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Financing of Private Hydropower Projects

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Chris Head is a director of Knight Piesold Limited in Ashford, Kent, England, and a consultant to the Energy Mining Network at the World Bank.

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Figure 3: One− and Two−Stage Models link

Foreword

Private financing of infrastructure projects in developing countries has grown substantially during the 1990s, especially in the electricity sector. Much has been written about the evolution of private participation in the development and operation of greenfield thermal generation facilities in the form of build−own−operate (BOO) or build−operate−transfer (BOT) projects. While private financing was notable in thermal power development, the universe of successfully financed private hydropower projects has so far been very limited due to their capital intensity and complex risk profiles. It is likely that a framework for private financing of thermal power projects may fall short of addressing all the challenges of private hydropower development.

Proper development of indigenous hydropower resources could meet needs for clean renewable energy to address concern over global warming. The growing trend toward lower−risk, easier−to−construct thermal power plants and a sharp decline in hydropower development are believed to be not due to major changes in the benefits of hydropower generation, but as a result of difficulty in attracting private financing to hydropower schemes in these days of shortages in public infrastructure financing.

This study examines ten hydropower projects with private participation in five developing countries: the Philippines, Lao PDR, Nepal, Turkey and Brazil. Although hydro schemes could be unique and different, including multi− and single−purpose projects for domestic supply or for export, the study intends to review common issues in private hydropower development, emerging trends in regulations, risk allocation and feasible financing schemes. We would expect that it would provide some insight for both policymakers of developing countries and private financiers in the challenge of mobilizing financing for hydropower development.break

NINA SHAPIRO
DIRECTOR
PROJECT FINANCE AND GUARANTEES
THE WORLD BANK

JAMES BOND
DIRECTOR
ENERGY, MINING & TELECOMMUNICATIONS
THE WORLD BANK

Abstract

This study provides an overview of the issues and challenges related to the private financing of hydropower projects in developing countries. From the very limited pool of projects that have already reached or are nearing financial closure, ten have been chosen for the study from five countries that have been among the most active in promoting private hydro development. The selected projects cover a range of physical and market characteristics, regulatory and concession environments, public−private risk−sharing arrangements, and financial structures. Collectively the case study projects provide a reasonable cross−section of private hydro schemes that have been or are being developed.

The financing of greenfield private infrastructure on a limited−recourse basis in developing countries faces certain common issues irrespective of the type of project. However, hydropower faces additional difficulties caused by the site−specific nature of projects, high construction risk and long construction periods, their capital−intensive nature with a high proportion of local costs, unpredictable output subject to river flows and broader water

management constraints, complex concession process to achieve transparency in the award and pricing of output, and environmental sensitivities. The study examines the selected projects and the way in which they dealt with these difficulties to allow lessons to be drawn for use in the future.

Private hydropower development is still in a state of evolution, with the process proving to be slow and expensive. There is a danger that interest will falter in the larger hydropower projects if prospective developers continue to be faced with high upfront costs and long preparation periods, with only limited prospects of success. The findings of the study suggest the need for longer−term financing to better suit hydropower characteristics; a regulatory framework and realistic public−private risk−sharing arrangements responsive to the requirements of hydropower projects; and the careful preparation of projects by the public sector to enable their formulation on an adequate technical and contractual basis for development as a private concession.break

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This study was co−sponsored by the World Bank's Project Finance and Guarantees Department (PFG) and the Energy, Markets and Reform Thematic Group of the Energy, Mining & Telecommunications Network (EMT). The report was prepared by Chris Head of Knight Piésold Limited under the direction of and in collaboration with Barry Trembath of EMT and Tomoko Matsukawa of PFG. It also benefited from the contribution and comments of several other Bank staff, in particular Suman Babbar of PFG, Mangesh Hoskote and Yves Albouy of EMT, and Johan Ahstrom of ABB (during his secondment to PFG).

In the course of preparing the report, developers, public sector agencies, financiers, contractors, equipment suppliers, consultants, insurance brokers and others involved in the business of private hydropower development were consulted. The task group of the report would like to thank all for their assistance and contributions.break

Abbreviations and Acronyms

ADB	Asian Development Bank
BOT	Build, Operate, Transfer
CWEC	CE (California Energy) Casecnan Water and Energy Company Inc.
E&M	Electrical and Mechanical
ECA	Export Credit Agencies
EEDF	Excess Energy Delivery Fee
EIA	Environmental Impact Assessment
EPC	Engineering, Procurement and Construction
GE	Guaranteed Energy
GEDF	Guaranteed Energy Delivery Fee
GW	Gigawatt
GWh	Gigawatt−hour
HPC	Himal Power Company
IADB	Inter−American Development Bank

IDA	International Development Association
IFC	International Finance Corporation
ILA	International Lending Agency
IPP	Independent Power Producer
JEXIM	Export−Import Bank of Japan (merged with the Overseas Economic Cooperation Fund, Japan and renamed as Japan Bank for International Cooperation in 1999)
km	Kilometer
km2	Square kilometer
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt−hour
LHC	Luzon Hydro Corporation
m	Meter
m3	Cubic Meter
MENR	Ministry of Energy and Natural Resources
MDBs	Multilateral Development Banks
MIGA	Multilateral Investment Guarantee Agency
MoU	Memorandum of Understanding
MW	Megawatt
NEA	Nepal Electricity Authority
NIA	National Irrigation Administration
NPC	National Power Corporation
NTEC	Nam Theun 2 Electricity Consortium
O&M	Operation and Maintenance
OECD	Organisation for Economic Co−operation and Development
PPA	Power Purchase Agreement
SRPC	San Roque Power Corporation
THPC	Theun−Hinboun Power Company
WDF	Water Delivery Fee

Executive Summary

The dismantling of the monolithic state power utilities and the move toward private ownership of generation, transmission and distribution are together the main consequences of the process that is generally referred to as power sector deregulation. The process has severely impacted the way in which new (greenfield) hydro projects are implemented and the rate of implementation. As traditional public sources of finance have dried up, they have

not been replaced in equal measure by private funds and, in consequence, the world is experiencing a sharp decline in new−start hydro.

This decline is not due to any change in the fundamental economic benefits of hydropower, but rather to the new priorities that have arisen in the context of private financing. These favor low−risk projects that are not capital−intensive, with short construction times and quick returns—in effect thermal power projects, and preferably gas−fired plants. In many countries the private sector has now completely taken over the role of developing new power stations. Yet at a time when there is serious concern over global warming and an urgency to find clean renewable sources of energy, the private sector is building over 40 megawatts (MW) of fossil−fuel thermal plants for each new megawatt of hydro.

In a study of ten privately financed hydro schemes this report examines the reasons and looks at ways of mitigating some of the problems. Although all hydro schemes are different, the selected schemes are sensibly representative of all but the smaller projects that are likely to be considered for private financing in the future. They are located in five countries where the power sector is at different stages of maturity and deregulation, and they include multi− and single−purpose projects intended for both domestic supply and export.

The financing of private infrastructure on a nonrecourse basis, where the security is essentially the project itself, raises certain common issues irrespective of the type of project. However hydro raises a number of additional problems that are caused by:

· the site−specific nature of the projects;

· their high construction risk and relatively long construction periods;

· their capital−intensive nature with a high proportion of local costs;

· unpredictable output subject to river flows and broader water management constraints;break

· the difficulty of achieving transparency in the award of concessions and the pricing of output; and

· environmental sensitivities.

All of these have a direct bearing on the financing of private hydro and on the type of schemes that the private sector will favor. The main issues that emerge from the study of the candidate projects are listed below.

Role of the Host Government

Host governments are still struggling to find the optimum regulatory framework for private hydro. A familiar pattern can be seen in a number of countries; governments invite prospective sponsors to bid for inadequately prepared projects without a full understanding of the requirements of the private sector, and are often disappointed by the poor response. After a period of reconsideration the policy is modified with the public sector accepting more responsibility and a higher level of risk exposure and a new solicitation process begins.

There is growing recognition that the regulatory framework for hydro cannot be the same as for thermal projects, because hydro inevitably has a wider public interest element and, in turn, requires more public support. Furthermore very large projects, or those with strong multipurpose benefits, may only be viable under some form of public−private partnership.

Most private hydro concessions have been directly negotiated. In part this may reflect the fact that they are pioneer projects and have accordingly received special treatment. Under pressure from the multilateral agencies, governments are trying to move toward a more transparent process. However competitively bidding an hydro concession is a complicated and costly process, and there is a danger that unless it is handled carefully it will simply deter prospective sponsors.

Role of the Host Utility

All of the projects considered have been financed on the basis of a long−term offtake agreement with the utility. Even the two autoproducer projects have support arrangements with their host utility. Without a long−term offtake agreement hydro would generally not be financeable, other than for small schemes.

In addition to acting as the offtaker, the utility should have a key role in the preparation of the project before the private sector becomes involved. This is to ensure that the project configuration is optimal for system requirements, and that a site is not sterilized by a development that fails to realize its full potential. In the future this project definition role is likely to become increasingly important.break

The utility is also generally required to manage land acquisition and any resettlement, but the tendency has been to leave the main responsibility for environmental permitting to the sponsors. This is not an area in which the private sector is comfortable because of the long delays and expense that can be incurred. Under their revised regulatory arrangements many governments are now recognizing that environmental clearance is a public responsibility that should be discharged before the private sector becomes involved.

Offtake Arrangements

All of the contracts effectively placed market risk with the offtaker through take−or−pay arrangements. Similarly the offtaker assumes foreign exchange risk. Both of these would be found in most thermal power purchase agreements (PPAs).

The issue of hydrological risk receives variable treatment. In some cases it is totally assumed by the sponsors, but more often it is shared or carried by the utility offtaker. It is clearly not easy for the sponsor to assume hydrological risk where there are existing or potential upstream developments that can interfere with flow patterns.

Construction risks remain a serious problem for sponsors and contractors alike, particularly where there has been only limited site investigation. In some cases this was addressed by allowing certain defined risks (such as geology) to be passed through to the public sector, either in the form of a tariff increase or by an arrangement under which the more risky civil works are financed in the public domain.

Tariff structures are still relatively undeveloped, being based either on energy alone, or on a capital recovery plus operating costs formula similar to that used for thermal independent power producers (IPPs). Payment for ancillary benefits does not feature in any of the offtake agreements, and there is only weak recognition of the premium value of peaking energy over base load. In consequence there is little incentive for a sponsor to develop anything other than a run−of−river, baseload station, which is predominantly what is happening at present.

Financing

The difficulty of accessing long−term finance is a serious problem. The tenor is important because short−term debt results in very high tariffs in the early years, making it difficult for hydro to compete with thermal plant. Under new OECD guidelines for private power projects Export Credit Agency (ECA) repayments can be

extended up to 14 years with a flexible profile, but this is still less than the 15 years allowed for nuclear power stations, and very short when compared with the commercial life span of hydro.

With its relatively low equipment content hydro offers only limited scope for export credit financing, which has been the traditional funding source for IPP thermalcontinue

projects. Generally the ECA element will be below 30 percent of project cost, with equity providing perhaps another 30 percent. This leaves a large financing gap that is difficult to fill by commercial loans because they are either not available, or of short tenor and high cost.

In many of the less creditworthy countries the only way of filling this gap is through use of direct funding or support mechanisms provided by the multilateral and bilateral agencies. This has been evident in the majority of the projects considered, most of which would not have been financed without public sector support in one form or another. Such support has been predominantly from multilaterals, like the International Finance Corporation (IFC) or the Asian Development Bank (ADB), in the form of debt and, to a limited extent, equity. To date there has been little use made of guarantees or other forms of credit enhancement.

Among the projects examined, virtually no funding has been sourced locally due to the relatively undeveloped state of the capital markets in the countries concerned. To date the exposure on foreign exchange risk has been almost as serious as for thermal projects although hydro, with its large local civil works content, has the potential to use more local financing than thermal if it is available.

Competitiveness

The construction cost of hydro is typically 100 to 200 percent more than a thermal power station on a $/kW basis. The gap is magnified by the so−called "soft−costs" which are invariably greater for hydro and include interest over the longer construction period, more burdensome EIA and project preparation requirements, and larger margins to cover the heavier project risks. Furthermore hydro tariffs are dominated by the capital cost and in consequence the price of hydro energy is dominated by financing considerations, much more so than in the case of thermal power stations.

There is a natural tendency for governments licensing private power generation to be primarily influenced by short−term tariff considerations. Under such an evaluation hydro will generally be disadvantaged and appear the more expensive option, even where it is economically attractive in the longer term.

By some very approximate calculations it can be shown that to compete on tariff with a typical 12− to 15−year time horizon, hydro has to be significantly better than an economically equivalent thermal plant. Many hydro schemes are economically viable but financially uncompetitive when judged over the short term against thermal generation. However such a simplified analysis, based on a limited time horizon, fails to take into account the longevity of hydro schemes with their ability to produce inflation−proof energy at reducing real costs almost indefinitely into the future.break

Offtakers faced with these difficult decisions need to be able to recognize when it would be desirable to accept higher tariffs in the short term in exchange for lower tariffs in the long term.

Project Implementation

Under private financing there has been a strong move toward engineering, procurement and construction (EPC) contracts, away from the traditional arrangements where the owner retains control of the design and the project is

managed as a series of single−discipline contracts. Whereas this makes little difference in the context of equipment supply, it has a big impact on the civil works, on the bidding process and on the overall cost of the project, which is generally accepted to be higher under EPC arrangements.

The move toward EPC contracts is being driven by financiers in the belief that it insulates the owner, and therefore the financiers themselves, from risk. However the record to date suggests that this may not be the case and serious contractual difficulties are occurring with increasing frequency on EPC hydro projects.

Problems arise when contractors are required to bid firm prices against a weak project definition and with inadequate site studies. Early attempts to put all of the risk onto the contractor have generally proved unsuccessful, and the trend is now toward some form of risk−sharing, especially for unforeseen geological conditions. When these risks cannot be passed on to the offtaker, provision has to be made for contingent financing through the project company.

Contractors are also appearing as equity holders and sometimes as project sponsors, although their primary interest generally lies in the construction contract itself. They remain important players in a field where there are not many natural sponsors, other than a few hydro−based utilities and the small number of independent power developers who are comfortable with hydro.

The Fully Deregulated Scene

It could be argued that this report is examining a transitory situation, partway between the old system and full deregulation. The situation will be very different when there is no longer a state−backed utility to enter into long−term offtake agreements and to undertake the project definition studies.

There is growing evidence, from the United States and elsewhere, that existing hydro will prosper in fully deregulated markets, particularly when the value of its ancillary benefits is accounted. Such markets place a premium value on storage because it allows the owner the flexibility to maximize his returns on short−term contracts bycontinue

allowing him to withhold generation until the price is favorable without damaging his overall production.

However there remains the serious problem of financing highly site−specific, capital−intensive projects against an uncertain future revenue stream. In this respect there are strong analogies to be drawn with the oil and gas industry, and with mining. Both of these are high−risk enterprises, but they are also high−reward because of the monopolistic nature of their product. Hydro does not enjoy the same protection because of its need to compete with other totally different forms of power generation, but it is likely to follow the same path toward balance sheet financing by large companies with the necessary resources.

Conclusions

Private hydro is still in a state of evolution, with the process proving to be slow and expensive. Small projects will continue to be developed, but there is a danger that interest will falter in the larger projects if prospective developers continue to be faced with high upfront costs and long gestation periods, with only limited prospects of success.

To mitigate these difficulties it is clear that action needs to be taken in a number of areas to:

· Encourage the availability of longer−term finance at low cost from international sources, including ECAs, and through the use of credit enhancement mechanisms such as the World Bank Partial Risk and Partial Credit

Guarantees;

· Foster a regulatory framework that is responsive to the needs of hydro, which includes a willingness on the part of governments to assume certain project risks that cannot easily be accommodated by the private sector;

· Ensure that the deregulation process recognizes that most hydro can only be financed on the basis of a long−term PPA signed with a credible offtaker and backed by a sovereign or similar guarantee; and

· Ensure that projects offered for private funding have been adequately prepared in advance by the public sector, based upon detailed technical studies and site investigation, with a clear contractual framework and security package already in place.

It will be necessary to develop project structures that involve a risk−sharing formula that is both bankable and cost−effective in terms of minimizing construction costs and the resulting tariffs. Two alternative models are considered in the report based upon a one−stage and two−stage bidding process. Another option is the hybrid project, under which some elements lie in the public sector and others are privately financed; only onecontinue

of the candidate projects follows this pattern, but it is likely to become more common in the future.

The multilateral development banks and bilateral aid agencies are uniquely placed to assist in this process through the provision of funding, guarantees and technical assistance. They have already played an important role, but it now needs to be reexamined in the context of the obvious need for the private hydro industry to have powerful organizations to champion its interests. The international lending agencies (ILAs) have acted in concert to encourage deregulation and privatization of the global power industry; they now need a similarly focused approach to address some of the difficulties that this has created in the hydro sector.break

Section 1— Background

Deregulation of the Power Sector

Hydropower's Global Role

Hydropower currently accounts for nearly one−quarter of the world's electricity production, with a total some 650,000 megawatts (MW) installed. It is not only a significant contributor in terms of the overall global energy balance, but is arguably the only renewable energy resource that is commercially exploitable on a large scale at present levels of technology.

Detailed figures are difficult to obtain, but there appear to be 135,000 MW of hydro currently under construction or in the final planning stages. However this statistic tends to be dominated by some very large public sector projects in a few countries such as China (Table 1). The figure masks the fact that in many areas with significant hydro potential the rate of hydropower development has slowed appreciably in recent years. For example, in India the proportion of hydro capacity in the system has dropped from 42 percent to under 25 percent in 20 years.

Hydropower is a widely distributed resource with potential on all continents. But the level of exploitation varies greatly, with relatively limited undeveloped resources remaining in North America and Europe; whereas large untapped potential still exists in Asia, South America and Africa (Figure 1). The regions with the largest untapped resources are also the parts of the world in which the greatest growth in electricity demand will be experienced in

the next century.

While there is clearly a limit to global hydro potential, it is important to emphasize that only about one−quarter of the economically feasible resource has been developed to date. On all continents there remain new resources to be harnessed for the production of clean, emission−free renewable energy.

Despite the obvious advantages that hydropower offers to a world that is becoming increasingly conscious of the problems of sustainability, and global warming in particular, there are serious challenges facing the industry. These arise primarily from the worldwide trend toward deregulation of the power sector, which means that the development and ownership of new power stations has passed into the hands of the private investors whose commercial priorities tend to favor other forms of generation. A secondary, but still important, factor is the environmental concerns that are tending tocontinue

cast a negative image over hydro as a whole, although these are primarily triggered by projects with large storage reservoirs.

TABLE 1: LARGE HYDROPOWER PROJECTS UNDER CONSTRUCTION

Project	**Capacity (MW)**	**Country**
Three Gorges	18,200	China
Ertan	3,300	China
Gunma−Nagamo Pumped−Storage	2,200	Japan
Caruachi	2,160	Venezuela
Karun−3	2,000	Iran
Lijaxia	2,000	China
Porto Primavera	1,818	Brazil
Tianhuangping Pumped−Storage	1,800	China
Xiaolangdi	1,800	China
Nathpa−Jhakri	1,500	India
Ita	1,450	Brazil
Karore	1,400	Japan
Dachaoshan	1,350	China
Serra da Mesa	1,293	Brazil
Salto Caxias	1,240	Brazil
Bieudron	1,200	Switzerland
Tianshenquiao−1	1,200	China
Koyna−4	1,120	India
Goldisthal Pumped−Storage	1,076	Germany

Masjed−e−Soleyman	1,000	Iran
Tehri	1,000	India

Source: Hydro Review Worldwide .

A Rapidly Changing Industry

Prior to 1990 the provision of electric power in most countries was the responsibility of the public sector, and where this was not the case the task was undertaken by closely regulated private utilities. In either situation the funding of new projects was based on the financial strength of the utility or the creditworthiness of the government that lay behind it.

With the deregulation of the power industry there has been a fundamental shift in the way projects are financed. The devolution of the industry into smaller competing units meant that it was no longer possible to rely upon traditional utility−based financing. The trend has been toward the funding of individual projects on a limited−recourse basis where the lender relies for debt servicing on the revenue stream of the project in question, with little or no security being provided by the sponsoring organizations. Under such conditions it is inevitable that financiers become much more closely concerned about the viability of the project itself, rather than the strength of the sponsors to whom they would have little recourse if things go wrong.break

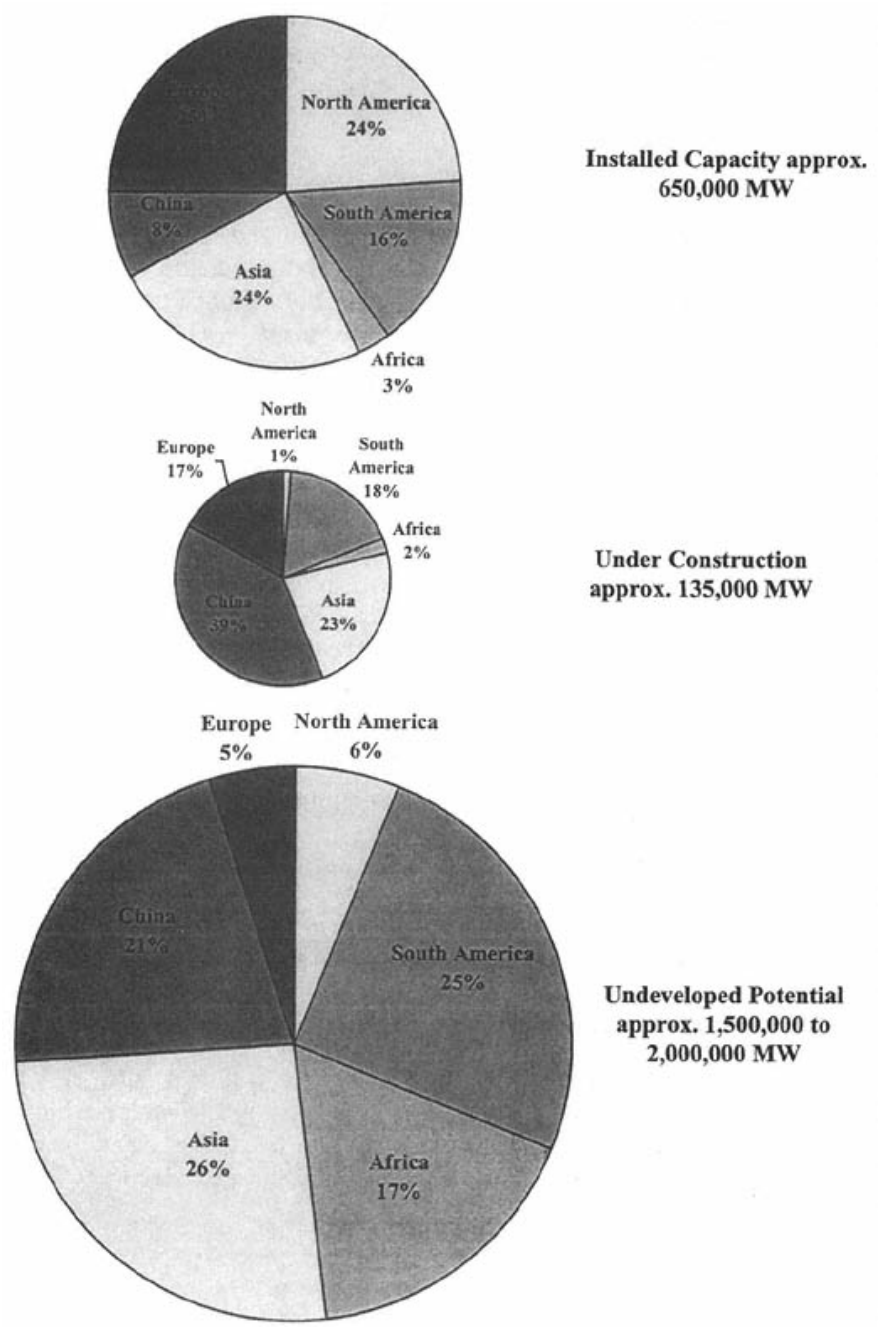


Figure 1
Worldwide Hydropower Situation—1998
Source: Hydro Review Worldwide.

As a consequence of these trends the hydro industry finds itself at a crossroads. The past has been dominated by projects financed in the public sector, usually under concessional arrangements. The future will be driven by private finance, and projects will have to stand on their individual merits in a world that is geared toward quick commercial returns. Under this scenario the record to date shows that hydro is finding it difficult to hold its position.

This deterioration in the apparent attractiveness of hydropower is not as a result of any change in its underlying economics. Hydro still remains a sound long−term investment whose shelf life is almost indefinite compared with the 15− to 20−year life cycle of a typical thermal power station. But what has changed are the criteria by which projects are selected for development, with the emphasis now being on the ability to finance a project from private sources. In consequence the bias has been toward low−cost thermal projects, particularly gas−fired plants, which are relatively easy and risk−free to construct, and whose limited life span comfortably matches the short tenor of most commercial lending.

For thermal power projects the independent power producer (IPP) structure is now well established, and the role and the risks assumed by the different parties are clearly understood. There is no such proven model for private hydro development where the contract structure and underlying allocation of risks vary from project to project. Moreover it is evident that no single template could cover the diversity of situations likely to arise in the private hydro sector. Notwithstanding this, there are lessons to be learned from the few large hydro projects that have reached or are nearing financial closure, and it is the object of this study to examine these and make recommendations for the future.

Comparison of Thermal and Hydro Projects

In terms of "bankability" (that is, the ability to raise finance to support a project) there are marked distinctions between hydro and other forms of power generation. If one excludes nuclear power as being, at least at present, an unsuitable candidate for independent power development on a number of grounds relating to environmental, safety and cost considerations, the principal comparison lies between hydro and fossilfuel thermal power stations. The differences are summarized in Table 2 below.

In making such a comparison it is easy to see why hydro has fallen out of favor since liberalization of the power sector because it is perceived to be capital−intensive, slow to implement and risky. This trend is clearly demonstrated in a recent World Bank−sponsored study on Power Project Finance.1 Table 3, reproduced here from that study,continue

1 *Power Project Finance —Experience in Developing Countries* , World Bank. January 1998.

TABLE 2: THERMAL VS. HYDRO—FACTORS AFFECTING BANKABILITY

	Thermal	**Hydro**
Capital Cost ($/kilowatt)	400−1,400	800−3,000
Operating cost	high	low
Construction risk	low	high
Construction time	2−4 years	3−6 years
Project life	15−20 years	>50 years
Decommissioning costs	yes	unlikely
Electrical and mechanical (E&M) plant	80%	30%
Site influence	low	high
Technology	changing	mature

Source: Private Financing of Hydro Projects , C R Head, PSWG Seminar, Croatia 1997.

shows that of the 239 privately financed power projects that reached financial closure over the period 1994−96, hydro accounted for only 7 percent by capacity, with the market being dominated by oil/gas (53 percent) and coal (36 percent). When only the larger projects that have been the subject of limited−recourse financing are considered, the hydro element drops to 5 percent, with thermal plants accounting for over 90 percent by capacity.

In practice the situation is actually worse than this because Table 3 is believed to include a number of hydro projects that eventually failed to go ahead as planned, particularly the 2,400 MW Bakun project in Malaysia which was questionable anyway as a private project because it was effectively sponsored by the government. A more accurate picture is probably given by CERA,2 in another study that suggests that in 1996 the proportion of hydro in total IPP closings was only 1.5 percent by capacity. The same study suggests that over the five−year period 1991−96, hydro accounted for only 2.5 percent of the total capacity of new, privately funded power projects.

These low figures are strongly at variance with the present position hydro occupies in the world generating mix, where it accounts for some 23 percent of installed capacity. The impression of a serious downturn in new hydro construction as a result of deregulation is widely supported by anecdotal evidence throughout the industry, although the effects are somewhat masked because of the number of public sector projects already in the pipeline before deregulation. It is unlikely that these will be replaced at the same rate by new, publicly financed hydro because of the structural changes in the industry and the drying up of traditional sources of public sector funding.break

2 *Sizing up the Global Power Market: On the Fast Track* . Cambridge Energy Research Associates, June 1997.

