PERU

Institutional and Financial Framework for Development of Small Hydropower

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ESMAP

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ABBREVIATIONS AND ACRONYMS

ATDR	Technical Administration of Irrigation District (Administración Técnica del Distrito de Riego)
BNDB	Brazilian National Development Bank
bp	Basis point (100=1percent)
BTU	British Thermal Unit
CCGT	Combined Cycle Gas Turbine
CDCF	Community Development Carbon Fund
CDM	Clean Development Mechanism
CER	Certified Emission Reduction
CIF	Cost Insurance Freight
COES	System Economic Operation Committee
CONAM	National Environmental Council (Consejo Nacional del Ambiente)
CO2	Carbon Dioxide
CUMEC	Cubic Meters per Second
DGAAE	General Directorate for Energy Environmental Matters
DGE	General Directorate for Electricty (Dirección General de Electricidad)
DSCR	Debt Service Cover Ratio
ECL	Electricity Concession Law DL 25844 of 1992
EPC	Engineering, Procurement and Construction
ERR	Economic Rate of Return
ETS	European Emission Trading Scheme
EU	European Union
E&M	Electrical and mechanical
FAO	UN Food & Agriculture Organization
FIDIC	International Federation of Consulting Engineers
FONAM	National Environmental Fund (Fondo Nacional del Ambiente)
FIRR	Financial Internal Rate of Return
GEF	Global Environment Facility
GHG	Greenhouse Gas
GoP	Government of Peru
GTZ	German Technical Assistance (Gesellschaft für Technische Zusammenarbeit)
GW	1000 MW
IDC	Interest During Construction
IEA	International Energy Agency
IFI	International Finance Institution
IGN	National Geographic Institute (Instituto Geográfico Nacional)
IGV	Value Added Tax
INADE	National Institute for Development (Instituto Nacional de Desarrollo)
INC	National Institute of Culture (Instituto Nacional de Cultura)
INGEMMET	Geologic Mining and Metallurgic Institute (Instituto Geológico Minero y Metalúrgico)
INRENA	National Institute for Natural Resources (Instituto Nacional de Recursos Naturales)
IPP	Independent Power Producer
LIBOR	London inter-bank offer rate (interest rate)
LNG	Liquefied Natural Gas

MCM	Million cubic meters
MEM	Ministry of Energy and Mines (Ministerio de Energía y Minería)
MEF	Ministry of Economy and Finance (Ministerio de Economía y Finanzas)
mm	Million
MUV	Manufactures Unit Value
MW	MegaWatt
OSINERG	Supervisory Commission for Investments in the Energy Sector (Organismo Supervisor de la Inversión en Energía)
OSINERGMIN	Supervisory Commission for Investment in the Energy and Mining Sector (Organismo Supervisor de la Inversion en Energía y Minería)
PAD	Project Appraisal Document (of the World Bank)
PCF	Prototype Carbon Fund
PMA	Environmental Management Plan (Plan de Manejo Ambiental)
PPA	Power Purchase Agreement
PROINFA	Programme of Incentives for Alternative Electricity Sources (Programa de Incentivo a Fontes Alternativas de Energia Elétrica)
PTC	Production Tax Credit
SENAMHI	National Meteorology and Hydrology Service (Servicio Nacional de Meteorología e Hidrología)
SHP	Small Hydro Project
SLF	System Load Factor
TUPA	Consolidated Text for Administrative Procedures (Texto Unico de Procedimientos Administrativos)
UIT	Unidad Impositiva Tributaria
UNFCCC	United Nations Framework Convention on Climate Change
VAT	Value Added Tax

EXECUTIVE SUMMARY

Introduction

Peru is favored by a stable and growing economy and the availability of indigenous sources of energy for electricity generation, hydro and natural gas. Installed capacity in Peru in 2006 was 6658 MW, of which 48 percent was hydro-based. However, regarding new investment in generation, there is reason for concern. Demand growth over the past five years has been 5-10 percent, with no signs of slowing down. At the rate of 10 percent demand growth, 400 MW of new generation capacity is necessary each year, representing at least US$250 million annually of new investment.

Peru produced roughly 27,255 GWh of electricity in 2007, of which about 68 percent was derived from hydropower. This represents a large decline in the relative importance of hydropower from just a decade earlier, when hydro generated over 85 percent of Peru's electricity. Almost all of the increase in demand is being supplied by new open cycle gas generation using subsidized natural gas from the Camisea field.

There is a consensus that hydroelectric power has an important role to play in current and future generation, since it uses an indigenous resource that has a long history of cost-effective, safe, and reliable electricity provision. Hydropower development in Peru has occurred with little social or environmental damage, since it has been mainly run of the river or constructed with small reservoirs. Hydropower also represents clean energy that does not release pollutants, including greenhouse gases, to the atmosphere, an increasingly important benefit given ever-growing concerns about climate change.

However, investment in new hydropower projects in Peru has been minimal in recent years. The problem is not unique to Peru, as commercial investors the world over tend to prefer low-risk, non capital-intensive projects with short construction periods and rapid returns on investment. Hydro projects, despite their significant economic benefits, have characteristics that make financing difficult: multiple requirements for approval at local, regional and national level, high capital costs, construction risks, uncertainty of output due to hydrological risks, and, in the case of large projects, high environmental and social visibility.

The Government is committed to increasing investments in hydro resources, and has taken several measures to encourage such investment. Most recently, in May 2008 the Government promulgated a Renewable Energy Decree for promotion of generation from renewable energy, including hydropower up to 20 MW. Other measures recently introduced to promote hydropower include: (a) early recovery of the value added tax (IGV) for projects with construction periods of more than four years; (b) a simplification of the permit system for small hydro projects of up to 20 MW; and (c) elimination of the import duty on equipment used for hydroelectric projects.

Given the potential importance of hydro generation and the fact that this potential is not being realized, the Bank and the Government agreed to carry out two studies to further investigate the situation and propose additional mechanisms to overcome existing barriers to development of hydropower, one focused on projects of small size below 20 MW (this report), and another focused on medium to large-scale projects, titled *Hydropower in Peru: a Framework for Investment*.

The present study on small hydropower contains the following sections: (i) introduction; (ii) technical potential for development of small hydropower in Peru; (iii) economic and financial viability of small hydro development in Peru; (iv) institutional and regulatory environment; (v) identification of barriers to small hydropower development and mitigation measures; (vi) international experience with small hydropower development; (vii) the potential impact of the Renewable Energy Decree; and finally, (vii) conclusions and recommendations.

Small Hydro Potential

There is no solid basis for estimates of the technical potential of small hydropower in Peru because of the lack of inventories of such resources. The main source of data on hydropower resources is the Hydropower Potential Study of 1979, which focused on identifying larger scale projects for development by state-owned integrated power sector monopolies. In such studies, small hydro cascades with daily peaking storage provided at the upstream sites were simply seen as uninteresting – yet precisely this concept is the main focus of small hydropower projects development in many countries.

These uncertainties notwithstanding, Peru has considerable potential for small hydropower development. The potential is estimated as at least 1,600 MW, of which 100 MW is at sites that would benefit from existing infrastructure, and 1,500 MW at greenfield sites. It would be useful for developers to have more information on small scale hydropower resources, including inventories of potential projects. However, even without such inventories, international experience has shown that wherever there are considerable water resources in hilly or mountainous terrain, developers have no difficulties in finding sites that are financially attractive –provided only that the tariff levels reflect full costs of alternative fuels and that the regulatory and institutional framework is rational.

There is sufficient national technical capacity available in Peru, in both the public and private sectors, to enable development of small hydropower. However, in most countries where small hydro has been successfully developed, government-sponsored technical assistance and training has played a role. Given strong national capabilities in design, construction and turbine manufacture in Peru, these activities would most likely focus on: (a) dissemination of design and contracting/construction standards and procedures in Spanish; (b) promotion of domestic manufacture of ancillary components such as control and communications equipment; and (c) training in operation and maintenance of small hydropower plants.

Economic and Financial Viability of Small Hydropower

Almost all new power generation installed in Peru during the last decade has been based on highly subsidized natural gas from the Camisea Field. The price of subsidized gas delivered to plants near Lima is estimated at US$2.15 per mm BTU. Given that Peru will shortly become an LNG exporter, the opportunity cost of natural gas is now linked to international prices. Under conservative assumptions about international gas prices, the netback opportunity cost for delivery to thermal generators in the Lima area will be at least US$4/mmBTU, resulting in a gas-based generation price of around 5.6 UScents/kWh.

Up to date cost information for small hydropower plants in Peru is limited. An analysis of nine projects showed capital costs ranging from US$975-3400 per kW. Using the actual data for these projects, and a sales price of 5.6 US cents per kWh, based on the opportunity cost of gas, four of the nine projects have an economic rate of return above the 14 per cent return required by the Sistema Nacional de Inversion Publica (SNIP), and are thus *economically* viable. If carbon benefits at a cost of US$15 per ton are included, six of the nine projects meet the SNIP cut-off rate.

However, because the financial cost of generation is set by the cost of gas based generation at a highly subsidized price for natural gas, small hydropower is not *financially* viable, except for a limited number of projects that benefit from existing irrigation infrastructure or that have relatively high load factors and benefit from carbon finance. At the present gas price to thermal generators in the Lima area of US$2.15 per mmBTU, the average price for generators is around 3.5UScents/kWh. At this price, a 17.5 percent financial rate of return (FIRR) on equity, a ten year loan period and a 70 percent load factor, the maximum capital cost that can be afforded for a hydro project is around US$850/kW. When carbon finance is taken into consideration, the allowable capital costs increases to around US$1000/kW – and precisely such projects (Santa Rosa, Poeches) are in fact being built. Nevertheless, greenfield small hydro projects cannot be built at such capital costs.

Using a generation price based on the economic opportunity cost of gas of 5.6 UScents/kWh and the same assumptions for FIRR, loan tenor and load factor, the allowable capital cost for small hydro increases to US$1,400/kW. Even with recent increases in hydro construction costs, this is a level that would make many small hydro plants financially viable. If a higher gas price is combined with carbon revenues at US$15 per ton, five of the nine projects examined in detail would become financially viable.

Therefore, to unlock the significant potential of small hydropower in Peru would require either the removal of the gas price subsidy or a preferential tariff for small hydropower that reflects the economic opportunity cost of gas powered generation, calculated on limited information available at around 5.6 UScents/kWh.

Additionally, the current maximum period of loans is 10 years. An increase in loan tenor from 10 to 15 years would have an important impact in permitting projects with capital costs higher that $1,400/kW, up to an estimated level of US$ 1,600/kW. The combined impact of a tariff around 6 US cents and access to debt financing on a project basis for a minimum term of 15 years would improve substantially financial viability of development of small hydropower in Peru.

Barriers to Small Hydropower Development in Peru and Their Mitigation

The main barriers to the development of small hydro in Peru are regulatory measures that have a negative impact on the financial viability of small hydropower projects. Chief among them has been the low generation tariff, which is fixed based on the cost of subsidized natural gas. Consequently, most hydro projects have not been financially viable, even taking into carbon revenues. There are two main solutions to solve this issue: the reduction of subsidies to natural gas, or the provision of a special tariff for small hydropower projects, as mandated in the Renewable Energy Decree (see section below).

In addition to the tariff issue, there are several regulatory issues that affect the financial viability of hydros that must be connected through regulatory cycles. The current definition of capacity payment does not adequately recognize (and therefore cover the cost of) hydro storage for energy shortages during dry season of peak hours. In terms of transmission cost, hydro is disadvantaged relatively to thermal generation from gas, as transportation costs from the Camisea gas fields to the plant are charged to the consumer, whereas equivalent costs for hydro are charged to the generator.

There are also serious issues in financing small hydropower projects, including the limited interest of commercial banks in project finance and/or small scale projects; the mismatch between expectations of those who own water rights and have an interest in building them (but who are generally financially weak), and of the asset funds and the banks, whose perceptions are shaped by the more publicized problems of large hydro projects; and the *practical* difficulties of securing long-term loans. While large, financially strong corporations would encounter few financing problems for any project on a balance sheet basis, these companies have little interest in small hydro (except in the case of mining companies who have long built small hydro projects for self-use). On the other hand, smaller companies that would be interested in making such investments are required to provide 100 per cent collateral, limiting their ability to finance projects.

These issues are encountered worldwide, and explain why many countries have special finance facilities, sometimes assisted by international financial institutions, to address the entire package of financing and provide the necessary technical assistance to the banking system to help them to develop risk assessment capability for project financing of renewable energy, including small hydro projects.

The issue of difficulty in obtaining water rights has been cited in a few instances as impeding the development of projects, and could be addressed by setting up new, transparent regulation for authorization of water use. In the same perspective, issues that have arisen from rights-of-way could be settled by requiring a social assessment for all hydro projects, including an analysis of mitigating measures, which would constitute a legal, binding document for all parties involved.

Finally, a number of technical barriers to the development of small hydropower projects - which also impact negatively transaction costs - were identified, but they are far less significant than the financial and regulatory barriers stated above, and easier to solve. Correcting these barriers would primarily involve the need to (i) set up clearer guidelines for the application for concessions and authorizations, and determination of environmental flows, (ii) promote the use of existing standardized design and costing procedures and contract templates, and (ii) reorganize the gathering and dissemination of hydro meteorological data, so to facilitate preparation of projects and economic assessment.

International Experience with Small Hydropower Development

The most extensive experience with measures to promote renewable energy, including small hydropower, is in Europe, where three main types of measures have been used: (a) feed-in tariffs, where electricity suppliers are obliged to purchase renewable electricity at a technology specific price (e.g. in Germany and Spain); (b) obligations on electricity suppliers where the renewable electricity price is set at technology specific auctions (e.g. Non-Fossil Fuel Obligation in UK); and (c) obligations on electricity suppliers where the renewable electricity price is set by trading renewable energy certificates (e.g. new system in UK, see Annex 14).

The most successful experience in Latin America has been with technology-dependant feed-in tariffs, combined with low interest loans, as exemplified by the Brazilian PROINFA program (see Table S-1). It is too soon to gauge the success of the Chilean approach of a renewable obligations requirement, the law having been passed just a few months ago. However, it may be noted that this law is much stronger than the new Peruvian Decree. In Chile there are penalties on the distribution companies if the obligation is not met, where as in Peru, the 5 percent is merely a limit on the amount of renewable energy that the system dispatcher must take.

Table S-1: Summary of Measures to Promote Small Hydropower in Selected Countries

Country/Measure	Definition Small Hydro	Preferential Tariff	Long-term Finance Assistance	Auction	Financing Support for Studies	Technical Assistance
	(MW)	(US cents/kWh)				
Brazil	<30	7.4	Yes	Yes	No	Yes
Chile	<20	Up to 7	No	Yes	Yes	Yes
Sri Lanka	<10	7	Yes	No	Yes	Yes
Turkey	<50	Avoided cost tariff	Yes	No	Yes	Yes
Zhejiang, China	<50	Yes	Yes	Yes, but of concessions	Yes	Yes
Vietnam	<30	Avoided cost tariff	Yes	No	Yes	Yes

The international experience shows clearly that for small hydro (or renewable energy) to be developed on a significant scale requires that tariffs be set at least at the level of avoided costs and often requires assisting promoters to gain access to long-term financing. In countries where a refinancing facility has been introduced offering loans of much longer tenor than previously available (Turkey, Sri Lanka, Nepal, India), there is evidence that the benefit is not just one of reducing financing costs, but that this has paved the way for involvement of commercial banks with renewable energy project lending and the necessary capacity building for risk assessment.

Promotion and capacity building in most countries with small hydro programs have included some of the following activities: support for development of a potential pipeline of projects; development of the legal and regulatory arrangements to facilitate such projects; improvement of dam safety regulation and introduction of modern techniques for dam safety monitoring and disaster mitigation; and the preparation of technical standards to lower the present transaction costs of project approval.

The Renewable Energy Decree

On 2 May 2008, the Government issued a new legislative Renewable Energy Decree for the promotion of investment in electricity generation using renewable energy (*Decreto Legislativo de Promoción de la Inversion Para la Generación de Electricidad con el Uso de Energía Renovable*). The key provisions of this decree are as follows:

- Every five years MEM is charged with issuing a target ceiling for renewable energy. For the first five years (until 2013), the ceiling is set at 5 percent of total national electricity consumption;
- Wind, solar, geothermic, biomass and tidal/wave energy are considered renewable energy sources, as well as hydro less than 20 MW (small hydro).
- Small hydro is not included in the ceiling of 5 percent, but will benefit fully from the incentives of the Decree.
- Renewable energy will have priority in the daily dispatch. Renewable energy plants will sell their energy production to the spot market.
- Renewable energy plants will receive the marginal (spot) price of energy plus a "premium" in case the spot price is lower than the tariff to be established by OSINERGMIN.
- The premium and tariff will be calculated taking into account the type of technology and other characteristics of the installations, and will be guaranteed a rate of return of no less than that for electricity concessions, currently 12 percent.
- The premiums will be "auctioned" by OSINERGMIN.
- Transmission cost to connect the renewable energy plant to the interconnected grid will be considered as part of the investment cost of the plant for the premium calculation.
- The incremental costs will be recovered by a user charge.

The Government has chosen to set a target ceiling for a share of renewable energy (excluding small hydro which will not be not subject to this ceiling), in combination with a premium price. In 2007, total generation was 27,255 GWh, so the 5 percent target ceiling would require 1,362 GWh from renewable energy sources. Assuming that most of this capacity would come from wind, at an annual load factor of 27.5 percent, this corresponds to 565 MW. Although, small hydro will not be considered in the indicated ceiling, hydro projects would compete in the auctions for the premium, mainly with wind in the short term.

