Newcourt Capital Project Finance Fund, a US\$500 million fund whose investors are eight major US insurance companies: American General, CIGNA, John Hancock, ING Investment, Lincoln National, Mutual of Omaha, New York Life and Pacific Life. Based on the credit strength of the geothermal projects, the financing received a 'BBB-' credit rating.

The second financing, provided by the same investors, was a US\$53 million 23-year leveraged lease to purchase an 80 MW geothermal plant, also in the Geysers region. It comprised US\$40 million in senior debt and US\$12.8 million in lease equity. The lease was backed by a power purchase contract from Pacific Gas & Electric Company.

As a result of these two transactions Calpine gained control of 80 per cent of the Geysers geothermal resources.

Calpine Construction Finance Company

In 1999 Calpine created the first open-ended revolving-credit project finance construction facility for a portfolio of greenfield merchant plants. Pricing comprised a commitment fee of 50 basis points (bps) over the London interbank offered rate (Libor) and borrowing margins ranging from 150 to 212.5 bps over Libor, depending on Calpine's leverage. As borrowed funds are repaid the company can borrow under the facility again to construct additional plants. At any one time there might be eight to 10 construction projects under way.

To provide security for the facility the company pooled four combined merchant/contracted power projects together in a flexible, crosscollateralised structure called Calpine Construction Finance Company (CCFC). The projects, located in Arizona, California, Texas and Maine, represent a combined capacity of 2,355 MW. With mortgages on these four plants serving as collateral, the company has the flexibility to finance the construction of additional plants. Unlike traditional project financing, this facility provides for financing of future plants not even conceived when the revolver was put in place.

To protect the interests of the 27 lending banks Calpine formed a four-bank 'technical committee' to conduct due diligence on each future project and accept or reject it as part of the loan portfolio, based upon the project's completing a set of prescribed conditions precedent to funding.

To help to syndicate this innovative facility Calpine provided US\$430 million of equity up front, which would amount to 30 per cent of the total capitalisation. The company planned to refinance some of the plants on a longer-term basis and some through leveraged leases, but most of the debt was expected to be taken out in the capital markets.

This new approach to power plant construction financing was motivated by the new merchant power environment, which made traditional project financing difficult considering Calpine's extraordinary growth rate. The company expected to construct in excess of one new power plant per month. Because Calpine was building primarily merchant plants, it could not always offer the power purchase agreements (PPAs) that secured traditional single-project loans. Further, the company and its banks would have found it virtually impossible to arrange

so many individual project finance loans in such a short time, especially considering that about a dozen banks are required to syndicate each deal. Manpower and credit limits were becoming stretched even in Calpine's most dedicated relationship banks. In addition, the lending capacity of the traditional bank project finance market was insufficient to meet the company's needs. It needed to tap the capital markets as well.

Under the CCFC setup Credit Suisse First Boston served as lead arranger, syndication agent and bookrunner, while Bank of Nova Scotia was lead arranger and administrative agent. CIBC and TD Securities acted as Arrangers and co-documentation agents.

CCFC II

The innovative construction pool introduced with CCFC was so successful that Calpine returned to the market just a year later, in 2000, with CCFC II, a much larger US\$2.5 billion facility that took the revolver concept one step further. Borrowings were slated not only for new plants but also to fund the advance purchase of turbines. To reach its target capacity of 70,000 MW the company planned to purchase 220 turbines for about US\$7 billion between 2001 and 2006. With CCFC and CCFC II Calpine anticipated that it would be able to finance the construction of about 50 power plants.

Credit Suisse First Boston again served as lead arranger and administrative agent, while Bank of Nova Scotia was lead arranger, syndication agent and bookrunner. Bank of America and ING (US) Capital acted as arrangers and syndication agents, while CIBC, TD Securities, Bayerische Landesbank and Dresdner Bank were arrangers and co-documentation agents.

Universal shelf offering

At about the same time that the CCFC II facility was arranged Calpine raised US\$1 billion in high-yield debt, US\$517.5 million in convertible bonds and US\$800 million in additional equity. In October 2000 the company filed for a universal shelf offering with the US Securities and Exchange Commission, so that it would have the flexibility to sell up to US\$1.15 billion in common and preferred stock and debt securities in various amounts at various times depending on market conditions. Calpine's management anticipated that it would need up to US\$1 billion in external financing each year over the next four years if it were to fulfil its growth plans.

Risk considerations and credit ratings

Construction risk mitigation

Power plants are often subject to construction delays. Calpine estimates that a two-week delay in completing a 500 MW plant would cost US\$575,000 in net income. The company minimises this risk and achieves a cost advantage with a roving staff that troubleshoots every site, signs off on design changes and orders parts in bulk.

Natural gas supply

Calpine has estimated that, assuming that its construction plan is fully implemented, by 2004 its plants will need 2.6 trillion cubic feet of natural gas per year, about 10 per cent of

estimated US supply, at an annual cost of about US\$10 billion. To assure its supply and protect its costs Calpine started to take steps to secure 25 percent of its natural gas on a long-term basis through long-term contracts with natural gas suppliers, and also through acquisitions of companies with natural gas reserves. In 2000 Calpine purchased TriGas Exploration, Inc., and in 2001 it agreed to purchase Encal Energy, Ltd, a Canadian company based in Calgary, Alberta.

Credit ratings February and April 2001

In February 2001, following Calpine's issuance of US\$1.15 billion of senior notes due in 2011 and its announcement that it would acquire Encal Energy, Standard & Poor's affirmed its 'BB+' corporate rating for Calpine. It assigned a 'BB+' rating to the US\$1.15 billion note issue, while affirming its 'BB+' ratings for US\$366 million in passthrough certificates and senior unsecured debt, and a 'B' rating for US\$1.12 billion in convertible preferred securities.

The 'BB+' corporate rating reflected the following risks.

- Cash flows exposed to market-based energy prices were expected to increase from about 60 per cent in 2000 to about 80 per cent in 2004. A sudden drop in energy prices could impair the company's financial flexibility.
- Recent acquisitions and financing had reduced Calpine's base-case-minimum and average consolidated funds-from-operations (FFO) interest coverage ratios to 1.9 times and 2.6 times, respectively, and lower energy prices could reduce these ratios to 1.7 times and 2.1 times over the following five years. These coverage ratios reflected the agency's adjustment to account for lease guarantee payments and partial debt treatment of convertible preferred stock.
- While Calpine was then managing just 5,000 MW of generating capacity, its aggressive growth strategy was predicated on being able to develop and manage 70,000 MW of capacity by 2005.
- The company's high forecast gross margins depended on its ability to acquire about 8.1 trillion cubic feet of natural gas reserves at below-market cost, a task that could become expensive – as much as US\$2 billion per year – and perhaps even riskier than generation.
- Calpine was just beginning to develop its expertise in achieving market power from a large asset pool in geographically diverse markets – markets that in general were just beginning to face deregulation and competition.
- Calpine's rapid growth forecast, which assumed that it could achieve operating margins of 30 per cent margins through its predominant gas-fired, F-generation technology, could come under pressure if high margins attracted other entrants or if other technologies or fuels became more competitive in the future.
- With a target of 65 per cent debt to total capitalisation, Calpine was more exposed to electricity price volatility than more conservatively leveraged generation companies.