TABLE 3: PRIVATE POWER CAPACITY BY FUEL TYPE (1994−96)

Fuel Type	**Project Finance**	**Contingent** a	**Balance Sheet**	**% of Total**
Coal (%)	44	61	10	36
Oil/Gas (%)	48	35	68	53
Hydro (%)	5	4	13	7
Other (%)	3	0	9	4
Total (%)	100	100	100	100
Total (GW)	27.3	5.4	14.0	46.7

a Projects being developed on balance sheet in the interim with a view to refinancing.

Source : Hagler Bailly IPP Knowledge Base.

Therefore at a time when political and environmental priorities are heavily focused on renewable energy and the reduction of greenhouse gases, public sector hydro is declining and the balance of new generating plant being promoted by the private sector is perhaps forty to one in favor of thermal. If current trends continue, the role of hydro in global electricity production will inevitably decline. This is clearly a situation with such serious implications that it needs to be urgently addressed.

Private Investment in the Hydropower Sector

Private investment in the hydropower sector comes in one of three distinct forms:

· Refinancing of existing hydro assets through sale or securitization;

· Upgrading or rehabilitation of existing schemes; or

· Construction of new "greenfield" projects.

While the first two categories are clearly important, they nevertheless represent a limited market that can have no significant impact on the overall global generating mix. This report therefore focuses on the problem of attracting private investment to new projects. However, for completeness all three options are briefly reviewed below.

Refinancing of Existing Assets

In general a completed hydro scheme represents a very durable, low−risk asset that is not particularly demanding in terms of either operation or maintenance. With few exceptions (such as where there is a siltation problem) such schemes represent sound investments that are well suited to a particular part of the market that is looking primarily for long−term security.

Refinancing is a mechanism for releasing the investment locked into these projects through either the sale of equity or a leasing arrangement, or by using the revenue stream for raising debt on the capital market. The approach is equally applicable in both the public and private sectors, although at present it is most actively beingcontinue

promoted through the sale of existing publicly owned hydropower assets in a number of countries, particularly in South, Central and North America.

Different approaches have been adopted to the privatization of existing hydropower assets, ranging from their outright sale to the granting of a concession without any transfer of ownership. In some cases an hybrid formula has been adopted, for example in Argentina, where the concessionaire owns the powerhouse but rents the dam and water conduits from the state, which imposes operating rules for the reservoir and thereby retains control over the multipurpose aspects of the project.

An example of securitization can often be found in China, which has traditionally funded infrastructure projects with public funds and recently refinanced some of them on completion through the issue of equity and debt in the capital market. Shares in what were originally state projects have been issued through offerings in the public equity markets, and in some cases limited−recourse debt has been raised by the project company on the basis of its anticipated revenues. In each case the end result is that the financing burden is transferred to the private sector.

Upgrading and Rehabilitation

The capital−intensive nature of hydro projects, combined with their long shelf life and relative robustness, has created another category of investment opportunities in existing projects that have simply been underinvested through either neglect or lack of resources, and require further funding for rehabilitation and upgrading to bring them to full production.

This is a market that is attracting the attention of private investors because it is more easily financed than greenfield projects, as expenditure is mainly on equipment and it generates an earlier cash flow stream. A further

advantage is that it usually avoids major civil construction risk. On the other hand there are issues relating to the assumption of responsibility for the existing works by the incoming concessionaire, and for this reason he may seek to ring−fence his liabilities, leaving gaps that are difficult to cover.

Most opportunities of this type fall into the ROM (rehabilitate, operate and maintain) category under which the concessionaire has the right to operate the scheme and sell its production for a specified period. There is generally no transfer of title involved.

Greenfield Developments

As already indicated, the number of successful closures on new−start private hydro projects has been disappointingly low, but there is evidence that the level of activity is increasing as developers seek to diversify toward renewable energy sources.break

New hydro is difficult to finance because it has an unfavorable risk profile, long payback periods and an unusually high proportion of local costs that are not eligible for export credits. The extent to which these factors concern potential investors is demonstrated in a recent survey of investor attitudes to new hydro projects.3 An unspecified number of international IPP companies were questioned on their appetite for pursuing new private hydro developments in Brazil, one of the world's largest hydro markets. Of the ten that replied:

· only one expressed a definite interest in investing in 'large" new hydro projects; and

· about half expressed qualified interest in investing in "small" hydro projects (below 300 MW).

The main reasons given for their reluctance to invest were:

· substantial completion risk;

· delayed revenue earning leading to the projects being "earnings dilutive";

· the mismatch between tenor of loans available and the revenue stream; and

· concerns over environmental opposition.

Although this is the only investor survey on the subject that the author is aware of, it reflects the views that are often heard from a wide range of independent power developers.

Trends in the Private Hydro Market

In response to these challenges certain trends are becoming apparent. These are not only dictated by the perception of developers, but also by the attitudes of the organizations that provide the funding and guarantees upon which the financing of private projects is dependent. In particular:

· There is a bias toward run−of−river projects, and away from large storage schemes. While this might in part be influenced by the perception that dams present a greater completion risk than tunnels (not necessarily true), it is undoubtedly primarily driven by the wish to avoid the delays, costs and adverse publicity associated with the perceived negative environmental impact of reservoirs.

· Most privately financed hydro projects are small, typically under 100 MW. There are some up to 300 MW under construction, but few above this figure. Of the mega projects over 1,000 MW, only two have reached the

construction stage; both are incontinue

3 Coopers & Lybrand. Working Paper D3 for SEN/Electrobás.

Brazil and were only offered for private sector participation after the public sector ran out of funds.

Interviews with a number of the guarantee agencies like the Multilateral Investment Guarantee Agency (MIGA) and the Overseas Private Investment Corporation (OPIC), which are directly concerned with the protection of investments in private projects overseas, revealed very little involvement in anything but small hydro schemes. There was a negative attitude toward large hydro projects on environmental grounds, often without regard to the difference between run−of−river and storage schemes.

The trend toward smaller, run−of−river hydro projects is an understandable response by the private sector to ease the already difficult problem of attracting private finance to greenfield projects, but it is not necessarily conducive to maximizing the benefits of hydropower. Without storage many of the unique attributes that hydro brings to a system are lost, in particular the ability to store and redistribute energy within the load curve, and the ancillary benefits of frequency control and rapid−response reserve generation. Furthermore, in common with other forms of generation, hydro exhibits economies of scale and it is only the larger schemes that are likely to yield really cheap energy.

Candidate Projects

The object of this study is to draw on experience from a selection of candidate projects that have already reached or are nearing financial closure, with a view to examining the principal issues that arise in the development of privately funded hydropower projects. To supplement the information available from this source, views have also been drawn more widely from elsewhere in the private hydro industry.

A list of the candidate projects and their basic characteristics, is given in Table 4. They are chosen from the countries that have been among the most active in promoting private hydro development. In addition to providing a regional spread they include projects intended for export, for domestic consumption and captive power plants (autoproducers). Collectively the candidate projects represent a reasonable cross−section of the types of private hydro schemes coming forward for investment, and individually they exhibit a number of features of special interest as follows:

· ***CASECNAN (150 MW)*** is a multipurpose storage project in the PHILIPPINES, which is unusual in that it attracts almost half of its revenue from the sale of water. It is believed to be the first major hydro scheme to be financed on the US144A bond market.

· ***SAN ROQUE (345 MW)*** is also a multipurpose storage project in the PHILIPPINES. It is one of the few examples of a hybrid project that has been geographically dividedcontinue

into power and nonpower elements, which are separately financed in the private and public sectors.

· ***BAKUN (70 MW)*** is a more traditional run−of−river power project in the PHILIPPINES, and the only concession to be awarded in the first round of competitive bidding initiated by the National Power Corporation (NPC) in 1994. The project is conventionally financed by bank lending, which was initially supplied by local banks and later syndicated internationally.

· ***THEUN HINBOUN (210 MW)*** was the first of the IPPs developed in LAO PDR for the export of hydropower to Thailand. The project has strong public sector overtones as the principal sponsors are two publicly owned western utilities, and there is a major holding by the Lao government supported by concessional loans from ADB.

· ***NAM THEUN II (900 MW)*** is another LAO PDR export project. It represents one of the largest hydro IPPs to be considered for limited−recourse project financing, which will be dependent on securing the necessary World Bank guarantees. The project has been prepared in great detail by the promoters in close collaboration with the government, particularly on environmental issues.

· ***KHIMTI I (60 MW)*** was the first private sector hydro project in NEPAL and as such did much to establish the existing framework of agreements that back the government's (hydel) hydro policy. There was strong public sector involvement through the Norwegian utility, with support from the Norwegian government and two major multilateral development banks.

· ***UPPER BHOTE KOSHI (45 MW)*** is another run−of−river project in NEPAL, but it differs from Khimti I in that it is a more genuinely private development with no foreign utility or bilateral support. However there is still strong multilateral support through the International Finance Corporation (IFC).

· ***BIRECIK (672 MW)*** is the first major build, operate, transfer (BOT) hydro project in TURKEY, and as such it acted as a trailblazer but it took nine years to bring to financial closure. It is an example of a public−private partnership with the utility holding an equity stake and assuming many of the risks.

· ***ITA (1450 MW)*** is one of the several large projects in BRAZIL currently being promoted as autoproducers. The project started in the public sector but is now being developed in conjunction with the utility on a standalone basis using limited−recourse private financing. It provides an example of public−private partnership on the Brazilian model.break

· ***GUILMAN−AMORIN (140 MW)*** is another autoproducer project in BRAZIL, but unlike Ita it started in the private sector and is totally privately financed, with no equity participation from the utility. However the utility still has a significant role in the project as an operator and partial offtaker.

Further details of all of these projects are provided in the individual Project Profiles contain in Annex 1.break

TABLE 4: CANDIDATE PROJECTS—SCHEME CHARACTERISTICS

Project	Country	Capa−city (MW)	Function	Type	Dam Height (m)	Tunnel Length (km)	Powerhouse	Transmis−sion (km)	Current Status
Casecnan	Philippines	150	Multi−purpose	RR	−	26.00	Underground	−	Under construction
San Roque	Philippines	345	Multi−purpose	ST	200.00	−	Shaft	10.00	Financing completed
Bakun	Philippines	70	Power	RR	−	9.40	Surface	20.00	Under construction
Theun Hinboun	Lao PDR	210	Power	RR	−	5.20	Surface	100.00	Completed 1998
	Lao PDR	900	Power	ST	50.00	3.50	Underground	146.00	

Nam Theun II									Financing stage
Khimti I	Nepal	60	Power	RR	−	10.00	Underground	−	Under construction
Upper Bhote Koshi	Nepal	36	Power	RR	−	−	Surface	24.00	Financing stage
Birecik	Turkey	672	Power	ST	62.00	−	Surface	−	Under construction
Ita	Brazil	1,450	Power	ST	125.00	−	Surface	1.80	Under construction
Guilman−Amorin	Brazil	140	Power	RR	41.00	5.70	Surface	3.00	Completed 1998
Key:	ST	Storage							
	RR	Run−of−river.							

Source : Author's notes.

Section 2— Issues in the Financing of Hydro Projects

Characteristics of Hydro Projects

Hydro can be characterized in the following way:

· Very site−specific with no two projects being the same, and usually a number of possible ways of developing each site. It will often be more economical to develop a site to provide peaking energy, rather than base load.

· The high percentage of civil works (typically 70 percent by cost) means that it is difficult to accurately predict end−costs, particularly when high exposure to local inflation is a factor.

· High construction risks due to the nature of the works, with extensive exposure to geological conditions, flooding, access problems, etc.

· Uncertain energy production and vulnerability to wider water management issues that can constrain the flow available for generation.

· High capital costs but low operating costs, and very long plant life (minimum 30 years for electrical and mechanical—E&M—equipment and almost indefinite life span for civil works).

· Environmental costs clearly identified and fully internalized, in a way that is not the case for thermal plant. Extreme sensitivity on environmental and resettlement issues for reservoir schemes.

· Power stations with reservoirs have the ability to economically provide ancillary services and produce higher−quality energy than run−of−river schemes, as well as multipurpose benefits.

The most distinctive feature of hydro is there is no such thing as an "off−the−shelf" solution. The concept of standard frame sizes that dominates the development of thermal plants does not exist in hydro where the number of variable parameters introduced by the different characteristics of each site rule out any standardized solution.

For this reason site selection and the optimization of the project layout, installed capacity and technology are significantly more crucial and complicated in the case of a hydro project than in any other form of power generation.break

Types of Hydro Project

For the purposes of the chapters that follow it is necessary to briefly summarize the main features of the different types of hydro project. Broadly hydro can be classified as either:

· Run−of−river;

· Storage; or

· Pumped storage.

Run−of−river Projects

Run−of−river projects fall naturally into two categories:

· Upland projects that use the natural fall of the river to create the necessary head, which is then commanded by tunnel, canal or surface conduit. These are typically high−head, low−flow schemes.

· Lowland projects that are sited at barrages on the more mature, lower reaches of rivers, where they rely solely upon the head created by the barrage. These are typically low−head, high−flow schemes.

Most run−of−river schemes have negligible storage in the head pond upstream of the intake, and therefore production is determined by the instantaneous river flow. Sometimes there is limited storage sufficient to provide hourly or even daily regulation, but generally the output of the scheme is maintained to exactly match river flows. In consequence run−of−river hydro provides only relatively low−value baseload generation and it is not particularly attractive in hydrological regimes exhibiting wide seasonal variations in flow.

The environmental impact of upland projects generally focuses on the depletion of flow in the reach between the intake and the powerhouse. Otherwise the impact is usually minor, particularly if the works are predominantly underground, as there is only a small reservoir and no interference to the natural flow regime. Lowland schemes can be more sensitive because they are generally in more densely populated areas and involve a larger flooded area.

The principal long−term threat to run−of−river projects is the siltation of tunnels and waterways, and changes in the flow regime. Both of these can be seriously exacerbated if the upstream catchment is allowed to deteriorate.

Run−of−river schemes form the majority of privately funded hydropower projects currently under construction or at an advanced stage of planning.break

Storage Projects

Conventional

Storage projects use a dam to provide all or part of the generating head. If there is a reasonably steep fall on the river downstream, the additional head will generally be commanded by tunneling. Where there is no natural head to command downstream, the powerhouse is located immediately below the dam, usually on the surface but sometimes underground or occasionally within the dam body itself.

Storage schemes alter the flow regime, and therefore they must be viewed in the context of an overall integrated river basin development plan. Where a number of projects are to be sited on a single river, it is often more economical and environmentally less damaging to develop one large storage above a cascade of run−of−river schemes, as opposed to building a series of smaller storage projects.

The dam is the central feature of such schemes. Due to the safety and cost implications, detailed studies need to be undertaken to arrive at the optimum design for any dam. In practice the choice of dam type is closely linked to site topography, geology, diversion arrangements, and to the availability of construction materials. In consequence much work is needed before the optimum engineering solution for any particular site can be identified.

The attraction of a storage project lies in its versatility, because the existence of a reservoir allows:

· Higher water utilization through reduced spillages;

· Conversion of low−value baseload energy to high−value peaking energy;

· Load−following and frequency control;

· Provision of spinning reserve and emergency stand−by;

· Provision of reactive services for power factor corrections; and

· Other multipurpose benefits.

Where multipurpose benefits such as flood relief or irrigation are present it creates the possibility of financing these elements under concessional arrangements, thereby increasing the overall commercial viability of the project.

The mode of reservoir operation is the key to obtaining maximum benefit from storage schemes. Generally there will be a long−term reservoir management plan, updated monthly, which recognizes the current status of the reservoir, the seasonality of the river flow and other water management constraints. This will be supplemented by a short−termcontinue

daily operating plan that defines the limits within which the load dispatcher can call upon machines to meet system requirements.

Typically storage−based hydro is used in the mid to upper range of the load curve to displace high operating−cost thermal peaking plant. It provides load−following and frequency control, and units can be held on standby to cover any outage that may occur elsewhere on the system. It is these ancillary, or dynamic, benefits that give hydro its unique qualities in terms of system management, particularly where storage schemes are concerned.

However the dispatcher's ability to release water to maximize power benefits is sometimes constrained by downstream riparian interests that may require a different release pattern for other purposes (such as irrigation, river transport) and for this reason governments will often seek to impose operating limits on private reservoir owners. Such limits can have an adverse impact on the revenue stream from the power generation.

Environmental considerations are naturally more important with storage schemes because of the effect on flora, fauna and people in the reservoir basin, and the alteration of flow patterns downstream. Pressure from environmental lobby groups has made developers and financiers wary of such projects because of the delays and additional costs that can arise from a well−orchestrated campaign of adverse publicity.

Siltation is also a threat to storage projects. In extreme cases the deposition of silt in reservoirs can seriously deplete the live storage and reduce the value of the project by converting it gradually into a run−of−river scheme. For this reason many independent power developers will seek to include in the Concession Agreement an obligation on the host government to protect the upstream catchment or provide compensation in the event of it being allowed to deteriorate.

There are relatively few privately financed storage schemes being developed at present. Compared to the run−of−river alternatives, the ratio is less than one in five, and possibly as low as one in ten.

Pumped Storage

The benefits that pumped storage brings to a system are essentially the same as for conventional storage but with the added benefit that pumping constitutes an immediate on−demand load that enhances the system operator's ability to run a thermal plant at maximum efficiency. It is particularly used on mature systems where it is often better to separate the role of system management from the primary generating function.

Most pumped−storage schemes have negligible flow accruals to the upper reservoir. Such schemes consume energy as a result of efficiency losses on both the pumping and generating cycles, the combined loss being of the order of 30 percent. However these losses are usually more than offset by the increased value of the stored energy, which is converted from base to peak load, and by the benefits accruing from thecontinue

more efficient use of the thermal plant on the system. Being both a potential load and a source of generation, a pumped−storage scheme has a "reach," in terms of system management, equivalent to twice its installed capacity.

While there are a number of pumped−storage schemes owned by private utilities, and others are being planned, at present no privately financed pumped−storage projects have reached financial closure on a limited−recourse basis. The main obstacle appears to be uncertainty over the value and pricing of the ancillary benefits.

Hydro−Specific Problems

All private infrastructure development carries certain common risks beyond the control of the project sponsor (such as political risk, currency exposure, force majeure) but hydro is perceived as posing particular difficulties in a number of areas relating to project definition, risk, financing and regulation, as follows:

(a) ***Project Definition***

· High front−end costs;

· Difficulty in structuring procurement contracts;

· Potential conflict between the interests of the system and the private developer.

(b) ***Risk Profile***

· Unusually high construction risk;

· Hydrological risk;

· Environmental sensitivity and costs.

(c) ***Financing Constraints***

· Heavily capital−intensive;

· High proportion of local costs;

· Long payback periods.

(d) ***Regulatory Issues***

· Need to conform to overall river basin plan;

· Award of the Concession;

· Pricing of output.

The impact of each of these is briefly discussed below.break

Project Definition

The site−specific nature of hydro makes it impossible to define a project with any degree of certainty without significant expenditure on site investigations and front−end studies. Typically, under the traditional public sector arrangement, the utility would have spent 2 to 3 percent of the eventual cost before inviting priced bids for construction. This process took a number of years and involved a gradual progression through prefeasibility, feasibility and tender design stages. Over this period there gradually emerged the concept of the scheme that represented the optimum development of the site for the requirements of the power system it was to serve.

Public utilities took this approach because it was in their interest to achieve maximum benefit from the development of the site, and by tendering a well−investigated project they knew they would get competitively priced bids with less scope for subsequent contractual problems. However under private sector financing few promoters are prepared to engage in this level of front−end expenditure on a speculative basis without the certainty of an agreed position on the project. The logical procedure of first defining and pricing a project, and then finalizing the concession and tariff arrangements is in direct conflict with the commercial priorities of the promoter who will try to spend as little as possible before achieving exclusivity.

A further problem arises when projects are selected and defined by the developer without regard to the overall requirements of the system and the optimal development of the site. There is a natural tendency for developers to select the configuration that will provide the lowest risks and highest returns, irrespective of the fact that it may well represent an underutilization of the site, for example by creating a baseload run−of−river scheme where a storage project might be possible. The structuring of most hydropower tariffs generally still fails to reflect the

priorities of the system, and therefore unless a developer is coerced he is likely to opt for the project that suits his objectives rather than the requirements of the system.

Risk

Construction Risk

The principal construction risk in hydro projects arises from geological conditions. This encompasses a wide range of issues (such as slope stability, ground treatment, depth of excavation, rock support), any of which can have a major influence on both the schedule and final cost. Although geological risk may be mitigated by careful selection of the site and project layout, and by adequate advanced site investigation, it is inevitably a factor in the construction of every hydro project.break

Other principal sources of construction risk arise from the location of the sites in river valleys, often in remote areas where the works are vulnerable to flooding and logistical problems.

Unfortunately the historic record has not been good. A study of 125 World Bank−financed power projects over the period 1965−861 showed that, on average, hydro schemes overran 27 percent on cost and 28 percent on schedule. The comparable figures for thermal projects were 6 percent and 30 percent. However it should be noted that all of the projects analyzed were carried out in the public sector under different contractual and cultural arrangements from those currently being imposed in the private sector. Experience on privately funded thermal power stations has shown that, under a stringent system of accountability, projects can be delivered on budget and within schedule. Although hydro is more complex it is reasonable to expect a similar improvement.

The capital−intensive nature of hydro means that the potential losses of developers through construction delays can be very large, to the point where it becomes difficult to cover them by contractual penalties or insurance. For example, a 300 MW project operating at a 65 percent capacity factor will be generating about 140 gigawatt−hours (GWh) per month, worth perhaps $10 million a month in revenue. A six−month delay on completion, resulting from a 15 percent overrun on schedule, would represent a loss of $50 million, which would be nearing the acceptable limit of liquidated damages for most contractors on a project of this size.

Hydrological Risk

Hydrological risk lies outside the control of any of the parties to a private power contract. Furthermore the assessment of project hydrology necessarily has to be based on historic data, which can be highly variable in its reliability.

The traditional approach to hydrology has been to assume that, in statistical terms, historic flow patterns would be replicated in the future. Nobody has seriously challenged this premise, although it could be called into question at a time when there is increasing concern over long−term changes in the global weather patterns.

There are three main types of hydrological risk that will concern a private investor:

· The risk of flood damage, either during construction or to the completed structure;

· Short−term production deficits arising from a sequence of dry years below the long−term average; andbreak

1 Besant−Jones, *An Analysis of World Bank Financed Power Projects* .

· Sustained production deficits arising from either an incorrect original assessment of the average hydrology, or subsequent changes in the hydrological regime.

Although the significance of these will vary from project to project, all can have a bearing on the security and viability of any IPP investment

The management of floods during construction is essentially a commercial decision, balancing the incremental costs of increased flood protection against the probability and consequences of specific floods occurring. This is primarily a matter of risk allocation between the owner, the contractor and his insurer; it would generally not involve the host government.

In contrast the definition of a dam's permanent spillway capacity is of direct concern to the government due to its public safety implications, as historically most dam failures have occurred through flood damage caused by spillway deficiencies. There are well−established international norms for the sizing of spillways and although these still leave some latitude for differing interpretations it is to be expected that ultimately the government will play a large part in determining what is acceptable for any scheme.

Production deficits are of concern to the private investor if the project company carries the hydrological risk. Where this risk is totally or largely assumed by the offtaker, the private investor is protected against fluctuations in revenue due to river flows.

Where there is exposure on the part of the project company, it can be a temporary problem arising from short−term variations in hydrology around the long−term average (that is, a sequence of dry years) or it may be more fundamental if the long−term average flow reporting to the project is lower than expected.

In practice, temporary production deficits are not generally a serious problem because on a mixed generating system hydro normally moves toward the peak of the load curve in dry spells. Lack of water usually results in an energy deficit, as opposed to a loss of capacity, so the viability of the system is not threatened although it incurs the additional variable operating cost of the extra thermal generation needed. In the context of a private hydro plant selling into a large mixed system, the utility should therefore be able to carry the risk by diversification, provided it equally benefits from excess hydro production in periods of high flow.

Where long−term average production falls below expectations it is clear that no mitigating mechanisms are possible and the cost of the deficit has to be borne between the parties.break

Environmental Risk

Lenders and guarantors are highly sensitized on environmental issues, and they invariably require that a project meets not only local environmental permitting requirements but also acceptable international norms as defined by organizations such as the World Bank.

In the case of hydro schemes the environmental issues can be complex, and they will vary substantially between projects. Storage schemes, in particular, tend to be sensitive if they involve resettlement or the loss of rare habitat.

In the past promoters have generally been left to obtain their own environmental clearances. This can be a time−consuming and expensive business, and it represents another area of unwelcome risk and delay as far as the private developer is concerned. The cost of environmental mitigation is invariably borne by the project.

Financing Constraints

Hydro is highly capital−intensive, and in consequence a very large proportion of the tariff during the debt−servicing period is attributable to capital charges. This is a marked contrast to thermal IPP plants where fuel and operation and maintenance (O&M) costs constitute perhaps half the tariff. In making a comparison between the two this creates a number of adverse impacts on hydro, in particular:

· The capital sums that have to be raised for hydro are proportionately much larger;

· The increased cost of capital that comes from private financing is magnified to a greater extent with hydro because the costs are dominated by capital charges; and

· Cost−based tariff profiles result in high upfront prices with minimal escalation, which appears unfavorable in comparison with thermal where there is a lower base cost but a much greater escalating element in the tariff reflecting fuel and O&M.

A further factor in the comparison with thermal plants is the relatively high proportion of local civil costs in the average hydro scheme. These costs can be difficult to estimate because they can be subject to high and unpredictable local cost escalation and, more significantly, they are generally not eligible for financing through the export credit agencies (ECAs) that traditionally provide most of the funding for thermal IPPs. This leaves a financing gap that can be difficult to fill. Where local capital markets are sufficiently developed there is an advantage in favor of hydro if a portion of the funding can be raised in local currency, thereby removing some of the exchange rate exposure.

A major difficulty exists in trying to reconcile the relatively short tenor of ECA finance and commercial loans with the long productive life of an hydro project. Tariffscontinue

have to be heavily front−end loaded to meet debt service obligations, and the debt−equity gearing tends to be driven down to preserve debt−cover ratios. Both of these adversely affect the perception of hydro as an investment, particularly when compared with thermal projects where the project life span is more in keeping with the tenor of loans.

When all debt servicing obligations have been completed the obverse applies and hydro becomes disproportionately cheap, to the point where no other form of generation can compete. In transitional economies this is posing a problem because low−cost energy from existing hydropower schemes is distorting tariff structures and inhibiting the development of new generating facilities. The challenge in financing hydro projects is therefore to achieve some balance between their tendency to be uncompetitive in the short term and overcompetitive in the longer term.

Regulatory Issues

Private hydro poses a number of specific regulatory issues that arise from the fact that hydro entails the exploitation of unique natural resources which would generally be regarded as the property of the state and it often needs significant public sector involvement to ensure that projects are commercially viable and consistent with wider development objectives.

Unlike thermal power projects, which can be built and operated essentially in isolation, an individual hydro scheme has to be seen in the broader context of the river basin where there may be multiple water uses and other hydropower projects to be considered.

The award of any concession is complicated by the lack of project definition in the early stages and the fact that there is very little replicability between projects. Where concessions are invariably based on the sale of energy to the host utility the public sector has a role in determining the acceptability of the proposed tariff, but this can be a difficult area if the project is not sufficiently defined to be accurately costed at the time of concession award. Under such circumstances the finalization of the tariff tends to be delayed until after the concessionaire has completed his project studies, or in some cases the project itself, which raises concerns over transparency.

Tariff structure is important. For thermal IPPs revenue is generated approximately equally between Capacity Charges, which effectively cover the capital investment and other fixed costs, and Energy Charges, which cover fuel and marginal operating costs. If this approach is applied to hydro the tariff would consist almost exclusively of Capacity Charges. In practice this is seldom the case, and most hydro tariffs to date have been based heavily on Energy Charges. The relative costs of peak and baseload energy are often ignored and in general the premium value of peaking energy and the ancillary benefits that hydro provides, particularly from storage schemes, are being overlooked in offtake contracts because in the public sector such services were simply available,continue

unpriced. However this may change as the deregulated industry learns to cope with patterns of load−flow and plant operation that increasingly stress transmission systems because hydro projects that formerly provided reserves now tend to be operated to maximize "real power" revenues. Tariff structures now need to recognize that some hydro schemes may be more valuable when held in reserve. In the United States where deregulation is throwing these commercial issues into sharp focus, EPRI2 is currently investigating appropriate methods for valuing and pricing the ancillary services provided by hydro plants.break

2 Electric Power Research Institute.

Section 3—
Regulatory Background and Concession Arrangements

Regulatory Background

In recent years there have been great changes in the regulatory environment for the power sector in most countries. These were initially aimed at unbundling and privatization, and then at the development of privately financed generating plant. This chapter examines the regulatory background against which the candidate projects were financed, and then reviews more closely the specific circumstances and terms under which the concessions were let.