The financial analysis indicates that a price in the range of about 6 US cents per kWh for hydro would be economically justified based on the avoided economic cost of gas generation[1] and could unlock significant investment in small hydropower. There are two additional elements to take into account as regards the tariff. If the regulation maintains a two part tariff, the definition of capacity payment should recognize and reward storage capacity of small hydros. Another issue that remains to be addressed relates to the charging of transmission costs, which, based on current regulations, greatly disfavors hydro vs. gas thermal. The Decree does not appear to address this latter issue, which would require the regulator to include transmission in CCGT costs. Section 7 examines some issues and options with respect to regulation of these outputs of the decree.

[1] This price needs to be estimated with more precision based on further data on the economic value of natural gas for power generation.

Table S-2 summarizes the barriers that could be addressed through regulation of the Renewable Energy Decree, and also those that will no be affected by the decree and would require additional action.

Table S-2: Summary of Barriers to Small Hydropower and Potential Impact of Renewable Energy Decree

	Options for Mitigation	Responsible	Role of Renewable Energy Decree
Major Barriers			
Lack of remunerative tariff	(a) Reduce subsidies on natural gas for power generation (b) Introduce a preferential tariff. Government has elected option (b) in Renewable Energy Decree.	OSINERGMIN	Regulation must ensure premium is predictable as well as adequate. Recommend basing tariff on avoided economic cost of generation based on opportunity cost of gas.
Capacity charging methodology	Revise methodology to properly reflect capacity contributions of hydro (and to reflect the portfolio benefits)	OSINERGMIN	Regulation must ensure this. If the premium tariff is two-part, capacity charge should reflect capacity costs of SHP.
Transmission costs	Include costs of gas transmission in generation price of CCGT.	OSINERGMIN	Not affected by Decree
Security of water rights	New Water Act is under discussion		Not affected by Decree
Lack of clear regulations & norms when land is under “traditional” settlement ownership	Formalize a “Social Assessment” for hydro projects, with a defined scope, required documentation, approval process, agreements reached, implementation, & monitoring plan.	CONAM and MEM in collaboration with stakeholders	Not affected by Decree
Inappropriate requirements for connections	Existing national grid code should be revised and abbreviated version prepared for small generators.	MEM/DGE	Not affected by Decree
Financing problems-unrealistic risk assessment, lack of long term loans and project finance, and high transaction costs.	Financing facility using national development bank, commercial banks, or international finance facility Training and outreach to commercial banks can supplement but not replace facility.	MEM, MoF	Not affected by Decree
Other barriers			
VAT recovery discriminates against small hydro	Reduce construction period eligibility from 4 to 2 years for renewable energy projects	MEF	Not affected by Decree
Lack of guidelines on environmental flows	Draft and implement guidelines	CONAM and MEM/DGE	Not affected by Decree
Lack of standardized guidelines for design, feasibility studies, business and financial plans	Prepare guidelines, conduct training programs	MEM	Not affected by Decree

While the Renewable Energy Decree is an important step forward, there are many practical details to be settled as part of the process of developing the regulations that will permit implementation of the Decree. Only after these details are decided would it be possible to make judgments about the extent to which the new Decree will significantly assist small hydro (and renewable energy) producers.

Conclusions

Small Hydropower. Peru's significant small hydropower potential, conservatively estimated at over 1600 MW, merits development as part of a renewable energy development program on economic and environmental grounds. The fundamental constraint to developing Peru's hydro potential has been the low tariff faced by hydro generators, which is a consequence of the subsidies to natural gas. With gas costs cif Lima of only US$2.15/mmBTU among the lowest anywhere in the world outside the Middle East), CCGT generation costs are little more than 3.5UScents/kWh.

While the Government continues to maintain the natural gas subsidy, it recently decided to provide small hydro projects less than 20 MW with a premium on the tariff under the proposed new Renewable Energy Decree. The Renewable Energy Decree is an important first step to unlock the small hydro potential of Peru. Provided that the resulting tariff in Peru is set at about 6 UScents/kWh, a principal barrier to small hydro development would be overcome. However, whether the tariff premium to be given to qualifying facilities unlocks financing problems will depend not just on its magnitude, but upon its certainty at the time of financial closure.

Two further distortions in the tariff environment need to be corrected. The first concerns the allocation of transmission costs, which are allocated to generators in the case of hydro and to the consumers as part of the transmission system cost for natural gas. The second issue concerns the methodology for determination of capacity charges. While a single small hydro project may well add little to dry season capacity, studies of the capacity credit of renewable energy generation in other countries clearly show the diversity effects of a *portfolio* of projects, such that the capacity benefits to the system of the portfolio is much greater than the sum of individual capacity benefits. These benefits should be estimated and recognized in the tariff system.

The proposed preferential tariff under the new Renewable Energy Decree may improve the fundamental requirement of a remunerative tariff, and therefore increase the interest of potential equity investors in the sector. However, it is far from clear that this alone would also transform the debt market to enable project financing at long loan maturities.

For the commercial banks to modify their present perceptions about the risks of small hydro requires assistance from the Government to enable access to long-term financing for investors other than large corporations that can finance on the balance sheet. This financing could be done in many different ways, e.g. through a development bank as in the case of Brazil, or through a project that involves an international finance institution, as in the cases of Turkey, Sri Lanka and Zhejiang. International financial institutions (IFIs) are more experienced than national commercial banks in assessing the unique risk profiles of hydro projects, and can assist in building confidence.

With recent increases in carbon prices, and future expectations of yet further increases, carbon finance makes a significant difference to developers' cash flows and enhances debt service cover ratios required for non-recourse financing.

In addition to the preferential tariff and access to financing issues, actions to overcome the secondary technical and other barriers, including better access to hydrology data, clarification of requirements and approval process for obtaining water rights, clarification for environmental evaluation, social approval and ecological flows, relaxation of rigid connection requirements and other regulatory issues.

Medium Hydropower. In the particular case of Peru, where even medium scale plants have limited storage, it could be argued that small hydropower below 20 MW has no particular economic or environmental advantage over medium sized hydro in the 20-200 MW. The latter projects are also generally run-of-river projects (with minimal storage sufficient for daily peaking operation in the dry season) and with minimal numbers of project affected households and little impact on forests and agriculture. As shown in Section 2, the probable potential for hydro projects is much greater than for small hydro of less than 20 MW, and projects in this size category therefore have the potential for making a more significant aggregate contribution to meeting the fast growing power demands.

There is an argument to expand the coverage of the Renewable Energy Decree to such medium scale hydropower projects, or to find an alternative mechanism to permit their development as economically viable clean energy projects. The case for a more active Government role to promote such larger projects is much greater, since the potential for issues over water and land rights are more likely; and feasibility studies are more expensive, so there will be a greater reluctance of private companies to undertake them.

Recommendations

1. Implementation of the Renewable Energy Decree

The key to unlocking the small hydro potential will be a remunerative and predictable tariff, and an efficient and transparent auction system for tariff premium allocation. Implementation of the price premium and auction provisions in such a way to minimize uncertainty on the premium received is particularly important. Unless the preferential tariff is predictable, and the transaction costs minimized, the decree will have little impact. Some of the key issues to be decided include:

- The methodology for determination of an adequate tariff based on the "premium" defined in the Decree. It is recommended that a simple and economically justified method be used to set the tariff—such as using avoided economic cost of gas-based generation when gas is priced at opportunity cost.

- The way in which the decree will be applied to different technologies, and whether there will be technology bands that are treated differently with respect to tariffs and auction quantities. It is suggested that technology bands not be used or that number of technology bands be limited because of the small scale of the target.

- The way in which the proposed auctions will work in combination with the relatively small target ceiling, the premium and the lack of penalties for non-compliance with the Decree. The key is that the auction provides certainty of the premium price for sufficient time to enable financing of the Project, e.g. 15 or 20 years.

Part of the success of the Brazilian PROINFA program has been the simplicity and clarity of its implementation. It is suggested that MEM and OSINERGMIN would benefit from access to experts from other countries with renewable energy policy and tariff implementation experience, technical assistance that could be provided through a Workshop in Peru with the participation of such experts. It is proposed to organize and carry out such a workshop in the near future.

2. Capacity Charge Methodology

OSINERGMIN should review the methodology of setting capacity charges. It is clear that the portfolio benefits of hydro (small or large) are not properly captured in the present approach. If the implementation of the preferential tariff for small hydro is based on a German-style feed-in tariff, in which capital outlays are recovered in a one-part tariff, then the general methodology of capital cost recovery for the regulated market is not relevant. But if the preferential tariff for renewables is to be based on a two part tariff (with separate remuneration for capacity), the present approach will not provide for adequate recovery of investment costs.

3. Assistance to Access Long-Term Financing

A range of financing problems will face developers even if an adequate tariff is provided under the new Decree, including unrealistic risk assessments by the commercial banks, high transaction costs, and lack of long-term loans. These would all be mitigated by a long-term financing facility from domestic resources or with support from an international financial institution, along the lines of facilities in Sri Lanka, Vietnam and Turkey. Absent involvement of the Government in assisting access to project financing for small hydro, it is very unlikely that non-recourse project financing can be achieved for small hydro projects, and the present 100 percent collateral/corporate guarantee requirements of the commercial banks will remain a major barrier to all but large corporate sponsors.

A major long-term goal of such assistance is to demonstrate to the commercial banks that lending for small hydro (and other small renewable energy projects) is viable, and that whatever risks as are actually an issue can be mitigated by less draconian requirements than 100 percent cash collateral. The necessary technical assistance to the banking system is an integral part of all of such projects in other countries.

4. Water Rights

Most developers indicated that the main problem in obtaining water rights is the unpredictable process. The lack of a specific TUPA (Consolidated Text of Administrative Procedure) is the main complaint. What is needed is a TUPA that describes in detail the documentation requirements; who could submit a solicitation, its format and if a payment is necessary or not; the intervention of different internal units or offices, specifying their specific roles in the process and timing; type of official document and person(s) who sign the authorization or approval of the petition; if petition is rejected a full explanation of reasons for rejection; and finally specifying the maximum duration of the whole process, after which the petition is considered approved if there is no official rejection.

5. Rights-of-Way and Community Intervention

The regulations contain the necessary requirements and process to obtain, in a formal way, the necessary temporal and definitive use of the required land to develop a hydropower project. However, when land belongs to communities, legally registered or otherwise ("traditional" settlement ownership), the right-of-way problem, compounded with water use rights, is much more complicated. An agreement is more difficult to obtain due to the interventions of many people acting as leaders of the community, and the requirement that the majority of the community approves the final agreement. Also this type of agreement is not legally enforceable and is subject to change of opinion of leaders or the community.

To deal with the indicated problem, the study agrees with the recommendation made by some developers, to formalize a "Social Assessment" of hydropower projects, with a defined scope, required documentation, approval process, agreements reached, implementation and monitoring plan. The approved Social Assessment of a project, including rights-of-way and water use agreements, would be a binding document to all parties, the community, the developer and the government.

6. Early Recovery of VAT

The early recovery of VAT is limited to projects with construction periods of four years or more. At the same time, thermal projects, which are less capital intensive, can be financed as lease deals, one of the principal advantages of which is immediate recovery of VAT. But lease deals cannot be done for small hydro projects (because the tariff cannot support the high payments implied by the typically much shorted lease terms). The net effect of these provisions is an unfair disadvantage for small hydro. We recommend that this discrepancy be eliminated (perhaps as part of the implementing regulations for qualifying renewable energy facilities under the new law).

7. Medium Scale Hydro Projects

A similar study is underway on hydro projects in the 20 MW - 200 MW size range. As noted above, such projects have a much larger potential role to meet the fast growing power demand of the country. At the same time, the case for a more active Government role in overcoming the institutional and regulatory barriers is at least as great. The special tariff incentives that the new decree provides to small projects will not be available to these larger projects under the 20 MW threshold set in the draft decree, which therefore implies the need for: (a) removal of the gas subsidy, which is desirable on macro-economic grounds; (b) raising of the 20 MW limit of the Renewable Energy Decree to higher levels; or (c) another approach to overcome the distortion of the low tariff based on the subsidized cost of gas.

1 INTRODUCTION

Peru is favored by a stable and growing economy and the availability of indigenous sources of energy for electricity generation, including hydro and natural gas. The Peruvian electricity sector is among the few in LAC that has not confronted a crisis in recent years. The power sector in Peru was reformed and restructured between 1991 and 1993, followed by a privatization and concession process. A modern legal and regulatory framework was established in the Electricity Concessions Law of 1992/93.

Installed capacity in Peru in 2006 was 6,658 MW, of which 48 percent was hydro-based. Demand growth over the past five years has been 5-10 percent, with no signs of slowing down. At the rate of 10 percent demand growth, 400 MW of new generation capacity is necessary each year, representing at least US$250 million annually of new investment. Peru produced roughly 27,255 GWh of electricity in 2007, of which about 68 percent was from hydropower. This represents a large decline in the relative importance of hydropower from just a decade earlier when hydro generated over 85 percent of Peru's electricity. Total hydropower generation increased by only 5 percent over the five years from 2003 to 2007 (only about 1 percent per year). Almost all the increase in demand is being supply by new thermal generation.

There is a consensus that hydroelectric power has an important role to play in current and future generation in Peru, since it uses an indigenous resource that has a long history of cost-effective, safe, and reliable electricity provision in Peru. Hydropower development in Peru has occurred with little social or environmental damage, because it has been mainly run of the river or constructed with small reservoirs. Hydropower is also clean energy that generates electricity without releasing pollutants, including greenhouse gases, an increasingly important benefit given ever-growing concerns about climate change.

However, investment in new hydropower projects in Peru has been minimal in recent years. The problem is not unique to Peru, as commercial investors the world over tend to prefer low-risk, non capital-intensive projects with short construction periods and rapid returns on investment. Thermal generation projects have these characteristics. Hydro projects, despite their significant economic benefits, have characteristics that make financing difficult: multiple requirements for approval at local, regional and national level, high capital costs, construction risks, uncertainty of output due to hydrological risks, and, in the case of large projects, high environmental and social visibility.

The Government is strongly committed to increasing investments in electricity generation, especially from hydro resources. Most recently, in May 2008 the Government promulgated a Renewable Energy Decree for promotion of generation from renewable energy, including small hydro up to 20 MW. Congress eliminated the import duty on hydroelectric equipment in December 2006 and the Ministry of Economy and Finance (MEF) has permitted early recovery of the value added tax (IGV), for projects with construction periods of four years or more. The Ministry of Mines and Energy (MEM) has simplified the permit system for small hydro projects.

Given the potential importance of hydro generation in Peru and the fact that this potential is not being realized, the Bank and GoP agreed to carry out two studies to investigate the situation and proposed mechanisms to overcome existing barriers to development of hydropower, one focused on projects of small size below 20 MW (this report), and another focused on medium to large-scale projects, titled Hydropower in Peru: a Framework for Investment.

The present study contains the following sections: (i) introduction; (ii) resource potential and technical capacity for development of small hydropower in Peru; (iii) economic and financial viability of small hydro development in Peru; (iv) institutional and regulatory environment; (vi) identification of barriers to small hydropower development and mitigation measures; (v) international experience with small hydropower development; and finally, (vii) conclusions and recommendations.

2 RESOURCE POTENTIAL AND TECHNICAL CAPACITY

Development of the hydropower resources of Peru started over a hundred years ago in the early years of the previous century. Initial developments took advantage of the accentuated topography, which features particularly in the rivers draining the Pacific side of the Andean chain, and augmentation of dry-season flows by snowmelt. Hydropower plants were intended for the supply of local electricity demands and, increasingly, the requirements of the mining industry.

In the second half of the last century regional power networks emerged and hydropower development began to encompass large-scale schemes. As shown in Table 2-1, by 1976 the total installed hydropower capacity in Peru had reached 1,406 MW (see Annex 2), accounting for around 75 percent of total installed capacity (and energy production) in the country.[2]

Table 2-1: Hydropower Installed Capacity in Peru 1976 and 2006

Installed Capacity Range	1976[1]		2006[2]	
	Installed Capacity (MW)	No. Plants (-)	Installed Capacity (MW)	No. Plants (-)
Greater than 30 MW	1,223	11	2,867	19
1 to 30 MW	183	-	306	71
Smaller than 1 MW			31	77
Total	**1,406**	**-**	**3,203**	**167**

Sources: 1. Lahmeyer-Salzgitter-MEM (1979), Vol 2, Tabla 2.3 (See Annex 2).
2. MEM (2007a), Anuario Estadístico Electricidad 2006, Anexo 6.

The total increase in hydropower installed capacity in this 30-year period shown in Table 2-1 was 1,797 MW,[3] of which the 154 MW increase in small hydropower installed capacity (up to 30 MW) represents only 8.5 percent. It appears, therefore, that the major efforts in hydropower development in these years have concentrated on construction of large-scale hydropower projects (or expansion of existing large plants) for integration in the national interconnected power system. This represented an average annual growth rate of just 2 percent over the 30-year period.

Table 2-2 lists the hydropower projects with installed capacity in the range 1 to 20 MW which have been commissioned in the years 1998 to 2006, i.e. since a few years after deregulation of the electricity sector. Over 30 percent of the total of 58 MW is made up by three projects, (Poechos II, Santa Rosa I and Santa Rosa II), which have involved the incorporation of hydropower generating facilities in already existing irrigation infrastructure.

Table 2-2 also shows that 15 percent of the total 58 MW comprises hydropower projects constructed by enterprises (mining companies) for their own consumption, not for public service.

[2] Lahmeyer-Salzgitter-MEM (1979).

[3] MEM (2007a).