Standard & Poor's cited several strengths as offsetting these risks.

- Because less than half of Calpine's existing power plant portfolio had project-level debt, the portfolio was expected to provide adequate cash flow to service the company's senior debt obligations.

- The company's *pro forma* interest in 66 power plants and steamfields, representing 11,600 MW of capacity, created a true portfolio effect, because no single project contributed more than 10 per cent of cash flow.
- Calpine's existing projects all had excellent operating histories, with average availability of 95.7 per cent for gas-fired plants and 98.9 per cent for geothermal plants.
- To date all of the company's construction projects had been built on time and within budget.
- Early financial results indicated that Calpine had been able to earn above-average returns by siting plants in areas where it could take advantage of capacity shortages or transmission constraints.
- Increasing electricity demand in the United States appeared to support Calpine's plant-construction plans, although the agency warned that older generating capacity may not be retired as fast as the company had anticipated.
- The agency observed that Calpine had been successful in raising capital and assembling the human resources needed to manage an annualised 44 per cent growth rate over the past few years.

Standard & Poor's cited similar risks and strengths in April 2001 when it assigned a 'BB+' rating to Calpine's issuance of US\$850 million convertible debentures. The company planned to use US\$717 million to refinance existing project debt at 10 of its generation facilities and the remaining US\$133 million to prefund new construction projects. Because of their zero-coupon feature the bonds would not affect interest coverage ratios up to 2003, but after that time they could accrue interest during any period when their market price was less than 98 per cent of accreted value.

Financing in October 2001

In October 2001 Calpine raised US\$654 million in structured lease obligation bonds (SLOBs) and US\$2.6 billion in a multitranche securities issue. The SLOBs freed some cash and refinanced sale-and-leaseback transactions on three natural-gas-fired plants in the United States. They functioned as passthrough certificates, allowing Calpine to bundle payments and pass them on to security holders as interest.

The multitranche bond issue refinanced senior bank debt, including a US\$1.2 billion loan for the acquisition from Dynegy of the Saltend power station in the United Kingdom. Five concurrent offerings of senior notes were made in the US dollar, Canadian dollar, sterling and euro fixed-income markets. By issuing all of them at once Calpine could gauge investors' appetites and adjust the size of each tranche.

With all the senior notes guaranteed, this was essentially a corporate deal. It was consistent with Calpine's policy of maintaining flexibility and creating value by financing its power plants on the balance sheets and running them as a system.

At the time of the financing both Fitch and Moody's raised Calpine to a 'BBB-' investment-grade rating, while Standard & Poor's maintained its 'BB+' rating. Credit Suisse First Boston, which served as the arranger and underwriter, considered the split rating helpful for such a large-sized issue, because it helped in selling the bonds to both investment-grade and high-yield investors. The issue turned out to be well-timed, because Calpine's investment-grade ratings from the two agencies would not last for long.

Perfect storm

By December 2001 Calpine's financial outlook had been changed by a confluence of events that included recession in the United States, declining power prices resulting from a cool summer followed by a mild winter, the collapse of Enron and a sort of guilt by association that spread throughout the power industry. Calpine's share price plunged from US\$60 in mid-2001 to US\$6 in February 2002. Calpine's CEO, Peter Cartwright, emphasised that Calpine had an asset-based business profile that was not comparable to Enron's. However, following Enron's bankruptcy the entire power industry was subjected to closer scrutiny and Calpine became a target because of its aggressive growth. The company also had a Houston-based trading operation, which began to have difficulty when market conditions changed, and some transparency issues. While Calpine was not accused in any way of improper accounting, the amount of interest that it was able to capitalise while its plants were under construction was considered by some to create a misleading picture of earnings growth, although it reflected a common power industry practice. Of course no one had ever seen a power company with such an aggressive plant construction programme.

In mid-December, amid market jitters related to the Enron bankruptcy, Moody's downgraded Calpine once again to a 'BB' rating. The agency was concerned about the precipitous decline in Calpine's stock price as well as the reduced operating cash flow available to service its heavy debt burden.

At the same time Standard & Poor's assigned a 'B+' rating to a planned issuance of US\$400–500 million of convertible debentures due in 2006, and affirmed its 'BB+' corporate rating and its 'BB+' rating on the company's senior unsecured debt. The ratings reflected the following risks.

- Current market conditions could hurt Calpine's business and put some stress on its liquidity. The company could be forced to exceed its targeted ratio of debt to capitalisation because of the reduced power demand, reflecting the recession, lower power prices and the difficulty of issuing equity.
- Calpine's merchant portfolio represented one third of its capacity, exposing the company's cash flow to potential volatility, as demonstrated by the dramatic swings in power prices in California and other western states during 2001. Even contracted revenues could be affected by market cyclicalities, to the extent that contracts expired and were replaced with new contracts at higher or lower rates.
- Calpine had substantial exposure to the California market through contracts with the Department of Water Resources and Pacific Gas & Electric Company, which represented about 25 per cent of its cash available for debt service in 2005. The California Public Utility Commission had publicly challenged the validity of these contracts and Calpine had begun talks to renegotiate them.
- Calpine's minimum and average consolidated FFO interest coverage ratios of 2.2 and 2.8 times fell below the investment-grade targets for the next five years set by Standard & Poor's for developers with a speculative component to their revenue streams. The risks were exacerbated because about 25 per cent of Calpine's debt was at floating rates. Once again these ratios reflected the agency's adjustment to include guarantees on lease payments and partial debt treatment of convertible preferred stock.
- Calpine's target of 65 per cent debt to total capitalisation made the company vulnerable to electricity price volatility or a period of sustained price depression. The

agency's adjustments to include guarantees on lease payments and partial debt treatment of convertible preferred stock increased debt to total capitalisation from 65 per cent to 70 per cent.

- Because of Calpine's preferred method of construction, the company was fully responsible for construction delays and cost overruns, and did not benefit from the liquidated damages in many EPC contracts. Calpine also faced the possibility of stranded assets in construction if long-term electricity prices dropped.

Standard & Poor's cited the following strengths to mitigate the risks at the 'BB+' rating level.