Philippines

Until 1987 the National Power Corporation (NPC), a government−owned corporation, had an effective monopoly on the generation, transmission and sale of bulk power throughout the Philippines. In that year Executive Order No. 215 stated that the generation of electricity was no longer a natural monopoly and it prepared the way for the Build, Operate, Transfer (BOT) Laws (Republic Acts No. 6957 of 1992), which provide for the private sector to finance, construct, own and operate infrastructure projects for a "Cooperation Period" after which ownership reverts to the government. During the Cooperation Period the private sector is allowed to recover its costs with profit through payments related to the projects output, the cap for such payments being the avoided cost that would have been incurred if the government had implemented the project itself.

In the early 1990s, against a background of severe power shortages, the breaking of the NPC monopoly was followed by a spate of thermal IPPs (gas, diesel, coal, geothermal) but despite a long tradition of hydro

development in the country, it was difficult to mobilize the same level of interest in the hydropower sector.

From the outset NPC adopted a competitive tendering approach, comparable to that for other publicly bid infrastructure projects. In following this they had the advantage of having available a number of feasibility studies for small to medium hydro projects, which had specifically been prepared under World Bank funding for private funding. Furthermore they had a backlog of other larger projects awaiting development as there had been no publicly financed large hydro scheme constructed in the Philippines for many years.break

The issue of water rights had to be addressed before the bidding could be opened to international companies. Under the constitution the right to exploit natural resources (such as rivers) is confined to local entities with at least 60 percent Filipino ownership. To prevent this becoming a bar to external investment, NPC acquired the water rights for their privatized projects with a view to temporarily assigning them to the promoters.

The BOT Law sets out a number of incentives available from the government, including:

· Fiscal incentives such as tax holidays, reduced taxes and simplified customs and import procedures;

· Direct government support such as the provision of the sites, responsibility for environmental mitigation and resettlement costs, provision of access roads and transmission lines;

· Contractual support in the form of guarantees and other forms of credit enhancement, minimum offtake provisions and the like; and

· International arbitration.

The tendering process for BOT concessions requires them to be advertised publicly in advance. Prequalification of consortia is based on their financial strength and technical competence. Applicants do not necessarily have to nominate the entire project team as it is recognized that proponents may wish to competitively bid the construction later. A period of about six months is allowed for bid preparation.

Bids have to be accompanied by detailed technical studies containing the project definition, and minimum design and performance standards. NPC provides a copy of the draft power purchase agreement (PPA) defining the risk−sharing mechanisms and legal relationship between the parties. Bids are evaluated first on technical acceptability and then on price. The technically compliant bid having the lowest net present value tariff over the 25−year contract period is recommended for contract award, subject to the proposed tariff being below NPC's avoided cost.

In the event of there being only one bidder NPC is free to enter into direct negotiations. Once the BOT contract is awarded the concessionaire is allowed to procure goods and services as he wishes.

NPC has a policy that projects offered for bidding should be backed by full feasibility studies prepared by NPC at its own expense. This does not, of course, prevent prospective promoters from preparing their own feasibility studies for making proposals on unsolicited projects. Where unsolicited proposals are made, they are themselves subjected to competition under the "90−day rule" during which period competing bids are solicited.break

There are no special incentives in the legislation to favor hydro above other forms of generation, other than for small schemes below 10 MW where a number of privileges are granted to local companies with a minimum of 60 percent Filipino ownership (Mini−Hydroelectric Power Incentives Act, RA No. 7156 of 1991).

Lao PDR

In contrast to the other countries covered by the case studies, the deregulation of the power sector in Lao PDR and the associated legislative reform to facilitate foreign investment were primarily aimed at the export market.

Historically the generation, transmission and distribution of power in Lao PDR has been the responsibility of the state−owned utility, Eléctricité du Lao (EdL). In 1986 the government introduced the New Economic Mechanism which, among other things, aimed at encouraging private funding into the power sector to increase export earnings from electricity sales based on hydropower.

In response to these changes the Hydropower Office was established as a separate entity to EdL, to concentrate on the planning and implementation of IPP hydropower projects for the export of power to neighboring countries, primarily Thailand. This left EdL, as the public sector utility, focused on serving the domestic market. Both organizations come under the Department of Electricity.

Any private investment in Lao PDR is effectively foreign, and as such it is channeled through the Foreign Investment Management Committee which ultimately negotiates the terms of any concession and obtains the necessary approvals from the various government bodies involved. A major concern for prospective investors has been the relatively unformed state of the banking and legal system. Recognizing this the government embarked on a series of reforms culminating in the Foreign Investment Law (Law No. 01/94) of 1994, of which the principal provisions are:

· Property and investments of foreign investors are protected by the laws of Lao PDR and cannot be requisitioned, confiscated or nationalized except for a public purpose and upon prompt and adequate compensation.

· Foreign investors can invest either as a joint venture with local partners or as a wholly foreign−owned enterprise.

· Foreign investors may lease land and transfer leaseheld interests. They may own and transfer land improvements and other moveable property.

· Foreign investors will give priority to Lao citizens in recruiting employees, but will have the right to employ skilled foreign personnel when necessary.

· Foreign investors may repatriate earnings through a Lao bank or a foreign bank established in Lao PDR.break

· International arbitration.

There is no specific BOT legislation, and no set procedures for the award of BOT concessions. All of the hydro concessions in Lao PDR have been directly negotiated with the government.

Nepal

Nepal, in common with other low−income countries, traditionally relied heavily on concessional financing and grant−aid for the development of its infrastructure. But over the last decade the environment has changed to place less reliance on public funding and more on the induction of private finance into an increasingly free market.

Like Lao PDR, Nepal is a small country with indigenous hydro resources that far exceed its domestic requirements. It also has on its border a large neighbor (India) that is short of power and with whom it has had a limited history of cross−border trading in electricity. However to date, despite talk of major export projects Nepalese private hydro developments have been entirely focused on the domestic market.

The economic liberalization program that made this possible started in 1992 with the adoption of a new Industrial Policy, followed shortly thereafter by a number of decrees including the Foreign Investment and Technology Transfer Act, and Hydropower Development Policy, both in 1992. At the same time the Electricity Act (1992) and the Electricity Regulation (1993) began the process of freeing up the electricity sector. All of these reforms were aimed at attracting foreign investment into small−to−medium projects to meet internal demand.

Despite these changes a number of encumbrances to conventional project financing remains. In particular Nepal does not have an internationally recognized credit rating, and the legal and regulatory frameworks are still in their formative stages. However over the last six years an attractive incentive program for inward investment in hydropower has emerged, largely based on the experience of the two IPP hydro projects referred to in this study. These include:

· Government willingness to provide partial guarantees;

· Fiscal incentives including tax holidays and import concessions;

· Acceptance of foreign ownership and protection of those rights and the right to repatriate foreign earnings;

· Fixed royalty payments;

· International arbitration (in Nepal).break

The process of securing BOT hydro concession requires an application under the Water Resources Act (1993) under which a license is granted for the utilization of water resources at a particular site for a period up to 50 years. There is no specific requirement for competition. The licensee then has to enter into an Electricity Sales Agreement with the Nepal Electricity Authority (NEA).

Due to its transitional state in moving from the status of an International Development Association (IDA) country to one able to sustain commercial lending, Nepal is still heavily dependent on the multilaterals for quasi−commercial funding. One of these initiatives is the formation of the Power Development Fund with the support of the World Bank, with the intention that the fund would be used as a catalyst by providing:

· direct loans including senior and subordinated debt; and

· onlending facilities through local credit institutions; and

· contingent financing.

As the domestic capital markets develop and the investment environment becomes more self−sustaining, it is anticipated that the focus of the fund will broaden to include support for loan syndication and local equity participation

Having now made considerable progress on establishing and proving the investment climate for domestic projects, the Nepalese Government is now turning its attention to the regulatory framework that will be needed for the much larger, export−oriented projects that are now beginning to attract the attention of prospective developers.

Turkey

Despite being regarded as the birthplace of the BOT concept, private infrastructure projects in Turkey have become bogged down in constitutional and legal disputes that have seriously delayed the whole process,

particularly for hydro schemes.

Law 3096 (1984) liberalized the electricity sector and specifically allowed organizations other than the publicly owned utility, TEAS* , to establish and operate generating facilities, and to sell the output to TEAS at a tariff agreed with the Ministry of Energy and Natural Resources (MENR). At the end of the agreed term the project was to be transferred to the Turkish Government at no charge.

Against the background of a worsening energy crisis a number of IPP proposals, mainly for thermal power projects, were laid before MENR but progress was slowed by constitutional challenges to the BOT concept. These hinged around the issue of whether the contracts entered into between the private developer and MENR were "concessions" or contracts governed by private law. The distinction is critical because under the Turkishcontinue

constitution concessions are subject to the jurisdiction of the Danistay, the country's highest administrative court.

Among other things, this meant that the Danistay had to approve all BOT contracts, in itself a protracted process. Furthermore the court demanded certain conditions that were in conflict with the requirements of normal limited−recourse financing. In particular it could not accept the right to assign contracts in the event of a default by the project company (because this conflicted with the granting of a concession to a specific party) and it could not accept international arbitration as this would override the jurisdiction of the Danistay.

Following the enactment of Law 3096 a number of subsequent laws sought to clarify the situation, in particular Law 3996 ("The BOT Law") under which the legislature specifically defined certain projects as not being concessions and therefore subject only to private law. A number of projects proceeded on this basis, but in March 1996 the Constitutional Court invalidated the relevant portions of the BOT Law, in effect saying that it was the courts, and not the legislature, that would determine whether contracts were concessions.

In 1997 the legislature passed the Build−Own−Operate ("BOO") Law in an attempt to overcome the concession issue. However hydroelectric projects are specifically excluded from this law and it must therefore be inferred that at present the key "Implementation" Agreement between the project company and MENR must still be submitted to the Danistay for all hydro projects.1

The terms under which such agreements are executed include the following provisions:

· Power offtake contracts with the utility (TEAS*) are denominated in foreign currency but payable in local currency with full convertibility. Treasury Guarantee in respect of the obligations of TEAS;

· No limitations on foreign ownership of the project company;

· Take−or−pay obligations, with full pass−through (to TEAS) of hydrological risk and certain unforeseen construction costs principally relating to geology;

· Fiscal incentives including tax concessions and access to government loans to meet revenue shortfalls during the debt repayment period;

· Supervision of construction by an Independent Consultant reporting to MENR.break

1 Since writing this the legislature has passed on an Act accepting the principle of international arbitration.

The procedures for tendering BOT contracts in Turkey are broadly similar to those of the Philippines. The government advertises the projects for which it is soliciting proposals, and goes through a prequalification process. Prequalified consortia are required to purchase existing technical studies from MENR, and to use them as a basis for preparing a detailed technical and commercial proposal for which they are typically given 4 to 6 months. There is no exclusivity at this stage, and it is up to each bidder to undertake whatever extra studies he considered necessary at his own cost. The criteria for awarding the bids is the lowest average tariff cost, subject to technical compliance.

Brazil

Brazil provides an example of a largely self−contained economy at an advanced stage of deregulation where, at the time of liberalization of the power sector, the installed hydro capacity was already about 50,000 MW. Hydro sources more than 95 percent of national electricity production.

From 1971 to 1993 tariffs were set by the Federal Government in a manner that gave the publicly owned state utilities little incentive to reduce costs or increase efficiency. By the early 1990s the power sector was virtually bankrupt, and faced with a load growth of 7 percent a year the government had little alternative but to embark on a major reform of the industry.

The process began in March 1993 with the passing of Law 8631 aimed at restructuring the power sector to encourage the resumption of investment. Under this Law the concept of a common tariff was dropped and each utility was entitled to charge on the basis of "full cost recovery plus a reasonable return on investment." Subsequently Decree 915 (September 1993) allows private sector participation in the generation of electricity, either for autoproduction or the sale of energy to the utility.

In 1993 Decree 1009 created a national transmission system, SINTREL, incorporating the principle of freedom of access to any supplier or offtaker irrespective of location, on payment of a wheeling charge. Thereafter it became possible for suppliers and consumers to enter into offtake contracts without regard to location.

In 1995 the "Concession Law" (No. 8987) established the principle that private parties may supply public services, and set out the conditions. In parallel the "Independent Power Producers" Law (No. 9074) set out the terms under which IPP concessions are awarded through a public bidding process for a maximum of 35 years.

In 1997 restrictions were lifted on the participation of foreign companies.

The process of reform continues with the Decree 2003 (1995), which is aimed at providing more transparency in the regulatory and tariff−setting processes for independent power producers and autoproducers. Over the last two years a number of decrees havecontinue

been enacted to establish the role and powers of the new power sector regulator, ANEEL, which will oversee the operation of the newly created wholesale energy market.

The procedure for awarding an hydro concession is regulated by ANEEL and hinges around the granting of a license to develop the site. It is not linked in any way to the energy sales arrangements that are a private matter between the developer and the offtaker who can be either one of the utilities or an individual consumer (subject to a minimum of 3 MW for hydro projects above 30 MW, and 500 kilowatts (kW) for small producers).

The procedure for granting the site license depends upon the size of the project. For projects above 30 MW a competitive bidding process is required. It is initiated by a private company undertaking the feasibility study at its own cost and making an unpriced application to ANEEL for the site license. ANEEL then publicly solicits offers

from other developers, and after a prequalification process, the feasibility study is made available to them. All prequalified parties, including the original proponent, are then given four months in which to prepare bids for the site. The winner is the one that offers the highest premium, in the form of an annual payment, for the right to develop the site. In the event of the original proponent not securing the concession, he is repaid the cost of the feasibility study by the winner.

For small projects, the concession can be authorized without competitive bidding on the basis of a feasibility study undertaken by the proponent and approved by ANEEL. If two or more companies are competing for the same site the position is unclear, but in the interests of creating competition ANEEL are likely to favor the company with least participation in the market.

Site licenses are granted for periods of 30 to 35 years, after which they are renewable by agreement with ANEEL. There is no provision for the transfer of the project back to the state.

Award of the Concessions

This section describes how the concessions for the candidate projects were awarded in the context of the regulatory framework described above. Table 5 summarizes the Concession Agreements concluded.

Bakun, San Roque, Casecnan (Philippines)

Following the breakup of the NPC monopoly and the emergence of the IPP sector in the early 1990s, NPC tried unsuccessfully to attract interest in the hydro sector by soliciting proposals on about 40 projects based only on reconnaissance−level studies. When this failed they selected a small number of projects that were then studied over the next two years at the feasibility level under World Bank funding, and these were offeredcontinue

TABLE 5: CONCESSION ARRANGEMENTS FOR CANDIDATE PROJECTS

Project	**Basis of Letting Concession**	**Concession Period** a	**Sovereign Guarantee**	**Royalties**	**Tax Waiver**	**Public Holding**
Casecnan	Negotiation	20 years	Yes	No	Partial	Nil
San Roque	Sole Bidder	25 years	Yes	No	6 years	Hybrid
Bakun, Philippines	Bidding	25 years	Yes	No	6 years	Nil
Theun Hinboun	Negotiation	30+10 years	No	5% of revenue	5 years	60% equity
Nam Theun II	Negotiation	25 years	No	5−30% of revenueb	not finalized	25−40% equity
Khimti I	Negotiation	50 years	Yes	2−10% of revenueb	15 years	Nil
Upper Bhote Koshi	Negotiation	40 years	Yes	2−10% of revenueb	15 years	Nil
Birecik	Negotiation	15 years	Yes	No	15 years	30% equity
Ita	Bidding	35 years	No	6% of revenue	No	39% equity
Guilman−Amorin	Bidding	30 years	No		No	Nil

	Bid to acquire CA

a From start of commercial operation.

b Royalties are usually phased in over concession period.

Source: Author's notes.

for competitive bidding in 1994. The first round of bidding was based upon a pricing formula with no minimum offtake or guaranteed payments, and which made no distinction between storage and run−of−river projects. Of the eleven projects offered, six received no bids whatsoever and three attracted bids with unacceptably high prices in terms of NPC's avoided costs.

The only project to emerge from this first−round bidding process was Bakun, where two originally independent schemes in cascade were combined into a single project, and a BOT contract was eventually concluded with a consortium comprising a large Filipino industrial company and its Australian partners.

Chastened by the poor response NPC reviewed its policy and determined to assume more of the risks, in particular by offering guaranteed payments through a minimum offtake formula for run−of−river schemes, and a capacity payment for storage projects. Other modifications were made to the commercial terms to make them more attractive to the private sector. A second bidding process in 1996/97 attracted a better response and six projects were brought to the negotiating stage. However the hesitancy persisted, and many bidders dropped out. For example, despite there being six prequalified consortia for San Roque, only one bid was actually received.

Casecnan followed a different route because of its origins as a multipurpose storage scheme being promoted by the National Irrigation Administration (NIA). The original proposal for a storage project was subsequently superseded by studies of a phased development, financed from World Bank trust funds. The unsolicited bid from the private sector effectively adopted the first phase from these studies based upon a run−of−river option. In accordance with Filipino Law the unsolicited bid was market tested for a period of 90 days during which competitive bids were invited, and in the absence of any better offers the concession was negotiated with the original proponent.

Under the terms of the Concession Agreements for the two other NPC projects (San Roque, Bakun) there are specified minimum offtake obligations and NPC hascontinue

responsibility for resettlement, land rights and easements, transmission lines and access roads. The concession is for a 25−year operating period and the government provides guarantees for the obligations of NPC and in respect of such aspects as currency convertibility. For Casecnan the position is more complicated because of the involvement of two parastatal bodies but in general the division of obligations between the public and private sectors is broadly the same. However in this instance the concession was negotiated with NIA, which purchases both the water and power before onselling the latter to NPC. The concession period in this instance is 20 years.

Theun Hinboun, Nam Theun II (Lao PDR)

Following the introduction of the New Economic Mechanism, in June 1993 the Government of Lao PDR signed a memorandum of understanding (MoU) with the Thai Government for the supply of 1,500 MW of hydro−based power by the year 2000. This was later extended to 3,000 MW by the year 2006. A similar MoU was signed with Vietnam in September 1995, under which Lao PDR would supply 1,500 MW by the year 2010, and in April 1996 an agreement was signed with Cambodia under which the two countries would collaborate in using Laotian hydro resources to supply areas of northern Cambodia.

Following the signing of the original power export agreement with Thailand, the Government of Lao PDR was approached by a number of prospective project developers. There was no formal soliciting of proposals or bidding process, each project being individually negotiated through the Foreign Investment Management Committee. The actual procedure followed was that an MoU was signed, which effectively gave the prospective developer exclusivity of the site for an unspecified period. In practice a large majority of these MoUs have not materialized into specific project proposals.

From the outset it was apparent that the private projects in Lao PDR were going to be different from those elsewhere. The undeveloped legal and regulatory framework, together with the inadequate country credit standing, were all serious encumbrances to conventional project financing. It was important for the government to demonstrate that privately funded hydro was viable, and to do this it needed the help of the multilateral development banks.

The 210 MW Theun Hinboun project was the first IPP to be negotiated. The MoU was signed in June 1993 between the Government and Nordic Hydropower AB (a joint venture of the Norwegian and Swedish utilities and MDX Ltd. of Thailand). The MoU envisaged the setting up of a Joint Venture Company, to develop and operate the project in which Eléctricité du Lao (EdL) would have a major shareholding. From the outset the Asian Development Bank (ADB) was heavily involved, both in an advisory role to the government and as the eventual sources of funds for the EdL equity.break

Closely following Theun Hinboun were two other projects, Houay Ho (150 MW) and Nam Theun II, the latter then envisaged as a 680 MW baseload station. Houay Ho was being funded from the balance sheet of a large Korean industrial conglomerate, with no formal project financing or PPA in place until late in the construction phase.

In contrast Nam Theun II was as the first major foreign investment in Lao PDR to be conventionally financed on a nonrecourse basis. It was evident from the outset that multilateral guarantees would be needed in support of the commercial credits, and from an early stage the developers entered into a dialogue with both IFC and the World Bank. The concession was directly negotiated following the signing of an MoU with Transfield of Australia in 1993. Subsequently EdF of France joined the sponsor's consortium as leader, together with a number of Thai companies, and in June 1994 a more detailed mandate setting out the terms of the concession and granting full exclusivity was signed.

In 1996, at an advanced stage in the financing process, serious concerns were raised over the environmental acceptability of the project, primarily due to its large reservoir. The government, the developers and the World Bank agreed a program that comprised five substudies relating to environmental and social aspects, together with an extensive public consultation process, to examine the overall acceptability of the project. By the time the studies had been completed in 1998, with findings that generally endorsed the choice of the project, the Asian economic crisis had changed EGAT's priorities. The project was required later and as an intermediate peaking station instead of baseload energy source that was originally envisaged. In consequence it is now scheduled for progressive commissioning as a 900 MW scheme over the years 2004 to 2005.

The concessions in Lao PDR are not standardized, reflecting the formative nature of the process in these early projects. Concession periods vary between 25 and 30 years of operation, with the option to extend for another 5 to 10 years. All three of the projects listed above have a significant EdL equity holding, ranging from a minimum of 25 percent in Nam Theun II to 60 percent on Theun Hinboun.

Theun Hinboun was successfully completed in 1998 and Houay Ho is scheduled for completion in 1999. With the exception of Nam Theun II, which is recognized as a priority project, there is some doubt about other Lao export projects being implemented in the immediate future because of the economic situation in the region.

Khimti I, Upper Bhote Koshi (Nepal)

Following reform of the energy sector in Nepal the government faced the problem of attracting investment to the domestic hydro sector in a country with no credit rating or record of private infrastructure investment. It was inevitable that Khimti I, the first project to break through this barrier, would have to depend heavily on public support in one form or another.break

The concession for Khimti I was directly negotiated between the government and a consortium of Norwegian and Nepalese companies, the central feature being the granting of a site license for 50 years. Notwithstanding this, the PPA with NEA is for only 20 years of operation, after which ownership of 50 percent of the project transfers to NEA and a new PPA is negotiated. As well as receiving a high level of official support from Norway, the project rests heavily on the provision of debt and subordinated loans from two major multilateral development banks, IFC and ADB.

After Khimti I, the next IPP project to be granted a site license was Upper Bhote Koshi. Again the terms of the concession were directly negotiated and they largely reflected those of the earlier scheme. However in this instance the sponsor is genuinely private sector, with the controlling ownership passing from a consulting engineer (Harza, United States) to a US private power developer (Panda) and then to a Canadian finance company (MCN Investment Corporation). The project has the same provision of a 50−year site license with the transfer of 50 percent of the equity to NEA after 20 years.

Under the Licensing Agreement for both projects the Nepalese Government guarantees NEA's payment and performance obligations, and grants a 15−year tax holiday and full coverage for foreign exchange risk. There are wide−ranging covenants protecting the rights of the foreign investors.

Preliminary licenses have now been issued for more than 20 other private hydro projects in Nepal, totaling over 1,000 MW in capacity. Among these the 750 MW West Seti storage scheme has been granted a site license for 36 years. However such projects depend on the export market and are proving slow to progress. The Nepalese Government, supported by the World Bank, is preparing seven small−to−medium projects aimed primarily at the domestic market for IPP development, and it is currently reviewing the options for awarding the concessions.

Birecik and Other Turkish BOT Hydro

Birecik

The Birecik concession dates back to the mid−1980s when the group that eventually became the promoter first studied the project as a potential BOT development. It was three years before the government granted an exclusive mandate in April 1989, and another seven years before financial closure was achieved. The technical definition of the project was based upon detailed feasibility studies originally undertaken in the public sector, for which the promoter had to make a payment to the government on financial closure.

The project is being developed by a strong European consortium sponsored by CEGELEC (France) and Philipp Holzmann (Germany) with heavy dependence on ECA finance from a number of European countries. There is significant Turkish Governmentcontinue

support in the form of guarantees, subordinated loans and risk−sharing. The public utility TEAS* holds 30 percent of the equity.

The concession was directly negotiated from the outset and, being one of the first Turkish BOT projects in any

sector, progress was slow and aggravated by continuing uncertainties over the Danistay issue. Birecik was eventually decreed by the Legislature to be a "nonconcession" project, but in this respect it is unusual because a subsequent ruling of the courts suggests that other hydro projects would not be similarly classified.

The master agreement between the government and the project company is the Implementation Contract under which the company is authorized to build the plant and then operate it for 15 years. TEAS is obliged to take all of the energy on a cost−plus tariff structure, which guarantees returns to the developer irrespective of cost levels and water flows. In this respect the risk−sharing arrangements are similar to those of a traditional public sector project, with the utility effectively paying a lease rental for the project. There is provision for international arbitration in Vienna.

Other Turkish BOT Hydro

In addition to Birecik the Turkish Government has been seeking to develop a large number of other privately funded hydro projects on the basis of a competitive tendering process similar to that being pursued in the Philippines. In 1997 MENR invited expression of interest from consortia on 42 prospective schemes totaling 4,387 MW. The response was patchy and almost exclusively from local companies who in general lacked the financial resources and credibility to raise money internationally. The poor foreign response was attributed to general concerns over the status of the BOT law, and worries over the lack of access to international arbitration and the difficulty of raising finance.

In addition to the 42 projects for which bids have been solicited, unsolicited offers have been made on an unknown number of other hydro schemes.

Despite the prospect of severe power shortages in the future, and an abundance of identified projects, the BOT hydro program in Turkey has been disappointingly slow. About 80 projects appear to have either received approvals or to be near it yet, other than Birecik, there are only two or three schemes totaling less than 300 MW actually under construction. This is to be compared against a forecasted annual load growth of 2,000 MW a year. There is a backlog of proposals under review by MENR, and for those that do emerge the problem of attracting finance seems in many cases to be insurmountable.

Most BOT hydro projects being considered in Turkey are below 150 MW. For larger projects the Turkish Government appears to have adopted a policy of concluding bilateral agreements with foreign governments to provide mixed funding packages for conventional public sector projects. This has grown out of a recognition that the BOTcontinue

process is not delivering the expected results in the hydro sector, particularly at the larger end of the scale.

Ita, Guilman−Amorin (Brazil)

Both Ita and Guilman−Amorin have their origins in Decree 915 of September 1993, which was enacted against a background of growing concern on the part of heavy energy consumers regarding the future reliability and cost of energy from the grid. The decree allowed autoproducers to form consortia to construct schemes for the supply of their own needs, with any surplus energy going to the utility.

At the time there were a number of large, publicly financed hydropower projects on which work had simply stopped through lack of funds. The Ita project, which was being developed by one of the regional utilities, ELECTROSUL, was among them. In 1994 to resolve the funding problem ELECTROSUL launched a competitive bidding process to identify a private sector consortium to finish Ita in partnership with the utility. Only two consortia presented proposals, and the one comprising four leading Brazilian companies in the

petrochemicals, steel and cement industries was selected. The concession was negotiated with ELECTROSUL taking a 39 percent holding based largely on its existing sunk investment in the project.

The position on Guilman−Amorin is somewhat different as the private sector participants—a large steel manufacturer and an iron−ore producer—entered the project at the beginning without any prior public involvement other than the original studies. In this respect it is Brazil's first power project to be sponsored entirely by the private sector. Under the terms of the concession awarded in January 1995, the sponsors have the right to generate energy for their own consumption for 30 years. Additional output will be offered to the utility CEMIG on a first−refusal basis. CEMIG will operate the plant and guarantee a continuous supply of power to meet the sponsor's requirements irrespective of local hydrological conditions.

Concessions for both projects were granted by DNAEE, the then regulatory agency under the Ministry of Mines and Energy, which has now been replaced by autonomous Federal Regulatory Agency ANEEL.

Royalty Arrangements

About half the projects considered had royalty arrangements of one sort or another. In general they are based on a percentage of revenue or net income, and they are phased in over a number of years. A common feature is the very low level of royalties in the early years after commissioning when the debt burden is at its highest. This underlines the fundamental point that all royalty payments have to be viewed in the context of affordability.break

In Nepal royalties payable amount to about 2.5 percent of revenue in the first 15 years of operation, and thereafter the levy jumps to about 15 percent. In Turkey there are no royalty arrangements payable. In Brazil the royalty is the annual site payment on which the concession is bid and awarded.