Table 2-2: Small to Medium-sized Hydropower Plants Commissioned from 1998 to 2006

Year	Plant	Owner	Installed Capacity[1] (MW)
1998-2001	-	-	-
2002	Quanda	Electro Oriente S.A.	2.88
	Huanchór	Sociedad Minera Corona S.A.	18.86
	Chiquián (Extension)	Electronorte Medio S.A. - HIDRANDINA	1.62
	Baños IV	Empresa Administradora Chungar S.A.C	1.20
	Tingo	Empresa Administradora Chungar S.A.C	1.20
	Baños III	Empresa Administradora Chungar S.A.C	0.98
	Baños II (Initial)	Empresa Administradora Chungar S.A.C	0.54
2003	Monobamba (Extension)[2]	Compañía Minera San Ignacio de Morococha S.A.	5.35
2004	Poechos II	Sindicato Energético S.A.	15.64
	Santa Rosa II	Eléctrica Santa Rosa S.A.C.	1.50
	Membrillo (Extension)[2]	Compañía Minera Sayapullo S.A.	1.05
	Baños II (Extension)[2]	Empresa Administradora Chungar S.A.C	1.00
2005	Llaucán	Minera Colquirrumi S.A.	1.00
	Carpapata (Extension)[2]	Cemento Andino S.A.	1.20
2006	Santa Rosa I	Eléctrica Santa Rosa S.A.C.	1.20
	San Martín de Porres	ICM Pachapaqui S.A.C.	1.60
	Huari (Maria Jiray), Unit 2	Electronorte Medio S.A. - HIDRANDINA	1.50
	TOTAL		**58.32**

Source: MEM (2007), Anuarios Estadísticos Electricidad, 1998 to 2006.
1. Declared installed capacity (may differ from effective installed capacity).
2. For own-consumption.

In addition, local and regional governments as well as mining companies have continued to construct a number of mini-scale hydropower plants with installed capacities of less than 1 MW.

From this brief review of hydropower development in Peru to date it can be seen that development of small hydropower, in particular greenfield projects for public service, has remained limited over the past 30 years, against a background of steadily decreasing overall growth in hydropower development.

2.1 THE POTENTIAL FOR SMALL HYDRO

There has never been a nation-wide inventory and ranking (or master plan) of small hydropower schemes in Peru. The evaluation of the national hydroelectric potential by Lahmeyer-Salzgitter-MEM (1979) – the so-called Plan Maestro - was restricted to projects with installed capacities greater than 100 MW, lower installed capacities being considered only in the case of projects with large reservoirs providing over-year storage or those comprising part of an overall river basin development scheme (see Box 1).

Box 1: The Peru Hydropower Potential Study in 1979

The only comprehensive evaluation of the hydroelectric resources in Peru was undertaken by the MEM under an agreement with the German technical cooperation agency GTZ (Gesellschaft für Technische Zusammenarbeit). It is commonly referred to as the Plan Maestro (Masterplan), although this was in fact a system expansion plan study carried out in 1980-81 after completion of the major work "Evaluación del Potencial Hidroeléctrico Nacional" in 1979. The 1979 evaluation study will be therefore referred to as the Hydropower Potential Study.

The objective of the Study was to identify projects which could form part of the expanding and interconnecting regional power generation systems. As such, it focussed on relatively large hydropower schemes. However, a brief analysis of the resulting catalogue of projects could provide some indication of the potential for further development of greenfield small hydropower projects.

The initial desk study phase of the Hydropower Potential evaluation study resulted in the identification of around 800 projects. After extensive field surveys and river basin optimization studies, about 250 projects were eliminated either:

- on account of unfavorable technical conditions (e.g. topography, geology), or
- on the basis of a minimum installed capacity of:
    - 100 MW for run-of-river projects,
    - 50 MW for projects with monthly storage, and
    - 30 MW for projects with over-year storage (except for isolated locations, in which case a minimum of 20 MW was applied.

The final catalogue contained a total of 543 hydropower projects. Of these, 163 projects featured installed capacities less than 100 MW, including some of less than 30 MW which formed part of the recommended overall basin development schemes. These 163 projects are listed in Annex 5, together with their principal characteristics (mean flow, net head, installed capacity, average annual energy production and estimated investment costs). The Hydropower Potential costs are given at January 1979 price level. As a very rough approximation, these costs were actualized to 2007 level using the Manufactures Unit Value (MUV) index published by the World Bank.

Similarly, while the Instituto Nacional de Recursos Naturales (INRENA) of the Ministry of Agriculture regularly publishes a national inventory of canals and other infrastructure associated with the principal irrigation systems,[4] there has never been a systematic inventory of possibilities for the incorporation of small hydropower projects in existing hydraulic structures (at reservoir outlet works, canal drop structures, etc.).

The Dirección General de Electricidad (DGE) of MEM publishes on its website, in addition to the lists of hydropower projects which have been granted concessions and authorizations, a list of "Projects with Studies". The latest list, comprising 21 projects, is reproduced as Table 4 in Annex 3. The studies behind this list were all carried out before deregulation and privatization of the power sector in the 1990s, generally within the framework of technical cooperation programs and multilateral banks assistance to with Electroperú or other government agencies. It may be noted that of the 21 projects in the list only 3 projects have proposed installed capacities of less than 30 MW.

As noted above, two basic opportunities exist for the development of small hydropower projects, namely i) incorporation of power plants in existing hydraulic infrastructure, and ii) 'greenfield' hydropower project development, i.e. projects, perhaps previously identified and already studied to some level of detail, but not involving any existing hydraulic infrastructure.

[4] Ministry of Agriculture (2005).

2.1.1 Small Hydro Projects Incorporated in Existing Hydraulic Infrastructure

Small hydropower developments of this type involve incorporation of power generating facilities in hydraulic structures already constructed for purposes of irrigation, mining or power production (see Box 2 for an example). Obvious advantages include easy access, limited geotechnical uncertainties, minimal civil works and hence short implementation times. Such advantages were specifically cited by several of the government organizations, developers and consultants interviewed by the Study Team. Nevertheless, they are also open to opposition from local stakeholders who feel inconvenienced by the project.

As indicated above, 18 MW of the 58 MW of the small hydropower projects brought on line since 1998 (about 30 percent) have been projects of this type, in all cases utilizing existing irrigation infrastructure. A further 28 MW, Poechos 2nd powerhouse and Quiroz-Vilcazán, are included in the list of projects with concessions and authorizations shown in Table 2-3.

While it is possible that the developers of the existing projects of this type have carried out some form of analysis of further possibilities for similar projects, it would appear that no systematic inventory (basin by basin, structure by structure - dams, diversion weirs and canal drop structures) has been carried out to date.

Box 2: The Santa Rosa Project

The Project is composed of three small run-of-river hydroelectric power plants located in Lima, Peru, Province of Sayan. The project has a total generation capacity of 4.1 MW and an annual energy production of approximately 30,000 MWh (Santa Rosa I: 7,900 MWh, Santa Rosa II: 12,000 MWh and Santa Rosa III: 10,000 MWh), which will be dispatched to the National Grid by connecting to the 22.9 kV transmission line belonging to Edelnor. Santa Rosa I and II are now in operation and Santa Rosa III is expected to be in operation in 2009.

Santa Rosa is the first small hydro project in Peru to benefit from carbon finance. The World Bank as Trustee of the Community Development Carbon Fund (CDCF) will purchase the first 88,300 tCO2-eq (ERs) generated by the project at a unit price of US$5 per ton. Total CER purchases will be US$441,500. This total includes recovery of project preparation expenses such as those related to baseline establishment, validation, monitoring, verification and certification. The World Bank will also have the option to purchase a further 62,400 tCO2-eq generated by the project after the Contract ERs have been delivered, on the same terms as the Contract ERs.

The three plants will take advantage of the hydro resources from the existing Santa Rosa irrigation infrastructure which has been in use since 1963. They use the same water flow and will be located in a cascade in the three sections of the existing canal.

Santa Rosa has a 5-year PPA with EDELNOR (a distribution company) to take 100 percent of output of Santa Rosa II at the regulated price (which is marginal cost and capacity charges as determined by the regulator). Santa Rosa I and III will be covered by a third party (Cahua) at the spot market price (which is generally somewhat higher than the regulator's marginal cost).

Source: World Bank (2005).

An indication of the possible outcome of such a survey is provided by the results of a recent investigation carried out jointly by the National Irrigation Commission and the National Energy Commission in Chile.[5] In a survey covering 97 percent of the total irrigated area in Chile the investigation identified a total of 290 possible hydropower plants with installed capacities in the range 2 – 20 MW which could be installed in existing irrigation infrastructure. The total installed capacity amounted to 860 MW, 75 percent of which corresponded to run-of-river plants constructed in canals. According to the AQUASTAT database

[5] CNR-CNE (2007).

of the UN Food & Agriculture Organization (FAO) the total irrigated area in Chile amounts to around 1.9 million hectares, while that of Peru comes to about 1.1 million hectares. Assuming the same ratio of total installed capacity to irrigated area, it could be expected that a similar survey in Peru would result in a total technical potential of around 510 MW for small to medium hydropower plants incorporated in the existing irrigation infrastructure.

The survey carried out in Chile identified only the technical potential for hydropower incorporated in the existing irrigation infrastructure. No attempt was made to assess the costs or financial viability of the identified possibilities. However, as noted during the workshop held in January 2008 at which the results of the survey were presented, the costs of such projects for which Environmental Impact Assessments have already been submitted (mandatory for projects with installed capacities of 3 MW and above) have been in the range US$1,500 to US$3,000 per kW.[6] Experience with the existing projects in Peru (Poechos, Santa Rosa) would indicate that somewhat lower costs are achievable. Nevertheless, bearing in mind the upper limit of US$1,250 per kW cited by some developers for an economically acceptable project under present conditions in Peru, it would seem that a conservative estimate of the total capacity which could be additionally installed in the existing irrigation infrastructure would be at least in the range 100 – 200 MW.

2.1.2 Greenfield Small Hydro Projects

Given the lack of good inventories, and the focus of the Plan Maesto on larger projects (mostly over 30 MW), estimating the small hydro potential at the present time is quite difficult.   While the 163 projects in the Plan Maestro include many projects on the principal tributaries of most river basins, possibilities for smaller-scale projects on a number of tributaries were ignored. At the same time, not all tributaries are likely to provide suitable possibilities for such projects. Tributaries in the middle or lower reaches of basins in the Atlantic watershed, for example, have almost zero flows during much of the April-November dry season unless there are significant areas of permanent snow (above about 5,000 m asl) and/or natural (or regulated) lakes in their headwaters   Based on our extrapolation of the Plan Maestro (Box 1), and the experience in other countries, the potential of greenfield small hydro is estimated at around 1,500 MW, or some 150 projects of 10 MW, assuming a maximum capital cost of US$3,000/kW.

These results are of course very tentative, given the limitation on project size considered in the Hydropower Potential study. However, a new Hydro-GIS study underway by MEM under the Rural Electrification Project assisted by the World Bank will provide a more reliable assessment of the technical potential for small to medium-sized hydropower development.

Not all of this technical potential is necessarily economically or financially feasible, since the latter depends on other important assumptions about which there is also high uncertainty (such as the annual load factor, and the ability to provide low cost daily peaking storage).

2.1.3 The Potential Project Pipeline

Current plans for development of Peru's hydropower resources can be represented by the concessions and authorizations which MEM has issued (see Annex 3 published by MEM in October 2007), which include definitive concessions, temporary concessions and authorizations for hydropower schemes. A list of

[6] Red Agricola (2008); http://www.redagricola.com/content/view/82/1/.

hydropower projects ‘with studies’ is also included. Table 2-3 shows the small hydropower projects (1 – 30 MW) which feature in the lists in Annex 3.[7]

The MEM has also published a list of hydropower schemes, shown in Annex 4, which it has considered as candidates projects for inclusion in the Plan Referencial 2006 – 2015[8] for the national interconnected power system. None of these candidate projects is a small hydropower plant with installed capacity less than 20 MW.[9] Of course, not all the above projects will necessarily be implemented, in particular those with Authorizations (which must be obtained before field studies can be undertaken) and those which are simply described as ‘with Studies’.

2.2 TECHNICAL CAPACITY FOR SMALL TO MEDIUM-SIZED HYDROPOWER

This section reviews briefly the national capacity of Peru for i) the identification, design and engineering of small hydropower projects, and ii) the construction of civil works and manufacture of equipment for such projects.

2.2.1 Project Identification, Design and Engineering

Project Identification

As noted above, MEM regularly publishes a list of power projects for which concessions and authorizations have been issued, as well as a list of ‘projects with studies’ (see Annex 3, Table 4). This list comprises principally those projects for which more detailed investigations than a simple desk-study have been carried out by a state organization on behalf of itself or another state organization, all before deregulation of the electricity sector in the early 1990s. As such, the composition of the list is somewhat arbitrary. Furthermore, with respect to small hydropower, it can be seen that the list contains only 3 projects in the capacity range 1 to 20 MW.

The only comprehensive national inventory of potential greenfield hydropower projects available at present is the Hydropower Potential study,[10] described in Box 1 above. Although specifically concentrating on larger-scale developments (lower limits for run-of-river projects 100 MW, projects with over-month storage 50 MW and projects with over-year storage 20 MW) and based only on hydrological information available thirty years ago, it is nevertheless evidently still in use by small-scale developers (as confirmed by at least one of the developers interviewed by the Study Team).

While there is no currently available inventory of potential hydropower projects incorporated in existing hydraulic structures, the Instituto Nacional de Recursos Naturales (INRENA) of the Ministry of Agriculture publishes a national inventory of canals and other infrastructure associated with the principal irrigation systems.[11] The latest inventory is for the year 2004.[12] The latest comprehensive inventory of lagunas and small dams constructed for flow regulation for agriculture, however, appears to be that

[7] The survey separates hydros into various groups, the first one being 1-30 MW, hence the fact that the table includes plants from 20 MW-30 MW.

[8] MEM (2006).

[9] It can also be seen that there are differences, in some cases significant, between the values given in Annex 3 and Annex 4 for installed capacity and estimated investment costs of some projects.

[10] Lahmeyer-Salzitter-MEM (1979).
[11] Ministry of Agriculture (2005).

[12] Ministry of Agriculture (2007).

prepared by the Oficina Nacional de Evaluación de Recursos Nacionales (ONERN, now INRENA) in the year 1980.[13] These inventories could serve as a basis for preparation of an inventory of potential small to medium-sized hydropower stations which could be incorporated into existing hydraulic structures.

Table 2-3: Small Hydropower Projects with Concessions and Authorizations

No.	Name	Project Sponsor	Design Capacity (MW)	Estimated Annual Production (GWh)	Estimated Investment (US$ Mio.)
Definitive Concessions					
1	Centauro I and III	Corporación Minera del Perú S.A. – CORMIPESA	25	-	14
9	Pías I	Aguas y Energía Perú S.A.	11	82	13.4
10	Poechos (2nd Powerhouse)	Sindicato Enérgetico S.A. – SINERSA	10	-	9
		Subtotal	46		
Temporary Concessions					
9	Quiroz-Vilcazán	Junta de Usuarios del Distrito de Riego San Lorenzo	18	-	-
15	Uchuhuerta	Electroandes S.A.	30	235	36
16	Pías II	Aguas y Energía Perú S.A.	16	-	-
		Subtotal	64		
Authorizations					
1	Caña Brava	Duke Energy Egenor S. en C. por A.	5.65	-	6.05
3	Gratón	SIIF Andina S.A.	5.00	-	4.72
4	Ispana-Huaca	Inversiones Productivas Arequipa S.A.C.	9.60	-	-
5	La Joya	Generadora de Energía del Perú S.A.	9.60	-	9.57
6	Patapo	Generación Taymi S.R.L.	1.02	-	0.77
7	Roncador	Agroindustrias Maja S.A.C.	3.80	-	2.5
8	San Diego	Duke Energy Egenor S. en C. por A.	3.24	-	2.93
9	Shali	ABRIngenieros S.A.C	8.95	-	8.1
		Subtotal	46.86		
With Studies					
1	Aricota III	Empresa de Generación del Sur-EGESUR	19.00	66	21
3	Camana	Plan Maestro	2.80	23	8
5	Culgul	Electroperú S.A.	20.00	133	54
		Subtotal	41.80		
All Projects		**Total**	**198.70**		

Source: Ministerio de Energía y Minas, Dirección General de Electricidad, October 200.7 The numbers in the left-hand column refer to the corresponding numbers in Annex 3, in which further details of the projects are given.

[13] Ministry of Agriculture (1980).

In summary, there is currently no list of possibly suitable small to medium-sized hydropower projects available to a potential developer. Such a list, either of a comprehensive nature or of only selected projects, should indicate the level of study to which each project has been taken; in this connection the guide to the scope and accuracy of hydropower project studies presented in Annex 7,[14] could be of use.

Project Design

The availability of the basic field information required for project design is generally good:

- Electronic versions of topographic maps at 1:100,000 scale are immediately available from the Instituto Geográfico Nacional (IGN) and electronic maps at smaller scale (e.g. 1:25,000) can be obtained from IGN upon request.
- Similarly, 1:100,000 scale geological maps and several smaller-scale regional and local maps are available from the Instituto Geológico Minero y Metalúrgico (INGEMMET).
- Hydrometeorological data are available from the Servicio Nacional de Meteorología e Hidrología (SENAMHI), but it is evident the capacity of this organization has been deteriorating over the past decade or so.

The above-mentioned Hydropower Potential study[15] notes that in 1978 SENAMHI operated a total of 145 hydrometric stations and approximately 900 meteorological stations (of which 145 provided information on other climatological variables in addition to precipitation). According to information provided in an interview with SENAMHI personnel, the number of hydrometeorological stations operated by SENAMHI had evidently risen to nearly 2,000 around 25 years ago, i.e. in the early 1980s. Currently, however, SENAMHI operates only 780 hydrometeorological stations, including 156 hydrometric stations.

Experience of obtaining and using data from SENAMHI usually reveals a number of shortcomings in the service which the organization is currently capable of offering, e.g. excessive time required to obtain data, non-availability of recent observations, absence of information on how data were obtained (in the case of flow data, for instance, the number and frequency of flow measurements carried out in order to derive rating curves and the range of water-levels and discharge covered) so as to enable some judgment to be made on the reliability and precision of the data. These shortcomings are the result of budget limitations on manpower and on hardware and software for acquiring and processing field data.