- Calpine's growth strategy had been focused on building power plants in the United States and other developed markets, such as the United Kingdom and Canada. The company faced less sovereign and regulatory risk than those power companies that had invested heavily in Latin America or Asia.
- Over the course of 2001 Calpine had proved its ability to manage multiple plants in a timely and efficient manner. The company had successfully built its power projects on time and within budget. Because most of its new plants were combined-cycle facilities using the F turbine technology, Calpine was able to standardise the design of its plants, and achieve economies of scale in design and maintenance.
- The company had been successful in recruiting and training a strong and capable management team to direct new aspects of its business, such as development, gas exploration and production, construction, marketing and trading, and operations.
- Calpine had built up a strong trading and marketing organisation in slightly more than one year by acquiring leading talent from major energy trading companies and investing heavily in supporting technology. The company's trading organisation was focused on stabilising earnings and cash flow, by managing commodity risk exposures arising from its generating assets and gas reserves.
- A large proportion of Calpine's plants were powered by highly efficient gas turbines, which were expected to ensure a higher level of dispatch compared to the older plants that Calpine's competitors had purchased over the past few years.
- Calpine's policy was to mitigate merchant risk by covering two thirds of its capacity with long-term contracts. Revenues from existing contracts covered 100 per cent of debt service, although not at levels commensurate with an investment-grade rating.
- Calpine's revenue stream benefited from a portfolio effect because of its generating assets and gas reserves in various US markets, although it was less diversified than some other developers that owned generation, transmission and distribution assets in various parts of the world.

On 11 January 2002 Calpine's received commitment letters from its lenders for a US\$1 billion one-year unsecured working capital credit facility that provided for borrowings up to US\$350 million and letters of credit for up to US\$1 billion. Taking into account an existing US\$400 million unsecured working capital credit facility, expiring 24 May 2003, Calpine would be able to borrow up to US\$750 million and post letters of credit up to US\$1.4 billion. Adding in the company's revolving construction credit facilities, the company had US\$4.9 billion bank financing in place. Bob Kelly, President of CCFC, said that, along with a recent sale of US\$1.2 billion in convertible debentures, the new credit facility demonstrated that the

company had competitive and timely access to the capital markets, providing it with sufficient liquidity to meet its current and ongoing capital requirements.

During January 2002 Calpine delayed 34 projects that would have added 15,000 MW to its capacity. That still left the company with 27 projects planned for 2002. They were expected to more than double its capacity to 23,000 MW by the end of that year and to increase it further to 26,000 MW by the end of 2003. Calpine's President and CEO, Peter Cartwright, said that the company was working to strengthen its balance sheet with the goal of restoring its investment-grade rating. If necessary it would take additional steps, such as outsourcing the operation of blocks of power, arranging sale-and-leasebacks or issuing additional equity. At this time the company estimated that it would sell about US\$250 million of assets during 2002, including oil and gas fields, power sales agreements, and power plants.

In late February 2002 Calpine announced plans to pledge its entire 1.7 trillion cubic feet of US and Canadian gas assets, and its Saltend power plant in the United Kingdom, to secure three classes of debt:

- its US\$1 billion 18-month revolver;
- its US\$600 million two-year term loan; and
- its existing US\$400 million revolver expiring in May 2003.

Standard & Poor's was concerned that this new security added further to the already substantial assets pledged under the US\$3.5 billion construction revolver, which included power plants under construction. As a result the agency put its 'BB+' corporate rating, its 'BB+' rating on Calpine's existing senior unsecured debt and its 'B+' rating on the company's convertible preferred stock on CreditWatch with negative implications.

In late March Standard & Poor's downgraded Calpine's corporate rating to 'BB' and its unsecured debt to 'B+'. In a conference call to explain the downgrades the agency's analysts warned investors that they were unlikely to raise Calpine's ratings for at least two years because the company would be handcuffed by rising debt payments and falling electricity prices. They said that Calpine would probably have to pledge more assets to secure additional loans in the future, and expressed concern about how the company would repay US\$3.5 billion unsecured debt coming due in late 2003 and early 2004.

A few days later, in early April, Moody's downgraded Calpine's senior unsecured debt three notches from 'Ba1' to 'B1', four notches below investment grade. The downgrades reflected the company's high leverage, its limited financial flexibility, its substantial ongoing capital expenditure requirements to complete its reduced build-out programme and concerns about the company's liquidity profile.

As a result of the rating downgrades and concern about renegotiated contracts with the State of California, several wholesale power traders stopped doing business with Calpine. The company began to go through third parties for some of its power trades, which included selling large blocks of power for one- to two-year terms. At this point Calpine was reportedly negotiating the sale of various nonstrategic assets for net proceeds of about US\$250 million, as well as a sale-and-leaseback of 11 California peaker facilities, which was expected to generate about US\$500 million during 2002. A peaker, or peak load plant, is a power plant usually housing old, low-efficiency steam units; gas turbines; diesels; or pumped-storage hydroelectric equipment normally used during peak-load periods. The company was also looking for a joint-venture partner, with a higher credit rating, for its trading and marketing

operations. A large integrated oil company that wanted to move into power had been considered for some time to be the type of partner that Calpine needed, but some questioned whether any of the oil companies would be interested in such a partnership.

Calpine's results for the first quarter of 2002 reflected a US\$168 million charge resulting from cancellation of orders for 35 turbines. As of April 2002 Calpine had 12,000 MW of capacity in operation at 64 plants and an additional 14,000 MW at 24 plants under construction. Most of the plants under construction were scheduled to come on line in 2002 or 2003. Elizabeth Parrella, an analyst at Merrill Lynch, estimated that Calpine had sold under contract about 65 to 70 per cent of its capacity for 2002 and 50 per cent of its forecast output for 2003.²

In August 2002 Calpine increased its estimate of asset sales for the year to US\$650 million. Unlike power plants for sale in the current market environment, the company's gas reserves and power sales contracts were bringing good value. The more gas reserves Calpine sold, the more its power plants would be subject to market prices for natural gas, but the company still expected to retain about one trillion cubic feet of proven natural gas reserves.

Reflecting the sharp decline in electricity prices and spark spreads, Calpine reported a 50 per cent decline in net profit in the third quarter of 2002 compared to the same period in 2001, even though it was generating 70 per cent more electricity. A more positive interpretation was that the company was still profitable in a difficult market. The issue was whether it could service a US\$13 billion debt load over the next couple of years while it was completing power plants that were already under construction. As of the end of 2002 Calpine had 20,950 MW capacity in operation and 9,874 MW under construction. Company executives hoped that a recent slight firming of electricity prices would help them to negotiate an extension of US\$2 billion of debt coming due in 2003 and another US\$3.5 billion coming due in 2004.