Not all royalty payments are made to the central government. They sometimes appear as local taxes in the form of water charges levied by the Provincial Authorities. For example, the new hydel policy in Pakistan allows a levy of 4 percent of revenue for water charges to be paid as a Provincial Tax. In the Philippines a small water charge is payable to the local authority.

In considering royalty arrangements a distinction should be drawn between export and domestic projects,. It could be argued that domestic projects bring to the economy the benefit of stable energy prices, and that if a royalty is imposed it simply reflects itself in an increased domestic prices. Similar reasoning cannot be applied to export projects where the royalty represents a return to the State for the use of its natural resources. For example, in the case of Theun Hinboun the Lao Government receives a royalty of 5 percent in addition to its revenue as a shareholder. Similar considerations can arise within a country where water resources are owned at the local level by the state or province, and the power is being exported to other parts of the country.

In addition to royalties the government directly benefits in a number of ways, through the creation of employment and the stimulus that such projects inevitably give to regional development. Furthermore the project company and its employees will generate tax revenue, although this will obviously depend upon the dispensations granted at the time the concession is negotiated.

In most cases significant tax concessions are offered by the host government to the private developer. For example under Philippine law the tax holiday is 6 years from start of operation; in Nepal it extends to 15 years; and in the case of the Lao projects there appears to be total exemption from all taxes, except income tax, for the full period of the concession.

The present practice of transferring the project to the government free of charge at the end of the concession period is, in many respects, also a delayed royalty payment. There appears to be scope for further examination of

the linkage between the concession period, transfer values, royalties and tax so that the benefits to the government can be considered in their totality.break

Section 4—
The Offtake Contracts

Key Issues

In any power offtake contract there are a diversity of issues to be addressed, many of which are common to all types of generation. However hydro throws up some specific problems, outlined in Section 2, which give rise to a number of additional issues that also need to be addressed in the Offtake Agreement. These include:

· The role of the project (such as peaking, baseload);

· Powers of the parties in terms of reservoir operation and dispatch;

· Pass−through of construction risk where tariffs are cost−related;

· Apportionment of hydrological risk (such as variations in production);

· Allocation of environmental and resettlement costs;

· Servicing of the debt burden in the early years of operation; and

· Tariff structure (energy, capacity, ancillary benefits).

A general review of the PPAs of the candidate projects follows.

PPAs for the Candidate Projects

Financing of all the projects, except the two in Brazil, is based on a long−term power purchase agreement (PPA) with the state−owned utility. The Brazilian projects are autoproducers so the bulk of their energy is consumed by the private sponsors, but they nevertheless also have agreements with the utility to take their surplus production. There are no merchant plants among the candidate projects. Details of the contracts are given in Table 6 and summarized below.

Philippines

Bakun and San Roque

For both Bakun and San Roque NPC is the utility offtaker. The general principles of the NPC hydro policy, as reflected in the Offtake Contract, are as follows:break

TABLE 6: BASIS OF PPA FOR CANDIDATE PROJECTS

Project	Basis of Tariff	Duration of Agree−ment	Offtake Obligations (Market Risk)	Hydrology Risk	Energy Price (¢/kWh equiv)	Defining Cur−rency	Escalation	Trans−mission Liability
Casecnan	Energy + water	20 years	Take−or−pay (100%)	Shared	15.50a	US$	None	Utility
San Roque	CRF + OFb	25 years	Guaranteed minimum	Shared	n/a	US$ + Yen	Operation only	Utility
Bakun, Philippines	CRF + OFb	25 years	Take−or−pay	Shared	n/a	US$	Operation only	Utility
Theun Hinboun	Energy only	30 years	Take−or−pay (95%)	Owner	4.30	US$ + Baht	1−3% a year	Shared
Nam Theun II	Energy (2 part)	25 years	Take−or−pay	Ownerc	4.50	US$ + Baht	Partial	Shared
Khimti I	Energy only	20 years	Take−or−pay	Owner	6.00	US$ + NR	Yes	Utility
Upper Bhote Koshi	Energy only	25 years	Take−or−pay	Owner	n/a	US$	3% a year	Promoter
Birecik	Cost recovery	15 years	Take−or−pay	Utility	n/a	DM	Yes	Utility
Ita	Energy exchange	35 years	Autoproducer	Utility	n/a	R$	n/a	Utility
Guilman Amorin	Energy exchange	30 years	Autoproducer	Utility	n/a	R$	n/a	Utility

a Excludes uplift and existing hydro stations and water tariffs.

b CRF + OF = Capital Recovery Fee and Operating Fee.

c Indicates principal risk carrier.

Source : Author's notes.

· Projects are clearly defined at the bid stage before the PPA is negotiated.

· No pass−through of construction risk to NPC.

· NPC bears the costs of resettlement, relocation and compensation, and is responsible for executing these aspects.

· NPC makes available, at no cost to the developer, the land, easements and rights−of−way for the project.

· NPC is responsible for the transmission line, but reserves the option to devolve the responsibility for its construction onto the company, with a commensurate increase in the tariff.

· NPC generally accepts responsibility for providing the access road (although at the time Bakun was negotiated it was within the developer's scope of works and remains so for that particular project).

· Minimum offtake obligations: NPC guarantees payments for capital recovery based on Dependable Capacity for storage schemes, and Firm Energy for run−of−river projects, irrespective of actual output.

· NPC is obligated to purchase any additional energy generated, over and above the contracted energy, but at a lower unit cost.

· Penalties apply for the nondelivery of the minimum contracted capacity and/or energy unless it can be shown to be beyond the operator's control.

· Tariffs are based upon a two−part structure with Capital Recovery Fees and Operating Fees. The Capital Recovery Fee is US dollar−denominated, with NPC taking the currency risk. Only the Operating Fee is in local currency.break

· There is no escalation provision for Capital Recovery Fees, but there is provision for escalation of the Operating Fees based on a local Filipino index.

Casecnan

The primary offtaker on Casecnan is NIA. In contrast to the NPC projects, Casecnan derives 45 percent of its income from the sale of water, for which it has a guaranteed Water Delivery Fee (WDF), irrespective of the actual amount delivered. The remaining income is made up of a Guaranteed Energy Delivery Fee (GEDF), which accounts for another 30 percent of total revenue—again not related to output, and an Excess Energy Delivery Fee (EEDF), which accounts for remaining 25 percent and is the only element strictly based on actual production.

Both water and energy are purchased by NIA which then onsells the energy to NPC. The WDF (29 cents per cubic meter—¢/m3 —based on 1994 cost levels) is escalated at 7.5 percent a year for the first five years and remains level thereafter.

The GEDF and EEDF are fixed through the duration of the concession period at 15.96 ¢/kilowatt−hour (kWh) and 15.09 ¢/kWh respectively, measured as the production from the new power station only. When uplift at the existing Pantabangan and Masiway hydropower stations downstream is taken into account, these figures equate to 11.25 ¢/kWh and 10.63 ¢/kWh of new energy supplied.

As approximately 75 percent of the revenue comes from guaranteed payments, irrespective of actual production, the hydrological risk appears to sit mainly with the offtaker. However the project company takes its exposure on the "top slice" of the hydrology and as such is more likely to suffer in the event of low flows.

In most other respects the division of responsibilities on Casecnan follows the arrangements for the standard NPC projects.

Lao PDR and EGAT (Thailand)

The offtake agreements for the Lao export projects are both with EGAT of Thailand. The agreements were negotiated against a background of some 20 years of cooperation between the two countries on small power exchanges across their common border, with the predominant flow in the direction of EGAT arising from surplus production at the existing Nam Ngum I and Xeset hydropower projects in Lao PDR. Historically these energy exports have been about 500 GWh/year. After the commissioning of Theun Hinboun, Nam Theun II and Houay Ho this figure will increase to around 7,500 GWh/year, producing an annual hydro−based export revenue in excess of $400 million.break

The negotiation of the PPAs inevitably involved the Government of Lao PDR as well as EGAT. Progress has been slow and all of the Lao agreements have taken a long time to negotiate, to the extent that in the case of both Theun Hinboun and Houay Ho the PPAs were not signed until construction was well advanced. The negotiations on Nam Theun II were suspended in 1996 and have been further impacted by the Asian financial crisis which has forced EGAT to revise its requirements in terms of timing and the role of the project.

The PPAs were negotiated against a high level of project definition. There was no pass−through of construction risk or environmental costs, both of which are fully to the account of the project company. For Theun Hinboun the key commercial principles finally agreed with EGAT are as follows:

· Take or pay under which EGAT guarantees to buy at least 95 percent of available energy. Hydrological risk rests mainly with the project company.

· The PPA is valid for 25 years.

· Initial tariff (energy only) is 4.3 ¢/kWh escalated at 3 percent a year from 1994 up to 4 years' maximum from the start of commercial operation. Thereafter escalation at 1 percent a year.

· Escalation rate to be renegotiated after 10 years, or failing agreement the 1 percent a year tariff escalation to continue.

· Tariff to be 50 percent in US dollars and the remainder in Thai Baht converted at the exchange rate prevailing at the signing of the PPA, to reflect the actual funding split.

· The project company is responsible for delivery of the energy to the border. EGAT is responsible for the construction, operation and maintenance of transmission lines in Thailand.

The PPA for Nam Theun II has yet to be finalized, but the 1996 version generally followed similar lines, with the exception that being a storage scheme the project company has the right to determine reservoir management policy. EGAT had the right to dispatch within short−term operating limits set by the company. The indicative tariff at the time negotiations were suspended was slightly higher than that for Theun Hinboun, reflecting the additional value of storage but without specific payment for ancillary benefits. There was provision for a 3 percent a year tariff escalation during the five years of construction, and thereafter escalation at 35 percent of the official US Cost Price Index.

Nepal

PPAs in Nepal are negotiated in accordance with the guidelines set out in a series of acts passed from 1992 onward. Many of the terms in the Nepalese PPA trace theircontinue

origin to the original negotiations on Khimti I, the first BOT hydro project in the country. The essential features of the Khimti I contract are as follows:

· 20−year agreement between the utility (NEA) and the project company, renegotiable on prevailing market terms at the end of the said period when NEA acquires 50 percent ownership for a nominal sum of 1 Rupee.

· No pass−through of construction risk to NEA. Project company assumes any environmental costs.

· NEA is obliged to purchase the agreed Contract Energy (350 GWh/year) subject to availability. In addition NEA has an obligation to purchase Excess Energy during the dry season up to the full output of the plant.

· There is no obligation to purchase Excess Energy above the contracted amount in the wet season.

· Hydrological risk rests with the project company, but in practice this is limited to water flow in the dry season (October−March) as wet season flows far exceed plant capacity.

· Payments are denominated in both US dollars and Nepalese Rupees, to reflect the respective percentages in the financing plan. The risk of exchange rate fluctuation rests with NEA.

· The tariff has an escalation clause linked to the US Cost Price Index.

The PPA for Upper Bhote Koshi is broadly similar with the same provisions for renegotiation of the tariff following the partial transfer of the ownership at the expiry of the original 20−year term. NEA is again obligated to take all dry season production, and wet season production up to the monthly Contract Energy. In practice, as the Contract Energy figure is very high, the utility is effectively obliged to buy almost all of the output. Hydrological risk again rests with the company, but in this case the exposure is increased because some of the upstream catchment lies beyond the border in Tibet. The company has no protection against upstream abstractions.

Turkey

Birecik

The PPA for Birecik is between the project company and TEAS* , the publicly owned utility. It is effectively a leasing arrangement under which payment is made on a cost−plus basis irrespective of river flow, subject to plant availability and sponsor performance. The essential features are as follows:

· The PPA is for 15 years, the duration of the operational part of the site license.break

· TEAS* is obligated to buy all production on a take−or−pay basis, and has full freedom to dispatch the sets and operate the reservoir as it wishes.

· The Base Tariff is updated every six months to reflect actual costs, and "adjusted" every month to reflect actual energy production (for example, due to variations in river flow).

· An Excess Energy tariff is payable if certain minimum plant efficiency criteria are exceeded. It is not related to hydrology.

· Hydrological risk is completely borne by TEAS.

· Certain construction risk (unforeseen ground conditions) are passed through to TEAS in the form of adjustments to the tariff.

· Payments are denominated and payable in Deutsche Marks. Foreign exchange risk rests with TEAS, and ultimately with the Turkish Treasury.

· The Turkish government is to be responsible for land purchase, rights of access, easements and the like.

Other Turkish BOT Hydro

Although Birecik is not typical of the smaller BOT hydro schemes being promoted by MENR, similar features appear in other agreements now being negotiated in Turkey. These typically include:

· Provision for tariff adjustment to reflect unforeseen geological conditions and changes in long−term hydrology (that is, pass−through of defined construction risks to the offtaker).

· Take−or−pay provisions up to a specified level of guaranteed energy production, with the right to take surplus energy beyond that amount at a lower tariff.

· Penalties in the event of failure to meet generating targets, other than for natural reasons.

· Access to loans from the Electrical Energy Fund to cover funding gaps arising from short−term hydrological deficits.

· Tariff defined in US dollars but paid in Turkish Liras at the prevailing exchange rate. Therefore TEAS assumes the foreign exchange risk.

· Treasury guarantees regarding payment obligations of TEAS, and the convertibility of currency.

One of the main differences between the standard PPA and that for Birecik, is that the standard PPA does not permit international arbitration. This is currently under reviewcontinue

and it remains to be seen whether projects can be internationally financed without a relaxation of this constraint.1

General Observations

In reviewing the offtake contracts the most notable fact to emerge is the diversity of the arrangements. There is no single standardized formula as is generally the case for thermal IPPs. This reflects not only the individual nature of hydro projects, but also the relative immaturity of the process of developing a PPA that properly values the contribution of hydro to the system.

All of the tariffs were negotiated on the basis of an agreed project cost that was generally defined in advance of construction, and often on the basis of only a preliminary project definition. This meant that the owner, or his engineering, procurement and construction (EPC) contractor, was usually required to assume the full construction risk including geological conditions. There were exceptions, in particular Birecik where there is provision for a tariff reopener in the event of unforeseen ground conditions (which is common to all Turkish BOT hydro projects).

There is an inherent conflict between the need of the utility to fix the tariff early in the concession process, and the fact that for most schemes the final cost cannot reliably be determined in advance of construction. Although the tendency in the past has been for the utility to seek to place this risk on the developer, there is a growing consensus toward some form of risk sharing between the three parties—the offtaker, the developer and the contractor. This can involve a tariff reopener, as in the Turkish model, or a geographic splitting of the project into public and private elements, as in San Roque where the public partner assumed responsibility for the riskier civil works.

The treatment of hydrological risk presents similar problems. Early attempts to place all of the risk onto the developer generally failed because the schemes proved impossible to finance, with the result that the trend is now

toward the sharing of hydrological risk or its total assumption by the offtaker. Among the candidate projects the developer was the primary carrier of the hydrological risk in about half the cases, but in practice this exposure was sometimes reduced through other guarantees provided by the utility.

Where there are upstream storages or abstractions that can influence the flow reporting to the power station it becomes increasingly difficult to expect the private owner to assume hydrological risk, and the exposure inevitably falls on the utility. This iscontinue

1 Since writing this the legislature has passed on an Act accepting the principle of international arbitration.

the case in Birecik, where the owner gets paid irrespective of flow, provided the prescribed plant availability is maintained.

On international rivers the situation is more difficult because there are no widely enforceable water laws to preserve natural flows for downstream riparian states. In the case of Upper Bhote Koshi the owner accepted the risk of interference with upstream flow accruals in Tibet because it was considered that the exposure was low, but this will not always be the case on international rivers, and in such circumstances private schemes will only be bankable if the utility assumes the hydrological risk.

Tariff structures tend to be based on energy for run−of−river schemes subject to a guaranteed minimum offtake, and on capacity and energy for storage projects. In some cases a dual energy tariff has been used to reflect the higher value of firm energy over dump energy. Where there is no capacity charge or other fixed payments, the minimum offtake or "firm energy" tariff is usually structured to ensure that it covers these elements, thereby effectively guaranteeing the minimum necessary revenue for debt servicing.

All of the tariffs are denominated in foreign currency, usually US dollars with the currency fluctuation and conversion risk falling on the utility. In some cases the exposure of the utility has been reduced by having the tariff denominated in local currency, with only the proportion representing the foreign funding and offshore equity convertible into hard currency (at a predefined exchange rate).

A conspicuous omission from all of the offtake agreements was any form of payment for ancillary services such as frequency control, spinning reserve and emergency standby. The absence of such payments means that in many cases hydro is being seriously undervalued. As already noted, such services were not explicitly accounted for in the past but there is growing evidence that in the future, as deregulation reveals the real cost of the different components of a power system, the ancillary functions of hydro will become increasingly significant elements to be included in any offtake agreement.break

Section 5—
Financing Arrangements

General

All of the candidate projects are financed on a standalone basis, on the strength of the project cash flow and security package, with little or no recourse to the underlying balance sheets of the sponsors. On average, debt provided about three−quarters of the total funding needed.

The difficulty of accessing long−term international finance is proving to be a serious obstacle in raising debt for privately funded hydro projects. This is exacerbated by concerns over currency exposure and the relatively

undeveloped state of local capital markets in many countries with good hydro potential.

In contrast there appears to be no serious shortage of equity for good projects, although equity holders' expectations on returns (20 to 25 percent a year) are often in variance with those of the host utilities.

The candidate projects reveal a wide diversity of approaches to financing, ranging from a heavy dependence on public sector institutions to projects almost completely financed in the private sector. The reliance on public support is most evident in the low−income countries where there is no domestic financial market to draw upon and where both the legal and regulatory environment, as well as the credit standing of the country, is perceived to be less than adequate by international financiers.

Details of the financing arrangements are given in Table 7. It should be emphasized that some of the projects listed have yet to reach financial closure and therefore the eventual financing plan may differ from that shown.

Equity Financing

All of the projects have been financed through locally incorporated special−purpose companies in which the equity is held by the sponsors and, in some cases, the host utility.

On average, equity accounts for about 27 percent of the total project cost, although on an individual project basis the actual proportions vary between 15 and 40 percent. The amount of equity that a developer has to put into a project is largely determined by the lender's perception of the risk. This is reflected among the candidate projects where the higher gearings (that is, lower equity proportions) were achieved oncontinue

projects where most of the risk has been deflected away from the project company, as for Birecik and San Roque; or where there was no longer a serious exposure to construction risk, as in Ita.

TABLE 7: FINANCING PLAN FOR CANDIDATE PROJECTS

A. In US$ million

Project	Project Cost			Equity Portion			Project Debt			
					Public through		Private Debt		Public−Suppor Debt	
	Total	Equity	Debt	Sponsors	MDB/bilat	Utlty/Gov	Commercial	Bonds	ECA a	MDB/b
Casecnan	495	139	356	139	−	−	−	356	−	−
San Roqueb	580	134	446	134	−	−	44	−	302	100
Bakun, Philippines	147	44	103	44	−	−	103	−	−	−
Theun Hinboun	317	126	190	44	66	−	122	−	62	23
Nam Theun II	1,227	368	859	276	−	92	−	−	400	459
Khimti I	139	43	97	34	9	−	−	−	30	67
Upper Bhote Koshi	98	30	69	27	3	−	−	−	−	69

Birecik	1,236	179	1,057	125	−	54	299	−	758	−
Ita	1,070	267	800	163	−	104	−	−	−	800
Guilman−Amorin	148	30	118	30	−	−	−	−	−	118
	5,457	1,360	4,095	1,016	78	250	568		1,552	1,636
Total Equity	1,360	25%								
Total Debt	4,095	75%								
	5,455	100%								

a Includes ECA direct lending and commercial debt benefiting from ECA insurance.

b Refers to private element only.

Note: Totals may not add due to rounding.

Source: Author's notes.

B. By Percentage

Project	**Project Cost**			**Equity Portion**			**Project Debt**			
					Public through		**Private Debt**		**Public−Suppor Debt**	
	Total	**Equity**	**Debt**	**Sponsors**	**MDB/ bilat**	**Utlty/ Gov**	**Commer− cial**	**Bonds**	**ECA** a	**MDB/ bilat**
Casecnan	495	28	72	100	−	−	−	100	−	−
San Roqueb	580	25	75	100	−	−	10	−	68	22
Bakun, Philippines	147	30	70	100	−	−	100	−	−	−
Theun Hinboun	317	40	60	40	−	60	59	−	30	11
Nam Theun II	1,227	30	70	75	−	25	−	−	46	54
Khimti I	139	28	63	80	20	−	−	−	31	69
Upper Bhote Koshi	98	30	70	90	10	−	−	−	−	100
Birecik	1,236	15	85	70	−	30	28	−	72	
Ita	1,070	25	75	61	−	39	−	−	−	100
Guilman−Amorin	148	20	80	100	−	−	−	−	−	100

a Includes ECA direct lending and commercial debt benefiting from ECA insurance.

b Refers to private element only.

Source: Author's notes.

Despite their appearance as private projects, it will be seen from Table 7 that the public sector accounts for nearly 30 percent of the equity holdings. This is mainly money sourced from multilateral development banks, either in the form of loans to the host utility to allow it to purchase shares in the project company or as a direct equity

holding by the multilateral bank. Political risk insurance for foreign equity holders, arrangedcontinue

through public organizations like the Multilateral Investment Guarantee Agency (MIGA), is not included in these figures.

Private equity sponsors for the candidate projects broadly divide into four categories:

· State−owned foreign utilities with a strong hydro background (such as EDF, Statkraft, Vatenfall);

· Foreign engineering firms, primarily civil contractors and plant manufacturers;

· Independent power producers and foreign trading houses; and

· Local industrial groups, not necessarily previously involved in power generation.

In a number of cases the host utility is also an equity participant in the project company. This occurs in the Lao export projects where the government holdings has been externally financed, and in the very large schemes costing beyond $1 billion (Birecik, Ita) where the volume of funding required is steering the projects toward a partnership arrangement between the public and private sectors.

Debt Financing

Sources of Debt

Debt typically provided three−quarters of the project costs, and it was raised in the form of direct lending and guarantees from a number of sources, including:

· **Export Credit Agencies (ECAs)** , which provided both direct loans and guarantees in support of bank lending under terms regulated by OECD and administered by the appropriate government agencies in the principal exporting countries. This is an accessible form of credit widely used for power projects in general, but restricted in the volume of support it can provide for hydro schemes because of their relatively low export content. Subject to certain restrictions, ECA support for nonrecourse power projects can now be stretched to 14 years from the start of commercial operations.

· **Multilateral Development Banks (MDBs)** like the World Bank Group, the Inter−American Development Bank (IADB) and the Asian Development Bank (ADB). These public institutions have played an important role in the provision of debt financing in seven out of the ten projects reviewed by direct loans (such as IFC "A" Loans) and through acting as the Lender of Record for syndicated loan facilities (such as IFC "B" Loans). The other increasingly important aspect of MDB participation is guarantees and insurance facilities (for example, the guarantee programs of the World Bank and political risk insurance of MIGA). Loan tenors are broadly in line with those of the ECAs.break

· **Cofinancing** through bilateral funds generally in the form of soft loans to the project company, or grants to the government to cover related social and environmental costs. This is a relatively minor source of financing but, like multilateral funds, it is important as a catalyst for mobilizing other sources of debt. In certain economies government agencies and local public funds, for example from development banks such as BNDES in Brazil, play an important role.

· **Commercial banks** have provided substantial sums under the umbrella of the ECAs, and a much smaller amount of pure commercial debt. In many markets commercial debt is severely limited in volume, and short maturities combined with high prices make it unattractive. Debt denominated in local currency often carries very high interest rates. As international commercial debt is often raised on the back of ECA funding, the relatively low proportion of the ECA eligible component in hydro projects also adversely affects the prospects for commercial loans.

· **Bond issues** for hydro schemes are still relatively rare. Casecnan is believed to be the first major scheme of its type on the US bond market. Having been rated BB by Standard and Poors, the project raised $270 million relatively easily in three tranches with the bulk of the debt on a 10− to 15−year maturity. Pangue hydro project in Chile raised $81 million on the domestic bond markets, but as the project company is effectively owned by the utility, it was not a true test of local bond markets as a source of private capital for hydro projects.

Foreign Exchange Exposure

Despite the large local civil content in all of the projects there was virtually no locally sourced debt, with nearly all of the financing being from international sources in foreign currency.

The dangers of this approach have been illustrated recently in a number of Asian countries such as Indonesia, where serious devaluation of the local currency has resulted in a situation where neither the utility nor the government are able to maintain foreign exchange payments. By contrast IPP projects in Malaysia were generally sourced from local capital markets in local currency, and have therefore not been subject to the same pressures. With the large civil works content of hydro, it is desirable if the local element can be financed in local currency, thereby avoiding much of the foreign exchange exposure.

Recent experience of governments seeking to retrospectively renegotiate offtake agreements has fueled the suspicion that long−term PPAs for power projects, particularly those with a large element of foreign financing, may not be sustainable. This is reinforced by the general trend toward totally deregulated markets where electricity trading is likely to be on the basis of the spot market or, at best, short contracts that provide no long−term security for a prospective financier. Quite apart from the obvious implications this has incontinue

terms of trying to raise long−term finance against an uncertain income stream, it also heightens the developer's exposure to foreign exchange risk that can no longer be passed to the utility.

Support of the Public Sector (Official Assistance)

The support of the public sector, in one form of another, has been crucial to the financing of all of the projects, even where public funds have not been directly involved. The most obvious support has been the provision of guarantees by the host government, particularly in respect of payment obligations of the utility, and the provision of funding and guarantees by the MDBs. A significant role has also been played by the ECAs of a number of governments.

In most cases the projects would have failed without public support. The projects in Lao PDR, Nepal and Brazil would almost certainly not have been financed without the strong involvement of ADB, IADB and IFC. It is equally likely that difficult projects like San Roque, which are not viable in the private sector alone, would not have proceeded without substantial public support—in that case from the Export−Import Bank of Japan (JEXIM—merged with the Overseas Economic Cooperation Fund, Japan and renamed as Japan Bank for International Cooperation in 1999).

MDBs were the largest single source of funds, in the form of debt and both direct and indirect equity. To date their guarantee programs have not been widely used, possibly because they are still relatively new instruments. In addition the programs such as those of the World Bank require the counterguarantee of the host government, which relatively creditworthy countries are often not willing to give to private developers. World Bank guarantees were until recently only available to IBRD countries, but the Partial Risk Guarantee was then extended to "enclave" projects, where the project itself is located in an IDA country but the power purchaser is creditworthy. This is the situation that exists for the Nam Theun project, located in Lao PDR but selling power to the utility in Thailand. The World Bank recently extended such guarantees to IDA countries on a trial basis, which is likely to result in increased demand.

To a lesser extent some of the candidate projects have enjoyed bilateral support through investment vehicles that provide equity financing, financial guarantees and medium− to long−term loans. This type of support invariably follows a wider national interest in a particular project, and it is confined to the low−income countries like Lao PDR and Nepal. Examples are the Nordic Investment Bank credit on Theun Hinboun, Norwegian aid for Khimti I, and possible French cofinancing for Nam Theun II.

ECAs have generally been used to the fullest extent possible but, with the exception of Birecik and San Roque, funding from this source has generally not exceeded 30 percent of project cost. Birecik has an unusually high ECA content which is unlikely to be repeated, and San Roque is for the power station only. In countries like Brazil,continue

which have a strong domestic manufacturing capability, the scope for ECA financing is further reduced. Uncovered commercial debt has played only a limited role in the financing of the candidate projects, and is likely to remain a secondary source of funding because of its short tenor, relatively high cost and limitations on availability.

In general the host governments' role in financing the projects was confined to providing the necessary guarantees and undertakings that would be common for all IPP projects. However in a number of cases this was extended to include:

· Participation as an equity holder in Theun Hinboun and Nam Theun II on the basis of concessionary funding provided by external agencies, and in Birecik by direct funding.

· Provision of loans through public financial institutions or the utility, or directly by the government (San Roque, Ita). These have sometimes been funded by concessionary loans from external agencies.

· Buyout obligations entered into by the government on a number of projects in the event of a failure of the project company.