Another principal aspect of the hydrometeorological data in Peru today is the increasing fragmentation of data collection activities, in particular since deregulation of the electricity sector. Many more hydrometeorological stations are now being installed and operated by private power companies, mining companies and developers. It is understood that, according to the law, permission to install and operate such stations should be obtained from the government and also that the information obtained from the station should be made available to the government, but this is apparently rarely done in practice. In addition, other national and local state agencies, e.g. the Instituto Nacional de Recursos Naturales (INRENA), the Instituto Nacional de Desarollo (INADE), the Direcciones Regionales Agrarias, the regional Distritos de Riego and other entities within the Ministry of Agriculture, continue to operate stations and compile data which are not stored in any central location.

The difficulty in accessing all available hydrometeorological data does indeed affect some aspects of the project design, e.g. design floods and dimensioning of spillways, sediment transport and the sizing of decanters or other sediment exclusion structures. For such design aspects – and also for estimation of output during the low-flow season – the results of regional studies would be of undoubted assistance.

[14] Oud and Muir (1997).

[15] Lahmeyer-Salzgitter-MEM (1979).

The above situation results in the perception that the difficulty in accessing all available hydrometeorological data relevant to a project is a major obstacle in the design and economic assessment of the project. In practice, this is in fact generally not the case. Even for small hydropower schemes, the installation of a hydrometric station at or close to the proposed project site and operation of the station for a period of one or two complete years must be considered a minimum requirement. Together with long-term data at hydrometeorological stations in the same (or even adjacent) river basin – obtainable from SENAMHI and/or other government agency at not insignificant expenditure of time and money – a reasonable estimate of average energy production (and possibly even 'dependable' dry season output) can usually be obtained.

From the above description of the impediments posed to potential developers of hydropower projects – small, medium or large – it is evident that a radical reform of the current situation with regard to hydrometeorological data is not absolutely necessary. Some of the impediments could be removed by the realization of regional studies of floods, sediment, low flows and basin-wide water balances, extending the work initiated by UNESCO (2006) under its Programa Hidrológico Internacional - Latin America & Caribbean (PHI-LAC). Such studies could be carried out, with little expense, by SENAMHI (or other government agency, e.g. INRENA) or by university research departments.

A central repository of all hydrometeorological data would also be of considerable assistance to developers and designers of small hydropower projects. In this connection the World Bank-supported Hydrology Project in India[16] could serve as an example of how a Hydrological Information System for use by all potential users concerned with water resources planning and management, both public and private, can be established and sustainably operated.

[16] World Bank, (2004b).

Box 3: Hydrology Project in India

The World Bank-supported Hydrology Project in India was initiated in December 1995 in response to the perceived need for a reliable and easily accessible hydrometeorological data base for various activities in planning and management of India's water resources to meet the challenges of ever increasing demand for reliable and good quality water supply for various uses such as domestic and industrial water supply, agriculture and irrigation and power generation.

The main objective of the Phase I Hydrology Project was to improve the institutional and organizational arrangements, technical capabilities and physical facilities available for measurement, validation, collation, analysis, transfer and dissemination of hydrological, hydrometeorological and water quality data, and for basic water resources evaluations within the concerned agencies at Central Government level and in nine participating States. The project, therefore, aimed at upgrading and expanding hydrometry and data management, and improving institutional management through TA and training. A primary activity in Phase I was the development and implementation of a Hydrologic Information System (HIS) with a network of data banks and data bases, integrating and strengthening the existing Central and State level agencies. The phase I was completed in December 2003. The data base developed provided uniform, acceptable and accessible hydrological records in the nine states and six central agencies it covered. But the system continued to be deficient in terms of geographic coverage and use of modern analytical tools and skilled manpower for hydrologic modeling and analyses.

In January 2006 the Government of India and the World Bank signed a loan agreement of US$105 million for the Hydrology Project Phase II. This Phase II will extend and promote the sustained and effective use of the HIS, by all potential users concerned with water resources planning and management, both public and private (i.e. four more states and two central agencies, the Central Pollution Control Board and the Bhakra-Beas Management Board). A longer-term aim of the project is to assist the governments at both central and state levels with regard to issues of intra-sectoral demands, and overall resource planning and management.

The project will be implemented over a period of six years by the Ministry of Water Resources.

In any case, in addition to collection and analysis of the basic field information available as described above, local topographic, geological and hydrometric investigations at the project site must be carried out. For this purpose there is general agreement that there is sufficient local capacity in all the required areas, with a number of firms offering up-to-date services in competitive bidding for these services

There are also a number of national consulting engineering companies able to carry out project design services (see Annex 8) for any type of small hydropower project. In addition there are a number of international consulting engineering firms, e.g. MWH (USA), Lahmeyer International (Germany), with offices in Peru, staffed largely by Peruvian nationals. Suitable expertise is available at most levels, although it could be argued that, as a result of the limited number of larger-scale water resources schemes designed and constructed in recent years, there are only a limited number of people with the comprehensive and long-term experience required for successful overall project management.

There is no evidence that systemized project design, which could reduce the time and costs associated with the design of small hydropower, is currently being used in Peru. In this connection some of the design manuals for small hydropower produced by a number of national and international organizations could be of use, e.g. International Energy Agency (IEA), European Small Hydropower Association (ESHA), Hangzhou Regional Center (Asia-Pacific) for Small Hydropower, China (HRC). It is suggested that efforts could be made to organize workshops, translate manuals etc., perhaps with the assistance of foreign funding.

National capacity in the field of the environment is also not lacking. The MEM maintains a list of 125 consulting companies authorized to carry out environmental impact analyses,[17] of which 74 are authorized to work in the electricity sector. It should be noted, however, that the list includes not only most national engineering consulting companies as well as the local offices of many international engineering and environmental consulting firms.

There are also a number of locally-based companies offering services relating to the Clean Development Mechanism (CDM) and the acquisition of carbon credits, e.g. A2G and some engineering consultants, as well as international companies such as Eco Securities, Net Source, AHL Carbon and Econergy.

Project Engineering

As for project design it is generally agreed that there is sufficient national expertise/experience among the consulting engineering companies listed in Annex 8 to carry out all the services required in the preparation of contract documents for construction and the supervision of contractors and suppliers during construction.

This expertise/experience covers both the 'traditional' client-consultant-contractor form of project arrangement, as well as the engineering procurement and construction (EPC) type of contract, although, as pointed out in other parts of this report, the latter may not be the most appropriate arrangement for small to medium-sized hydropower projects.

One area, however, where some of the engineering tasks for small hydropower projects could be facilitated is the preparation of specifications and contracts. It would appear that in most cases specifications and contract documents are prepared from scratch or at least on the basis of other previous similar projects. The use of standard contract documents, such as those produced by the International Federation of Consulting Engineers (FIDIC), although intended principally for larger projects could possibly be of assistance in this respect. It may be noted that previous attempts to use the Spanish-language versions of the FIDIC contract documents in Peru have highlighted some differences of interpretation of certain words in the context of Peruvian law.

2.2.2 Construction and Equipment Manufacture

Civil Engineering Construction

National capacity with respect to civil engineering construction of small hydropower projects may be viewed as fully sufficient. Larger-scale projects, including some with reasonably long tunnels, have been constructed by national contractors. A list of national contractors with experience in significant water resources development projects, including hydropower projects, is shown in Annex 9. In addition, there are a number of international contractors which have established local offices, e.g. San Jose Perú S.A.C., Abengoa Perú S.A. and Cobra Perú S.A. (all Spanish) largely staffed by Peruvian nationals. Much of the major equipment used by the contractors is imported.

Equipment Manufacture

There is at present only one company in Peru fabricating the Francis and Pelton types of turbines suitable for small hydropower projects with medium to high heads. Other companies manufacture cross flow

[17] MEM (2007b).

turbines of the Mitchell-Banki type. Further details of these companies, which also produce the associated generators and control systems, are given in Annex 10.

As can be seen in Annex 10, the maximum size of Pelton or Francis turbines currently manufactured locally is 5 MW. Projects with large unit sizes are therefore subject to the present rapidly increasing price rises of turbines on the international market as well as to the increasingly long delivery times.

Most hydraulic steel structures (gates, valves, etc.) required in small hydropower projects can be manufactured in Peru, although equipment for opening/closing (servomotors) may need to be imported. Transmission lines at the voltages associated with small to medium-sized hydropower projects, including towers and cables, can also be manufactured in Peru, with some components (e.g. insulators) being imported.

2.2.3 Technical Assistance and Training

Development of small hydropower in Peru could be facilitated through technical assistance and training of personnel from all technical fields and geographic (central and regional) areas (e.g. in workshops, training programs, etc). The fields covered could include areas such as operation and maintenance, fabrication of turbines and control equipment, etc.

A number of national and international organizations offer technical assistance and training programs (including online courses) dealing with hydropower, some specifically small hydropower. These include:

- International Centre for Hydropower, Norway (www.ich.no)
- International Energy Agency (Hydropower Competence Network) (reef.iea.org/moodle)
- International Hydropower Association (www.hydropower.org)
- Hangzhou Regional Center for Small Hydropower (sponsored by UNDP) (www.hrcshp.org)
- Organización Latinoamericana de Energía – OLADE (www.olade.org.ec)

Given that the potential developers and operators of small hydropower schemes are likely to be mainly private organizations, it would be necessary for a government agency, presumably the Dirección General de Electricidad (DGE) of the Ministerio de Energía y Minas, to take the initiative in organizing such training courses and programs. That is, the DGE would need to make contact with the above organizations, establish the market for possible training courses, and arrange for the training to take place, recovering any costs involved (some organizations may be able offer grants) from the participants.

In most countries, both developed and developing, where small hydropower and other non-conventional renewable energy sources have been successfully developed to a significant degree government-sponsored technical assistance and training has played an important role. This is true even in those countries (e.g. India, Nepal) where that development has increasingly involved public-private partnerships as well as private companies alone. In such instances, however, the targets of government-sponsored promotional efforts have been not so much the ‘traditional’ targets (energy ministries, national utilities, consultants and contractors – provided with assistance in preparing master plans and project studies) but rather ‘community’ organizations such as trade associations, technical institutes, universities, publishers, libraries, conference organizers, regional support centers, etc. Such activities have covered the start-up and strengthening of these ‘community’ organizations, participation in trade missions (to and from the country involved), assisting the establishment of partnering arrangements (e.g. US Hydropower Council for International Development partnerships in India and Mexico), dissemination of information, etc.

Suggestions for mitigating some of the specific technical impediments to small hydropower development in Peru are presented in Section 5.3 below. Further assistance to small hydropower development could be similarly facilitated through government-sponsored activities such as those outlined in the previous paragraph. Given the national capabilities project design, construction and turbine manufacture, described in Sections 2.2.1 and 2.2.2 above, these activities would most likely best focus on:

- Dissemination of design and contracting/construction standards and procedures in the Spanish language;
- Promotion of domestic manufacture of ancillary components such as control and communications equipment;
- Training in operation and maintenance of small hydropower plants.

A number of national and international organizations offer technical assistance and training programs (including online courses) dealing with hydropower, some specifically small hydropower. These include:

- International Centre for Hydropower (ICH), Norway

ICH (www.ich.no) is an international association of companies and organizations which are active in all aspects of hydropower generation, its principal activities covering i) improving the standards of competence of industry personnel by organizing intensive training (including online courses – see below), ii) disseminating technical, financial, social and environmental know-how relevant to the hydropower sector, and iii) organizing seminars, workshops and conferences.

- International Energy Agency (IEA) - Hydropower Competence Network (HCN)

The IEA's HCN (www.reef.iea.org/moodle) provides online training courses, organized by the International Centre for Hydropower, on a range of hydropower topics, including technology management, operation and maintenance

- International Hydropower Association (IHA)

Formed under the auspices of UNESCO in 1995 as a forum to promote and disseminate good practices relating to hydropower development and operation, the IHA's (www.hydropower.org) activities include the publication of design and operation guidelines and organization of workshops and seminars.

- European Small Hydropower Association (ESHA)

The ESHA (www.esha.be) is a non-profit association that promotes renewable energies- small hydropower plants - with emphasis on environmental integration and is active in the dissemination of information, the organization and promotion of seminars and conferences.

- International Network on Small Hydro Power (IN-SHP), China

IN-SHP (www.hrcshp.org), based in the Regional Center for Small Hydropower, Hangzhou, China, is an international organization sponsored by the United Nations Development Program (UNDP) and United Nations Industrial Development Organization (UNIDO). It specializes providing training in small hydropower planning, design and operation & maintenance.

- U.S. Hydropower Council for International Development

The U.S. Hydropower Council for International Development (www.us-hydropower.org) advocates hydroelectric power as a preferable energy option, serving global environmental and energy policy objectives, and initiates and participates in trade missions, conferences, workshops, and other educational activities, policy development and recommendations projects, partnering and joint venture facilitation, special analysis and reports, such as needs assessment and capacity potential.

- Organización Latinoamericana de Energía (OLADE)

Founded over 30 years ago to promote agreements between its Latin American and Caribbean countries and carry out actions to satisfy their energy needs by means of the sustainable development obtained from the different sources of energy, OLADE (www.olade.org.ec) offers online and at-site training courses in a range of topics including micro and small hydropower development.

An initial step could be the holding of a workshop or seminar in Lima, with participation by a range of local stakeholders and possibly international organizations, with the specific objective of establishing precisely what forms of technical assistance and training are required for promoting small hydropower development under the conditions in Peru prevailing at present.

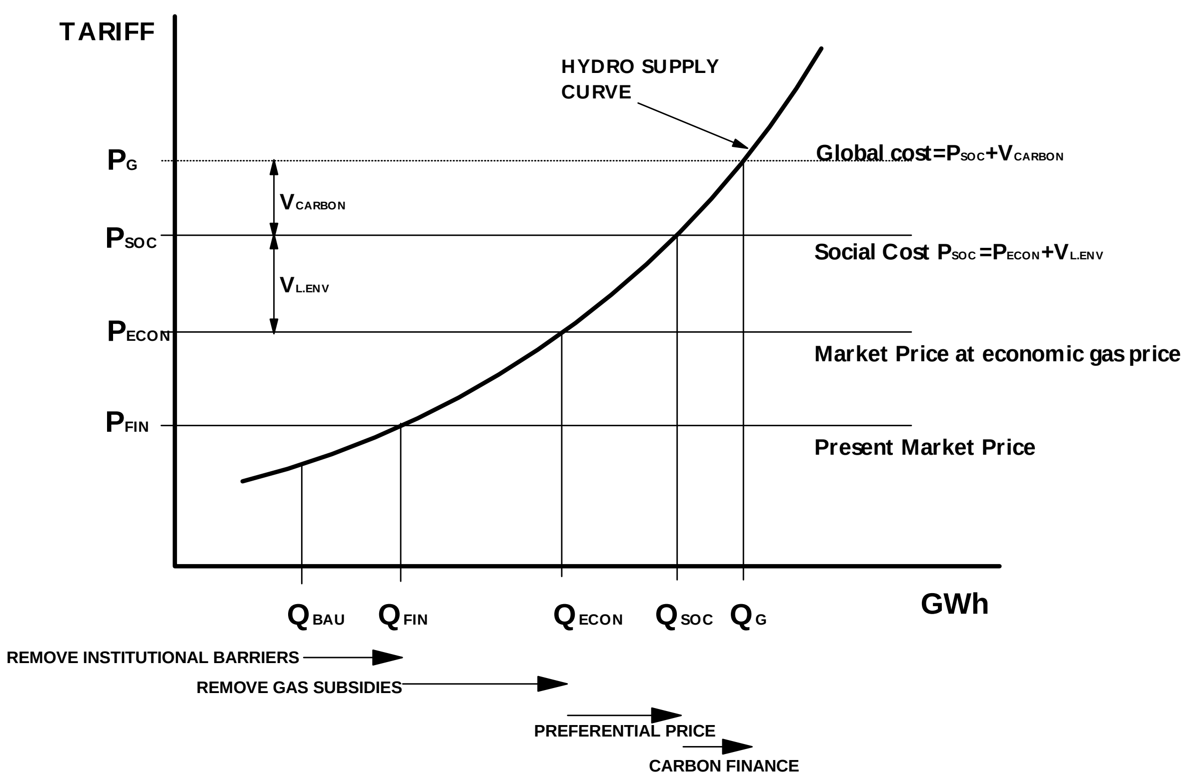
3 ECONOMIC AND FINANCIAL VIABILITY OF SMALL HYDROPOWER

This section examines the economic and financial viability of small hydropower projects. It first examines the general question of the economic benefits of hydro and the need for a hydro generation tariff that reflects these benefits (Section 3.1). This is followed by an assessment of the economic viability of small hydro projects (Section 3.2), an analysis that uses economic rather than financial costs and which is therefore based on the unsubsidized price of natural gas. We then examine the financial viability at the present *subsidized* price of natural gas (Section 3.3), and establish the conditions under which small hydro becomes financially viable. This is followed by an assessment of the ability to raise equity for small hydro projects (Section 3.4), and the ability to raise debt finance (Section 3.5).

3.1 THE BENEFITS OF HYDRO AND RATIONAL TARIFFS

In competitive generation markets, prices will be set on the basis of financial rather than economic input prices, so to the extent that these inputs are subsidized, market prices will not reflect the economic costs of the marginal generators. This means, as illustrated in Figure 3-1, that the quantity of hydro that is induced by the present financial price ($\boldsymbol{P_{FIN}, Q_{FIN}}$), is smaller than that induced at the economic price of thermal generation, ($\boldsymbol{P_{ECON}, Q_{ECON}}$). Indeed, as we show in Section 4, the many institutional barriers prevent even this level of hydro from being implemented (represented in Figure 3-1 as the business as usual quantity, $\boldsymbol{Q_{BAU}}$).