Lessons learned

An unfavourable market environment forced a drastic scaling back of the largest construction programme in the history of the world power industry. Calpine has funded its aggressive capital expenditure programme and growth targets with high debt, which threatens its survival over the next couple of years. Nonetheless, the company is likely to survive because it consistently has completed its power plants on time and within budget, and it has become a leading low-cost IPP in the US market.

¹ This case study is based on 'The Brave New World of U.S. Power Project Finance,' by Enid L. Vernon and Louis D. Iaconetti, *Journal of Project Finance*, Spring 2001, *Calpine Corporation: The Evolution from Project to Corporate Finance*, a Harvard Business School case (N9-201-098, 19 May 2001) by Michael Kave, Dean's Research Fellow and Professor Benjamin C. Esty, a review by Rohn Crabtree of Calpine, and recent articles in the financial press.

² 'Financial Woes Prompt Marketers to Stop Trading with Calpine', *Megawatt Daily*, 8 April 2002, p. 1.

Casecnan Water & Energy Company, the Philippines

Type of project

Irrigation and hydroelectric power facility.

Country

The Philippines.

Distinctive features

- One of the largest irrigation and hydroelectric power generation projects in the world.
- One of the largest high-yield project bond offerings.
- Large amount of financing for a Philippine project.
- Financing divided into several tranches to appeal to different investors' interests.
- Tight time frame for original financing.
- Default by South Korean equipment, procurement and construction (EPC) contractor, subsequent drawing under standby letter of credit and refusal by opening bank to pay.
- Strain on project liquidity and need for parent support because of construction delay.

Description of financing

The 1995 financing was in three tranches, all placed privately under Rule 144A:

- US\$100 million in senior secured notes, Series A, due in 2005;
- US\$181 million in senior secured bonds, Series B, due in 2010; and
- US\$75 million in floating-rate notes due in 2002.

Project summary¹

The Casecnan Water & Energy project consists of structures in the Casecnan and Denip Rivers that divert water into a 23-metre tunnel into the Pantabangan Reservoir for irriga-

tion and hydroelectric use in the central Luzon area of the Philippines. An underground powerhouse located at the end of the water tunnel houses a 150 megawatt power plant. The high-yield bond offering illustrated the market's capacity to finance a large and complex project in an emerging-market country. It was structured in three tranches to meet different investors' needs, and closed after a very tight time schedule to sell the bonds to institutional investors. During the course of construction the original EPC contractor failed and was replaced; payment under a standby letter of credit backing the original EPC contractor's performance was made by a South Korean bank only after a prolonged legal battle; and the replacement EPC contractor's completion was delayed by tunnel-drilling difficulties. Parent financial support was required because the construction delay strained project liquidity.

This high-yield-bond project financing illustrates the market's capacity to finance a large and complex project.

Background

Project company, cost and purpose

The project company is a privately held Philippine corporation formed in September 1994 solely to develop, construct, own and operate a multipurpose irrigation and hydroelectric power facility, with a rated capacity of approximately 150 MW, on the island of Luzon in the Philippines.

At the time of the project financing the company was owned indirectly by California Energy International (CalEnergy), now a subsidiary of MidAmerican Energy Holdings Company, which held 35 per cent; Peter Kiewit Sons, Inc., which also held 35 per cent; and two Philippine minority shareholders.

CalEnergy was the largest independent geothermal power company in the world. It had over 500 MW of geothermal power projects under construction in the Philippines. CalEnergy made a commitment to the Philippine government that the project would be completed in four years. With geothermal projects in the country worth more than US\$1 billion, CalEnergy already had a strong commitment to the Philippines.

Kiewit was a large, privately held construction, mining and telecommunications company, with extensive hydroelectric, mining and tunnelling experience. Kiewit already had an international joint venture with CalEnergy and occasionally took an equity interest in its overseas projects.

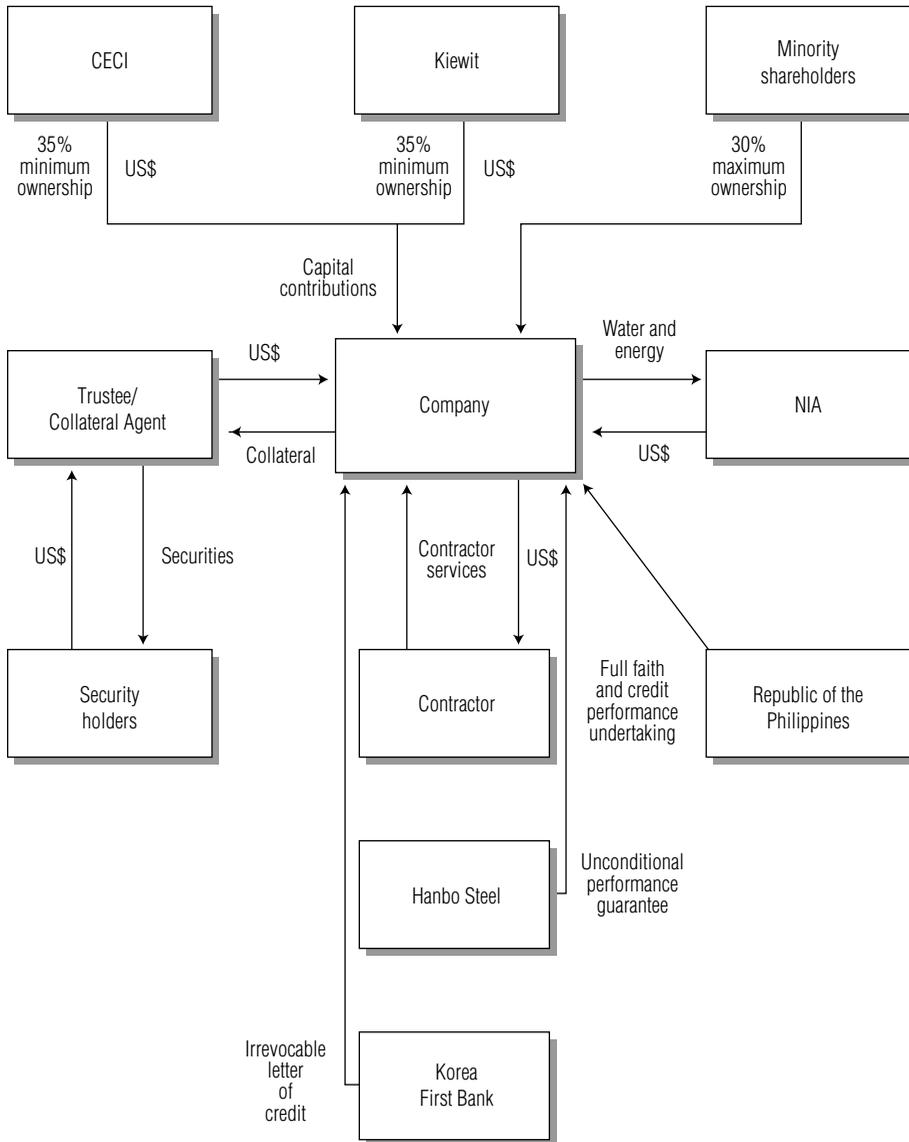
To finance the project the sponsors explored using a World Bank guarantee programme, but they decided not to pursue it because they could not get a counter-guarantee from the Philippine government within a reasonable time. When CalEnergy approached Credit Suisse First Boston about the project its primary interest was to raise the funds quickly, but it also wanted the best possible price.