· The assumption of hydrological risk through the provision of funds to cover shortfalls in revenue due to temporary low flow conditions (the Electrical Energy Fund under the Turkish BOT model).

Financing is more complicated where export projects are involved because host government guarantees are largely irrelevant to the security of the payment stream. In the case of the Lao export projects the guarantees obtained from the Lao government largely related to the nonsequestration of the project, but payment guarantees were not provided by the Thai Government as the utility offtaker EGAT was considered creditworthy in its own right.

Summary Financing Arrangements (Candidate Projects)

There follows a brief comment on the financing arrangements of each of the candidate projects. More details are provided in Annex 1.

Casecnan was successfully financed on the 144A US bond markets on the back of contract arrangements that apparently passed all of the construction and performance risk onto the EPC contractor, with the government underwriting much of the hydrological risk. In practice the construction contract ran into difficulties, and the original contractor failed. This formula may not be repeatable because of the reluctance of most contractors to assume the onerous contract conditions that were imposed.

San Roque relies heavily on JEXIM financing in two portions, one public and the other private. The public loan to the government on concessionary terms coverscontinue

"nonpower" items like the dam and spillway, which carry the highest construction risk. JEXIM also provides loans to the project company and a political risk guarantee to cover commercial lenders. The private developer is therefore left with a more manageable construction and performance risk which he has passed on to the EPC contractor, and no exposure to hydrological risk.

Bakun was initially financed through a loan facility backed by the sponsor's own securities. This was later converted to nonrecourse project financing through a consortium of local and foreign banks, which provided a 10−year loan facility. There was no multilateral or any other public sector involvement.

Theun Hinboun is an example of a project where a multilateral agency, in this instance ADB, was involved from the outset advising the government and ultimately providing concessionary loans for the purchase of government equity. There was also strong bilateral elements with grant aid from Norway and a loan from the Nordic Development Bank. The presence of the Norwegian and Swedish state−owned power utilities as project promoters undoubtedly facilitated the funding.

Nam Theun II is scheduled to reach financial closure in 2000 and therefore the financing plan remains unsettled. In many respects the arrangements are similar to Theun Hinboun with the principal proponent again being a publicly owned power utility (EDF) and anticipated heavy dependence on public support in the form of ECAs, IFC loans and World Bank guarantees. At the time of the original negotiations the offtaker EGAT was regarded as creditworthy in its own right without government guarantees.

Khimti I was the first privately financed hydro scheme in Nepal, and like Theun Hinboun it is in many respects a transitional scheme with a dominant holding by the Norwegian power utility and the debt being provided by two MDBs (ADB, IFC) with additional funding from Norwegian aid. There was again a strong bilateral flavor to the project, with Norwegian firms strongly represented among the contractors.

Upper Bhote Koshi , like Khimti I, relies heavily on multilateral funding for debt financing with all of the debt being provided through IFC "A" and syndicated "B" loans, both with 11−year maturities. The remainder of the funding is largely provided by the private sponsors, with a small equity holding by IFC.

Birecik has an unusually large offshore supply element which has allowed ECA financing for approximately 60 percent of the project cost, with the remaining debt being provided by commercial loans. The high cost of the project reflects the fact that for financing reasons offshore supply was given priority over local supply. The debt sums involved were large ($1 billion) and the financing depended upon a high level of risk assumption by the Turkish government.break

Ita is being financed on the basis of an apparently large equity input of the order of 270 million pounds, but a substantial portion of this derives from the original public sector investment in the project before privatization. The private sponsors, which comprise some very large Brazilian companies, have also put up over $160 million in equity. The $800 million debt financing was roughly equally split between IADB and the Brazilian National Development Bank, with maturities of between 12 and 15 years.

Guilman−Amorin is financed on a 20/80 equity−debt split, which is highly geared for a private hydro project. The complete debt of $119 million was provided by IFC under the "A" and syndicated "B" loan arrangements, worth respectively $30 million and $89 million, with maturities of 15 and 10 years respectively. Financial support arrangements derived mainly from the strengths of the sponsors who are large Brazilian companies.break

Section 6—
Project Implementation Arrangements

General

This section covers the ways in which the project companies implemented the schemes, with reference to the hydro−specific problems identified in Section 2 of this report. These included the following:

· The need for expensive and time−consuming front−end studies to determine the optimum project parameters.

· The difficulty of establishing in advance of construction a firm cost and completion date.

· The need to apportion construction risks in a way that does not unduly inflate the contract price.

The traditional arrangement for implementing hydropower projects in the public sector was for the utility to award a number of separate contracts on the basis of a well−defined project. Responsibility for the overall design and coordination of the separate contracts lay with the utility. By arranging matters in this way the utility assumed most of the construction risk, but prices were generally competitive because contractors were bidding against a limited risk exposure for work that lay wholly within their own specialization.

Under the private financing scenario this arrangement has a number of drawbacks. In particular the ultimate cost of construction cannot be clearly determined in advance, and in the event of things going wrong issues of liability can become blurred. In short the project company is exposed to levels of risk that many financiers find unacceptable.

In response to these concerns the trend is now firmly toward EPC or "turnkey" contract arrangements under which a single contractor or consortium assumes full responsibility for the delivery and performance of the complete project, often on a fixed−price basis.

As an indication of the rapidity of this change, ten years ago it would have been rare to find a hydro scheme being built under anything other than traditional arrangements. Among the candidate projects only two, Theun Hinboun and Khimti I, followed this route, with the remaining eight being implemented as EPC contracts.break

Selection of Contractors

The majority of the construction contracts were awarded to firms that had no previous link with the project company. However in about one−third of the cases the contracting consortium comprised firms that shared

common ownership with at least some of the equity holders in the project company. For example, on Birecik the private sponsor of the project was the same group of contractors and manufacturers that comprised the construction consortium. Notwithstanding this the contracts were all set up as fully accountable "arms−length" arrangements to avoid any cross−subsidy from the project company to the contractors.

Among the candidate projects the contractors were overwhelmingly foreign, except in Brazil which has a strong local contracting capability. The absence of domestic contractors, despite the significant proportion of local civil works in a typical hydro scheme, can only be partly attributed to the lack of suitably qualified local firms. It also reflects the funding arrangements and the requirement of the developers and the financiers that the works should be carried out by experienced contractors who have the resources to rectify problems when they occur, and sufficient substance to carry heavy performance liability if things go badly wrong.

Competitive tendering from a shortlist of prequalified contractors was the preferred route for most of the developers. However contractors are often reluctant to bid EPC hydro contracts unless they are on a short list of no more than two or three prequalified groups, because of the time and expense involved. This arises from:

· The tendency of project companies to offer minimal design information in the bid documents, leaving the tenderer with the burden of developing the design to the point where he can confidently submit a firm price.

· The need for a consortium approach often involving four or more companies to provide the totality of services required, which invariably complicates the bidding process.

A further factor that has a large bearing on the quality of the response in any solicitation process is the proposed risk allocation between the project company and the contracting consortium. This matter is discussed below.

Risk Allocation between Client and Contractor

Stages of Development

A typical hydro project goes through a number of evolutionary stages during which the final design gradually emerges. They are shown in Table 8 below.break

TABLE 8: STAGES OF DEVELOPMENT OF A TYPICAL HYDRO SCHEME

STAGE	WORK COMPONENT
Reconnaissance	Identification of potential sites, often from existing maps without a site visit.
Prefeasibility	Outline of scheme concept, based on existing mapping and regional geology. Preliminary estimate of costs and benefits. Normally involves a site visit, but no site investigation.
Short Feasibility	Preliminary optimization of main project parameters based largely on existing data, with minimal field data collection. Cost estimate based upon provisional quantities. Limited environmental impact assessment (EIA).
Full Feasibility	Detailed site mapping and geological investigation, leading to optimized concept with main project parameters well defined. Cost estimate based on reasonably reliable quantities. Full EIA.

Design (Tender Design)	Structure−specific site investigations. Development of design and specification for individual structures, with all leading dimensions. Basis for Engineer's estimate. Traditionally used for tendering.
Detailed Design	Detailed design of each element of the works, including rebar detailing, fabrication drawings, and so on. Carried on in parallel with construction and modified as necessary to meet changing site conditions.

Source: Author's notes.

Under the traditional arrangements construction contracts are bid at the end of the Design Stage based on a full project definition arrived at after extensive site investigations. Contractors bid to a prescriptive formula under which they follow the instructions of the Engineer (working for the utility) and are protected against additional costs arising from matters outside their control including design changes.

Under EPC arrangements the trend is for the construction contract to be awarded at a much earlier stage on the basis of only limited project definition and a preliminary site investigation. This not only reflects the reluctance of developers to incur heavy front−end costs, but it is also in keeping with the philosophy of giving the contractor the freedom and responsibility for developing his own designs, an approach that is likely to be reinforced by the owner's lawyers who generally view information supplied to the contractor as a potential source of future claims.

The earlier a contract is let in the development cycle, the more difficult it is to predict the final form of the scheme, and its ultimate cost. This applies equally to the award of the concession and the award of the construction contract. Under the private financing scenario, the tendency is for these two key contracts to be awarded early to avoid incurring heavy front−end costs on the part of the government and sponsors, and the liabilities inherent in providing more detailed information to the next party down the contractual chain. However the penalty for this is probably a higher cost in the long run and, perhaps more importantly, the surrender of any meaningful control over the project design on the part of the utility and the owner. This may not always be a matter of consequences, but in general there is danger in agreeing a fixed price in the absence of a clear project definition.break

Among the candidate projects there was a widely differing approach to the stage at which contracts were awarded. Most were tendered on a fairly high level of project definition, but this was largely as a result of preparatory work that had previously been undertaken in the public sector. Others were tendered on the basis of short feasibility studies and minimal site investigation.

Geological Risk

Risk allocation between the project company and the contractor tends to hinge around the issue of unforeseen ground conditions that are an excluded risk under the traditional contract arrangements. By the nature of hydro these risks are significant, and this is confirmed by the fact that there are known to be substantial geologically related claims pending on a number of the candidate projects, notwithstanding the fact that the contracts were let on a notionally fixed−price basis.

Under the Turkish model geological risk is passed through the project company to the offtaker. This is relatively unusual; more commonly the project company is left carrying the risk, or attempting to pass it on to the contractor. When work is scarce contractors seem prepared to take such risks, although it is questionable whether it is in either party's interest. For example on Casecnan, which involves a 26−kilometer (km) tunnel and underground powerhouse, and for which there had been very little site investigation, the contractor assumed the entire risk of unforeseen ground conditions within his fixed price. He failed partway through the contract and had

to be replaced.

The problems of this approach are also evident on the Bakun project where excavation of the pressure tunnels has revealed weaker rock conditions than anticipated, requiring an extension of the steel liner. This is a common problem that often only manifests itself during construction, but it has large cost implications that cannot easily be absorbed by a contractor on a lump sum basis unless the price is already inflated for such contingencies. In such circumstances the EPC contractor may be able to ameliorate the cost impact by design changes but this inevitably raises concerns that the quality of the end product is being jeopardized and it leaves much scope for argument over whether the proposed modifications are acceptable under the contract.

There is growing recognition that in many situations competitively priced bids can only be achieved with some form of risk sharing, and among the approaches to this problem currently being used in the candidate projects and others, are the following:

· Contracts involving a lump sum and remeasurable element, the latter being mainly related to civil works and unforeseen geological risk in particular.

· Capping of the remeasurable element of contracts, so that the owner assumes a limited risk, and beyond that the contractor's risk is unlimited.break

· A layered approach in which the owner, the contractor and commercial insurance all assume a prescribed quantum of risk in a predefined order.

· Sharing of cost overrun on an agreed percentage basis.

· Passing through specified geologically related construction risks to the offtaker.

The implications of such risk−sharing formulas are that the project company will need access to additional funding that may not be needed but if it is required will have to come from the sponsors rather than the lenders. This provision is seen in the financing arrangements for a number of the candidate projects where the sponsors have been required to make available contingent equity to cover possible cost overruns.

General Observations

One of the most marked consequences of the switch to private funding has been the way in which projects are implemented. The move toward EPC contracts has been driven by the belief that they pass all construction risk, and most performance risk, to the contractor. In theory, having specified his requirements, the owner simply awaits delivery of the completed project.

In practice the process is not as straightforward as this, and many private developers new to the hydro scene are learning to their cost that the implementation stage has to be closely managed. Civil works of the type encountered in hydro projects cannot be adequately prescribed in advance solely by a performance specification, and the construction process inevitably involves a constant interaction between the contractor, his designer and the owner.

To assume the risks now being thrust upon them, contractors obviously require to be paid more. Although hard factual comparisons cannot easily be made, the general consensus among those active in the industry is that the EPC approach, in which most of the risk is passed to the contractor, adds over 20 percent to the project cost. Even where owners apparently had "fixed price, time sure" contracts, experience has shown that these are difficult to enforce where conditions actually encountered are significantly different from those anticipated.

As only a small number of the candidate projects have been completed, and even then there are outstanding contractual issues to be settled, it is too early to draw conclusions on the effectiveness of the implementation arrangements. However there is not a lot of evidence to date to suggest that the EPC route is proving to be as easy and trouble−free as expected by some of the sponsors and financiers.break

Section 7—
Role of the Host Government and Utility

General

Having examined the circumstances surrounding the financing of the candidate projects, it is now possible to recognize several key factors that are crucial to a successful private hydro sector. They are:

· The central role that any host government has in establishing a favorable regulatory environment to encourage investment in what would otherwise be a difficult area for private finance.

· An appreciation of the effect that the capital−intensive nature of hydro has on the issues of bankability and tariff structure, and the need for financial support mechanisms to ease these problems.

· The need for realistic risk−sharing models to reduced prices and avoid the costly delays and failures that have characterized much of the private hydro industry to date.

These issues will be examined in the remaining sections of this report, starting here with the host government's role in establishing an appropriate regulatory environment.

Regulatory Environment

Hydro−Specific Regulatory Issues

It is now widely recognized that hydro raises specific regulatory problems of its own because the host government, in granting a concession, is transferring to the private sector the right to exploit a unique national asset. Despite this the public sector is still likely to be called upon to provide a high level of support in the form of guarantees, financing and risk−sharing. Therefore in the award of any concession the government has a number of basic obligations. It must ensure that:

· The site is developed in an optimal manner, not only for the power system but also for multipurpose uses where appropriate;

· The selection of the concessionaire and the contract arrangements, including the setting of tariff levels, meet adequate standards of public accountability;

· A sensible balance is achieved between the benefits that the state receives and the support that it provides.break

· The engineering, operation and maintenance of the project are consistent with public safety requirements and maximizing the project life (as most hydro schemes eventually revert to the state).

The regulatory environment for private hydro is still evolving but a familiar pattern can be found in many countries; governments initially offer poorly prepared projects for private development under proposed contract

arrangements that allocate virtually all of the risks to the private sector—and are disappointed by the lack of response. This is followed by a period of reflection, and the reissue of new guidelines intended to address the obstacles that were seen to be deterring interest in the initial solicitation.

It is noticeable that in each of the countries considered there has been an ongoing reappraisal of the approach to BOT hydro. Although there are still significant differences in the regulatory environment between countries, there is a perceptible trend toward the host governments recognizing that they have to play a larger and more supportive role if they are to attract private finance; in particular by:

· Assuming responsibility for project definition and site investigations.

· Arranging all environmental permits and site acquisition in advance; and managing any environmental mitigation plans.

· Sharing in some of the project risks, in particular relating to hydrology and geology.

The regulatory environment for private hydropower is still at a formative stage with governments experimenting to find the right balance between the public and private sectors. This is evident in each of the five countries considered, where the current position can be summarized broadly as follows:

· In the **Philippines** a limited private hydro program is under way after a series of false starts. Only a very small number of concessions have been awarded compared to the many solicited, and the situation is now further complicated by the pending privatization of NPC itself. Against this background the future for private hydro is uncertain and much less favorable than it appeared to be several years ago.

· In **Lao PDR** expectations of a large hydro−based export program have had to be heavily trimmed back in the wake of the Asian currency crisis, and consideration is now being given to the private financing of smaller domestic projects. There is no clear regulatory framework for this, and the task is likely to be made difficult due to the country's weak economic base and lack of credit rating.

· **Nepal** 's original "Hydropower Development Policy" dates from 1992 but future policy is again under review as the country moves forward on the basis of the two directly negotiated IPPs described in this document toward a more open market in domestic projects, and the granting of concessions for large projects aimed at thecontinue

export market in India. Country credit risk remains a problem and there is still a high dependency on multilateral support.

· In **Turkey** , despite its favorable climate in terms of risk−sharing, the private hydro sector appears to be losing ground to public sector projects financed under bilateral protocols. Once again, a large number of BOT projects have been solicited but only a very small proportion are actually proceeding to implementation. The main obstacle lies on the financing side, fueled by unrealistic expectations concerning the availability and cost of financing in Turkey. The future role of private hydro will be reviewed as part of the overall restructuring of the power sector due to take place in the next year or so.

· **Brazil's** restructuring of the power sector has encouraged autoproducers, but the pending privatization of the utility companies will make it more difficult for hydro developers who need long−term PPAs for raising finance. The state has effectively stepped back from providing this support, leaving private generators to establish their own offtake contracts where they can. Such contracts will often not be a sufficient basis for securing the necessary debt. While there may be some prospect of financing very small hydro projects on a merchant plant basis, this is an unlikely prospect for the large projects on which the expansion of Brazil's generation is predicated.

A similar process is happening in other countries. The "Policy Framework and Package of Incentives for Private Sector Hydel Power Generating Projects in Pakistan" was published in 1995 and superseded by the "Policy for New Private Independent Power Projects" in 1998. The Indian Government issued a new policy document in 1998 specifically aimed at facilitating the private development of larger IPPs including hydro. The pertinent parts of revised Indian and Pakistan policies are listed below as an indication of the current thinking in two other countries trying to attract private finance to the hydro sector.

New IPP Policy for Pakistan (1998)

The newly issued IPP policy in Pakistan is specifically aimed at promoting indigenous energy resources, specifically hydro. This follows on from the earlier 1995 hydro policy, which has failed to bring a single project to financial closure. The relevant sections of the new policy are:

· Preferential tax incentives for hydro and other energy projects using indigenous fuel.

· Competitive bidding of all hydro projects above 20 MW on the basis of the lowest levelized tariff. Smaller projects may be awarded uncompetitively.

· Full project definition studies to be prepared by the public sector before bids are invited, and subsequently paid for by the winner.break

· Two−part tariff comprising capacity and energy payments (but no payment for ancillary services). Hydrological risk assumed by the government through the capacity charge.

· Units to be dispatched on merit order on the basis of energy charges only, thereby ensuring that hydro is preferentially dispatched. No take−or−pay obligation.

· Standard security package and draft contract documents to be issued with Request for Proposals. Government guarantees.

· Unsolicited bids will be subjected to competition and must be accompanied by a full feasibility study paid for by the original proponent who will be reimbursed if he loses.

New Power Policy for India (1998)

Faced with a very low success rate in attracting private finance to the hydropower sector, the Government of India has recently revised its power policy to stimulate investment and prevent a further decline in the share of hydroelectric generation in the country. Among other incentives the new measures include:

· Levying a tax on all power consumption to accumulate funds specifically for investment in the hydro sector.

· Prearrangement of all the necessary approvals by the public sector before a project is offered to IPPs through international tender.

· Rationalized tariff structure aimed at protecting debt servicing, with an additional premium for peak energy.

· Further exemptions from federal taxes and customs duties.

· Creation of a new Federal Utility to purchase power from IPPs for onward sale to the State Electricity Boards (SEBs) to increase purchaser credibility.

· A special program of incentives for small hydro schemes below 25 MW.

· Hydro developers to be compensated for unforeseen geological and hydrological risks, cost escalation and "natural occurrences."

· Promotion of larger projects by joint ventures formed between the public and private sectors.

The new Indian policy recognizes the need to give the private developer protection against a wide range of natural risks over which he has no control. In this respect it is similar to the hydro policy in Turkey, which is among the most favorable to the private developer in terms of risk allocation.break

Role of the Utility

The global trend toward deregulation of the power sector has dramatically changed the role of the national power utility as it existed in most countries. The traditional, vertically integrated organizations that were responsible for all aspects of generation, transmission and distribution are being broken down into separate companies, often privately owned. This process naturally leads to the concept of IPPs contracting individually with offtakers, or selling into short−term power markets. Therefore in making the comments below it has to be recognized that the form and existence of utilities themselves is in a state of transition, but it has been assumed that in many parts of the world there will continue to be a national (or regional) utility company to interact with the private hydro developer.

Ultimately most private hydro projects are a form of partnership with the utility, in the sense that it will act as the offtaker, as the counterpart government agency and sometimes as an equity partner. For large or multipurpose projects the utility is likely to be nominated as the codeveloper, financing and owning the nonpower elements, as in the case of San Roque.

All of the candidate projects were financed on the basis of offtake agreements with a publicly owned utility whose obligations were often backed by sovereign guarantees. Even the autoproducers had arrangements for trading electricity with the regional utility. The role of the utilities, and the governments behind them, in effectively guaranteeing a long−term revenue stream was undoubtedly crucial to the financing of the projects. Yet nearly all of the utilities named are facing privatization, which inevitably raise concerns that in future the same financing mechanisms may not be available due to the lack of a bankable, government−supported offtaker.

In addition to acting as the offtaker there is much that the public utility can do to facilitate the investment flow into private hydro projects by:

· Undertaking project preparation studies ahead of the bidding and award of concessions.

· Obtaining, in advance, the necessary statutory and environmental clearances.

· Providing a contractual framework that is realistic in its apportionment of risk and commercial expectations.

· Handling resettlement, compensation, wayleaves, land and water rights issues at an early stage.

· Mobilizing the support of the multilateral agencies are likely to be central to the financing plan.break

Certain utilities have now moved a long way in this direction, but there remains in many countries a failure to appreciate that the private sector will only be interested in viable, well−prepared projects with a realistically short

lead time and an acceptable security package. It is the primary role of the public utility to facilitate this process, supported by the host government.break

Section 8—
Issues in the Financing of Private Hydro Projects

Cost Profile of Private Hydropower Projects

The key issues in the financing of private hydropower projects are bankability and affordability. Although the operating costs of hydro are minimal and the project life almost infinite, there are multiple cost−related factors that make hydro difficult to finance on a private basis, particularly when compared to equivalent thermal projects. These include the following:

· **High Capital Costs** . The specific cost of a hydro power station ($/kW) is typically 100 to 200 percent more than a thermal power station, depending upon the site characteristics and the type of thermal plant. This gap widens when private financiers require fixed price EPC contracts, because the contingency that has to be priced in for hydro is much higher than for thermal power projects. Furthermore private development invariably implies higher equity returns and higher interest costs so that the capital−intensive nature of hydro is magnified relative to its thermal competitor. For thermal projects capital charges may constitute less than half of the tariff. Therefore the consequences of using private capital are diluted; but for hydropower, where capital charges dominate annual costs, the impact of higher capital charges is much more pronounced.

· **High Front−End Costs** . All private projects have to internalize their front−end costs. These include transaction expenses for legal, financial and due diligence services; they also include engineering costs, technical and environmental consulting fees, environmental mitigation and the developer's own expenses. These "soft costs" are generally much higher for hydro than for thermal plants, because of the longer time that hydro takes to prepare for private financing and its greater complexity. As an indication, Table 9 shows that on average the soft costs for the candidate projects, including financing charges, were 45 percent compared with 25 to 30 percent for a typical thermal project.

• **Long Construction Period** . Most hydro projects of any size will take four to five years to construct. This is to be compared to under two years for a gas−fired power station, or three to four years for other types of thermal power station. The longer construction period increases the interest and equity returns during construction (considered above as a component of "soft" costs). However, the late start to the revenue stream also adds to the perception of project risk, and in turn increases the risk premium in the financing charges.break

TABLE 9: TOTAL COSTS AND CONSTRUCTION COSTS BREAKDOWN

Project	Capacity MW	Total Cost $ million	Total Unit cost $/kW	Type of Contract	Construction Cost $ mln	Construction Unit Cost $/kW	Soft Cost Ratio (total/ construction)
Casecnan	150	495	3,300	EPC	259	1,727	1.91
San Roque	345	1,053	3,052	EPC	792	2,296	1.33
Bakun, Philippines	70	147	2,100	EPC	102	1,457	1.44

Theun Hinboun	210	317	1,510	Traditional	219	1,043	1.45
Nam Theun II	900	1,227	1,363	EPC	820	911	1.50
Khimti I	60	140	2,325	Traditional	108	1,800	1.29
Upper Bhote Koshi	36	98	2,722	EPC	58	1,611	1.69
Birecik	672	1,236	1,839	EPC	917	1,365	1.35
Ita	1,450	1,070	738	EPC	705a	486a	1.52
Guilman Amorin	140	149	1,062	EPC	112	800	1.33
	4,033	5,931b	1,882		4,092	1,311b	1.45

a Completion of works only.

b Excluding Ita.

Source: Author's notes.

· **Limited Availability of Export Credit Financing** . The high civil work content of most hydro schemes severely limits the availability of export credits. Generally the ECA element will be no more than one−third of the direct project costs, which may be only 20 percent of the total funding requirement. In contrast the majority of the finance for thermal power stations is in the form of ECA credits. The low proportion of ECA funding for hydro not only increases the financing gap, but it also makes it more difficult to raise commercial funds, which are usually piggybacked onto ECA loans. Where commercial loans are available they are often expensive and of short tenor—unless extended by Partial Guarantees.

· **Mismatch of Loan Tenor and Asset Life** . For both thermal and hydropower projects the tenor of available ECA credits and commercial loans is considerably less than the asset life. For thermal projects, loans may extend for up to 12 years from the commissioning date, compared to an asset life of perhaps 20 years. The accelerated repayment required is reflected in higher initial tariffs than would be the case if the project were publicly financed. For hydropower projects, the effect is exacerbated, since loan tenors are the same while asset life is conventionally assumed to be 50 years or longer.

· **Peak and Baseload Plant** . Most hydro plants are intended to operate in the medium to upper range of the load curve, while many thermal IPPs are operated at high capacity factor near baseload. In practice this makes it misleading to compare energy costs without recognizing that the value of mid−range and peak energy is usually significantly higher than baseload generation. Tariff comparisons should always be on the basis of the quality of the energy supplied, which is reflected by the position it occupies in the load−duration curve and the ancillary support services it provides.break

Tariff Burden for Economically Equivalent Plant

The above factors combine to widen the apparent price gap between hydro and its thermal alternative. In order to demonstrate this additional burden, a hypothetical exercise has been undertaken to compare the tariffs that would be required for economically equivalent thermal and hydro plants operating under similar base and peak load conditions.

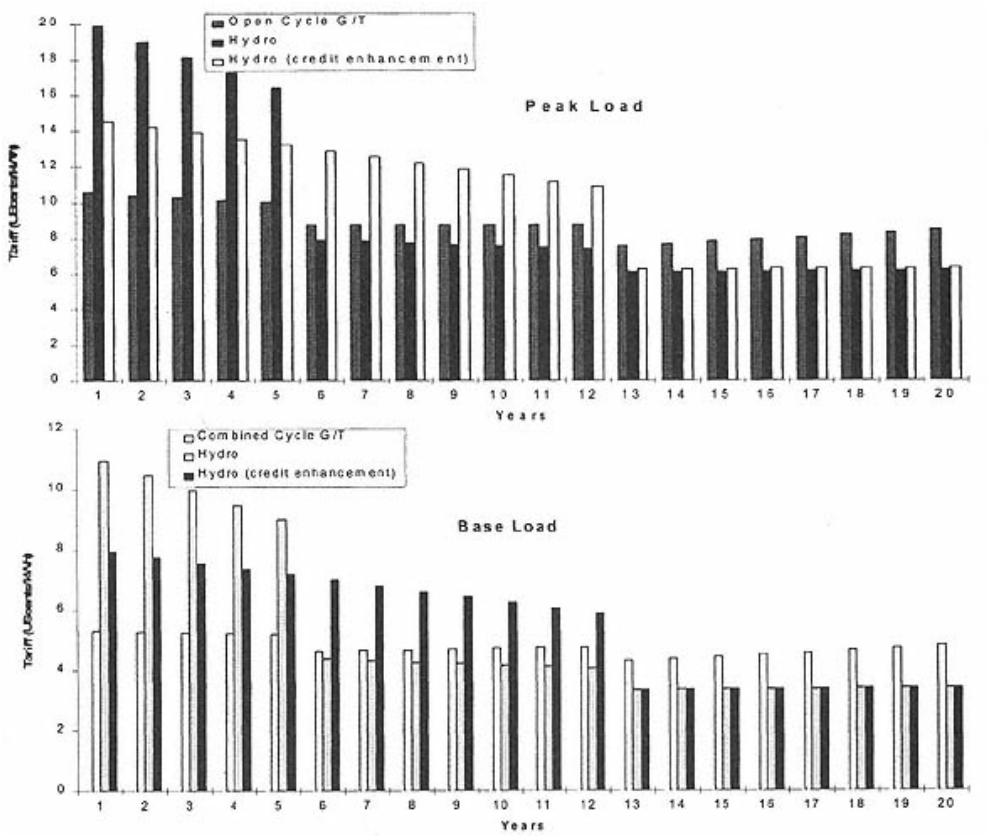
For the purpose of this exercise, economically equivalent plants are taken to be those that under normal operation have equal levelized unit energy costs, derived by discounting construction and operation expenses for plants performing a similar function in the load curve. The assumed construction cost contingencies are those normally used in an economic analysis and the levelized tariff has been calculated using a discount rate of 12 percent. By back calculation, the capital costs of base and peak load hydropower plants are derived to provide equal levelized tariffs and thus "economic equivalency" in the sense that from the national viewpoint one scheme is as favorable as the other.