Figure 3-1: A Framework for Rational Hydro Tariffs



However, the economically rational level of hydro (or renewable energy in general) in the system will be given by the intersection of the hydro supply curve with the avoided *social* cost of thermal generation

($\boldsymbol{P_{SOC}}$, $\boldsymbol{QSOC}$), which includes consideration of the local environmental damage costs of thermal generation ($\boldsymbol{V_{L.ENV}}$). In many countries where coal is the mainstay of thermal generation (China being the most notable example), these local damage costs can be several US cents/kWh. In Peru, given that thermal generation is largely gas, and the main gas power stations being some distance away from the major population centers, these costs are much smaller – though they are unlikely to be zero.

To be sure, the presumption of this representation is that the environmental externalities of the hydro projects are internalized in the total project costs represented by the supply curve. Under current practice that requirement is generally met, given the stringent requirements for adequate relocation and resettlement compensation, and environmental requirements. Indeed, in the particular case of small hydro, such impacts as may be associated with large storage reservoir projects are almost entirely absent.

Given the clean energy benefits of hydropower, a rational hydro tariff should be based on at least the avoided economic cost of thermal generation. If the elimination of gas price subsidies cannot be achieved – or achieved only over a longer time period, then the second best solution is to set a preferential tariff directly at $\boldsymbol{P_{SOC}}$. This approach has been adopted by most countries in their efforts to increase the level of renewable energy generation – although there are many different ways to achieve this (as discussed in Section 7).

The final step in achieving the *globally* optimal level of hydro development is to include the cost of carbon damages. This additional quantity of hydro (to $\boldsymbol{Q_G}$) will depend upon the value of avoided carbon. We examine below in the discussion of carbon finance the likely impact this will have on development of the small hydro resource in Peru.

There are in principle a number of additional benefits to small hydro that are quite difficult to account for a hydro tariff. While large hydro projects may have undesirable social-economic impacts on remote rural communities (for example large but temporary construction camps), small hydro projects are generally seen to have a positive impact on small communities. More importantly, where electricity consumption is growing very fast, small hydro brings in sources of equity (and debt) not available for large power plants (from small domestic entrepreneurs and construction companies).[18]

3.2 ECONOMIC VIABILITY OF SMALL HYDROPOWER PROJECTS

Gas prices for power generation in Peru are among the lowest in the world (see Table 3-1), largely as a consequence of the pricing policy that has set a cap on the Camisea sea field price for power generation. Current prices at the Camases field to generators are set at US$1.30-US$1.39/mmBTU. Delivered prices to generators near Lima in 2008 are US$2.13-US$2.24 /mmBTU.

[18] Another potential advantage of small (grid-connected) hydro systems is in providing system stability and voltage support at the rural extremes of the distribution network to which such generators are connected. However we know of no example where this benefit has been quantified.

Table 3-1: Natural Gas Prices (Site of Generation)

	Gas Price, (US$/mmBTU)	Corresponding CCGT Generation Variable Cost, (UScents/kWh)
Peru[19]	2.15	1.70
Vietnam	3.20	2.24
Georgia (imports from GAZPROM)	3.50	2.45
Azerbaijan (imports from Russia)	6.77	4.74
USA, October 2007 Henry Hub Spot Price	7.02	4.91

Thus the present Peruvian price of gas for power generation is far below the opportunity cost as set by the international market for traded LNG. Now that Peru is becoming an LNG exporter (see Box 4), the economic cost of natural gas, netted back to the Camases gas field, is likely to be very much greater than the current ex-field price for power generation of US$1.31- US$1.39/mmBTU.

Box 4: The Peru LNG Project

The LNG plant will be located at Pampa Melchorita on the Pacific coast of Peru, 169 km south of Lima. The project consists of one 4.4 million ton per annum liquefaction plant train and related loading facilities, supplied by a 408 km 32 pipeline extension to the existing TGP pipeline, sourcing gas from Blocks 56 and 88 of the Camisea gas field. The project sponsors, Hunt Oil Company (USA), SK Corporation (South Korea) and Repsol YPF S.A. (Spain) will provide approximately US$1.7 billion in equity and the balance is long-term senior secured debt, including US$400 million from the Inter-American Development Bank. With a total cost of US$3.8 billion, this is the largest foreign investment project in the country.

The output of the LNG Plant will be sold to Repsol Comercializadora de Gas S.A. of Mexico under an 18-year sale and purchase agreement. While the sales price of LNG is unknown for this transaction, the World Bank forecast for US gas prices, not likely to be that different from Mexico, is as follows:

2008: US$8/mmBTU
2009: US$7/mmBTU
2010: US$7/mmBTU
2015: US$6/mmBTU

It is obvious that the *economic* netback price at the Camisea gas field will be substantially greater than the current field price for power generation of US$1.30- US$1.39/mmBTU.

A recent study for the World Bank[20] highlights the sharp increases in thermal generation capital costs over the past few years. While most assessments of CCCT capital costs still use costs at around

[19] The 2008 prices for thermal generators using Camisea gas set by OSINERGMIN are as follows (in US$/mmBTU):

	Ventanilla	Santa Rosa	Chilca	Kalpa
Price at Camisea	1.31	1.38	1.38	1.40
Transmission	0.74	0.74	0.74	0.74
Distribution (Chilca-Lima)	0.12	0.12		
Total	2.17	2.24	2.11	2.14

[20] URS, *Study of Equipment Prices in the Energy Sector*, World Bank, 2008

US$600/kW, according to the new study, the completed cost for actual plants ranges from US$ 1,410/kW in the USA to US$ 1,140-1,170/kW in Eastern Europe and India.[21] If the latter range is representative of Peru then Table 3-2 shows that at an economic gas price of US$4/mmBTU, the total economic generation cost including capital recovery in 2008 is estimated at UScents 5.6/kWh (Column 2).

Table 3-2: Generation Costs for Combined Cycle Gas Turbine Plants in Peru

		Economic Gas Price ($4/mmBTU)		Present Gas Price ($2.15/mmBTU)	
		Capital Cost 2006 Estimate [1]	Capital Cost 2008* [2]	Capital Cost 2006 Estimate [3]	Capital Cost 2008 * [4]
Fuel cost					
Plant heat rate	kcal/kWh	1800	1800	1800	1800
Gas Cost, coif Chilca/Kalpa	$/mmBTU	4.0	4.0	2.15	2.15
	BTU/kCal	3.968	3.968	3.968	3.968
	$/kWh	**0.029**	**0.029**	**0.015**	**0.015**
Non-fuel operating cost					
O&M	$/KW/year	22	22	22	22
Capital cost	$/kW	600	1150	600	1150
Life	[years]	20	20	20	20
Discount Rate	[ ]	10.00%	10.00%	10.00%	10.00%
Annual Cost	$/KW/year	70	135	70	135
Total Fixed Costs	$/KW/year	92	157	92	157
	$/kW/month	7.7	13.1	7.7	13.1
Plant Factor	[ ]	0.65	0.65	0.65	0.65
Fixed Costs	[$/kWh]	**0.016**	**0.028**	**0.016**	**0.028**
Total Cost	[$/kWh]	**0.045**	**0.056**	**0.032**	**0.043**

(*) URS, Study of Equipment Prices in the Energy Sector, World Bank, 2008.

3.2.1 Economic Returns to Hydropower Development

Table 3-3 shows the small hydro projects for which there are sufficient data to make estimates of economic and financial returns. While the reliability of the energy estimates is uncertain, the average of the load factors is 67 percent. Estimates of capital costs also require great caution, for there are wide variations in the published sources of data on these projects. For example, in Table 3-3, whose source is MEM dated November 2007, the capital cost estimate for the 5.66 MW Caña Brava project is shown as US$6.05 million (or US$1,071/kW). Yet the UNFCCC published CDM registration document shows a capital cost of US$1,600kW, for a capital cost of US$9.04 million, a difference of close to 50 percent.[22]

[21] The costs at January 2008 price levels are summarized as follows:

	U.S.	India	Romania
Gas turbine combined cycle plant, 140 MW	$1,410/kW	$1,170/kW	$1,140/kW
Gas turbine simple cycle plant, 580 MW	$860/kW	$720/kW	$710/kW

[22] Nor is it clear whether the costs in the 2007 MEM presentation consistently include or exclude VAT. For example, the Terucani cost in the MEM presentation is US$54.3 million. In the Terucani CDM cost presentation, the capital cost is given as US$50 million without VAT and US$52 million with VAT. These are presumably costs estimated in 2005 since the CDM project was approved in 2006. On the other hand, in the case of Poechos, the US$16.9 million construction cost given in the 2007 MEM compilation is exactly the same as the corresponding CDM document – excluding VAT.

Table 3-3: Small Hydro Projects

Project		Company	Installed Capacity (MW)	Energy (GWh)	Load Factor	Capital Cost (US$M)	$/kW (MEM)	$/kW Current Estimate
			[1]	[2]	[3]	[4]	[5]	[6]
Caña Brava	Cajamarca	Duke Energy Egenor	5.6	38.6	0.78	6.05	1,071	1,285
Poechos	Puira	SINERSA	15.4	60.0	0.44	16.9	1,097	1,317
Moche I&II	La Libertad	Electricidad Andina	20.6	100.2	0.56	16.7	811	975
Gratón	Lima	Electricidad Andina	5.0	27.7	0.63	5.4	1,080	1,284
El Sauce	San Martin	Electricidad Andina	9.5	39.6	0.48	11.7	1,232	1,487
Cerro Mulato	Lambayeque	Electricidad Andina	8.0	56.9	0.81	8.7	1,088	1,210
Camana		ElectroPerú	3.0	23.0	0.88	8.0	2,667	3,200
Culqui		ElectroPerú	20.0	133.0	0.76	54.0	2,700	3,240
Aricota III		EGESUR	19.0	66.0	0.40	21.0	1,105	1,326

Source: Ministero de Energía y Minas (2007b).

An additional source of uncertainty is the impact of recent increases in inflation, and the extent to which the forecasts for the MUV-index[23] that may be used as a proxy for prices in imported goods really applies to imported hydroelectric equipment. The sharp recent increases in the value of the index have been driven largely by the recent depreciation of the dollar against the Euro and Yen. Given that most small hydro equipment will be imported from Europe rather than the US, the impact on E&M equipment costs may be greater still.

There is similar concern regarding cost escalation for civil works, with a number of anecdotal reports suggesting increases significantly higher than the general rate of inflation. Estimates of recent construction cost increases for larger hydro projects suggest some significant problems: for example, the 2006 cost estimate for the 220 MW El Platanal project now under construction was US$170.3 million; the estimate at 2008 prices is US$217.4 million,[24] an increase of 28 percent. For these reasons, the MEM capital cost estimates of Table 3-3 have been escalated by 20 percent. The resulting estimates in column 6 of this table are used in the following analysis.

The following additional assumptions are made for the economic analysis:

- ***Construction disbursement:*** A two-year construction period, with 50 percent disbursed in each year.
- ***Own-consumption***: 1.5 percent of gross generation
- ***Transmission connection:*** These vary widely. Among examples the two extremes were a 1 km 66 kV to connect the first powerhouse of the planned Santa Cruz cascade and a 91 km 138 kV for the Tarucani project costing US$10 million. For the calculations it is assumed that transmission costs are included in the total investment cost. The developer is responsible for building the line. With meters at the plant site, the transmission energy losses in the connecting line are paid by the buyer.
- ***Global environmental benefits:*** the avoided carbon emissions are valued at US$15/ton$CO_2$, with an emission factor of 0.57 kg/kWh, based on the recently approved Caña Brava.[25]

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[23] MUV index: Manufacturing Unit Value index

[24] From an ongoing World Bank study of large hydro projects in Peru.

[25] The baseline emission factor for the 5.67 MW Caña Brava small hydro project is 0.56927 kg CO2/kWh (Caña Brava CDM Project Design Document). This emission factor is used in the illustrative calculations.

At realistic values of the opportunity cost of natural gas (US$4/mmBTU), and realistic values of capital costs of CCCTs (US$1,150/kW), resulting in an economic value of gas generation of 5.6 UScents/kwh, four projects have economic rates of return (ERRs) substantially above the Sistema Nacional de Inversion Pública (SNIP) hurdle rate of 14 percent (Table 3-4).

Table 3-4: Small Hydro Projects ERRs and Gas Price Switching Values to Achieve 14 percent SNIP Hurdle Rate (excluding carbon benefits)

	Capacity Factor	Capital Cost	ERR (At $4/mmBTU)	Gas Price For ERR=14 percent	Result
	percent	$/kW	percent	$/mmBTU	
	[1]	[2]	[3]	[4]	[5]
Cerro Mulato	81%	1210	26.0%	<1.00	
Caña Brava	78%	1285	24.1%	1.00	Economic at
MocheI&II	56%	975	21.7%	1.60	present gas price
Gratón	63%	1284	18.7%	2.20	
Poechos	44%	1317	12.7%	4.60	
El Sauce	48%	1487	11.3%	5.20	
Aricota	40%	1326	9.9%	6.00	
Camana	88%	3200	8.4%	6.80	
Culqui	76%	3240	5.8%	6.80	

3.2.2 Economic Return Taking into Account Social Benefits (Psoc, Qsoc)

In principle, the economic analysis should take into consideration not just the avoided global environmental damage costs, but also the avoided *local* environmental damage costs of the fossil-fuel generation that it displaces – and indeed in many countries – most notably China – the damage costs from coal-fired generation in particular are a major incentive for renewable energy and small hydro projects.

However, in Peru most of the thermal generation is located in a sparsely populated area some 60 km south of Lima. Gas-based power generation has no significant particulate or sulfur emissions, and only NOx emissions are of major concern. With low population density in the area, and the predominating weather regime being land and sea breezes (blowing emissions either over the ocean, or into the even less sparsely populated mountain area to the east, rather than North into the Lima metropolitan area), there is no evidence of power sector emissions causing human health damages or acid rain related consequences on agriculture or buildings. Lima itself is suffering from increased air pollution problems, but these are the result of automobile emissions, which are orders of magnitude greater than the power plant emissions. In the absence of any evidence of such damage costs from power generation in Peru, there are no grounds for including these in the economic analysis.

3.2.3 Economic Return Taking into Account Carbon Benefits (Pg, Qg)

Eight of thirteen of Peru's registered CDM projects as shown in Table 3-5 are hydro.[26] The benefit of carbon finance on the economic return of small hydro projects depends on the carbon price. The first small hydro project in Peru to obtain carbon finance was Santa Rosa, which achieved a carbon price of US$5/ton: the Poechos project expects 4.1 Euros/ton (US$6.47/ton) for CER purchases. The Tarucani and Quitaracsa projects (which are larger hydro projects of 49 MW and 115 MW, respectively) have been registered under CDM, and expect to get US$15/ton from a European thermal plant company that needs the carbon offsets.

[26] By comparison, Bolivia has three registered energy sector CDM projects (of which one is SHP); Ecuador 11 (of which 5 are SHP).

Table 3-5: Peru's Energy Sector CDM Projects

Date	Project	Technology	UNFCCC CDM Reference #
Withdrawn	Paramonga CDM Bagasse Boiler	Bagasse	70
23 Oct 05	Santa Rosa	SHP	88
14 Nov 05	Poechos	SHP	86
06 Sep 06	Tarucani I	SHP	285
05 Mar 07	Huaycoloro Landfill Gas Capture and Combustion	LFG	708
06 Apr 07	Quitaracsa I	SHP	874
06 Jul 07	Peruvian Fuel-Switching Project	Fuel Switching	1073
23 Sep 07	Palmas del Espino – Biogas Recovery and Heat Generation From Palm Oil Mill Effluent (POME) Ponds, Peru	Biogas	1249
30 Nov 07	Ancon – EcoMethane Landfill Gas	LFG	1104
04 Jan 08	Rehabilitation of the Callahuanca Hydroelectric Power Station	SHP	1245
08 Feb 08	Caña Brava Hydroelectric Power Plant	SHP	1444
Requesting Registration	Carhuaquero IV Hydroelectric Power Plant	SHP	1424
Requesting Registration	La Virgen Hydroelectric Plant	SHP	1445

Source: UNFCCC.

By far the largest volume of carbon is traded in the European Emissions Trading Scheme with €24 billion (US$30 billion) traded in 2006, up from €8billion (US$10 billion) in 2005. However, the prices have been volatile, in 2006 ranging from €15/ton (US$23.7/ton) to €30/ton (US$47.3/ton) CO_2, and with spot prices recently down to as little as €1/ton (US$1.6/ton) (Figure 3-2). In an apparent effort to avoid a collapse of the carbon market, in October 2007 the Commission has set an EU-wide CO_2 cap of 2.08 billion tones for 2008-2012, giving member states 10 percent less CO_2 allowances than requested: this is expected to bring the price back into the €20-25/ton range.

Figure 3-2: Carbon Prices in the European Trading Scheme

Source: World Bank (2007a).

Carbon prices in the funds administered by the World Bank (such as the Community Development Carbon Fund used by the Santa Rosa project) have seen much lower, but also more stable prices: typical CDM and carbon fund transactions over the past few years have been at carbon prices of US$5-7/ton CO_2. But prices are rising: a CDM aggregation project for small hydro projects currently under negotiation in Vietnam has been offered a US$10/ton price for CERs by the World Bank carbon finance unit.

Obviously, including carbon benefits has a positive effect on the economic return of the hydro projects under consideration (using the economic netback gas price). At US$15 per ton of CERs, ERRs increase between 2.5 and 5 percent and only 3 of the nine projects fail to meet the 14 percent SNIP hurdle rate (Table 3-6).