The transaction structure and the capital cost of the project are illustrated in Exhibits 15.1 and 15.2.

The project consists of diversion structures in the Casecnan and Denip Rivers that divert water into a water tunnel about 23 kilometres long. The tunnel transfers the water from the rivers into the Pantabangan Reservoir, for irrigation and hydroelectric use in the central Luzon area. An underground powerhouse at the end of the water tunnel, in front of the reservoir, houses a new power plant with 150 MW of rated capacity. A tailrace tunnel about three

Exhibit 15.1

Transaction structure



kilometres long delivers water from the tunnel and the powerhouse to the reservoir, providing additional water for irrigation and increasing the potential electrical generation of two existing downstream facilities of the National Power Corporation (NPC), the government-owned utility that is the primary supplier of electricity in the Philippines. The project is expected to provide irrigation for about 35,000 hectares of new rice lands and to stabilise the water supply for 102,000 hectares of existing rice lands, resulting in increased rice production of about 465,000 tonnes per year over the next 50 years.

Exhibit 15.2

Estimated project capital cost

| | <i>(US\$ thousands)</i> |
|--|-------------------------|
| Turnkey construction contract | 235,700 |
| Initial materials and spares | 1,000 |
| Construction administration costs | 15,184 |
| Financing costs | 19,289 |
| Commercial insurance during construction | 7,250 |
| Project contingency | 20,000 |
| Debt Service Reserve Fund | 42,462 |
| Interest during construction | 154,448 |
| Total estimated cost | 495,333 |

Early stages of the project

In early 1994 President Fidel Ramos recognised the need for an irrigation and hydroelectric project that would provide increased water flows for irrigation to the rice-growing area of central Luzon; would be environmentally sound, technically feasible and economically viable; and would require no flooding or relocation of local residents. He directed the Philippine Department of Agriculture and the NPC to work together with other interested agencies to develop a combined irrigation and hydroelectric project.

Shortly afterwards the project company approached the Philippine government with a proposal to develop the project on a build-operate-transfer (BOT) basis. After a public solicitation for competing proposals the National Irrigation Administration (NIA) selected CE Casecnan as the BOT developer and entered into a project agreement with the company.

Under the Project Agreement CE Casecnan is committed to develop, finance and construct the project over an estimated four-year construction period, and then own and operate the project for a 20 year 'cooperation period'. The project is expected to operate for at least 30 more years beyond the cooperation period. During the cooperation period the NIA is obliged to accept delivery of all water and energy. As long as the project is physically cap-able of operating NIA will pay the company a guaranteed fee for the delivery of water and electricity, regardless of the amounts actually delivered or generated. In addition NIA will pay a fee for the delivery of all electricity in excess of a threshold amount, up to a defined limit. All fees paid by NIA to the company will be paid in US dollars. The guaranteed fees for the delivery of water and energy are expected to provide about 70 per cent of the company's anticipated revenues. The Project Agreement protects the company from increases in Philippine taxes or a change in Philippine law. It also exempts CE Casecnan from various Philippine taxes during the construction period, including value-added taxes, documentary and stamp taxes, withholding taxes on bonds and contracts, registration fees, and customs duties. If certain *force majeure* events occur the NIA is obliged to buy the project for an amount that always exceeds the amount of its outstanding debt. At the end of the cooperation period the company will be transferred 'as is' to the NPC and the NIA for no additional consideration.

The project was originally to be constructed on a joint and several basis by Hanbo Corporation and You One Engineering and Construction Company, Ltd, both of which are South Korean corporations, pursuant to a fixed-price, date-certain, turnkey construction contract, which was guaranteed on a joint and several basis. Hanbo, which held a controlling interest in You One, was an international construction company. You One was a leading contractor in tunnel projects with more than 25 years' experience in tunnel construction, using both drill-and-blast and tunnel boring machine methods. The total cost of the project, including development, construction, testing and startup, was estimated to be approximately US\$495 million.

The South Korean contractors failed and were replaced in 1997. Replacement of the EPC contractors, tunnel-drilling difficulties and other problems resulted in a cost overrun. These events are discussed in detail below.

Environmental impact

The project was designed to make the least possible impact on the surrounding environment. The rivers flow through a rain forest that is inhabited by the Bugkalot people. Building a dam to capture the water's electricity-generating potential would have flooded their land, while the tunnel, about 21 feet in diameter, was not expected to disrupt the area significantly. The power generation plant was built underground to preserve the appearance of the surrounding lands. Areas excavated for construction were later covered with topsoil and planted with 50,000 citrus seedlings, to encourage the revegetation of the area and to create the country's largest citrus nursery. The project company also helped the Bugkalots to develop an operation manufacturing rattan furniture.

Project risks

Economic viability is not an issue. After completion the project is tantamount to a sovereign credit. The capacity payments that the NIA is obliged to make cover 70 per cent of projected cash flow, which is more than the amount required to service the debt. There are plenty of data to show that river flow should be more than adequate.

The most important risk was construction risk, particularly the financial risk related to relatively small contractors. By world standards Hanbo Steel and You One were not well-known. They were selected because of You One's experience in tunnelling and the amount of tunnelling equipment that it had available: nine tunnel-boring machines, each the size of two locomotive engines and costing about US\$30 million. Kiewit, by contrast, had only three tunnel-boring machines, and did not bid as aggressively for the construction work on the project. As South Korea is very mountainous, with many roads going through tunnels, it seemed logical that the country would have a leading tunnelling contractor. The project's construction risk was mitigated in three ways:

- a very generous construction budget with contingencies;
- liquidation damages of 100 per cent guaranteed by Hanbo Steel; and
- a letter of credit for 50 per cent of the liquidated damages from Korea First Bank.

Marketing the bonds

The biggest problem for Credit Suisse First Boston, Bear Stearns and Lehman Brothers in marketing the bonds was the sheer size as well as the maturity of the offering. It was more than three times the size of the recent Subic Bay power plant offering. Unfortunately, the Subic Bay bonds were held heavily by one institution, so institutional investors in general did not have a lot of experience with Philippine high-yield bonds.