Hypothetical tariffs have then been calculated for each case assuming a private financing scenario with typical front−end "soft" costs (including project preparation, transaction costs, risk premium and interest during construction) of 0.5 times the engineering cost estimate for hydro and 0.3 for thermal.

The results are shown in Figure 2, which indicates tariff levels for economically equivalent hydro and thermal plants operating as baseload (80 percent load factor, combined cycle) and in the peaking mode (25 percent load factor, open cycle). In the case of each hydro plant an alternative tariff has also been shown, assuming the availability of a credit enhancement facility that converts the commercial debt to the same terms as the ECA debt. Levelized tariffs are also shown for each case for short−, medium− and long−term operating periods.

Although economic equivalency means that the choice of generation should in theory be a matter of disinterest to the host government, this ignores issues of sustainability and exposure to uncertain future fuel costs for thermal plants. In practice therefore it could be argued that in such cases hydro would usually be the preferred option. However Figure 2 illustrates three crucial points, namely:

· Taking a long−term view, levelized tariffs for hydro are about one third higher than for the economically equivalent thermal plant. This is largely attributable to the higher soft costs and the fact that the thermal tariff is proportionately less influenced by changes in the capital cost arising from private financing.break



Base Load Levelized Tariffs (US¢/kWh)

Years	Thermal	Hydro	Hydro (credit enhanced)
1-5	5.25	10.08	7.58
1-12	5.01	7.63	7.14
1-25	4.91	6.74	6.35
1-40		6.58	6.20

Peak Load Levelized Tariffs (US¢/kWh)

Years	Thermal	Hydro	Hydro (credit enhanced)
1-5	10.33	18.35	13.81
1-12	9.67	13.89	12.99
1-25	9.31	12.27	11.55
1-40		11.98	11.30

Assumptions

	Hydro		Thermal	
	Base	Peak	Base	Peak
Capital Cost (US$/kW)	1,960	1,115	600	450
Plant Load Factor (%)	80.0	25.0	80.0	25.0
Plant Relative Availability (%)	95.0	95.0	85.0	85.0
Heat Rate (%)	n/a	n/a	45	30
Fuel Cost (US$/mln Btu)	n/a	n/a	3.0	3.0

Figure 2
Tariff Profiles for Economically Equivalent Hydro and Thermal Plant
Source: Prepared in collaboration with B. Trembath and T. Matsukawa of the World Bank (who also co−authored Section 8). Hypothetical tariffs have been calculated in each case assuming a private financing scenario with typical front−end "soft" costs including IDC of 0.5 times the engineer's cost estimate for hydro and 0.3 for thermal, 70:30 debt−equity ratio, different availability of ECA−supported debt (20 percent of total financing for hydro; 50 percent for thermal). Under the credit enhancement scenario for hydro plants, 5−year commercial debt is assumed to be replaced by 12−year debt of the same terms with ECA debt. The calculation omits various important assumptions required for actual financial projections and is for illustrative purposes only.

· Assuming a normal financing case, hydropower tariffs in the short term are almost double those of thermal, although the difference reduces to about 78 percent in the case of peak load plant, since the tariff of a peaking thermal plant has a higher capital proportion than that of a baseload thermal plant.

· Where a credit enhancement mechanism is used to extend the tenor and reduce the interest rate of the commercial loans to match ECA terms, the result is to substantially lower the hydro tariff in the early years, to the stage that it would be reasonably affordable in the short term, albeit at the cost of raising tariffs in the medium term. Overall it has the effect of lowering levelized tariffs by about 6 percent.

In practice these differences may be partly illusory because the calculation has been carried out on an assumed 2 percent a year inflation rate, which gives little margin against long−run increases in fuel prices and O&M costs that weigh heavily on the thermal tariff. Furthermore the difference is reduced over longer periods of 25 years or more, which lies within an economic planning horizon but far beyond most financial horizons. There may well be scope for narrowing the gap by reducing the soft cost effect through the offtaker assuming more risk, particularly those risks where the developer and financier's perception of risk is higher than that of the offtaker (such as environment and resettlement) and where the offtaker can better withstand the exposure (such as hydrology risk, through having multiple generating sources). Preparing projects to the stage that they can be reasonably priced, and adopting concession procedures to reduce the upfront costs to the developer would also assist in driving down the soft cost markup.

On the financing side, there would appear to be scope for extending credit enhancement to further levelizing the tariff. One productive avenue would be to provide refinancing guarantees, effectively allowing loan tenors to be extended to match asset life. While such guarantees have not yet been used in the context of hydropower development, the possibility should be studied by the multilaterals and bilaterals.

However, even if all such measures are taken, it is clear that a hydro scheme has to be significantly better than its economically equivalent thermal competitor if it is to stand any chance of development in the private sector in the absence of a long−term view by the offtaker and government, or an incentive framework if they are so inclined. At favorable sites hydro can be financially competitive but a similar analysis based on *financial equivalence* suggests that whereas it might be economically attractive, from the national perspective, to develop peak hydro at $1,115/kW as an alternative to open−cycle gas turbines, such a project would need to cost less than about $900/kW to be viable as a private development. For baseload hydro, matched against combined−cycle gas turbines, the corresponding figures are $1,960/kW and $1,550/kW. It has to be emphasized that these figures are illustrative and for comparative purposes only because they are based upon a number of assumptions that will inevitably vary from situation to situation, but they nevertheless clearly illustrate the gap that exists between economic and financialcontinue

viability in hydro projects. This is significant because a large proportion of the world's identified hydro potential falls within this gap.

In practice most hydropower stations operate at mid−range, typically at load factors of 35 to 55 percent. The best sites, which can be developed at around $1,000/kW or less, will generally be able to compete with thermal on equal terms within this range. In certain circumstances the price threshold may be raised where fuel prices are high because of a lack of natural resources and high transportation costs, or where there are other factors tilting the balance in favor of hydro. However only a minority of the world's hydro sites will fall into this favorable category and many schemes will be economically viable but remain financially unattractive in the sense that they will be unable to compete with thermal tariff levels, at least in the short to medium term.

One way of overcoming this problem at suitable sites is to plant up an hydro scheme. For example a baseload station at a specific cost of $1,850/kW might have its capacity increased at an incremental cost of $400/kW. In converting such a plant from 80 percent to 25 percent load factor, the specific cost is reduced to $884/kW, which would make it financially viable based on the above analysis. This approach will not always be possible, and in particular it is confined to storage schemes, but it is consistent with maximizing the benefits of hydro and with the fact that in mixed generating systems hydro generally progresses toward a peaking role as the system grows.

A number of other factors could improve this situation, such as the widespread application of carbon taxes or crediting hydro with the full value of its ancillary benefits. Both of these could significantly raise the unit cost at which hydro would become financially competitive. However at present a large proportion of potential hydro schemes fall within this "economically viable, financially nonviable" gap and while this remains the case, such schemes will only be financed by the private sector with some form of intervention by the host government. This can take a number of forms, but in the end it devolves down to either the public sector financing the nonviable elements, or the acceptance of higher charges than would be obtainable from other types of generation. Both of these options are seen in the candidate projects where host governments have demonstrated their willingness to pay a premium for the use of indigenous resources to achieve long−term price stability in their power markets, and the wider benefits that hydro brings in terms of system management and multipurpose uses.

Credit Enhancement and Risk

Local financing of infrastructure projects has been very limited in many developing countries because of the immature state of the domestic financial markets. Where such financing is available, interest rates are usually too high to make projects affordable. For these reasons it is likely that for the foreseeable future most privatecontinue

hydropower projects will continue to be financed using offshore funds, as in the case studies.

While the international banks traditionally provide the major share of offshore project debt under an ECA umbrella with maturities of up to 14 years, commercial bank loan maturities for developing country projects can be very short (3−7 years) without multilateral cover. In addition, lending banks normally expect loan principal amortization to start soon after completion of the project with equal semiannual installments. Such repayment terms, aggravated by short maturity periods, result in high debt service requirements in the initial years of operation.

The use of international capital markets to access long−term institutional funds has been explored by private power companies, and project finance bonds have been used, principally in refinancing situations. However, compared to commercial banks, familiarity with nonrecourse project finance debt is still limited among bond investors, and their appetite has been seriously blunted by the recent financial turmoil in parts of the developing world. In consequence capital markets remain wary of infrastructure project financing in emerging economies.

Official support mechanisms, such as export credit insurance and multilateral guarantees, are available to reduce these problems. Their main advantage is to reduce project risks and therefore lower the required interest rate, and to reschedule and extend the tenor of commercial debt beyond what would be available under purely commercial arrangements. This can be particularly valuable in the case of hydropower projects where the terms of the debt impact particularly heavily on tariff levels. The effect that improvement in the debt terms, through longer maturities and lower interest rates, has on required tariff levels is indicated in Figure 2.

Required returns on equity are closely linked to the perception of risks. Where the project is structured in a manner that passes most of risks outside the control of the sponsor to the utility or the host government, and where the legal, regulatory and institutional environment ensure the contractual rights of project financiers, the sponsor will accept lower equity returns, possibly as low as 15 percent a year. In contrast, a high−risk project would probably not attract equity investors at all, or the investors will demand returns higher than 25 percent a year. Among the candidate projects, the actual returns on equity lie between these two extremes, generally averaging around 20 percent a year.

There is no established pattern for risk allocation in private hydro projects and the accepted norms are still emerging, driven largely by what is required to achieve financing. However Table 10 gives a summary of the main risks and an indication of the way that they are tending to be allocated in a number of countries as the

market develops. The arrangements shown reflect the level of risk assumption that generally needs to be assumed by the public sector to make a project bankable. It will be seen that the publiccontinue

sector is increasingly having to bear many of the risks that they did under the traditional utility−led implementation arrangements, and this is likely to remain a feature of most medium−to−large privately financed hydro developments for the foreseeable future. This obviously raises some fundamental questions regarding the rationale behind the practice of developing new hydropower stations in the private sector if the public sector still carries much of the riskbreak

TABLE 10: NORMAL RISK SHARING ARRANGEMENTS FOR HYDRO PROJECTS

RISK	PRIMARY OBLIGANT
Hydrology	
· temporary deficits	Usually PC, but sometimes access to GV funds. Insurable
· long−term deficits	GV/UT increasingly assuming this risk. Not insurable
· flood damage (construction)	Generally CO risk unless force majeure, or insurance
· flood damage (permanent works)	PC risk. Insurable
Construction Risk	
· changes in quantities/cost overruns	Depends on reason. Either CO, PC or shared
· unforeseen ground conditions	Increasingly borne by the UT or shared. Partly insurable
· delayed completion	Normally CO risk, but some exposure by PC
Performance Risk	
· equipment	Plant supplier or turnkey contractor
· project performance	CO, and possibly PC
· transmission	Usually the responsibility of the UT
Environmental Aspects	
· permitting	PC or, by preference, UT
· land acquisition/resettlement	GV/UT
· EMP	GV/UT
Market	
· market risk	Usually UT through take−or−pay
· dispatch	Obligation and right of the UT
Force Majeure	
· continued debt servicing	

	Generally obligation on the UT to maintain payments
· rehabilitation costs	Principal exposure on the UT (increased tariff) and insurers
Political	
· obligations of utility	GV obligation often backed by political risk insurance
· changes in law	GV obligation often backed by political risk insurance
· changes in tax	GV obligation often backed by political risk insurance
· nonsequestration/buyout obligations	GV obligation often backed by political risk insurance
Financial	
· increase financing costs	Generally passed to UT in the tariff, or absorbed by PC
· exchange rate	Generally passed to UT, backed by GV
· cost escalation	Usually reflected in tariff during construction and by limited tariff escalation thereafter

GV − Government

UT − Utility

PC − Project Company

CO − Contractor

Source: Author's notes.

Potential Role of the Multilaterals

It will be evident from the reading of the case studies that the role of the multilateral development banks has, in most cases, been essential for the success of the projects. Furthermore, that the assistance that such banks provide can come in a number of forms. Their potential role in assisting the financing of private hydropower projects can be through the use of loans, equity investments and/or guarantee instruments, which are described below in the following ascending order of dependence on public sector support:

· Loans/equity investments to the private partner,

· Partial Risk Guarantees (covering government undertakings),

· Partial Credit Guarantees (to extend the maturity of debt financing), and

· Loans to governments and other public entities.

Loans/Equity Investments to the Private Partner

In recent years all of the major multilateral development banks have established either freestanding private sector arms like IFC, or internal departments focused exclusively on financing for the private sector. The function of these organizations is to facilitate the flow of international private capital by acting in a catalytic role.

In general such organizations will provide loans and take a minority equity position. This is often a crucial factor in building the confidence of commercial lenders and investors. Transactions are usually on a strictly commercial basis, with the main object of MDB involvement being to facilitate the process of private funding by its presence. Support from these sources can include some or all of the following:

· Direct lending from the MDB's own resources (e.g. IFC "A" loans).

· Providing an umbrella under which commercial loans are syndicated using the MDB as the lender of record (e.g. IFC "B" loans).

· Participation of the MDB as an equity holder in the private project company.

The extent of MDB investment in a single project (including direct loans, equity investment, guarantees and underwriting commitments) will usually be restricted to around 25 to 30 percent of the total cost of the project. This is in line with the MDB's perceived role as a catalyst for external financing rather than acting as a competitor to the private sector. By the same token equity investments will generally not exceed 25 to 30 percent of the share capital, and the MDB will not be the largest single investor in the enterprise.break

Partial Risk Guarantees (Covering Government Undertakings)

Many private infrastructure projects, especially large ones, are financed on a limited−recourse basis. For projects in developing countries, private financiers may have concern over the stability of the legal and regulatory framework and creditworthiness of local contracting parties.

To facilitate financing in these circumstances multilaterals, such as the World Bank, can provide commercial lenders with Partial Risk Guarantees covering sovereign/policy risks and specific contractual obligations of the government and other public bodies. Such guarantees can substantially reduce project risks not controllable by private financiers. They would extend the maturity and lower the cost of debt financing, thereby reducing tariff levels.

As the objective is to assist the host government in establishing credible regulatory and institutional framework for private hydropower projects, only the minimum level of guarantees required to mobilize private financing is provided. The types of sovereign risk covered under the Partial Risk Guarantees for hydro projects would depend on specific circumstances, but may include the following:

· Maintenance of laws and regulations affecting the project;

· Provision of necessary approvals, licenses and permits;

· Permitting agreed tariff collection and adjustment;

· Underwriting the power and water purchase obligations of the public utility;

· Underwriting other payment obligations of public entities;

· Ensuring the supply obligations of public entities (for example, water flow);

· Permitting foreign exchange convertibility and transferability;

· Certain force majeure events not commercially insurable at reasonable cost.

While the multilaterals, such as the World Bank, would normally provide a guarantee or other political risk mitigation measures only for a portion of the debt financing, the participation of a major multilateral should provide comfort to other financiers including the sponsor and ECAs, and therefore facilitate the mobilization of capital into private projects.

Partial Credit Guarantees (To Extend the Maturity of Debt Financing)

Private debt financing (bank loans and/or bond issues) available for projects in developing countries tends to be shorter than desirable for hydropower development and offshore creditors may have concern regarding the stability of the investment environment over a long−term period. Therefore the government or public sector entity,continue

which might opt to partially provide debt financing of private hydropower projects to fill the funding gaps, may find it difficult to borrow long−term from the commercial debt market, particularly if their credit standing is weak.

Multilaterals, such as the World Bank, can provide commercial lenders with Partial Credit Guarantees covering a portion of debt servicing due from the borrower to extend the maturity of debt and lower the cost of debt financing. This in turn will lower required tariff levels. While it is conceivable to structure this type of guarantee in various ways, examples could include the following:

· Sovereign borrowing: The government or public entity would borrow commercial debt to partially support the financing of a private project with a Partial Credit Guarantee to stretch the maturity of sovereign debt beyond what is available in the commercial markets based on its sovereign credit standing. This would be a viable alternative for direct loans from the multilaterals.

· Project finance borrowing: The private project company would borrow from the commercial debt market to finance the project with a Partial Credit Guarantee, with the intention of lowering initial debt service requirements. This could be to stretch the maturity of commercial debt; or to ensure the refinancing of debt (therefore delaying the burden of principal repayment in tariff calculation). Partial Credit Guarantees for private projects would need to be structured carefully to provide sufficient incentives for the project company to seek commercial refinancing of the guaranteed debt. These guarantees may require to have a fall−out provision in the case of commercial failure by the sponsor in completing the project.

Loans to Governments and Public Entities

Lending to governments and/or public sector entities has been the traditional route for multilateral institutions supporting infrastructure development. In the case of private hydropower projects, the public entity may provide part of the necessary funding to lower the private financing requirements and to facilitate the mobilization of private capital. The multilaterals can provide loans to the government, public development banks and utilities to cover their shares of financing. This may include the following cases:

· To fund the equity contribution of a public partner (such as the utility) in a public−private joint−venture project. Public equity investment may be made on a passive basis without interfering with the management control of the

private sponsor. This could be made on a subordinated or delayed−return basis to lower initial equity returns and therefore tariff levels;

· To fund loans made by the government or public entity to a private project company to fill the debt financing gap. Public loans to the project can be on a subordinated basis to enhance the senior debt−coverage ratio, and could have lower debt servicecontinue

requirements initially (for example, zero coupons) to enhance the affordability of the project;

· To fund the costs of environmental mitigation measures and resettlement, which could be costly and incur risks not controllable by the private sector. The participation of major multilaterals such as the World Bank in environmental mitigation and resettlement measures enhances confidence, not only of private financiers but also many ECAs and bilaterals that are often reluctant to provide support for potentially controversial hydropower schemes;

· To fund the public works portion of an hybrid project. As observed in some cases, major civil works (dams and tunnels) can be wholly or partially financed by the public sector to lower private financing requirements and the risk premiums otherwise charged by the private contractor;

· To fund support payment obligations on the part of the government or public entity to a private project. This may include the public share of construction cost−overrun risks due to unforeseeable events.

A further area of support to the public sector can be in the form of grants or loans to establish the appropriate condition for private sector entry. This can involve the funding of front−end studies for project preparation, together with assistance in developing the appropriate policy frameworks, solicitation procedures and the like to ensure that private funding is attracted on acceptable terms.break

Section 9—
The Solicitation Process

Policy Decisions by Government

Governments wishing to attract private finance to the hydro sector need to address a number of fundamental issues:

· At what STAGE in the project cycle should the private sector be introduced?

· In what FORM should that participation occur?

· The nature of the SOLICITATION process.

This section examines the various options open to the host government in these areas.

Intervention Points for the Private Sector

In general terms there are three points in the project life cycle where the private sector might be introduced. These are illustrated in Table 11.

TABLE 11: INTERVENTION POINTS FOR THE PRIVATE SECTOR

		Stage in Project Life Cycle	
Option	**Definition**	**Construction**	**Operation**
1	Public	Public	Private
2	Public	Private	Private
3	Private	Private	Private

Source: Author's notes.

The principal features of each option are as follows:

· **Option 1** : The public sector develops the project using its own resources and then privatizes it by the sale of equity in the project company, or refinances it through granting a concession to a private operator.

· **Option 2** : The public sector completes the project definition studies (technical feasibility, site investigation, and so on) and then brings in the private sector to finance, design, construct and operate the project under concession.

· **Option 3** : Where the public sector is unable or unwilling to finance project definition and other preparatory studies, the private sector conducts such studies and assumes responsibility for the full project cycle.

The relative merits of these options are discussed below.break

Option 1—
Sale or Lease of Projects Already Developed in the Public Sector

In a number of countries hydro assets constructed in the public sector are being privatized. While this is generally being undertaken as part of a wider unbundling of the power sector, it could in principle become a self−sustaining process under which the capital raised is used by the government to finance further projects that are then privatized on completion. As an alternative to privatization, completed projects could be offered to the private sector in the form of time−limited operating concessions where the operator effectively refinances the project on the basis of the revenue stream, leaving its ownership in the public sector.

The advantages of this approach are:

· It is easier to raise private finance on a completed project, as all the main construction risks are no longer present and there is an immediate revenue system.

· The public utility can design and construct the project that is best suited to its requirements.

The disadvantages are:

· It depends on the availability of public finance and the existence of a competent public sector body to initiate and develop the project up to the point of sale or leasing.

· It fails to bring the private sector into the most challenging part of the process, which is at the implementation stage.

· The value of the project, and hence the capital raised, will be based on the anticipated revenue stream and for this reason is unrelated to the original cost, and could drop below it.

From the viewpoint of bankability, the sale of an existing hydro asset is undoubtedly the easiest way of attracting private finance. Projects that would not be financeable in the private sector as greenfield developments could be readily refinanced upon completion by the private sector. An example of this concern can be found in China where thermal power plants and highways constructed under World Bank loans are now being formed into companies that raise capital on local and international financial markets to fund new development.

The sale is potentially controversial because the private sector can bring very little to improve the operation of most hydro projects, which is a relatively inexpensive and undemanding exercise. Therefore there is no merit in the state selling an existing hydro scheme other than for releasing the tied−in capital. However there is a strong case for linking the sale of an existing hydro asset with the obligation to develop a new greenfield project, and this option is examined further in Section 10 below.break

Option 2—
Private Sector to Develop and Operate Projects Defined in the Public Sector

The majority of the candidate projects fall into the category of having been planned in the public sector, often with the original intention that they should be developed by the utility, and later taken over by the private sector. The advantages of this route are that:

· The utility can define the project that is best suited to system requirements and be reasonably confident that this is what will ultimately be built.

· It encourages project definition studies of an adequate quality, thereby producing a better−defined, less risky and consequently cheaper project.

· It provides the opportunity to bid the concession with reasonable transparency on the basis of a clear project definition.

The disadvantage of this option is that:

· It still leaves the public sector to fund fairly expensive front−end studies, and it depends upon the existence of a competent utility to manage the project definition stage.

Although most private projects fall into this category, the quality of the public sector studies on which the private participation is based varies a great deal. Many of the project concepts are not optimal for private development, being either too expensive or too risky, and most studies fail to address anything other than technical issues. This often leaves prospective sponsors with information that is of doubtful value and meaningless in contractual terms because it is unwarranted by the utility. Furthermore, the sponsor is generally left with the burden of obtaining environmental and other clearances.

If these shortcomings can be overcome there are clearly strong arguments in favor of this approach, and the models considered later in this section are all based upon the concept of the private sector entering the project cycle after a significant level of project definition by the public sector.

Option 3—
Private Sector over the Full Project Cycle

Under this scenario the private sector is responsible for all stages of development including the project definition studies.

From the viewpoint of the private sector this is not an attractive proposition unless ways can be found of reducing the time and cost of the front−end studies, which typically can take 12 to 24 months and cost 2 to 3 percent of the ultimate price. In the relatively few cases where private developers have funded detailed project definition studies it has been only after securing exclusivity on the project, for example on Nam Theun II wherecontinue

the sponsors have put substantial resources into extending the original, public sector studies. Where exclusivity has not been forthcoming, the scope of the front−end studies has usually been severely curtailed.

The advantages of this approach are:

· It is more appropriate to a fully deregulated situation because it does not depend upon the continued presence of the utility.

· It has the potential for efficiency gains through the introduction of commercial disciplines at an early stage of planning.

However the disadvantages are:

· Regulatory problems in awarding the concession for a project where the principal parameters are still largely unknown.

· The optimization of the project is less likely to take account of overall system requirement and other multipurpose aspects, which are unlikely to be of commercial interest to the promoter.

· The private sector is not interested in project definition studies, which simply postpone the time when the investors will receive a revenue stream.

· Inadequately resourced definition studies by the project developer are likely to lead to increased construction costs and upward pressure on the end−price of electricity.

The basic flaw with this option lies in the government's inability to award a concession with transparency in the absence of a clearly defined project. The private sector will not assume the burden of the project definition studies without exclusivity and a clear commitment on the part of the government to proceed with the project. Yet at the time these commitments have to be made there is an unquantified project cost and output, to be confirmed at a later date. Combined with the other disadvantages listed above, these are serious deterrents to both the public sector and prospective private participants.

Models for Future Developments

General Requirements

In considering models for the participation of the private sector in future hydro development, it has to be recognized that no single prescriptive formula can apply to the diversity of situations that can occur. In particular, in the case of large and multipurpose hydropower projects, development entirely in the private sector may not be a

practical option.break

All of the models outlined below are focused on meeting the following general criteria:

· The project must represent the optimum development of the site in terms of the future requirements of the power system and in the broader context of other riverine developments, both existing and potential.

· The award of exclusive rights to the site, and endorsement of the tariff structure must satisfy reasonable standards of transparency.

· Implementation contracts need to be structured in a manner that encourages competitive and responsible pricing.

· A security package acceptable to international financiers has to be developed at an early stage.

In response to these requirements a number of possible basic solicitation processes present themselves. These are summarized below and described in more detail in the following pages.

· **One−Stage Model.** In this model it is assumed that the prospective concessionaire has enough information at his disposal to determine the price of the project at the time of bidding for the concession. The process is similar to that already in use in the Philippines and Turkey, where the concessionaire is selected on the basis of the lowest tariff offered during a single round of bidding. The public sector is not involved in any way with the underlying construction contract. The difficulty with this approach in the past has been that the private sector has been faced with too many uncertainties at the bid stage, which has deterred prospective sponsors. To overcome this the public sector will need to go further in securing the necessary clearances and environmental permits, and in establishing beforehand a realistic risk−sharing formula and security package acceptable to international lenders. Site investigation and technical studies need to be undertaken to a reasonably advanced stage (preliminary design level). This information is then integrated into a single Project Information Memorandum on which prospective developers are required to base their proposals.

· **Two−Stage Model** . Under this arrangement the bidding of the concession is separated from the pricing of the works, and hence the procurement process takes place in two stages. The government (or utility) is party to the award of both the concession and the construction contracts, in a process that allows it first to select the sponsor on his own merits, and later to jointly arrange with him the construction contracts in a manner aimed at minimizing the cost. The sponsor is selected on the basis of his capability, resources and an indicative tariff based on an assumed construction price. He then undertakes at his own expense the project definition studies and invites bids for construction, after which a target cost is agreed with the utility and the tariff revised accordingly. Construction is then managed by the sponsor under a risk−hard

sharing mechanism with appropriate incentives and penalties for the private sector partner in areas where he can control the risk. Some construction risks, like unforeseen ground conditions, may pass back through the sponsor to the utility.

· **Hybrid Model** . A final option, which will serve some situations, is a hybrid model under which the private sector builds, owns and operates the power elements of a project that is otherwise in the public sector. This arrangement is likely to be applicable to large and complex multipurpose projects with a significant nonpower element that are unlikely to be viable on their own in the private sector. For example, in a multipurpose project the dam and basic site infrastructure could be funded publicly using concessional financing, leaving the private developer to build, own and operate the power intakes, penstocks and powerhouse. The model could also be used in retrofit situations, where a power station is added to an existing publicly owned irrigation or water supply dam.

The consequence of separating off the nonpower elements is generally to pass the major civil works construction risk back to the public sector, making it easier to finance the private portion.