Table 3-6: Small Hydro Projects ERRs including Carbon Benefits at US$ 15/ton

Project	**Installed Capacity**	**Capacity Factor**	**Capital Cost**	**ERR (at $4/mm BTU)**	**GHG Benefit**	**ERR Including GHG Benefit**
	[MW]	[percent]	[$/kW]	[percent]	[percent]	[percent]
	[1]	[2]	[3]	[4]	[5]	[6]
Cerro Mulato	8.6	81%	1,210	26.0	4.3	30.2
Caña Brava	5.7	78%	1,285	24.1	4.0	28.1
MocheI&II	20.6	56%	975	21.7	3.9	25.5
Gratón	5	63%	1,284	18.7	3.5	22.2
Poechos	15.4	44%	1,317	12.7	2.8	15.5
El Sauce	9.4	48%	1,487	11.3	2.8	14.2
Aricota	19	40%	1,326	9.9	2.8	12.7
Camana	3	88%	3,200	8.4	2.7	11.1
Culqui	20	76%	3,240	5.8	2.7	8.5

3.3 FINANCIAL VIABILITY OF SMALL HYDROPOWER PROJECTS

This section begins by assessing the financial viability of small hydro projects under the current tariff conditions, with an average tariff yield of 3.5 UScents/kWh, which would be the purchase price of bulk power under a power purchase agreement (PPA) with a distributor selling to consumers in the regulated market under the prices set by OSINERGMIN. This price is based on subsidized natural gas. The subsequent sensitivity analysis assesses the tariff needed to make small hydro projects financially viable.

Even though in reality small hydro financing in Peru has always been based on recourse to the corporate sponsor (or has required 100 percent collateral), the analysis below reflects the structure as might be typical in a non-recourse project financing. This reflects the cash flow analysis that would be prepared by a project sponsor even if the actual financing deal is on the basis of corporate guarantees.[27]

All calculations are at nominal prices, with O&M rates escalated at the rate of inflation. The nominal net cash flows are then adjusted for inflation to derive the cash flows at constant 2008 price levels to calculate the real FIRR. The following additional baseline assumptions are used for this analysis:

[27] A large mining corporation could finance a small project on the basis of a lease deal, with a cash flow that would look quite different.

- ***Construction disbursement:*** Equity contributions in construction are *pari passu* with debt.
- ***Debt terms:*** 10 years, two year grace, IDC capitalized, interest = 6.3 percent +2 percent spread for assumed primate corporate sponsor +1.5 percent project spread (see Section 3.4) = 9.8 percent. Debt repayments as an annuity.
- ***Debt: Equity***: 70:30
- ***Corporate tax:*** The standard rate of 30 percent, as there are no holidays or reduced rates. There are tax concessions in Loreto (Amazon region) for all projects, not just power projects, but this requires a corporate office in Loreto to qualify.
- ***Depreciation***: as specified in Table 3-15 for a conventional financing.
- ***VAT***: assumed at the standard rate since small hydro construction periods are less than 4 years. The impact of leasing that incorporates immediate recovery is examined in the sensitivity analysis below.
- ***Regulation Fee:*** 1 percent of sales revenue, 0.6 percent to OSINERGMIN, 0.4 percent to MEM.
- ***Own-consumption***: 1.5 percent of gross generation
- ***Carbon price***: no carbon credits are assumed in the baseline. The impact of carbon finance on financial returns is assessed later in this section.
- ***Inflation***: Set at the current inflation target of the Central Bank of Peru at 2 percent.[28]
- ***Tariff*:** US cents 3.5/kWh
- ***Project Life*:** 20 years

3.3.1 Financial Returns

Financial Return at Current (Subsidized) Price of Gas

At the present *financial* gas price of US$2.15/mmBTU (cif Lima), the average revenue yield for generation is taken as 3.5 US cents/kWh, with the results for financial returns (FIRR) as shown in Table 3-7. The table also shows the natural gas price necessary to make a given project financially viable, taken here as meeting a 17.5 percent return on equity. None are financially viable at the present gas price; but four projects would be so at an unsubsidized gas price of US$4/mmBTU. The remaining projects require gas price valuations in excess of US$8/mmBTU to be viable under the financing assumptions noted.

Table 3-7: Financial Returns of Small Hydro Projects
(At subsidized gas price and without carbon revenues)

	Installed Capacity	Capacity Factor	Capital Cost	FIRR-nominal	Gas Price at FIRR= 17.5percent	Required Tariff for FIRR= 17.5percent	
	[MW]	[percent]	[$/kW]	[percent]	[$/mmBTU]	[UScents/kWh]	
Cerro Mulato	8.6	81%	1,210	11.1%	3.5	4.1	
Caña Brava	5.7	78%	1,285	9.8%	3.8	4.3	Viable at tariff of
Moche I&II	20.6	56%	975	6.6%	4.5	4.8	5.6 UScents/kWh
Gratón	5.0	63%	1,284	4.0%	5.4	5.5	
Poechos	15.4	44%	1,317	-0.8%	8.4	7.5	
El Sauce	9.4	48%	1,487	-2.8%	>8.0	7.6	
Aricota	19.0	40%	1,326	-4.5%	>8.0	7.6	
Camana	3.0	88%	3,200	-6.1%	>8.0	7.6	
Culqui	20.0	76%	3,240	-8.7%	>8.0	>8.0	

[28] Central Bank of Peru (2008).

Financial Viability Based on the Economic (Unsubsidized) Cost of Gas

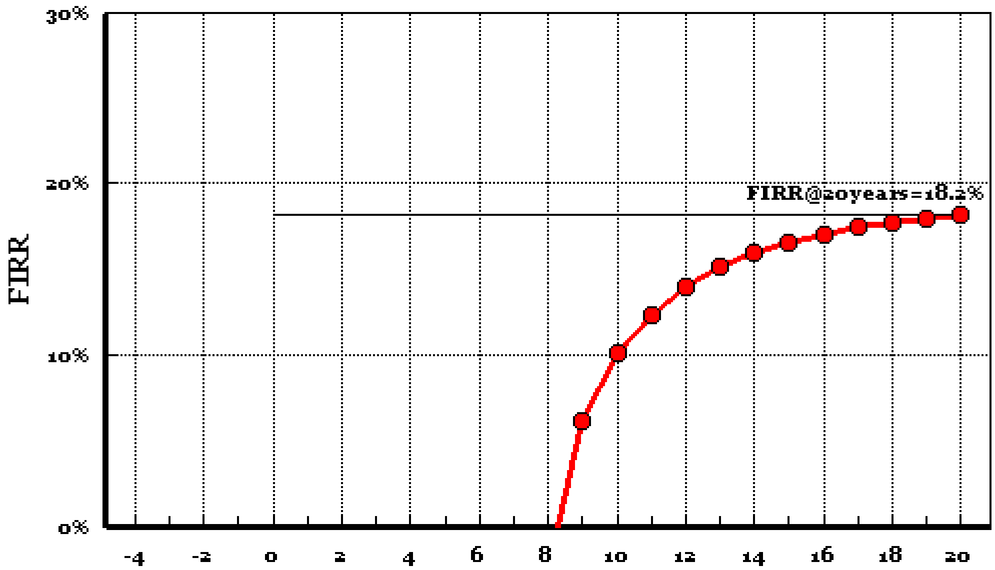
A rational tariff for small hydro should be based on the avoided costs of thermal generation (in Figure 3-1, $\boldsymbol{P_{ECON}}$ if not $\boldsymbol{P_{SOC}}$). Using realistic assumptions about the capital cost of CCGTs, and the economic cost of gas (US$4/mmBTU), then Table 3-2 (Column 2) shows an estimated cost of $\boldsymbol{P_{ECON}}$ at 5.6 UScents/kWh. Table 3-8 compares the FIRR at this unsubsidised gas price ($\boldsymbol{P_{ECON}}$) with that for the subsidized price shown in Table 3-6. As expected the top four projects are now financially viable, but not the remaining projects.

Table 3-8: Financial Returns of Small Hydro Projects
(Without Carbon Revenues)

	Installed Capacity	Capacity Factor	Capital Cost	FIRR-Present Gas Price (3.5 UScents /kWh)	FIRR Unsubsidized Gas Price (5.6 UScents /kWh)
	[MW]	[percent]	[$/kW]	[percent]	[percent]
Cerro Mulato	8.6	81%	1,210	11.1%	30.7%
Caña Brava	5.7	78%	1,285	9.8%	27.2%
Moche I&II	20.6	56%	975	6.6%	23.0%
Gratón	5.0	63%	1,284	4.0%	18.2%
Poechos	15.4	44%	1,317	-0.8%	9.3%
El Sauce	9.4	48%	1,487	-2.8%	7.5%
Aricota	19.0	40%	1,326	-4.5%	5.6%
Camana	3.0	88%	3,200	-6.1%	3.6%
Culqui	20.0	76%	3,240	-8.7%	0.4%

The standard calculation of FIRR is to the assumed end of the economic life of the project – taken here at 20 years. For example, the Gratón project has a nominal FIRR of 18.2 percent. But this is the value attained only in year 2030 – as shown in Figure 3-3, the payback period is 8 years, and even after 10 years, the FIRR is only 10 percent. These are long investment horizons. It therefore comes as no surprise that many investors appear to have little interest in hydro generation, and that the only real interest in developing the larger hydro projects comes from Peruvian mining and industrial companies with a long-term view of the development of the Peruvian economy.

Figure 3-3: Gratón FIRR versus Time



Sensitivity Analysis

The above analysis looked at a number of individual projects. The basic question for evaluating the financial viability of small hydro potential is the following: given the minimum expectations of financial returns to equity in the 15-20 percent range, and the likely terms and conditions of financing, what combinations of load factors and capital results are viable at different levels of tariff?

Table 3-9 shows the tariff required to achieve a 17.5 percent FIRR, as a function of load factor and capital cost. Conditions below the bottom left staircase are combinations of load factor and capital cost that are feasible at the present tariff of 3.5 UScents/kWh. The entries in bold, between the first and second staircase, represent the increased range of combinations that become feasible at the estimated economic avoided cost of gas generation – rounded to 6 UScents/kWh. Finally, the shaded area represents the combinations that would require a tariff higher than 6 UScents/kWh.

Table 3-9: Tariff Required as a Function of Load Factor and Capital Cost (UScents/kWh)

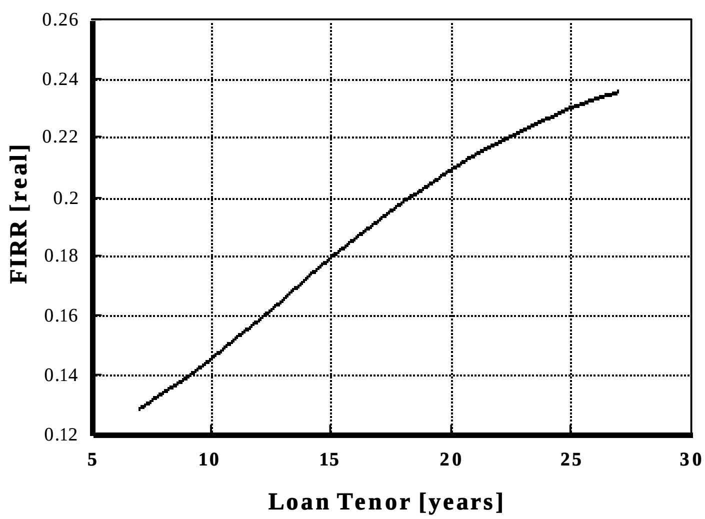
	Capital Cost ($/kW)											
Load Factor	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000
35%	7.2	7.9	8.6	9.3	10.0	10.7	11.4	12.1	12.9	13.6	14.3	15.0
40%	6.3	6.9	7.6	8.2	8.8	9.4	10.0	10.6	11.2	11.9	12.5	13.1
45%	**5.6**	6.2	6.7	7.3	7.8	8.4	8.9	9.4	10.0	10.5	11.1	11.6
50%	**5.1**	**5.6**	6.0	6.5	7.0	7.5	8.0	8.5	9.0	9.5	10.0	10.5
55%	**4.6**	**5.0**	**5.5**	**5.9**	6.4	6.8	7.3	7.7	8.2	8.6	9.1	9.5
60%	**4.2**	**4.6**	**5.0**	**5.4**	**5.9**	6.3	6.7	7.1	7.5	7.9	8.3	8.7
65%	**3.9**	**4.3**	**4.6**	**5.0**	**5.4**	**5.8**	6.2	6.5	6.9	7.3	7.7	8.1
70%	**3.6**	**4.0**	**4.3**	**4.7**	**5.0**	**5.4**	**5.7**	6.1	6.4	6.8	7.1	7.5
75%	3.4	**3.7**	**4.0**	**4.4**	**4.7**	**5.0**	**5.3**	**5.7**	**6.0**	6.3	6.7	7.0
80%	3.2	3.5	**3.8**	**4.1**	**4.4**	**4.7**	**5.0**	**5.3**	**5.6**	**5.9**	6.2	6.5
85%	3.0	3.3	**3.6**	**3.8**	**4.1**	**4.4**	**4.7**	**5.0**	**5.3**	**5.6**	**5.9**	6.2
90%	2.8	3.1	3.4	**3.6**	**3.9**	**4.2**	**4.5**	**4.7**	**5.0**	**5.3**	**5.5**	**5.8**

While the economically justified price requires more precise analysis, it can be seen that projects with load factors in the range of 60-65 percent would be financially viable at capital costs up to US$1,300-1,400/kW. At capacity factors of 70-75 percent, capital costs could increase to US$1,500 to US$1,600/kW. This indicates that a considerable number of projects could be developed, if small hydropower were to receive a price equivalent to the economical avoided cost of thermal generation.

3.3.2 The Importance of Loan Tenors

Loan tenors have significant effect on FIRR (Figure 3-4). In the example shown, for a generic project with capital costs of US$1,000/kW, and a load factor of 55 percent, the difference between a 10 and a 15-year tenor is an increase from 14.6 percent to 18 percent: a further extension to 20 years raises the FIRR to 20.9 percent. This is the reason that many countries have domestically or internationally financed programs that assist investors in renewable energy, including small hydropower, to obtain long-term financing. It is normally difficult for sponsors of small projects to access such financing without such assistance. A refinancing program that extended tenors from 10 to 15 or 20 years would make a significant difference to financing feasibility.

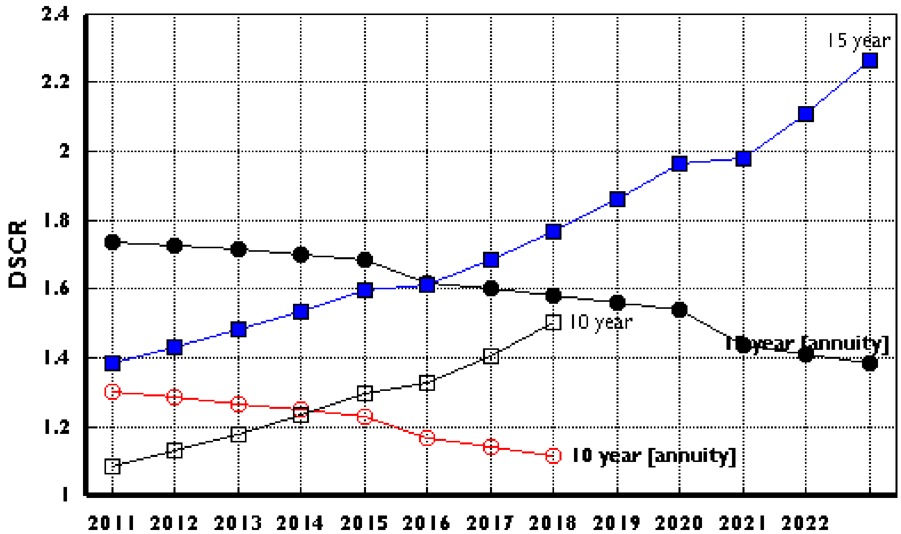
Figure 3-4: FIRR and Loan Tenor



As shown in Figure 3-5, whether financed as an annuity, or with constant principal repayments, DSCRs in the early years are significantly better with the longer loan maturities.[29]

[29] However, when financed as an annuity, DSCRs fall over time (because under the assumptions made here of a constant tariff but O&M costs increasing over time (as a result of inflation), net revenue decreases over time, and hence DSCR falls. On the other hand, under constant principal repayments, DSCR improves over time, because the reduction in interest payable as principal is paid off more than offsets the effect of inflation on O&M costs.

Figure 3-5: Impact of Loan Tenor on DSCR



Longer loan tenors also extend the feasible range of capital costs and load factors, as shown in Table 3-10. Extension of tenor by 5 years (from 10 to 15 years) is equivalent to a 5 percent increase in load factor, or an increase in the allowable capital cost by about US$100/kW.

Table 3-10: Impact of Loan Extension to 15 years on Feasible Combinations of Capital Costs and Load Factors

Load	Capital Cost ($/kW)											
Factor	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000
35%	6.7	7.4	8.0	8.7	9.3	10.0	10.6	11.2	11.9	12.5	13.2	13.8
40%	5.9	6.4	7.0	7.6	8.1	8.7	9.3	9.8	10.4	11.0	11.5	12.1
45%	5.2	5.7	6.2	6.7	7.2	7.7	8.2	8.7	9.3	9.8	10.3	10.8
50%	4.7	5.2	5.6	6.1	6.5	7.0	7.4	7.9	8.3	8.8	9.2	9.7
55%	4.3	4.7	5.1	5.5	5.9	6.3	6.7	7.2	7.6	8.0	8.4	8.8
60%	3.9	4.3	4.7	5.1	5.4	5.8	6.2	6.6	6.9	7.3	7.7	8.1
65%	3.6	4.0	4.3	4.7	5.0	5.4	5.7	6.1	6.4	6.8	7.1	7.4
70%	3.4	3.7	4.0	4.3	4.7	5.0	5.3	5.6	5.9	6.3	6.6	6.9
75%	3.1	3.4	3.7	4.0	4.3	4.6	4.9	5.2	5.6	5.9	6.2	6.5
80%	2.9	3.2	3.5	3.8	4.1	4.4	4.6	4.9	5.2	5.5	5.8	6.1
85%	2.8	3.0	3.3	3.6	3.8	4.1	4.4	4.6	4.9	5.2	5.4	5.7
90%	2.6	2.9	3.1	3.4	3.6	3.9	4.1	4.4	4.6	4.9	5.1	5.4

3.3.3 Impact of Carbon Finance on Financial Viability

Table 3-11 shows the impact of carbon finance on the 9 hydro projects examined previously. The impact of carbon finance on financial viability is very significant. At typical load factors of 50-80 percent, carbon finance can add 1.5-7 percent to the project FIRR, using the avoided economic sot of generation at an unsubsidized price of natural gas. Both Cerro Multato and Caña Brava have FIRRs in the feasible range with carbon finance.