The underwriters decided that the bonds would have to be marketed around the world and that they should be divided into several tranches to appeal to different investors' interests. Asian institutional investors, both bank and nonbank, tended to be floating-rate, short-term buyers. A US\$75 million floating-rate tranche maturing in seven years was developed for them. A number of US high-yield mutual funds had been enthusiastic about CalEnergy and, although the project was unusual, they were expected to give CalEnergy the benefit of the doubt. The high-yield mutual funds tend not to like maturities of more than 10 years, so a 10-year high-yield bond with a seven-year noncall provision was developed for them.

Finally, a bond with a 15-year maturity and a 12-year average life was developed for emerging-market investors who already had experience with project finance investments and were willing to stretch for some additional yield.

The US\$75 million Asian tranche looked likely to be an easy sell, but it turned out to be the most difficult because a corruption scandal occurred in South Korea close to the time of the offering and many Asian institutions shied away from the bonds because of the Hanbo exposure. When this happened the underwriters had to do additional due diligence, change their disclosure and print new prospectuses. In the end a large part of this tranche was sold to institutional investors in the United States.

During the 10-day road show in November 1994 Credit Suisse First Boston held meetings with 48 investors, typically investment-grade buyers, high-yield buyers and emerging-market buyers. Twenty-nine investors from 13 cities participated in the transaction. About 50 per cent of the securities were sold in one-to-one meetings, about 30 per cent were sold at group functions such as lunches and breakfasts, and about 20 per cent were sold to investors with which the company held no meeting. The amounts purchased by investors ranged from US\$600,000 to US\$50 million. Jonathan D. Bram, Managing Director, Project & Lease Finance, Credit Suisse First Boston, recalls that people took longer to analyse this deal than they do with most projects. Because of the work that CalEnergy did the entire financing effort took just under three months and could have taken even less time if the scandal had not erupted in South Korea.

Initial credit rating

Standard & Poor's initially rated all three of the tranches 'BB'. The agency cited three primary risks:

- construction risks related to boring 23 kilometres of tunnels in a remote region of the Philippines over a four-year period;
- the credit of the NIA, which was a function of the sovereign credit; and
- the sponsors' lack of experience in operating hydroelectric and irrigation projects.

The agency cited several strengths that, in its view, offset these risks:

- the liquidated damage provisions and the letter of credit;
- the Philippine government's support of the offtake purchaser's contractual obligations;
- the strategic importance of the project to the Philippine government;
- the negligible risk of interruptions to the flow of water from the rivers; and
- projected debt service coverage ratios averaging 1.9 times over the life of the project.

Events since 1996

On 24 January 1997 Standard & Poor's put CE Casecnan's BB-rated senior secured debt on CreditWatch with negative implications because Hanbo Steel Company in South Korea, the guarantor of Hanbo Construction and Engineering Company's obligations under the EPC contract, had been forced into bankruptcy by its creditor banks. Although Hanbo Steel had failed to make a loan payment, the basic issue was a battle for control of the company. Standard & Poor's noted that the implications of Hanbo Steel's insolvency were unclear, and

that it had not relied on the guarantee of Hanbo Steel when it issued its original rating because Hanbo Steel itself was unrated.

In early May 1997 CE Casecnan terminated the EPC contract. It announced that the Hanbo Group had defaulted on the EPC contract for several reasons, including the fact that it had filed for court receivership protection in South Korea. CE Casecnan added that the bankruptcy filing was related to Hanbo's alleged participation in fraudulent kickback schemes involving banking and government officials.

At the time the EPC contract was terminated about 600 metres of the tunnel had been excavated and a tunnel-boring machine was in position, abandoned by the EPC contractor. Most of the large-scale electromechanical components were in the bidding process or already on order. To replace the contractor's functions the company assembled a consortium of other contractors and subcontractors that already had stakes in the project.

On 7 May 1997 CE Casecnan announced that it had signed a lump-sum, date-certain, turnkey contract with a new limited-liability consortium as EPC contractor, organised under Italian law, headed by Cooperative Muratori e Cementisti (CMC) di Ravenna and Impresa Pizzarotti & C Spa. Other members of the new consortium included Siemens AG, Sulzer Hydro Ltd, Black & Veatch, and Colenco Power Engineering Ltd. Standard & Poor's confirmed that its 'BB' rating remained on CreditWatch with negative implications and would remain on CreditWatch at least until CE Casecnan was able to draw under the Korea First Bank letter of credit, the replacement contractor was completely mobilised, and the agency had reviewed the new contracts and security arrangements.

Also on 7 May Casecnan tendered a certificate of drawing to Korea First Bank under the standby letter of credit that it had issued as financial security for the obligations of the Hanbo Group. The bank dishonoured the drawing, upon which CE Casecnan filed for action in the New York State Court.

On 12 May Orlando Soriano, head of the NIA, cited complaints about unpaid wages from some local contractors as evidence of Hanbo's financial problems. He said that on a recent visit to the project site he had found some of the contractor's engineering and construction work to be defective. Soriano also said that police and army battalions had been sent to the area to secure valuable equipment and property that would be left behind by the departing Koreans.

At that time the New York State Court granted CE Casecnan's request for an order requiring Korea First Bank to deposit US\$79,329,000 in an interest-bearing account with a bank in the United States. Korea First Bank appealed against the ruling, but the appeal was denied by the State Appellate Court. Korea First Bank made the bank deposit as ordered by the court on 19 May.

The next day John G. Sylvia, Chief Financial Officer of CE Casecnan, said:

We are very surprised and disappointed that Korea First Bank, South Korea's second largest commercial bank, would let its troubled relationship with Hanbo interfere with its independent obligations to CE Casecnan under its letter of credit. Korea First Bank's failure to honour its standby letter of credit is indefensible and will only result in increasing the bank's exposure to Hanbo-related problems. It appears that the criminal investigations in South Korea which have been reported in the press, in connection with the alleged fraudulent loans-for-kickbacks scheme implicating a number of top South Korean government, Korea First Bank and Hanbo officials, has greater ramifications than previously reported [...] It is essential that international lending institutions honour their obligations under standby letters

*of credit. We believe it is virtually unprecedented that Korea First Bank has failed to comply with customary banking practices and failed to honour its obligations. The sponsors of the Casecnan Project recognise the value and importance of this facility to the Philippines. Accordingly, we plan to proceed to complete construction of the facility and pursue all resulting damages from Korea First Bank.*²

CE Casecnan issued a notice to proceed to the replacement EPC contractor on 7 August. Daniel M. O'Shei, Jr, CEO of CE Casecnan, said:

*We are pleased to have our replacement contractor proceeding with the important Casecnan project in the Philippines. Given the priority that our client, the Philippine National Irrigation Administration, and the Philippine government place on this flagship project, it was necessary that the replacement contractor be given a notice to commence work. Although Korea First Bank has still not honoured the draw made by CE Casecnan on the irrevocable standby letter of credit issued by the bank to support the obligations of the Hanbo contractors, CE Casecnan's issuance of the notice to proceed to the replacement contractor demonstrates our commitment. The receipt of the letter of credit funds from Korea First Bank remains essential and we will continue to press for Korea First Bank to honour its clear obligations under the letter of credit, and to pursue Hanbo and Korea First Bank for any additional damages arising out of their actions to date.*³

CE Casecnan received a favourable summary judgement against Korea First Bank in the New York State Court on 27 August, although the judgement was subject to appeal. O'Shei said:

*It is essential that international lending institutions honour their obligations under standby letters of credit and we believe it is virtually unprecedented that Korea First Bank has failed to comply with customary banking practices and failed to honour its letter of credit obligations to date. However, if Korea First Bank chooses to appeal [against] this court ruling and thereby further delay CE Casecnan's receipt of the requested funds, we intend to pursue Hanbo and Korea First Bank for all additional damages arising out of such actions as well as their actions to date, including making such additional draws as may be required on the remaining balance of the letter of credit.*⁴

In September 1997, CalEnergy's board of directors approved a US\$1.1 billion buyout of stock held by its 30 per cent shareholder, Kiewit Diversified Group (KDC), a unit of Peter Kiewit Sons, as well as KDC's interests in the UK power distributor Northern Electric, and in several power projects CalEnergy was focusing on developing in Asia, including its 35 per cent interest in CE Casecnan. KDC decided to sell the interests so that it could devote more management time and capital to its information services business. Later that month Standard & Poor's confirmed its 'BB+' senior debt rating for CalEnergy, noting that the company would buy out the minority interests through a combination of cash, new debt and a new equity offering, after which its debt would be about 80 per cent of long-term capital.

On 8 April 1998 the New York State Appellate Court ruled in CalEnergy's favour, ordering Korea First Bank to honour draws of US\$93 million plus interest under the standby letter of credit. The court unanimously denied the bank's appeal against the earlier summary judge-

ment in CalEnergy's favour. By that time a fourth draw under the letter of credit had increased the unpaid amount to US\$117.5 million. Craig M. Hammett, senior vice president and chief financial officer of CalEnergy, said that the bank's action was 'virtually unprecedented in international lending transactions'.⁵

On 17 April CE Casecan announced that it had reached mutual agreement with the Hanbo entities and Korea First Bank to settle their differences related to the Casecan project. Under the settlement Korea First Bank agreed to pay CE Casecan US\$90 million; the parties 'discontinued with prejudice' the pending arbitration and litigation proceedings; and they released each other from all claims arising out of the litigation and arbitration.

In July 1998 Standard & Poor's removed its rating on CE Casecan from CreditWatch and raised it from 'BB' to 'BB+', the same level as the foreign currency rating for the Philippines. The agency's rating for CE Casecan had a negative outlook only because of its negative-outlook Philippine country rating. The agency said that it was satisfied that the replacement EPC contract and security arrangements did not expose the project to major additional risks. Factors that it cited to support the rating upgrade included:

- the payment from Korea First Bank under the letter of credit;
- strong and predictable future cash flows, complemented by a new and stronger construction programme;
- a government undertaking to support the project; and
- evidence of a capable and persevering sponsor, particularly in a stressed situation.

In August 1998 CalEnergy and MidAmerican Energy Company announced plans to merge. MidAmerican had among the lowest all-in production costs in the mid-continent region of North America, which would offset some of the higher-cost geothermal and hydroelectric plants in CalEnergy's global portfolio. CE Casecan would become a subsidiary of the new combined company, MidAmerican Energy Holdings.

CMC, the new EPC contractor, had begun work on the main 23-kilometre tunnel in 1997, with one tunnel-boring machine. As progress was slowed by the friability of the rock the contractor brought in two additional borers. In late 1999, after continued delays related to poor rock conditions, the contractor abandoned the borers in favour of more conventional, but more labour-intensive, drill-and-blast tunnelling techniques. The EPC contract was amended to extend the completion date by seven months, to 31 March 2001. Stone & Webster, one of the project engineering firms, said that the new EPC contract was still feasible because the river diversion had been proven to be working, and the supply and installation of the two 75 megawatt turbine generators was largely on schedule.

In December 1999 Moody's reaffirmed its 'Ba2' rating for the project, but changed its outlook from positive to negative. Moody's said that the delay in the project's completion and related changes in the construction contract would not substantially increase risks to bondholders, because damages payable for failure to meet the new completion date had been increased under contract amendments, and the contractors' obligations were backed by letters of credit from banks rated 'A2' and above. The reason that the agency changed the rating outlook from positive to negative was that the project would have reduced financial flexibility if further delays arose. However, Moody's believed that such risk was mitigated by assurances from CE Casecan, the EPC contract consortium and the independent engineer that the new completion date was achievable.

Standard & Poor's took similar action the same month, affirming its 'BB+' rating but revising its outlook for the project from stable to negative. In its discussion of the project risks the agency cited problems not only with rock quality but also with on-site management and labour productivity. It said that liquidity could become a problem if corrective measures failed to speed the progress of construction. Under the revised construction schedule the first principal payment would be due four months before project completion and the second payment immediately after startup. These payments were likely to absorb all but US\$6 million of the funds budgeted for the debt service reserve fund. Standard & Poor's noted that this was the sponsors' first irrigation and hydroelectric project. Other risks that it cited were:

- the NIA's reliance on the willingness of the Philippines and the ability of its central bank to pay in US dollars;
- a short-to-medium-term electricity oversupply in the Philippines that could exert downward pressure on tariffs and affect project economics; and
- uncertainties concerning the Philippine judicial system that could hinder the enforceability of contracts and security pledges, including the implementation of offshore judgements.

The agency said that the following strengths offset the risks and supported its 'BB+' rating for the project:

- a provision in the amended EPC contract that raised liquidated damages from US\$65,000 to US\$125,000 per day and prevented the contractor from reducing its liability by claiming change orders relating to underground risks;
- the fact that the new EPC contractor was continuing to assume construction risk under a fixed-price, turnkey, date-certain contract providing liquidated damages of up to 93 per cent of the contract value for delay;
- security equal to 33 per cent of the contract value in the form of guarantees from Crédit Agricole Indosuez, Commerzbank AG and Banca di Roma;
- a revised construction plan that shifted tunnelling from the problematic boring machine to more reliable drilling and blasting, increasing the likelihood of the completion date's being met;
- the largely on-schedule construction of the powerhouse, weirs (dams), desilting facilities and most of the remaining tunnels;
- the Philippine government's undertaking to support the performance of the oftaker's contractual obligations;
- MidAmerican Energy Holdings' commitment to the project for its 25-year life; and
- debt service coverage ratios that were expected to average 1.6 times for the first eight years and rise to four times for years nine and ten.