Each of the above models is now briefly described below.

The One−Stage Model

The One− and Two−Stage Models are illustrated in Figure 3. Under the One−Stage Model the project is extensively prepared by the public sector before inviting bids from private developers. In some countries a multilateral or bilateral agency would be needed to effectively adopt the project at this stage, by providing guidance to the government and funds for the preparatory studies that should include:

· Technical studies with full site investigation, preliminary design, bills of quantities (for pricing) and technical specifications.

· Economic optimization studies, leading to preliminary financial projections and decisions on the appropriate tariff structures.

· Environmental impact studies with mitigation plans, cost estimates and all the necessary clearances and permits.

· Project risk analysis leading to decisions on the key framework agreements setting out the principles of risk−sharing between the public and private sectors, identification of the level of government and/or multilateral support needed.

· Preparation of bid documents including the draft Concession Agreement and PPA with an outline security package and detailed technical project information.break

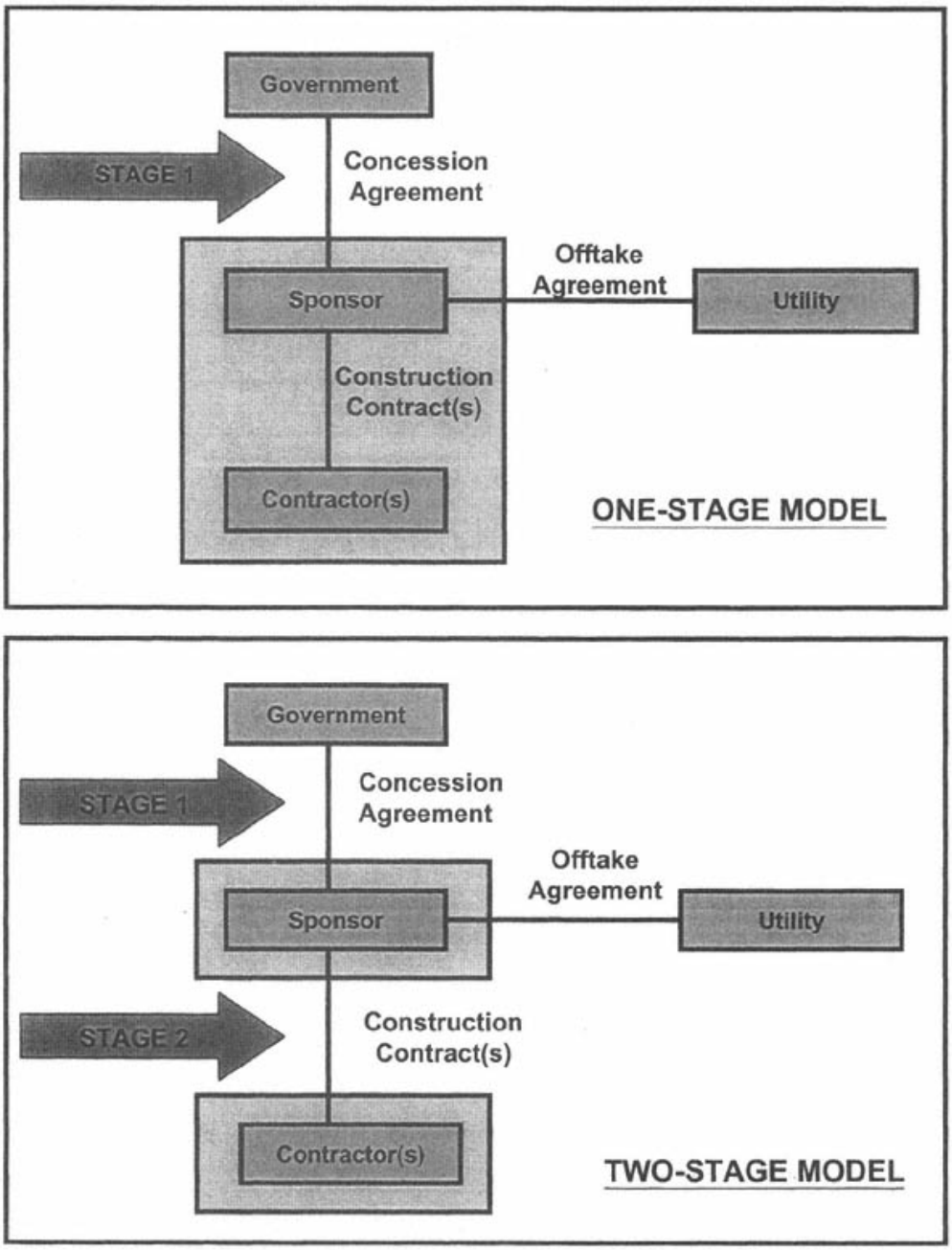


Figure 3
One− and Two−Stage Models
Source: Originated by author.

The essential point is that uncertainties over project definition and cost, concession arrangements and the overall bankability of the project are reduced as much as possible before the private sector is invited to bid. The pivotal contractual document is a Project Information Memorandum, which would need to be warranted to the extent that it contained factual data (geology, topography, hydrology) on which bidders are likely to base their price. The preparatory work should be carried out as an integrated exercise by experts offering a combination of technical, environmental, financial and legal expertise. The cost of these preparatory studies would be of the order of 3 to 4 percent of the total project cost, and they could take over two years. However the result should be a more

effective tendering process with the strong probability that it will attract a higher−quality response than has previously been the case when ill−prepared projects have been offered for open bidding.

In this model much of the burden of the preparatory work has been lifted from the private sector and in consequence the solicitation is likely to attract civil contractors and equipment suppliers as well as the traditional independent power producers. In this respect it should widen the field of prospective bidders.

An essential part of attracting wider interest is the need to instill confidence in the risk−sharing mechanism. While this will undoubtedly vary from project to project, depending on the perception of risk and government policy, the following basic terms are likely to be needed:

· Sponsor to be protected against:

· unforeseen site conditions, particularly of a geological nature;

· factual inaccuracies in warranted data provided in the Project Information Memorandum;

· failure on the part of the government to fulfill its obligations;

· certain conditions of force majeure.

· To maintain incentives, the sponsor should be free to optimize the design, subject to government/utility approval, without a change in the tariff.

· Sharing of the hydrological risk, or its assumption by the utility offtaker.

Despite the higher level of documentation provided, the bidding process based upon this formula would still be complex because of the need to establish at the outset the project cost. Unless the sponsors are proposing to act as their own contractors this would involve a secondary level of negotiation between the parties bidding for the concession and prospective EPC contractors. This negotiation would need to be conducted in parallel with the sponsor's own bidding procedures and for this reason it is unlikely that any solicitation of this type will attract serious interest unless it is based upon a restrictedcontinue

shortlist of prospective sponsors comprising no more than two or three applicants at the most.

The One−Stage Model is the simplest of the models, and it is most appropriate when site conditions are reasonably straightforward (a well−defined concept with most of the works on the surface) and where there is a clearly defined power market. In this respect it has similarities with a thermal power project.

The Two−Stage Model

Under the Two−Stage Model the sponsor is appointed early in the project cycle to work in partnership with the utility on the basis of a cost−plus formula for the capital works with some sharing of construction risk. Once again it will almost certainly be necessary to have a strong multilateral agency involved from the outset. Under this staged approach the sequence would be as follows:break

Stage 1: The project would be studied in the public sector to the point where a relatively clear definition existed in terms of the principal design parameters, cost and energy output (feasibility level). However the level of detail would be

significantly less than in the One−Stage Model. The principal terms of the concession and offtake agreements would also need to be in place. Proposals would be solicited from prospective concessionaires who would be bidding a tariff to finance, develop and operate the project on the basis of the assumed capital cost and output. If the actual cost and output turned out to be different, the tariff would be retrospectively adjusted within certain defined parameters.

As a further option the bidder might be required to include in his price a fixed sum for the supply and installation of mechanical and electrical equipment. This would tend to broaden the field of respondents to encourage the major equipment manufacturers into the role of developer, leaving only the civil works to be recosted in Stage 2.

Stage 2: Having acquired the rights to the project, the sponsor then finances further project development studies and the preparation of tender documents for the competitive bidding of the civil works (and the equipment contracts if they are not already included in Stage 1). The contractors would be prequalified by the government in advance of the appointment of the sponsor who would obviously need to be comfortable with the prospective construction team.

In order to achieve the most favorable pricing the civil works would be bid on a remeasurable basis in the main areas of risk, particularly geology. Having received the tenders, the sponsor would agree a revised target project cost with the utility, and the tariff would be adjusted accordingly. The tariff would also be adjusted if necessary to reflect any changes in financing costs as a result of market movements since the sponsor's original proposal.

At this stage the project then moves to financial closure, based on the tendered prices and a clearly defined risk−sharing arrangement between the utility, the project sponsor and the contractor.

The sponsor would then control the design and manage the construction contract under a formula, agreed at the outset, which incentivizes him to complete the project within the target cost. The contract would allow certain costs to be passed through to the utility where they clearly lie outside the control of either the sponsor or the contractors (e.g. unforeseen site conditions).

Although such a division of project into separate civil and equipment contracts is not favored by financiers it is a well−proven method for implementing hydro projects, and the price advantage is likely to outweigh the perceived benefits of a single−point EPC contract. Potential cost overruns need to be covered by contingent equity funding and could be limited under a price capping or other form of risk−sharing mechanism.

The feature of this arrangement is that it allows the main cost elements—the financing and management of the construction process, and the constructionitself—to be priced individually in a manner that removes much of the uncertainty from the bidders. This should logically result in lower prices. The sponsor will be concentrating on producing the most favorable development and financing package, without having to overlay his risk for uncertainties over the cost of the works, or doubts over the energy output. Equally splitting the construction contracts into separate equipment and civil work packages, bidders are able to focus on a scope of works and risks with which they are comfortable, without the need for high contingencies and the add−on costs inherent in consortia pricing.

The Two−Stage Model is most appropriate for more complex projects, where the configuration is not clear and there is considerable site investigation and optimization needed. In these circumstances the developer needs to work closely with the resource owner and power offtaker, perhaps for a considerable period of time, to finalize the project and arrive at an acceptable price in a transparent manner.

The Hybrid Model

San Roque is an example of a hybrid model under which a multipurpose project is geographically divided into public and private elements. In this case the powerhouse is being built by the private sector under BOT arrangements, while the dam is financed under concessional terms by the public sector. Despite this the project is being developed as a single entity under one EPC contract managed by the private partner.

There are, in principle, two forms of hybrid model:

· Separate financing with *separate implementation* arrangements; andbreak

· Separate financing with *unified implementation* arrangements.

Wherever possible, the unified implementation arrangement is preferable because it avoids interface problems that might arise from having the separately financed elements built under different contract arrangements. However there will be times when this is not possible, for example when the publicly financed works have a longer implementation period and have to be started well in advance of the private portion.. For example very large hydro projects, of the type now being developed in China, require long construction periods that are not consistent with private financing. The civil works require the long construction period but the powerhouse equipment is only installed at the end of the project and could therefore still be viable as a separately financed private element. In such a circumstance the private sector would be responsible for the supply, installation and operation of the powerhouse and ancillary equipment only.

Under hybrid arrangements, the public sector can maintain its traditional role as the project sponsor by preparing preliminary studies and arranging financing for the public component. Alternatively the private sector partner could act as the project sponsor from the outset, taking the lead in promoting the project and arranging the financing for both elements, as in the case of San Roque. Whichever route is adopted, the project will need to be driven by a strong sponsor.

In terms of private sector participation, the benefits of this approach are:

· Removal of much of the construction risk increases private sector confidence.

· Private sector is left with a higher plant content that is amenable to ECA financing.

· Participation of the public sector brings comfort to private investors.

· Shorter construction time for private elements.

In the wider perspective, hybrid projects have the advantage of allowing the host government to play a more central role in the exploitation of its own natural resources. Where there are extreme sensitivities over the ownership of land and exploitation of natural resources, the hybrid approach may be more acceptable than the handing over of an important site to the private sector, even where there may be government equity participation in the private project company.

Hybrid Models are best suited to multipurpose or very large projects where individual elements may, for various reasons, be unfinanceable in the private sector.break

Section 10—
Conclusions and Comments

A Changing Situation

Electricity sector reform is still a relatively new concept in most parts of the world. This report has covered five countries in various stages of regulatory reform, ranging from Lao PDR where the process has barely started, to Brazil where it is well advanced. However it should be noted that in each case the public utility is still in place to enter into long−term offtake obligations on which nonrecourse project financing has been based.

In some respects the report may be looking at a transitional situation, with the prospect that in the longer term public utilities will cease to exist in many countries. Under these circumstances the private hydro developer will have to sell into the short−term spot market or alternatively make longer−term arrangements with private offtakers. In either case it is going to significantly alter, yet again, the climate for private hydro financing.

This report has not attempted to examine the future scenario where there is no public utility in place, largely because there are no hydro schemes of any size currently being developed on a merchant plant basis. Indeed the strong consensus among financiers and developers is that individual hydro projects are not financeable without a secure long−term offtake agreement—at least as far as nonrecourse financing is concerned. This leads to the conclusion that if present trends continue the emphasis will have to swing toward balance sheet financing. In view of the risk and the size of the investments involved, such a trend will limit the field to large players only. This carries its own risks for the host governments who could find themselves faced by a small number of increasingly powerful developers.

In the long run hydro can be very competitive, and an existing scheme where the debt has been repaid will always be in an advantageous position in any spot markets, particularly where the ancillary benefits are properly valued. The financing problem is severe but it is also transitory, in that if it can be overcome the longer−term commercial viability of hydro is almost assured. One possible solution to this problem is bundling, combining the sale of an existing hydro scheme with the obligations to develop a new one. This is already happening in a small number of countries. Within the formula a number of possible permutations of payment can be used to ensure that the concessionaire has the necessary assets and revenue stream to finance the new development.break

The current situation is probably more favorable to private hydro than the fully deregulated market, but nevertheless hydro is finding it difficult to compete with thermal for private funding, particularly gas−fired plants. However the gas bubble is a finite resource, and it is probable that we are witnessing a short−term imbalance. Perhaps the greatest mistake has been to look upon hydro as just another form of power generation, and to try to fit it to the IPP model for thermal power. This patently does not work, and a more responsive approach is needed. It is against this background that the following conclusions and recommendations are made.

Conclusions

No Clear Model . Private hydro is in an evolutionary phase and governments are still trying to find a formula that will work in terms of risk−sharing and the level of public support to be provided. No single model is likely to be applicable to all situations but the lack of an established precedent means that much time and money is being wasted in abortive bids and protracted negotiations leading to high transaction costs. Governments need guidance

in this area aimed at a higher success rate based on a well−prepared solicitation process.

Host Government to Assume Risk . Hydro is competing for funds that will flow elsewhere if more attractive prospects present themselves. Very few promoters are exclusively committed to hydro and many are deterred when they are required to assume risks that lie outside their control. Experience has shown that the public sector is being driven toward shouldering these risks to attract private finance, to the point where it is bearing most of the risk that it would otherwise assume naturally under the traditional public financing scenario.

Comparative Tariffs . For a number of reasons, the privately funded option is more expensive than the public sector alternative. This is true for all types of power station; however the gap is widened with hydro because its capital−intensive nature substantially increases the cost of financing. At least some of this cost increase is due to publicly financed projects not being charged the full opportunity cost of capital, which is a market distortion. Hydro tariffs are dominated by capital charges, whereas thermal tariffs include a large element of recurrent (fuel) costs that are largely unaffected by the process of private financing.

Tariff Profiles . Hydro tariffs tend to be high in the early years to meet the heavy debt−servicing burden arising from a capital−intensive investment with a significant element of commercial funding. The tariff profile can be flattened by the use of Partial Guarantees and similar credit enhancement mechanisms that extend the tenor of commercial loans. While such facilities have limited impact on the levelized tariff or overall capital requirements, they make projects more affordable in the immediate post−commissioning period.break

Scheme Configuration . External pressures are pushing most private hydro developers toward small run−of−river schemes, which are producing low−value, baseload energy that competing with very economic baseload thermal generation. Hydro is generally more competitive in the middle and peaking portions of the load curve, particularly when backed by storage and if the ancillary benefits are correctly valued. However such schemes are often not bankable in the private sector. Host governments and utilities need to be more aware of the importance of optimizing the development of any hydro site to ensure that it produces maximum economic benefits as well as viable financial returns.

ECA Limitations . The limited scope for ECA financing in most hydro projects leaves a serious financing gap that is not easy to fill from commercial sources. Despite this, ECAs remain an important source of financing although the loan tenors are still unrealistically short for hydro projects. There is a case for a special Sector Agreement to be negotiated for hydro export credits, as there is for nuclear power, with provision for longer loan tenors to reflect the almost indefinite shelf life of hydro.

Local Funding . As hydro has a large element of local costs it would be logical to expect these to funded in local currency from the domestic capital markets. This would have the added advantage of limiting foreign exchange exposure. In most of the projects studied there was very little local funding, largely due to its high cost and nonavailability through the undeveloped state of the local markets. This is clearly a problem that can only be resolved with time, but eventually local funding should make private hydro more attractive to host governments and their utilities than thermal projects, which are heavily dependent on imported plants.

Guarantees . The scope for using commercial loans is limited due to their availability, high cost and short tenor. Guarantees and similar credit−enhancement mechanisms made available through multilateral agencies and some bilateral sources can help overcome this problem. However relatively little use has been made of such facilities in the cases studied, and there is a need to examine in more depth the reasons for this. The requirement for counterguarantees from the host government undoubtedly acts as a deterrent, together with the perception, on the part of some developers, that the agencies concerned will be less than fully responsive to their needs.

Role of Multilaterals and Bilaterals . In addition to offering guarantees it is clear that the international lending agencies have a pivotal role to play in acting as a catalyst for the flow of private funds into the hydro sector through the provision of technical assistance, loans and sometimes equity. They also have a general role in guiding host governments toward the preparation of projects for private financing on the basis of sound documentation and realistic expectations. There is a need for a coordinated approach among these agencies on the specific problems of privately funded hydro.break

Regulatory Concerns. Most hydro concessions have been directly negotiated, because it has not proved easy to award such concessions on a competitive basis. The increasing role that the multilaterals are likely to have to play in the future raises the issue of public accountability, which can only be addressed by the institutional strengthening of the utility and the provision of substantial front−end funds for a more structured solicitation process. In the absence of heavy public sector investment in this area it is probable that many future contracts will continue to be directly negotiated.

Risk−Sharing . Behind every greenfield hydro concession there lies a construction contract. The risk−sharing arrangements between the host government and its utility on the one hand, and the sponsor and the contractor on the other hand, will govern the final cost of the project. There is a need to examine ways in which this process can be more effectively structured to reduce the price to the final end−user. Two models are considered in the report that involve, on the one hand, the concessionaire absorbing the construction cost and, in the second case, the construction cost being treated as a pass−through to the utility. They now need to be developed further through actual usage.

Long−Term Offtake Agreements. There is a trend in the private power industry away from long−term PPAs and toward merchant plants. This is in keeping with the concept of total deregulation and confirmed by recent experience that casts doubt on the enforceability of long−term offtake agreements in situations of financial turmoil such as occurred recently in Asia. The prospects of privately financing large hydro without an offtake agreement that extends at least for the duration of the debt servicing are remote. This raises serious questions on the future direction of privately funded hydro in a totally deregulated environment.

Hybrid Projects. Projects that are not financially viable on their own in the private sector but nevertheless remain economically attractive may be developed through a private−public partnership where the private sector finances the power element only. There are very few projects following this route at present but it is known that a number are under contemplation. The hybrid concept is likely to become increasingly important in the future as a means of introducing private finance to projects that would otherwise rely entirely on a diminishing pool of public funds. Multipurpose projects could also fall into this category with a public subsidy for the "nonpower" elements.

Private hydro is, in many respects, at a critical juncture where a more structured and focused attempt to solve the industry's problems is now needed. Some suggestions to assist this process are made below.

Concluding Comments

Deregulation and privatization of the global electricity sector is itself part of a wider move toward reducing dependence on the state for the provision of basic infrastructure services. The policy has been very successful in attracting investment incontinue

certain types of project, but it is inevitable that in other areas difficulties will emerge that may need to be specifically addressed. Hydro appears to be one such problem area.

The deregulation process has not happened instantly. In most countries governments licensed thermal power projects while hesitating over what to do about hydro. There was much debate about the merits of retaining hydro entirely in the public sector, although in fact most governments considered a range of options that fell between this and full privatization.

The size of the project is important for a variety of reasons, namely the level of investment involved, the construction period and associated risks, and the uniqueness of the site. Small projects, below say 30 MW, are likely to continue to be bankable and built without much public sector support, but the evidence suggests that continued public support in one form or another will be needed for the medium and larger projects, where much of the global hydro potential exists. MDBs have played an important role in eight of the ten projects covered by this study, and there is a wide consensus of opinion that the involvement of multilateral and bilateral development agencies will continue to be an essential part of private hydro development.

The MDBs have a key role in anticipating and addressing important development issues. For this reason they championed the changes that have taken place in the global power sector over the last decade the same changes that are now giving rise to some of the difficulties that this report has identified. Their traditional role of direct lending to the public sector is diminishing and being replaced by a role as facilitator, encouraging private sector investment, particularly in the more difficult areas.

Hydro falls into the "difficult" category for several reasons, although not all are specifically related to private financing. In recent years an unrelenting campaign of opposition to hydro projects on environmental grounds has weakened the resolve of the international agencies to the point where many have almost withdrawn from funding hydro, particularly large schemes with storage. There is a growing view that this has been an overreaction to what is a genuine concern, and it is hoped that the initiative of the World Bank and the International Union for the Conservation of Nature in establishing the World Commission on Dams will find an acceptable way forward at a time when the world is facing difficult energy choices.

In the 1990s the private hydro industry has been characterized by the lack of a clear sense of direction, and by the largely uncoordinated efforts of a large number of organizations—public and private—bringing only a small number of schemes to fruition. It has already been pointed out that if present trends continue hydro will play a diminishing role in the production of the world's electricity, and many countries will be denied access to this indigenous, clean, renewable resource. To overcome this problemcontinue

governments, multilateral and bilateral agencies, ECAs and the private sector itself will need to work more closely to coordinate their efforts in the following areas:

· Provision of support to host governments on the regulatory aspects of private hydro development.

· Financing and overview of front−end studies performed under the auspices of the utility for prospective BOT projects.

· Advice and assistance to utilities on the structuring and negotiation of private hydro contracts.

· Encouragement of the further development and use of financing mechanisms that will facilitate the flow of private capital into hydro.

· Review and evaluation of the experience of countries under different project structures, to establish a portfolio of experience on proven development models.

· Coordination of financial support (loans/guarantees) by the various multilateral/ bilateral development banks and ECAs concerned with private hydro developments.

In conclusion, an industry that is currently fragmented and without a clear sense of direction needs a better−coordinated approach to what is inevitably a major exercise in public−private partnership. The role of the multilateral and bilateral development banks is changing. It may have diminished in the context of thermal power generation, but it remains as crucial as ever in the hydro sector if the challenge of attracting private finance is to be adequately met.break

Annex—
Project Profiles

Case Study No. 1—
Casecnan (150 MW), Philippines

General

Casecnan is a run−of−river diversion project that will transfer flow from the Casecnan/Denip river basin on Luzon Island across the watershed to the Pantabangan reservoir. It benefits both the power and irrigation sectors, by producing average energy of 406 GWh/year (of which 178 GWh/year is uplift at two existing stations) and providing water to irrigate an additional 50,000 hectares in the Central Luzon Valley.

The project itself comprises two diversion weirs, 26 km of tunnel and an underground powerhouse (2 × 75 MW); also 55 km of access road. National Power Corporation (NPC) will be responsible for the transmission line.

Casecnan is an unusual independent power producer (IPP) project because sales of water account for 45 percent of the revenue, and the main offtake agreement for both power and water is with the National Irrigation Administration (NIA). Under a subsidiary agreement NIA onsells the energy to NPC.

Concession Award

Originally studied in the 1980s as a public sector project based on a large storage reservoir, Casecnan was being reviewed as an alternative run−of−river concept in 1994 when California Energy approached NIA and NPC with a proposal for private development.. After a public solicitation process for competing proposals, NIA concluded an agreement with the original proponents offering a 20−year concession following on from a 4−year construction period. At the end of the 20 years the project reverts at no cost to NIA.

The obligations of NIA include provision of the site and responsibility for maintenance of the Casecnan watershed. NIA is also required to cause NPC to construct and operate the transmission line.

Project Structure

A special−purpose company named CE Casecnan Water and Energy Company Inc. (CWEC) was established under Filipino law, with the principal shareholders being California Energy (35 percent) and a major US contractor Peter Kiewit & Sons (35 percent). There is a 30 percent local holding.

Offtake Arrangements

The Project agreement between CWEC and NIA, signed June 1995, sets out the principal terms of the concession and power purchase agreement (PPA). NIA willcontinue

purchase all power and water on a take−or−pay basis, with all payments (except local value−added tax) denominated and paid in US dollars. Revenue is derived 55 percent from power and 45 percent from water. Approximately half the power income and all of the water revenue is paid on a notional output irrespective of river flows and actual production, unless production deficits are due to the default of the project company.

The energy tariff is 15.5¢/kWh of measured output from the new power station, but this apparently high figure is deemed to cover also the uplift at the two existing stations. There is no provision for escalation of the energy tariffs, although the water tariff of 2.9¢/m3 is escalated at 7.5 percent a year for the first five years.

Financing

Financing of the $495 million project is on a 72:28 percent debt:equity split, with $356 million of debt being provided through the placing of three tranches on the 144A bond market ($281 million fixed rate with 10− to 15−year maturity; $75 million floating with 7−year maturity).

The project, which was rated Ba2 by Moodys and BB+ by Standard & Poors, is believed to be the first IPP hydro to be financed on the 144A bond market. The deal was oversubscribed. Debt service ratios average 1.97, with a minimum of 1.45 over the duration of the debt.

The comprehensive security package included a performance undertaking by the government for all NIA's obligations. Payment of all fees will be made in US dollars into an offshore account. The provision of foreign currency is underwritten by the Philippine Central Bank. There is a buyout provision triggered by a number of identified events, including certain conditions of force majeure.

Construction

Construction of the project is being organized through an engineering, procurement and construction (EPC) contract under which the contractor takes full construction risk with onerous liquidated damages for late delivery or performance deficiency. The tendering process produced only two serious bids, from which Hanbo of Korea was selected with a contract price of $236 million. The terms included an irrevocable Letter of Credit from Korea First Bank for $118 million to cover the contractor's exposure to liquidated damages and other warranties.

The original construction contract was terminated after approximately one year on the grounds that Hanbo was filing for insolvency protection in Korea. CWEC has signed a new turnkey contract with a consortium led by CMC of Italy. This will result in a significant delay to completion, at some cost to the owners but within the 2−year grace period allowed in the Original Project Agreement with NIA.break

Case Study No. 2—
San Roque (345 MW), Philippines

General

San Roque is a multipurpose storage project, with an average energy of 1,065 GWh/year and associated irrigation benefits (87,000 hectares). The reservoir will also provide flood control and water improvement. The project will

supply peaking power to the Luzon grid.

The principal project features are a 200 meter (m) high embankment dam and associated works, a 3 × 115 MW underground powerhouse, irrigation headworks and 10 km of 230 (kilovolt) kV transmission line.

Concession Award

Original studies for the project commenced in 1974 and continued intermittently until the early 1980s when work started on construction, only to be aborted shortly afterward for economic reasons. An unsolicited build, operate, transfer (BOT) offer was presented in late 1994 but not pursued. In 1996 NPC solicited BOT bids but, despite prequalifying six consortia, received only one bid in February 1997. NPC approved the award of the contract to the only bidder in July 1997, and the PPA was signed in October of that year.

The obligations of NPC include the provision of the transmission line and access road, the project site and rights to the use of the water. It also includes the resettlement of 310 households displaced by the project.

Project Structure

The consortium formed a Philippines−registered single−purpose company under the name of San Roque Power Corporation (SRPC). SRPC will finance the powerhouse and associated works and construct the complete project under a single EPC contract. The dam, spillway and related facilities that comprise the "nonpower" works will be separately financed, but in other respects treated as part of the same project. Upon completion of the facilities, the project company will transfer the legal title to NPC without charge, but will operate and maintain the complete scheme until the end of the concession period.