Table 3-11: Impact of Carbon Finance at US$15/ton CO2 on Project Financial Viability (Unsubsidized Gas Price of US$4/mm BTU)

	Installed Capacity MW	Load factor	$/kW	FIRR	FIRR(with carbon finance)	Change in FIRR
Cerro Mulato	8.6	81%	1,210	30.7%	37.6%	6.9%
Caña Brava	5.7	78%	1,285	27.2%	33.3%	6.1%
MocheI&II	20.6	56%	975	23.0%	28.5%	5.5%
Gratón	5.0	63%	1,284	18.2%	22.5%	4.3%
Poechos	15.4	44%	1,317	9.3%	11.5%	2.2%
El Sauce	9.4	48%	1,487	7.5%	9.6%	2.0%
Aricota	19.0	40%	1,326	5.6%	7.4%	1.8%
Camana	3.0	88%	3,200	3.6%	5.3%	1.6%
Culqui	20.0	76%	3,240	0.4%	1.8%	1.4%

The impact of carbon finance can be more systematically assessed by analyzing the range of load factor/capital cost combinations that are feasible with carbon finance, as shown in Table 3-12. Again the shaded cells show the combinations that become feasible at this level of carbon finance. Carbon finance at US$15/ton considerably extends the range of potential costs and load factors that become feasible: at this value of carbon, any given tariff extends the load factor by about 10 percent, or the capital cost by US$100/kW. At load factors of 65-70 percent, capital costs of US$1,500- US$1,600 would become feasible.

Table 3-12: Impact of Carbon Finance on Feasible Combinations of Capital Costs and Load Factors (UScents/kWh)

Load	Capital Cost ($/kW)											
Factor	900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000
35%	6.6	7.3	8.0	8.7	9.4	10.1	10.8	11.5	12.2	12.9	13.6	14.3
40%	**5.7**	6.3	6.9	7.5	8.2	8.8	9.4	10.0	10.6	11.2	11.8	12.5
45%	**5.0**	**5.5**	6.1	6.6	7.2	7.7	8.3	8.8	9.4	9.9	10.5	11.0
50%	**4.4**	**4.9**	**5.4**	**5.9**	6.4	6.9	7.4	7.9	8.4	8.9	9.4	9.8
55%	**4.0**	**4.4**	**4.9**	**5.3**	**5.8**	6.2	6.7	7.1	7.5	8.0	8.4	8.9
60%	**3.6**	**4.0**	**4.4**	**4.8**	**5.2**	**5.6**	6.0	6.5	6.9	7.3	7.7	8.1
65%	3.3	**3.6**	**4.0**	**4.4**	**4.8**	**5.2**	**5.5**	**5.9**	6.3	6.7	7.0	7.4
70%	3.0	3.3	**3.7**	**4.0**	**4.4**	**4.7**	**5.1**	**5.4**	**5.8**	6.1	6.5	6.9
75%	2.7	3.1	3.4	**3.7**	**4.1**	**4.4**	**4.7**	**5.0**	**5.4**	**5.7**	6.0	6.4
80%	2.5	2.8	3.1	3.5	**3.8**	**4.1**	**4.4**	**4.7**	**5.0**	**5.3**	**5.6**	**5.9**
85%	2.3	2.6	2.9	3.2	**3.5**	**3.8**	**4.1**	**4.4**	**4.7**	**5.0**	**5.2**	**5.5**
90%	2.2	2.5	2.7	3.0	3.3	**3.5**	**3.8**	**4.1**	**4.4**	**4.6**	**4.9**	**5.2**

When combined with extension of loan tenor from 10 to 15 years, the range of feasible projects expands further, as shown in Table 3-13.

Table 3-13: Impact of Carbon Finance plus Loan Tenor Extension to 15 years on Financial Viability (UScents/kWh)

load factor	$/kW 900	1000	1100	1200	1300	1400	1500	1600	1700	1800	1900	2000
35%	6.1	6.7	7.4	8.0	8.7	9.3	10.0	10.6	11.3	11.9	12.6	13.2
40%	**5.3**	**5.8**	6.4	7.0	7.5	8.1	8.6	9.2	9.8	10.3	10.9	11.5
45%	**4.6**	**5.1**	**5.6**	6.1	6.6	7.1	7.6	8.1	8.6	9.1	9.6	10.1
50%	**4.1**	**4.5**	**5.0**	**5.4**	**5.9**	6.3	6.8	7.2	7.7	8.1	8.6	9.1
55%	**3.6**	**4.1**	**4.5**	**4.9**	**5.3**	**5.7**	6.1	6.5	6.9	7.4	7.8	8.2
60%	3.3	**3.7**	**4.0**	**4.4**	**4.8**	**5.2**	**5.6**	**5.9**	6.3	6.7	7.1	7.4
65%	3.0	3.3	**3.7**	**4.0**	**4.4**	**4.7**	**5.1**	**5.4**	**5.8**	6.1	6.5	6.8
70%	2.7	3.1	3.4	**3.7**	**4.0**	**4.4**	**4.7**	**5.0**	**5.3**	**5.6**	**6.0**	6.3
75%	2.5	2.8	3.1	3.4	**3.7**	**4.0**	**4.3**	**4.6**	**4.9**	**5.2**	**5.5**	**5.8**
80%	2.3	2.6	2.9	3.2	3.4	**3.7**	**4.0**	**4.3**	**4.6**	**4.9**	**5.1**	**5.4**
85%	2.1	2.4	2.7	2.9	3.2	3.5	**3.7**	**4.0**	**4.3**	**4.5**	**4.8**	**5.1**
90%	2.0	2.2	2.5	2.7	3.0	3.2	3.5	**3.7**	**4.0**	**4.3**	**4.5**	**4.8**

Carbon finance has already played a role in the development of larger hydropower projects. The Quitarasca project company was recently bought by a large mining group for whom the sale of CERs made the difference between a project that without the carbon revenues would not have met the necessary hurdle rate, and one that is now in active development (with tenders now underway).

3.4 POTENTIAL CORPORATE INVESTORS IN SMALL TO MEDIUM-SIZED HYDROPOWER

Table 3-14 lists small hydro projects (20 MW or less) currently underway in Peru. Most sponsors are small companies, established by small entrepreneurs to exploit small hydro. Needless to say, with most development rights in the hands of such small companies, project financing under such terms poses a formidable obstacle to large-scale development. Typically these companies have little financial strength, and must find more capable equity partners to raise the sort of guarantees required by Peruvian banks. This inevitably raises the usual issues of control, and the valuation of “sweat equity” – the costs invested by the promoters to obtain the water rights and conduct the initial studies.

One recent small hydro project in Peru, the 1.5 MW Santa Rosa I Project, commissioned in August 2004, is sponsored by Eléctrica Santa Rosa, a special purpose company created by five private investors to identify, build and operate hydro power plants. Santa Rosa II (1.5 MW) has been added since (see Box 2). The most important point about this project from the perspective of project financing is that the first phase required 100 percent cash collateral, making this in effect a project with 100 percent equity.[30] Upon completion of Santa Rosa II (the second stage), the debt: equity ratio of the company was improved to 33:67, and upon completion of Santa Rosa III, it is expected that this ratio could increase up to 63:37. These are relatively small percentages of debt by international standards, the reasons for which are discussed in the next section.

[30] This is the first hydro project in Peru to secure carbon finance, from the World Bank managed Community Development Carbon Fund. Box 2 describes this project in further detail.

Table 3-14: Hydro Projects Smaller than 20 MW

No.	Name	Status	Project Sponsor	Type	Dept.	Capacity (MW)
1	Pátapo	Auth	Generación Taymi S.R.L.	small company	Lambayeque	1.0
2	Camana	study	Plan Maestro	small company	Arequipa	2.8
3	San Diego	Auth	Duke Energy Egenor S. En C. Por A.	large company	Ancash	3.2
4	Roncador	Auth	Agroindustrias Maja Sac	large company	Lima	3.8
5	Gratón	Auth	Siif Andina S.A.	small company	Lima	5.0
6	Caña Brava	Auth	Duke Energy Egenor S. En C. Por A.	large company	Cajamarca	5.7
7	Shali	Auth	Abr Ingenieros Sac	small company	Lima	9.0
8	La Joya	Auth	Generadora de Energía del Perú S.A.	small company	Arequipa	9.6
9	Ispana-Huaca	Auth	Inversiones Productivas Arequipa Sac	small company	Arequipa	9.6
10	Carhuaquero IV	Auth	Duke Energy Egenor S. En C. Por A.	large company	Cajamarca	9.7
11	Poechos	Def	Sindicato Energético S.A. – Sinersa	small company	Piura	10.0
12	Pías 1	Def	Aguas y Energía Perú S.A.	small company	La Libertad	11.0
13	Pías II	Temp	Aguas y Energía Perú S.A.	small company	La Libertad	16.0
14	Quiroz-Vilcazán	Temp	Junta de Usuarios del Distrito de Riego San Lorenzo	cooperative	Piura	18.0
15	Aricota III	study	Empresa de Generación del Sur - Egesur	small company	Tacna	19.0
16	Culqui	study	Electroperú S.A.	Distr. comp.	Piura	20.0

Notes:

Def= Definitive concession
Temp=temporary concession for studies
Auth=projects with Authorization
Study = projects with no concession or authorization

Source: Annex 3

3.4.1 Pension Funds

In the past few years a number of potential sources of equity have emerged, notably Peruvian asset funds, a significant proportion of which are funded by Peru's fast-growing private pension funds. Other Latin American countries are also seeing interest from equity funds established expressly for investment in renewable energy projects.[31]

This assessment of the potential availability of small hydro equity investment from pension funds is based on discussions with ProFuturo, the largest of the four big private pension funds in Peru, which together manage some US$20 billion. ProFuturo has no project finance capability, and therefore entrusts its investment funds to specialist asset management firms (such as AC Capitales). At present, 55 percent of its overall portfolio is in fixed income securities, 45 percent in equity. Of the equity portion, 5 percent is invested internationally and 40 percent in Peru. In turn, of that 40 percent, 39.5 percent has been invested directly in the stock market, and only 0.5 percent in investment funds that are the potential providers of equity to small hydro projects. Nevertheless, these funds still account for several hundred million dollars.

The concentration in the stock market is a simple consequence of the spectacular returns achieved there over the past few years. However, ProFuturo recognizes that the present yields are not sustainable over the long run, and therefore has appetite for placing its growing assets in investment funds.

Until the end of 2005, ProFuturo offered its customers only one type of portfolio, but now it offers three: a "conservative" portfolio consisting of 90 percent fixed income and 10 percent equity; a "balanced" portfolio of 55 percent fixed income and 45 percent equity; and an "aggressive" portfolio of 20 percent fixed income and 80 percent equity. Customer demand for the aggressive portfolio has been growing especially fast, and ProFuturo needs to look at more ways of finding good equity investments.

[31] See section 6.2 for details of the Brazilian *PROINFA* programme.

ProFuturo has invested in six private investment funds in the local market:

- Operating and leasing, US$50 million managed by SIGMA
- Two real estate funds, managed by AC Capitales, US$25 million
- Infrastructure fund, US$50 million, managed by AC Capitales
- Agro-industrial fund, US$50 million managed by AC Capitales (just starting)
- Private equity, US$50 million, managed by ENFOCA.
- Venture capital, US$15 million, managed by SEAF.

Two more funds are in the process of being established, each at US$50 million. Management fees are 1-2 percent of assets under management. ProFuturo is looking for 15-20 percent returns from its infrastructure investment fund. ProFuturo would be in principle interested in mezzanine financing, but would not want to take a controlling interest in any venture, and in any event would take no more than a 49 percent interest in any special project vehicle.

3.4.2 Asset Funds

AC Capitales is one of Peru's major asset fund managers. Four of the six investment funds in the market are managed by AC Capitales. The firm's investment mandate for the infrastructure fund allows the inclusion in their portfolio of small hydro projects, even greenfield projects, since unlike some other private equity and venture capital funds, they expect returns as dividends, rather than the capital gains of an early exit strategy.

The US$50 million infrastructure fund was launched in 2004 with a three-year horizon. With US$40 million already subscribed, this fund is being enlarged to US$100 million, and its horizon extended to 5 years. This fund is a suitable vehicle for small hydro project equity, were a good proposal to be presented. The firm has seen a number of proposals from small hydro developers. However, they expressed the view that most had unreasonable expectations about the value of the development rights and whatever studies had been done to date. Few developers had sufficient equity of their own to contribute, and AC Capitales expressed considerable skepticism about valuation methodologies proposed by developers.[32] Requests to fund feasibility studies had also been rejected. To date, the fund has invested in 9 equity projects (none small hydro), of which 7 were operating assets, and only two greenfield projects. Of the two greenfield projects, one was an urban infrastructure project with an EPC, the other in an oil & gas venture with an internationally renowned contractor. For operating assets, 15 percent return is sought. For greenfield projects, returns in the high end of the 15-20 percent range would normally be sought. However, the fund managers noted that they did not see higher IRRs as mitigating completion risk.

Developers expressed doubts that Peruvian banks would take into account carbon revenues. However there are now several European banks that offer project financing under which some fraction of carbon revenues are directly pledged to the lending bank. Even more interesting from the perspective of raising equity, it was reported that some banks are apparently prepared to put up as much as 70 percent of the NPV of the carbon revenue stream as collateral, which in turn enables the developer to offer this as a contribution to equity.

[32] One such methodology is to value the developer's contributed equity as the present value of the difference between the projected revenue stream and what was necessary to give the fund a 15 percent return!

3.5 AVAILABILITY OF FINANCING FOR SMALL TO MEDIUM-SIZED HYDROPOWER

The *availability* of financing is closely related to the *type* of financing. For corporate balance sheet financing, the best clients (i.e. large companies) get corporate prime rate no matter what kind of project, and small hydro projects for which major companies are willing to provide balance sheet guarantees will encounter few difficulties in finding finance in the present situation of high banking liquidity.

The difficulties arise for project financing. Even where sponsors are deemed to be reputable and with strong balance sheets, when these companies create special purpose entities for power projects the banks insist on recourse back to the sponsors to at least project completion. Indeed, since the late 1990s, Peru has seen only few examples of non-recourse project-financing for even large scale infrastructure projects:

- Kalpa, a US$60 million, 170 MW open cycle generation project (sponsored by Globeleq),[33] financed by Banco de Crédito del Perú and Citibank
- In 2005, a gold field mining project
- In 1999, a transmission project sponsored by Hydro Quebec (80:20 debt equity)
- Two other transmission projects (national grid)

Very few small hydro projects have been seen by the banks over the past few years, typically no more than one or two per year. Among the banks interviewed, there was a general consensus that most of the small hydro proposals they had seen were from developers who had concession rights were judged to have inadequate experience to construct and operate the projects being proposed, and had little financial strength.

Moreover, in the view of the banks and some the fund managers, many developers have unrealistic expectations about the value of their development rights. Many developers propose valuations of their contributions (development rights, preparatory studies) that are an order of magnitude greater than valuations seen as reasonable.[34]

The combination of generally weak sponsors with unrealistic expectations and skeptical bankers is one of the main reasons why small hydro development is encountering the difficulties. The other main reason, discussed in more detail in the next section, is that of low off-take price: prices in both regulated and unregulated markets are set by a gas price that is substantially below levels encountered in most other countries.

Thus, in the view of the bankers, the interest of larger companies is in thermal projects, that are less capital intensive and offer shorter payback periods than small, or even large, hydro.

3.5.1 Loan Maturities

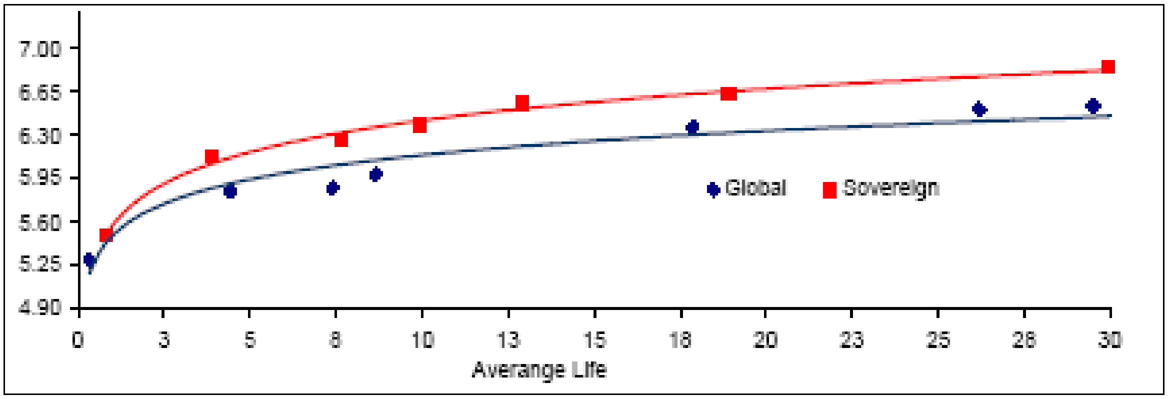
The increasing length of loan maturities reflects the increasing access of the Peruvian banking sector to global capital markets. The first 10-year financing was in 2005, considered a landmark. At present, unlike elsewhere in the world, there is no shortage of liquidity in Peru. The yield curve is relatively flat, with the difference between Government 10 year and 30 year only 50 basis points (6.3 percent and 6.8

[33] Globeleq is owned by CDC (Commonwealth Development Corporation of the UK). The Latin American operating power businesses, including Kalpa, were sold in May 2007 to a consortium of D.C.Constructions Ltd. of India and Israel Corporation Limited for $542 million.