In March 2000 Standard & Poor's reaffirmed its 'BB+' rating for CE Casecnan with a negative outlook for the project after its quarterly construction review, and an announcement that the acquisition investment team of Walter Scott, Jr, David Sokol (Chairman and Chief Executive of MidAmerican Energy Holdings) and Berkshire Hathaway Inc. had acquired CalEnergy, CE Casecnan's 70 per cent parent, through a cash buyout. To reflect the effect of that acquisition the agency rated MidAmerican 'BBB-' with positive implications. In the agency's opinion 76 per cent ownership by Berkshire Hathaway was a positive credit devel-

opment for lenders, although it did not expect that Berkshire Hathaway would inject equity to deleverage MidAmerican. It considered its consolidated leverage of 75 per cent of capitalisation to be high for a company with a 'BBB-' rating. Limiting an upgrade for MidAmerican at that time were its exposure to the California market through its Salton Sea project and construction delays in the CE Casecanan project.

In July 2000 Standard & Poor's reaffirmed its 'BB+' rating with a negative outlook for CE Casecanan, noting that construction remained on target for completion by 31 March 2001. It noted that since the beginning of the year MidAmerican and the EPC contractor had installed new on-site management teams, and improved labour productivity. Reaffirming its 'BB+' rating once again in November 2000, the agency noted that because the project had been 93 per cent complete as of September, the original completion date was still likely.

In December 2000 a partially completed vertical surge shaft collapsed because of a geological fault nearby. The EPC contractor evaluated whether the shaft could be repaired and completed, but, for timing and economic reasons, chose instead to excavate a new 550-metre tunnel and a new 140-metre vertical shaft. The work was expected to cause a five-month delay, pushing the completion and startup date to the end of August 2001. Stone & Webster Consultants, Inc. reviewed the revised construction schedule and budget, and concluded that the revised completion target date was realistic, and that the remaining construction funds of US\$47.3 million plus approximately US\$11.3 million of additional committed funds from MidAmerican (US\$4.6 million for debt service on 15 May 2001, and up to US\$7 million for construction and startup operating costs up to 1 September 2001) were reasonably sufficient to complete the project.

In February 2001, following CE Casecanan's public announcement of the tunnel collapse and the consequent construction delay, Standard & Poor's placed its 'BB+' rating on CreditWatch with negative implications. Despite MidAmerican's agreement to provide additional cash equity of US\$11.6 million, the agency was concerned about the weakening of the project company's liquidity position, the prospective lack of any meaningful cash cushion at startup, and the continuing construction delays. Moody's placed its 'Ba2' rating of the project's senior secured notes on review for possible downgrade for similar reasons. The agency cited the 'repeated failure of the project to achieve important project milestones' and the fact that there was 'little financial cushion against any further delays'.

By the spring of 2001 the advance tax payments made by CE Casecanan, which the Philippine government was committed to reimburse, had built up to US\$45.6 million. The contract between CE Casecanan and the government stipulated that such reimbursement could be made through an increase in the water delivery fees to be paid to the company by the NIA, which would begin when the project was completed. CE Casecanan's management observed that this reimbursement obligation did not appear to be included in the Philippine national budget and asked the NIA how the government intended to settle the obligation. The NIA in turn consulted the Interagency Investment Coordination Committee, which had responsibility for the government's contingent liabilities. The government, under pressure to keep expenses down, had to decide whether it was more economical to settle the full obligation in 2001, or amortise the liability with interest, in which case its ultimate payment to CE Casecanan could amount to US\$500 million or more.

On 12 October 2001 Standard & Poor's noted that the project had reached mechanical completion and would start generating electricity following that day's inauguration ceremony. The company was expected to announce the beginning of commercial operations by

the end of November. Nonetheless, Standard & Poor's kept its 'BB+' rating for the project on CreditWatch with negative implications, because of its weak liquidity. Without support from MidAmerican it would not be able to make its US\$35.3 million principal and interest payment the following month. Indeed, MidAmerican affiliates provided the funds required for that payment on 15 November. By that time the project had been tested under normal conditions, but CE Casecnan was taking additional precautionary measures before beginning normal commercial operations, to avoid the risk of damage that could result if the project caused instability in the Philippine transmission grid. The project began commercial operation on 11 December and began the 20-year cooperation period outlined in the Project Agreement with the NIA.

Meanwhile, because of a dispute with CE Casecnan the EPC contractor was resisting the payment of about US\$23 million in liquidated damages that it owed as a result of its construction delay. The damages were supported by a guarantee from Banca di Roma.

In March 2002 Moody's confirmed its 'Ba2' rating for CE Casecnan's notes with a positive outlook. The rating was based on the strong terms of the 20-year BOT contract with the NIA, backed by a performance undertaking from the government of the Philippines. The rating also reflected the NIA's strong commitment to the project, given the importance of the irrigation that it provided to one of the country's major rice-growing regions. However, the rating also reflected the outstanding arbitration with the EPC contractor, the outcome of which could have a material impact on the project's liquidity and its ability to meet its debt-service obligations. Moody's positive outlook was based on four factors.

- The project had begun to generate cash flow for future debt servicing.
- The agency expected the project's debt service coverage ratio to be at least in line with the Ba2 rating level, if not higher, given the historical hydrology of the region and the resulting performance of the hydroelectric dam.
- There were strong incentives for MidAmerican to continue to support the project even if the outcome of the arbitration with the EPC contractor was unfavourable.
- It was likely that the NIA would honour its obligations, even though all the canals required to carry water to the target irrigation areas would not be completed until 2004.

Lessons learned

The Korean EPC contractor was recognised as a weak link at the time of the project financing. EPC contractors often do not fail, standby letters of credit often are not called upon and, when they are, they often are not dishonoured by their opening parties. The Casecnan Water & Energy case study reminds us that these risks do materialise from time to time, and illustrates how the problems can be resolved.

¹ This case study is based on the project prospectus, articles in the financial press and an interview with Jonathan D. Bram, Managing Director, Project & Lease Finance, Credit Suisse First Boston Corporation.

² 'Court Orders Korea First Bank to Deposit \$79,329,000 in a New York Bank Account', *PR Newswire*, 20 May 1997.

³ 'CE Casecnan Issues Notice to Proceed to Replacement EPC Contractor', *PR Newswire*, 7 August 1997.

⁴ 'CE Casecnan Obtains Summary Judgement Against Korea First Bank on Letter Drecit Draw', *PR Newswire*, 27 August 1997.

⁵ 'CalEnergy Wins \$93 million Battle; Court Rules Against Korean Bank', *Global Power Report*, 17 April 1998.