Components not directly covered by the project will be separately financed and implemented by NIA. These comprise downstream developments such as the reregulating pond, irrigation canals and laterals necessary to serve NIA irrigation areas.break

Offtake Arrangements

NPC is obliged to buy all power generated by the project for the full concession period of 25 years, under a government−backed guarantee. NIA will use the water that requires no offtake agreement as it derives from the publicly financed portion of the works.

NPC shares part of the hydrological risk through minimum offtake provisions in the PPA. Payments for the delivery of electricity consist of US dollar− and Japanese yendenominated Capital Recovery Fees (CRF), and Peso−denominated Operating Fees (OF). The CRF is fixed, but the OF is escalated according to a local index.

Financing

The total project cost of $1,191 million is made up of separate public and private tranches. It includes a $400 million 15−year untied loan to the government (onlent to NPC for the construction of the dam facility) from JEXIM. This loan is raised on behalf of a number of government agencies who are perceived to be "nonpower" beneficiaries (NIA, DENR, DPWH). Should the actual cost of completing these facilities exceed the said amount, SRPC will recover the excess amount through the Capital Recover Fees provided in the PPA.

The private sector portion comprising essentially the powerhouse facility is being financed on 75:25 debt−equity split, with $134 million of equity; $302 million JEXIM loan (Overseas Investment Credit) and $144 million of commercial−base lending backed by political risk guarantees from JEXIM for NPC offtake obligations (Years 11

to 15). There are $14.5 million of contingent equity.

Financing for the downstream irrigation development components was obtained by NIA through the 23rd Overseas Economic Cooperation Fund, Japan (OECF—merged with JEXIM and renamed as Japan Bank for International Cooperation) Loan Package.

Construction

The project is being constructed by Raytheon of the United States under a single EPC contract covering both the privately and publicly funded elements but the project has been subjected to a number of delays arising from local opposition and it is not clear whether this will still be met.break

Case Study No. 3—
Bakun (70 MW), Philippines

General

Bakun is one of the few hydropower projects in the Philippines to have reached financial closure following the process of soliciting bids for BOT offers initiated originally by NPC in 1994. It is a run−of−river project on Luzon Island with an estimated average energy output of 225 GWh/yr.

The principal project features are a low intake weir, 9.8 km of waterways, mainly tunnel, and a surface powerhouse (2 × 35 MW) under 533 m generating head. The project also includes 18 km of 230 kV transmission line which is the responsibility of NPC.

Concession Award

In March 1994 NPC invited bids for the BOT development of a number of hydroelectric power projects including the Bakun A/B and C projects located on the Bakun River at the boundary of Benguet and Ilocos Sur provinces in Northern Luzon.

In December 1994 a consortium of project developers submitted a bid for a combined development of the two Bakun River projects (that is, A/B and C) as a single 70 MW project, now known as the Bakun A/C project. The consortium was selected by NPC as the preferred developers in February 1995 and following commercial negotiations during the latter months of 1995, NPC's Board of Directors decided to invite the consortium to negotiate the PPA based on a draft attached to the original bidding documents.

Project Structure

A special−purpose company, Luzon Hydro Corporation (LHC), was registered in September 1994. The three equal shareholders are Aboitiz, a publicly listed Philippines holding company with a diverse portfolio of interests; PacifiCorp Development Corporation, the nonregulated affiliate of a major US utility; and Pacific Hydro Limited, an Australian renewable energy project developer and operator.

Offtake Arrangements

NPC's payments for the delivery of electricity consist of Capital Recovery and Service Fees, Energy Fees for generation in excess of the nominated Contracted Capacity, Operating Fees and Watershed Management Fees. Capital Recovery Fees will be paid only during the first ten years of generation.

The obligations of the NPC include the provision of the associated transmission line, rights−of−way for the project site and the access road, and rights to use water. Thecontinue

hydrological risk is allocated to LHC along with the financing, construction and operating risk during the concession period.

Financing

The project is being financed on a 70:30 debt:equity ratio. Total cost is $147 million, of which $44 million is equity, which will be initially provided through a loan facility backed by a Letter of Credit against the sponsor's own securities.

The $103 million debt was originally underwritten by a consortium of local banks, and was subsequently partially syndicated to a group of foreign banks. The security for the debt is provided by the project itself and its contractual arrangements including the PPA, the EPC contract and the insurance agreements.

The obligations of NPC under the PPA are supported by a Performance Undertaking by the Philippines Department of Finance, while those of the EPC contractor are supported by performance bonds and parent company guarantees by the contractor.

Construction

Construction is being carried out on a turnkey basis by Transfield of Australia. The contractor has assumed all construction risk subject only to force majeure. It is understood that there have been contractual problems relating to unforeseen ground conditions.break

Case Study No. 4—
Theun−Hinboun (210 MW), Lao PDR

General

Theun Hinboun is the first of a number of IPPs resulting from a memorandum of understanding (MoU) signed between the governments of Lao PDR and Thailand in 1993, which provided for 1,500 MW of hydropower to be exported to EGAT in Thailand by the year 2000.

It is a run−of−river project that involves the diversion of water from the Theun to the Hinboun Rivers. Average energy production is 1,620 GWh/year, reducing to 1,350 GWh/year after the completion of Nam Theun II upstream.

The main elements of the project are a low diversion dam and approximately 10 km of waterways (5.2 km of tunnel) with a surface powerhouse (2 × 105 MW) operating under a head of 228 m. Also included is 100 km of 230 kV transmission line leading to a metering station on the Thai border.

Concession Award

Originally mooted as an IPP in the early 1990s, the project gathered momentum in 1994 with the signing of a joint venture agreement involving Eléctricité du Lao (EdL), and an MoU with EGAT of Thailand, under which EdL were to be a majority shareholder under a partnering agreement sponsored by MDX Lao of Thailand and the utilities of Norway and Sweden, with EGAT entering into an offtake agreement.

The concession was directly negotiated for a period of 30 years, with an option to renew for another 10 years. The government's main obligation is to provide access and land rights, and to undertake an environmental mitigation plan. There is no sovereign guarantee.

The project has only limited environmental impact, and there is little or no resettlement or loss of habitat. The main negative impact is the reduction of flow in the Nam Theun downstream of the diversion dam.

Project Structure

The project has been developed, owned and operated by the Theun−Hinboun Power Company (THPC) in which the government holds 60 percent equity through EdL. The sponsors and private sector partners are Nordic Hydropower (20 percent)—a joint−venture company owned by the utilities of Norway (Statkraft) and Sweden (Vatenfall AB)—and MDX Lao of Thailand, a subsidiary of GMS Power, one of Thailand's leading IPP developers (20 percent).break

Offtake Arrangements

Under the terms of the offtake agreement EGAT commits itself to purchase 95 percent of the output on a take−or−pay basis. The base rate tariff is 4.3¢/k Wh (1994) escalated at 3 percent a year for the four−year construction period, and at 1 percent a year for ten years thereafter. The price will be renegotiated at the end of the ten−year period. The currency of payment is 50 percent Thai Baht and 50 percent US dollar. EGAT is obligated to construct and operate the transmission line on the Thai side of the border.

Financing

Financing of the $280 million (budgeted) project is based on a 61:39 percent debt:equity split, with the $170 million debt being provided (in US dollars and Baht) by ECAs ($62 million), commercial credits from six Thai banks, Lao PDR ($8 million) and the Nordic Investment Bank ($15 million). The government's equity portion was largely financed through a $60 million soft loan from ADB.

The "security package" rested primarily on two main factors: the perceived quality of the credit of EGAT as the offtaker (together with the structuring of the cash flows into an offshore escrow account until after the lenders are paid); and the provision of political risk cover by a variety of ECAs to support the Lao government risk (the Thai banks did not need such cover).

Construction

Construction was arranged according to the traditional formula, under which the works were divided into six separate civil and E&M contracts that were competitively bid. Design and construction supervision were the responsibility of THPC under a separate contract.

Construction started in late 1995 although limited−recourse financing was not finalized until October 1996. The project was commissioned in early 1998, and commenced Commercial Operation in March 1998, and the formal certificate for Take Over of the Works was issued in May 1998.

The project was completed ahead of schedule at a cost of $240 million, well within the original budget of $280 million. However there are a number of contractual claims (mainly relating to unforeseen ground conditions) that remain to be settled.break

Case Study No. 5—
Nam Theun II (900 MW), Lao PDR

General

Nam Theun II is a planned storage project that will divert flow out of the Theun River above Theun−Hinboun, into a lower lying tributary of the Mekong. The project's average output of 5,850 GWh/year is primarily intended for export to Thailand. It is the largest of the IPP hydro export projects currently being developed in Lao PDR, and the only one currently remaining as a priority project to be developed under the original bilateral power export agreement with Thailand. The anticipated date of commercial operation is December 2006; predicted on financial closure occurring in 2001.

The project's main components are a 50 m high fill dam (creating a 450 km2 reservoir), with relatively short 3.5 km long tunnels leading to an underground powerhouse (4 × 225 MW) with a head of 365 m. The BOT developer is also responsible for the construction and operation of 146 km of 500 kV double−circuit transmission line to the Thai border. The project is intended to provide intermediate peaking power for 16 hours/day into the EGAT system, with secondary baseload energy.

Originally scheduled for completion in year 2000/2001, the project suffered a two−year delay while an extensive supplementary program of environmental studies and public consultation was undertaken. By the time these studies were completed in 1998 the Asian financial crisis had reduced load growth expectations in Thailand, with the consequence that EGAT requested a later commissioning date and a change in emphasis from the originally envisaged 680 MW baseload project to a 900 MW intermediate peaking scheme.

Project preparation has been very thorough and in its attention to project definition and the concern of the host government, local community groups and nongovernmental organizations, it represents what in many respects is a textbook model for private hydro development. But this has been achieved at a high cost in terms of the consortium's "at risk" expenditure, and the time it has taken to reach the present stage, which is still more than two years from financial closure.

Concession Award

The project evolved from a World Bank−financed feasibility study undertaken in the early 1990s. This was followed in 1993 by the signing of an MoU for its BOT development, which was later translated into a more detailed mandate granting exclusivity and setting out the terms of the concession (June 1994).

A special−purpose entity called the Nam Theun 2 Electricity Consortium (NTEC) has the right to develop the project and operate it for a period of 25 years, after which it reverts at no cost to the government of Lao PDR. NTEC is jointly owned by a consortiumcontinue

of private developers, led by EdF of France (30 percent) and comprising of Transfield of Australia and a number of Thai companies. Eléctricité du Lao (EdL) will hold a minimum 25 percent of the equity on behalf of the government.

Under the Draft Concession Agreement the government of Lao PDR warranted the full cooperation of all Laotian authorities, protection against expropriation, use of the site, water rights, and so on. The government will also be responsible for the Environmental Management Plan, including resettlement, although all agreed costs will be funded by the project. In return the government receives a royalty of up to 30 percent of gross income, and a Resource Levy of up to 30 percent of net income from NTEC in addition to its dividends as a 25 percent shareholder.

The project will generate over $250 million a year in revenues from electricity sales. The government's share over the concession period will total about 50 percent, which will represent an additional 3.2 percent of the country's gross domestic product.

Environmental Factors

Environmental concerns focus on the effect of the reservoir on flora, fauna and displaced people (800 families) on the Nakay Plateau. The original environmental assessment (undertaken in 1991) recognized the sensitivity of the issue and proposed the establishment of a "Multipurpose Management Area" to mitigate the impacts through an environmental management plan. This concept was later taken up by NTEC and endorsed by the government, but nevertheless it proved inadequate to prevent members of the World Bank Group from conditioning their support for the project to further investigations. These were launched in late 1996 and comprised the following five studies:

· Resettlement Action Plan (for 800 families);

· Environmental Assessment and Management Plan;

· Study of Alternative Sources of Generation;

· Economic Impact Study; and

· Watershed and Corridor Management Plan.

In conjunction with widespread public consultation these plans have resulted in a large number of initiatives to protect and enhance the natural environment and the conditions of the affected peoples, using revenue derived from the project.

Offtake Arrangements

The new offtake agreement has yet to be negotiated.break

The original contract with EGAT obliged the utility to purchase between 95 and 100 percent of output available at the metering station on the border. NTEC determines reservoir operating policy and availability, but EGAT dispatches within notified limits that are updated on a daily basis. In practice NTEC assumed most of the hydrological risk, although under extreme conditions it is shared. The tariff was denominated in US dollars and Thai baht, with limited provision for escalation linked to the US consumer price index. Under the revised arrangements it is anticipated that there will be a primary tariff for peak energy, and a secondary tariff for off−peak baseload. EGAT is responsible for the construction and operation of transmission lines in Thailand.

Financing

Financing arrangements have yet to be finalized, but a 70:30 percent debt:equity split is anticipated, with a total project cost of $1,227 million. The provision of debt financing will hinge around ECAs, World Bank Partial Risk Guarantees and IFC "A" and "B" Loans. It is assumed that there will be little appetite for pure commercial debt in the current situation; therefore any commercial bank involvement will be under the umbrella of ECAs or through cofinancing with multilateral agencies. The role of the World Bank Group is viewed as crucial to the financing plan.

Construction

Construction of the project is expected to be on the basis of an EPC contract. The sponsors are strongly represented in the Lead Contractor which will organize the works into four main packages, three of which will be submitted to full international competitive bidding. Geological risk will be shared between the contractor and the owner, on the basis of the contractor assuming specific risks in defined areas and related to the results of detailed site investigations.break

Case Study No. 6—
Khimti I (60 MW), Nepal

General

Khimti I is a run−of−river project with an average production of 350 GWh/year.

The project comprises a low diversion dam, about 10 km of tunnels and an underground powerhouse. It also includes a 132 kV transmission line that is the responsibility of the Nepal Electricity Authority (NEA) to construct and operate.

Khimti I was the first private power sector project in Nepal, and in consequence it has borne the brunt of developing the agreements on which other IPP hydro projects in Nepal will be based. Arranging the financing took 3.5 years.

Concession Award

The regulatory framework for private power generation in Nepal is based on legislation enacted in 1992/93, which provides for the letting of concessions for periods up to 50 years. This is the case for Khimti I but the PPA is for a contract period of 20 years after which Himal Power Company (HPC) will transfer 50 percent of the ownership to NEA effectively free of charge. The new company will then have the right to renegotiate a second PPA.

Under the concession the government guarantees all NEA's payment and performance obligations. In addition it grants HPC a 15−year tax holiday, rights on the conversion and repatriation of foreign exchanges and protection against adverse government actions.

Project Structure

The concession was directly negotiated with Himal Power Company (HPC) a locally incorporated consortium of developers led by Statkraft, the Norwegian state utility with a 73.9 percent holding. Other shareholders are the Butwal Power Company of Nepal (14.7 percent) and the equipment suppliers ABB and Kvaerner, each with 5.9 percent.

Offtake Arrangements

NEA will pay according to a two−part energy tariff in which there is a Demand Charge based upon the contract energy, and an Excess Energy Charge based upon any surplus supplied in the dry season. The tariff, initially equivalent to about 6¢/k Wh, is denominated in both US dollars and Nepalese rupees, based on their respective percentage in the financing plan. Escalation is linked to official US and Nepalese indices. Hydrology risk lies with HPC. Exchange rate risk is allocated to NEA.break

Financing

Financing of the $140 million project was arranged on a 68:32 percent debt:equity split, with nearly 90 percent of the debt being provided by two multilaterals, ADB and IFC, and export credits. Other financing was sourced from Norwegian aid. The process proved to be time−consuming and costly, and in particular the sponsors commented critically on the lack of cooperation between ADB and IFC, and the long and unpredictable nature of the process that they followed.

NEA's obligations under the PPA are supported by collateral arrangements (under the PPA itself) and a government guarantee. The collateral arrangements include an unconditional letter of credit equivalent to three months' project payments to be maintained by NEA in favor of HPC.

Political risk is covered by insurance arranged through MIGA and NORAD and the protection afforded by having two major multilaterals as lenders. Certain force−majeure situations will trigger a project buyout by the government.

Construction

Construction was arranged along traditional lines in which design (and project management) responsibility rested with the Owner, and there were separate civil and E&M contracts.

HPC managed the completion risk through fixed−price contracts with liquidated damages and warranties (the limit of liquidated damages was 25 percent for civil works and 10 percent on equipment contracts). The principal civil contractor, Statkraft Anlegg (part of the main shareholder's organization) assumed the gap risk between the contracts. In addition the sponsors provided a guarantee of $10 million in contingent equity to cover cost overruns.break

Case Study No. 7—
Upper Bhote Koshi (41 MW), Nepal

General

Upper Bhote Koshi (UBK) is the second of the privately financed hydro projects in Nepal. It is a run−of−river project with an average energy output of 246 GWh/year.

The project comprises a low diversion weir, a tunnel and a surface powerhouse (2 × 20.5 MW). It also includes 24 km of 132 kV transmission line that is included in the EPC contract and is the responsibility of the developer.

Concession Award

The regulatory framework for private power generation in Nepal is based on legislation enacted in 1992/93, which provides for concession periods of up to 50 years. The Concession Agreement and PPA were signed in July 1996. In this case Bhote Koshi Power Company Private Limited (BKPC) has a 25−year PPA with NEA, after which it will transfer 50 percent of the ownership to NEA at nominal cost. The parties will then negotiate and agree a new PPA for another 15 years. At the end of the 40−year period the plant transfers to the government at no cost.

Project Structure

The concession has been directly negotiated with Bhote Koshi Power Company Private Limited (BKPC), which was registered in June 1996. The original concession was taken by Harza of the United States, who subsequently introduced Panda Energy International as US−based IPP company with a strong background in gas. Panda led the

project but the bulk of the equity (70 percent) is held by a Canadian investment corporation MCMIC. The local partner is Himal Power Corporation.

Environmental Factors

The sponsors have prepared a full environmental impact assessment (EIA) identifying the key environmental issues. They have also conducted a full public consultation and disclosure program that appears to have satisfied all interested parties.

Offtake Arrangements

Under the PPA, NEA will pay on an energy−based tariff of 6.0¢/k Wh (1995) escalated at 3 percent for the first 15 years and indexed to the US consumer price index thereafter. The contract is effectively take−or−pay, although NEA is not obligated to purchase any output in the wet season above the Deemed Generation Level (98 percent load factor). An additional buffer is provided by the fact that the contracted capacity of the plant is only 36 MW, against 41 MW installed. Hydrological risk lies with BKPCcontinue

who is no protection against diversion of the water from the upper catchment that lies in Tibet.

Payments to NEA are denominated in both US dollars and Nepalese rupees in proportion to their percentage in the financing plan.

Financing

Financing of the $98 million project is based on a 70:30 percent debt:equity ratio, with all the debt being provided by IFC in two tranches ("A" Loan of $21 million and a syndicated "B" Loan of $47 million, both with 11−year maturities). The EPC contract accounts for some $48 million of the total project cost. Under the base−case scenario the minimum debt service cover ratio is 1.4.

The government guarantees the payment obligations of NEA and the availability of foreign currency. BKPC manages the construction risk through warranties from the contractor and liquidated damages with an ultimate liability on the part of the contractor for 100 percent of the contract price. However as this is backed by a Letter of Credit to cover only 25 percent of the contract price, there is some assumption of completion risk by BKPC who has agreed to provide additional funds of up to $10 million in contingent equity or subordinated debt to cover cost overruns.

Construction

The project is being constructed under turnkey arrangements by the China Gezhouba Construction Group Corporation (CGCGC) who has engaged Harbin of China to supply E&M equipment. The contract is fixed price with guaranteed delivery dates and liquidated damages of up to 35 percent for delay and underperformance. In order to maintain the overall delivery dates of October 15, 1999 and December 15, 1999 for the first and second units, the contractor was instructed to start work on February 1, 1997, ahead of Financial Closure.break

Case Study No. 8—
Birecik (672 MW), Turkey

General

Birecik is a major storage scheme on the Euphrates (part of the Southeast Anatolia GAP Scheme). The project is significant both for its size and the fact that it is the first large private hydro project in Turkey. It took nine years to bring the project to financial closure following the first BOT feasibility study in 1986.

The main elements of the project are a 62 m high embankment dam, 2.5 km long, four spillways and a surface powerhouse (6 × 112 MW).

Concession Award

The sponsors received their mandate giving exclusivity in April 1989 and the principal Implementation Contract was signed in March 1993. Financial closure eventually took place in November 1995.

Under the terms of the Implementation Contract between the project company and the Ministry of Energy and Natural Resources (MENR) the Company acquired the right to develop and operate the project for 15 years after completion. Energy is to be sold to TEAS* the publicly owned utility company, which would take a 30 percent stake in the project. On expiry of the 15−year operating period the project reverts at no cost to MENR.

Project Structure

The private sponsors of the project comprise a consortium of foreign and local contractors and equipment suppliers led by CEGELEC and Philipp Holzmann. Together with TEAS they form the Birecik Company. All of the contractors also appear in the construction consortium.

Offtake Arrangements

The Energy Sales Agreement signed between the company and the utility TEAS covers the full 15 years of the operating concession, and is on a take−or−pay basis. The base tariff, denominated in Deutsche Marks, is adjusted to reflect actual construction costs and actual production, so that much of the completion risk (in particular geological risk) is effectively passed through to the offtaker. TEAS also assumes the hydrological risk under a formula that adjusts the "expected generation every six months" on the basis of actual flows over the past three years. This denominates the target tariff, which is then further adjusted on a monthly basis for the determination of the tariff based upon the actual water flow. TEAS assumes the exchange rate risk.break

Financing

Financing of the DM 2,262 million ($1,250 million) project is on the basis of a 85:15 percent debt:equity split, with much of the debt being provided by ECAs (DM 1,388 million)—equivalent to 64 percent of the total project cost. The remaining debt (DM 465 million) is provided by commercial loans. A total of 44 banks participated in the loans, which combined both tranches on a pro−rata basis. Syndication was oversubscribed by 30 percent.

The government guarantees the performance of TEAS* under the Energy Sales Agreement and also the performance obligations of the Electrical Energy Fund, which will provide additional funding in the event of cost overruns in a number of identified areas including reservoir works (clearance, leakage) and final design modifications.

In the event of default by the project company there is a step−in provision under which the government assumes the debt and takes over the project.

Construction

Construction is being carried out under an EPC contract valued at about $900 million. Beneath the main contract there are separate consortium agreements (for equipment) and a joint venture for civil works that prevent the spillover of contract risk. There are provisions for variations in price for specified items including geological conditions and some design changes.break

Case Study No. 9—
Ita (1450 MW), Brazil

General

Ita is a storage project currently under construction in southern Brazil, with a projected average production of 5,852 GWh/year. Its primary purpose is autogeneration. There are few secondary multipurpose benefits.

The principal project works comprise a 125 m high, concrete−faced rockfill dam, two spillways and a surface powerhouse (5 × 290 MW). It also includes a short (1.8 km) 500 kV transmission line.

Concession Award

The project was originally studied in the public sector over the period 1977−90 by ELECTROSUL, one of the country's leading power utilities and a wholly owned subsidiary of ELECTROBRAS. Construction initially started under the public sector and then stopped through lack of funds. In 1994 a competitive bidding process was launched by ELECTROSUL to identify a private sector consortium to develop the project in partnership with the utility. Two consortia presented proposals, and that comprising four strong local companies in the petrochemicals, steel and cement industries won. Collectively the private sector companies are know as the sponsors.

Project Structure

To develop the project the sponsors created a special−purpose company named Ita Energética SA (ITASA) in which ELECTROSUL had a 39 percent holding. The formal legal structure limits the role of the project company ITASA to the construction, financing and leasing of the project assets to the sponsors. All other project agreements are signed by the sponsors who are, in effect, the genuine private element of the consortium.

ELECTROSUL is formally the leader of the consortium, as required by law. It will be responsible for quality aspects of construction and for the operation of the completed project. The overall coordination of the project is carried out by a Management Committee comprising all consortium members, including ELECTROSUL, with voting rights in proportion to their shareholding.

While the sponsors will finance and construct the hydro plant, ELECTROSUL receives its normal 39 percent share of the Guaranteed Energy (GE) in exchange for its past and future investments relating to past studies, site acquisition, resettlement and other environmental mitigation measures, construction of access roads and interconnection.break

Offtake Arrangements

Under the terms of the concession the sponsors have the right to 61 percent of the GE for use in their industrial plants irrespective of hydrological conditions, and ELECTROSUL has the remainder to sell to its consumers. Hydrological risk is therefore assumed by the utility partner.

Under the PPA the sponsors also agree to sell 15 percent of their share of the GE (536 GWh/year) to ELECTROSUL, together with any excess energy not utilized by themselves, at market prices.

Financing

Financing of the $1,070 million project is to be on a 75:25 percent debt:equity split. The debt of $800 million is being supplied roughly equally by the Brazilian National Development Bank (BNDES) and the Inter−American Development Bank (IADB). The IADB portion comprised an "A" Loan of $75 million and a syndicated "B" Loan of $300 million with respective maturities of 15 and 12 years. The BNDES debt has the same tenor as the IADB "A" Loan. Financial advisors are Credit Lyonnaise of São Paolo.

The project security package includes guarantees by ELECTROBRAS for the obligations of ELECTROSUL, which will be carried through in the event of the privatization of the utility. It also includes for the creation of offshore debt reserve accounts for each of the major lenders equivalent to 6 months' debt service payments. Foreign currency risks for the 37 percent financed in foreign exchange are assumed by the project company with the support of a standby facility provided by BNDES.

Construction

The project is being built under a fixed price, date−certain EPC contract with a consortium of construction companies (CONITA) led by CBPO, which ultimately shares common ownership with one of the sponsoring companies, ODERBRECHT.break

Case Study No. 10—
Guilman−Amorin (140 MW), Brazil

General

Guilman−Amorin (GM) is effectively a run−of−river project currently being completed in the state of Minas Gerais.

The project comprises a 41 m high concrete dam that creates an active storage of 1.7 million m3 , sufficient to permit 3 hours of peak load operation. There is a 507 km power tunnel leading to a surface powerhouse (4 × 35 MW). Also included is a short length (3 km) of 230 kV double−circuit transmission line to connect to the utility's (CEMIG) transmission system.

The plant is expected to have an average output of 580 GWh/year and will supply power via the CEMIG system to a major steel plant and mining complex owned by the sponsors.

Concession Award

The project is Brazil's first hydro scheme to be sponsored entirely by the private sector.

When the new regulatory framework allowed private investors to generate electricity for self−consumption (autoproducers) two of Brazil's largest energy consumers, Belgo−Minira SA (a steel company) and Samarco Minercao (an iron ore producer) decided to implement an hydroelectric project to ensure a reliable supply and hedge against future increases in energy costs.

The two companies formed a consortium Consórcio uhe Guilman−Amorin (the sponsors) that was awarded, in January 1995, a 30−year concession to develop the project and generate energy for self−consumption.

Project Structure

The sponsors formed a consortium pursuant to Decree 915 of 1993, which allows private sector companies to supply their own electricity needs and use the grid for transporting energy from the power plant to their factories.

Under Brazilian law the consortium is not deemed to be an independent legal entity from its members. Therefore having received the 30−year concession in January 1995 the consortium then formed a special−purpose company, UHGASA, for the sole purpose of constructing the power plant and leasing it to the consortium. Ownership of UHGASA remains entirely in the hands of the sponsors.break

Offtake Arrangements

Under the terms of the Concession CEMIG will operate and maintain the plant, and guarantee the sponsors 535 GWh/year of energy and maximum availability of the plant during peak hours regardless of hydrological conditions on the Pira Circaba River. Most of the hydrological risk is assumed by CEMIG, although the utility is relieved of its obligations to provide the guaranteed energy in the event of extreme low flows countrywide.

Financing

The total cost of the project is estimated at $149 million, of which the capital expenditure represents $112 million.

Financing has been arranged on a debt:equity split of 79.6:20.4 percent with the complete debt of $119 million being provided by IFC "A" and "B" loans (respectively $30 million and $89 million). The sponsor's equity and quasi−equity, in the form of subordinated loans, will total $30 million.

Financial support arrangements derive mainly from the strength of the sponsors who commit to providing additional funding in the event of cost overruns or other shortfalls, and to meet minimum levels of Debt Service Cover.

Construction

Construction was organized through a turnkey contract awarded to a consortium led by Andrade Guitierrez, one of Brazil's largest contractors, together with Voith and Siemens. Construction started in early 1995.break

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