[34] The bankers have seen proposed valuations of developer's equity "in the millions" when "a few hundred thousand" would be more reasonable.

percent, respectively). Spreads on LIBOR financing are 150bp on 5-year, 300-325bp on 10-year (Figure 3-6).

Figure 3-6: Yield Curve: Dollars and Nuevos Soles



Source: Peru Ministry of Economy and Finance: Daily Report, Sept.11, 2007

Longer maturities would more likely be available to strong corporate clients for balance sheet financing. One bank expressed the view that a 12-year financing at an interest rate based on the Government yield curve, plus 200 basis points for normal commercial lending plus an additional 150 basis points for a project financing would be feasible in the current climate of good liquidity, given a small hydro project with completion guarantees provided by a reputable EPC. However, there has been no such experience with project finance for small hydropower, and no examples of such lending exist. As noted above, project financing is generally difficult to obtain and the equity/debt ratios required by Peruvian banks for such projects are high by international standards.

3.5.2 Risk Factors and their Mitigation

Small hydro projects are subject to the following risks, which shape the perceptions of lenders to potential project financings:

- Price risk (less than expected revenue where off-take is at market price)
- Completion risk (including risks of delay due litigation during construction, cost overruns, delays due to geotechnical problems)
- Hydrology risk (less than expected electricity generation due to lack of water)
- Operational risk (inability to operate because of mechanical failures or operational problems at the plant)
- Off-take risk (failure of the buyer to take power due for reasons of dispatch, transmission congestion, or transmission line failure)

Price Risk

Banks in Peru do not see price risk as a major problem for hydro projects. The pricing mechanism is well understood, and the risk is easily mitigated by requirements for a certain portion of output to be covered by a PPA with large users or distribution companies. One bank uses outside consultants to provide projections of future market prices, which, as explained in Section 5.1, are likely to be set by gas-fired combined cycle generation over the short and medium term.

However, the PPA coverage requirement varies across the banks (and across generation technologies). One bank had different requirements for thermal and hydro projects: thermal projects require 75-100 percent PPA coverage, while hydro projects might be 50 percent or even zero: a reflection of the very high probability of hydro projects being dispatched, and receiving the system marginal price on the spot market (see Box 5 for an explanation of the functioning of the spot market). Another bank looks for 50 percent PPA coverage from small hydro projects.

Completion Risk

This is the major concern of lenders. The banks see the involvement of reputable EPCs as the appropriate mitigation for completion risk. But the difficulty is that the completion guarantees as may be provided by EPCs come at a high cost: indeed, even aside from guarantees, the participation of the EPC is costly to the developer, some of whom expressed the view that this could add 20-30 percent to the cost of projects (which, given the low off-take price, make projects uneconomic).

Even when large corporate sponsors set up special purpose entities (as in the case of the Plantanal 220 MW project sponsored by Cementos Lima, that was done without an EPC instead using an in-house engineering arm), banks look to the sponsors at least to completion. On the other hand, the Kalpa project was judged to have a strong EPC, and was done as a non-recourse deal.

Box 5: The Peruvian "Spot" Market

"Spot market" is something of a misnomer. In fact the procedure is more like a classic power pool, and the process is as follows:

- COES, the system operator, dispatches on the basis of "audited" variable costs, which are submitted monthly by the generators (except that gas generators may provide a yearly price). The marginal cost is therefore simply the cost of the most expensive unit in the system.
- Generators submit a single average value of variable cost, rather than in the form of curves as in some other countries
- Small and large hydro is therefore assured of being dispatched
- Uncontracted generators who are so-dispatched receive the observed system marginal cost, and transactions among the parties are equalised monthly in classic power pool fashion.
- There are "special rules" that apply to transmission congestion conditions, but these, in OSINERGMIN's view, were rare.

This procedure makes it likely that small hydro will be dispatched at all times largely mitigating any off-take risk because uncontracted power will invariably be taken at the system marginal cost.

The lack of certainty in water rights was cited as one of the completion issues, arguably more of a concern than geotechnical or engineering risk.[35] Several projects have been delayed by late interventions by NGOs and local communities, disputing the decisions made by the Central Government. There seemed general agreement that a new Water Rights act is required, which needs to clarify the jurisdiction of the various entities of Government.

It is unclear whether this concern is justified in the case of small hydro projects. Interventions by local communities and NGOs tend to arise in large projects sponsored by big corporations seen as insensitive to local concerns. Small hydro projects, by contrast, are rarely of a scale for which substantive questions about water use should arise, especially given the fact that they are generally run-of-river with no (or negligible) consumptive use, and little disturb the extant flow regime.

Indeed, much the same can be said of the general perception of small hydro projects that are shaped by the problems that arise from time to time with large hydro projects. Worldwide it can be said that small hydro developments very rarely encounter the sort of geotechnical (and tunneling) problems faced by

[35] The strongest views about the problems of uncertainty of water rights were expressed by financial lawyers.

large hydro, much less do small hydro projects result in the range of environmental impacts associated with major impoundments. Moreover, operating and maintaining a small hydro project requires a much lower level of technical sophistication than that required, say, for a combined cycle gas project, and the important tasks (keep trash racks clean, regular flushing of sediment accumulations, etc.) require minimal technical skills.

However, the reality is that individuals and small companies, even small civil engineering companies, would unlikely obtain project finance without the participation of reputable turnkey EPCs. Indeed, the first successful small hydro development in Peru, the 1.5 MW Santa Rosa project, required 100 percent equity. Special deals with mining companies have been used in some cases, but such circumstances apply only to a small fraction of the total number of potential projects.

Hydrology Risk
Neither the banks nor developers seemed concerned with hydrology risk. Yet the one bank that mentioned this risk, had not in fact reviewed any greenfield hydro sites, and stated that they would engage a local consultant to do a review of the hydrology assumptions. Another bank noted that if an otherwise sound small hydro project ran into financial difficulties consequent to cash flow problems attributable to several consecutive dry years, then such a project could simply be refinanced.

Operational Risk
This risk is rightly seen by the banks as low. For thermal projects, manufacturers of gas turbines offer very high availability guarantees, and hydro turbines and generators are perceived correctly as being of high reliability.

Chinese turbine-generator equipment is being offered in Peru at prices that are typically 70 percent of the established European suppliers such as Alsthom. The lower prices come at the price of significant efficiency penalties (e.g. 89 percent for Chinese turbines vs. 93 percent for Alsthom). As noted in Section 2.2.2, there are several Peruvian manufacturers of small turbines, but the prices offered are reportedly sometimes above Chinese equipment, and it is unclear how lenders would assess the reliability of such equipment. Some concern was expressed about the reliability of Chinese equipment, mainly in connection with the way in which Chinese equipment was being offered in Peru. It appears that Chinese suppliers appearing in Peru are mainly integrators rather than original equipment manufacturers, taking components from various sources, which raises some doubts about the quality of manufacturer's warranties being offered. However, the concerns about Chinese equipment reliability lacked any specificity.

Off-take Risk
Off-take risk is seen as small (and none of the banks even mentioned it). There are two potential sources of off-take risk: the failure to be dispatched, and the failure of the buyer to take the power for reasons of transmission line failure. Indeed, for a hydro project, failure to be dispatched is most unlikely, given the dispatch methodology in place (see Figure 4-1).

3.5.3 Lending Requirements

In addition to the lending terms themselves, small differences in lending requirements are reported to have influenced selection of lenders in the presently competitive Peruvian banking market.

Debt Service Escrow
Different banks have different requirements. One bank requires a 6-month debt service escrow, while another was of the view that a Letter of Credit would suffice.

Major Maintenance Escrow
Not generally required. One bank requires such an escrow for thermal projects, but this was not a concern for hydro projects because no major overhauls are anticipated within loan maturities.

Debt Service Cover Ratios
Most banks cited first-year debt service cover ratio (DSCR)[36] requirements as 1.2-1.3, though there were some differences in the definition of the ratio.[37] Needless to say, with a large portion of the debt covered by collateral, the DSCR plays less of a role than in the case of pure non-recourse financing.

Equity Contributions
The equity requirements for small hydro appear high in comparison to other countries. One bank presently looking at a 3 MW small hydro project would require 40 percent equity (and, as noted, the Santa Rosa small hydro project required 100 percent cash collateral, equivalent to 100 percent equity). In international experience of small hydro financing programs, equity requirements would normally be in the 25-30 percent range.

Depending upon the collateral in place, some banks would waive *pari passu* requirements (meaning that the bank would be content to fund first, and equity holders last).[38]

Lease Deals
All of the recent power sector project financings have been structured as leases, including the Kalpa thermal project and several transmission lines. In addition to accelerated depreciation, leasing enables up-front recovery of VAT on construction (recovered by the bank), rather than having to wait until offsetting of VAT receipts on sales becomes possible.[39]

Typically, separate lease deals are done for equipment (2 years), and civil works (5 years), with financing coincident with lease terms. Depreciation can be taken over the term of the lease deal, rather than over the normal lifetime of the works in question (Table 3-15)

Table 3-15: Depreciation Periods

	Civil Works	**Mechanical & Electrical**
Lease	5	2
Conventional Financing	33	15

Source: Banco del Crédito del Perú

There is a provision that VAT can be recovered up front in the case of projects with more than 4 year construction periods, but this concession is of no help to small hydro projects where construction is typically between 2 and 3 years.

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[36] For a given year, the ratio of net internal cash generation (net income adjusted for non-cash items such as depreciation) divided by the debt service obligation (interest and principal).

[37] One bank cited its more stringent definition of DSCR (including income tax) as one of the factors that led to the loss of a project financing to a competitor.

[38] Pari passu in the context of project financing means that every tranche of funding during the construction phase is made in the same proportions of equity and debt as is agreed at financial closure for the entire project.

[39] In other words, the difference is between immediate recovery of VAT, and the interest cost on the VAT on construction – VAT paid during construction is carried as an account receivable until the project starts operating, and the VAT recovered from VAT levied on sales. As discussed in the next section, the immediate recovery of VAT can add between 2 - 3 percent to the FIRR.

Whether leasing deals can be done over such short time periods in the case of small hydro projects is unclear. The problem is that the shorter the lease period, the higher are the lease payments, which may not be feasible if they must be sustained by project cash flow alone. In the case of a large company that has the ability to absorb cash losses, these may be offset by the tax advantages to the parent corporation. Several developers noted that a two-year lease on M&E could not be accommodated at current price levels.

3.5.4 General Conclusions on Financing

There presently appears to be adequate liquidity for Peruvian banks to finance infrastructure investment projects with maturities of around 10 years. Some Banks are beginning to consider lending for longer maturities of up to 15 years. However, actual project financing deals for power sector projects at tenors of over ten years have yet to materialize: lease deals (over 2-5 years) and balance sheet transactions are still the predominant approach.

A major concern is transaction cost. The corporate finance departments of the major banks have limited staff, and are understandably focused on larger transactions. A small 10 MW project needing US$7 million of debt finance is of relatively little interest, particularly where such projects are located in remote areas posing difficulties for due diligence. The transaction costs for a 200 MW CCGT near Lima are little different to that of a 5 MW hydro. While large, financially strong corporations would encounter few financing problems for any project on a balance sheet basis, these companies have little interest in small hydro (except in the case of mining companies who have long built small hydro projects for self-use). In contrast, smaller investors that might be interested are required by banks to provide 100 percent collateral.

Another issue is the lack of risk assessment capability within the Banks, whose perceptions are shaped by the more publicized problems of large hydro projects. Consequently, there is a mismatch between the expectations of those who own water rights and have an interest in building them (but who are generally financially weak), and those of the asset funds and the banks. This is in turn compounded by the *practical* difficulties of securing project financing and long-term loans.

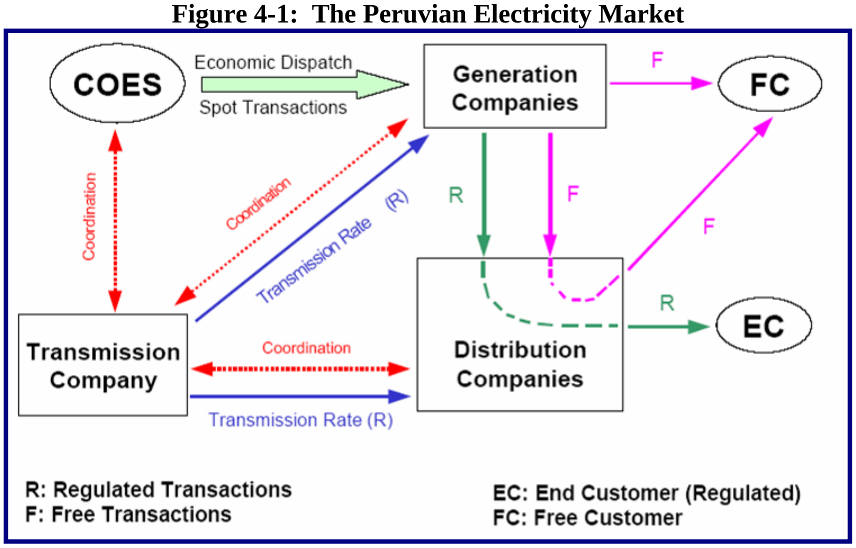
These issues are encountered worldwide. This explains why in many countries Governments have provided financing assistance to investors through national development banks (e.g. Brazil) or through finance facilities established in partnership with International Financial Institutions (IFIs) for small hydro financing programs, which address all of these issues together, and provide the necessary technical assistance to the banking system to help them to develop risk assessment capability for project financing of renewable energy projects.

4 INSTITUTIONAL AND REGULATORY FRAMEWORK

4.1 ELECTRICITY SECTOR BACKGROUND

The power sector in Peru was reformed and restructured between 1991 and 1993, followed by a privatization and concession process. As a result, a modern legal and regulatory framework was established in the Electricity Concessions Law of 1992/93. A transfer was made from public to private hands of assets ownership, management and operation of the main electricity facilities. As noted in the introduction, the legal framework also established the methodology for rate setting, the granting of concessions, customer service guidelines and accountability of the operators, plus changing the role of the State from owner and operator to policy maker, rule maker and regulator. The main regulatory body created by the law was the Organismo Supervisor de la Inversión en Energía (currently OSINERGMIN) ("*Supervisory Commission for Energy Investments*"), in charge of tariff setting, supervision and monitoring of the legal and technical regulations for the electricity sector. Figure 4-1 describes the organization of the Peruvian electricity market.

Figure 4-1: The Peruvian Electricity Market



The Peruvian electricity market is divided into three parts:

1. The regulated market, under which a generator may contract with a distribution company at maximum prices fixed by the regulator, OSINERGMIN.
2. The unregulated or free market, under which a generator may contract with major customers with demand greater than 1 MW, and which accounts for about 45 percent of the market
3. The "spot market," run by the Committee for Economic Operation of the System (COES), which balances supply and demand (the operation of this market was described further in Box 5).

During 2003-2004 spot prices of electricity increased considerably due to limited hydro production and delays in the expected implementation of new generation. The gap between the spot electricity price, determined by the economic merit order dispatch of the plants, and the calculated regulated generation price charged to retail consumers, caused generators to refuse contracting supply to distribution companies, which provide electricity to the regulated retail consumers. To address this problem, in June 2005 the Executive proposed to Congress a new/updated electricity law. Under this new sector legislation (approved by Congress in September 2006), distributors will conduct public auctions for electricity supply from generators, for short to long-term contracts, and to pass-through the resulting contract prices to the "regulated" price (see Figure 4-1).

4.2 RENEWABLE ENERGY DECREE OF MAY 2008

The economic analysis above shows that when opportunity costs are used to estimate the value of electricity in the wholesale market, small hydro is economic. However, because of the high subsidies on natural gas, at present small hydro is not *financially* viable, except for a limited number of projects that benefit from existing irrigation infrastructure. This section concluded that only the removal of the gas price subsidy or a preferential tariff for small hydropower would unlock significant small hydro potential.

On 2 May 2008, the Government issued a new legislative decree for the promotion of investment in electricity generation using renewable energy (*Decreto Legislativo de Promoción de la Inversión Para la Generación de Electricidad con el Uso de Energía Renovable*). The key provisions of this decree and its implications will be discussed in Section 7. As the Decree has not yet been regulated and is not yet effective, this section on institutional and regulatory arrangements will describe the situation prior to the effectiveness of the Decree.

4.3 ADMINISTRATIVE AND ENVIRONMENTAL FRAMEWORK FOR SMALL HYDROPOWER DEVELOPMENT

This section presents a summary of the main conditions prevailing in the Peruvian electricity sector law and regulations for the development of hydroelectric projects, including small hydropower projects. The contents of this summary draw mainly from data provided by the MEM and internal work by OSINEGMIN, the sector regulating entity

4.3.1 Administrative Requirements

The basic legal framework for all activities in the Peruvian electricity sector is the Electricity Concession Law DL 25844 of 1992 (ECL), complemented by the Law 28832 of 2006, and their main regulations. In the case of hydro generation, other regulations concerning water resources and protection of the indigenous heritage are also applicable. It is important to note that regulations of the Electricity Law apply only to systems with demand/capacity of 500 kW or more. Smaller systems are free of regulations under the Electricity Law, but are subject to other sectors regulations, and requirements from regional or local authorities (like permits and authorizations), which are usually not standardized.

Under the ECL and its regulations, hydropower plants are subject to authorization or concession depending on its capacity size. An "Authorization" is required for the development of activities to generate electricity using hydraulic resources for capacities from 500 kW up to 20 MW. A concession is required for power plants larger than 20 MW. A recent regulation transferred the authorization and concession process from MEM to regional governments for hydro power plants with capacities up to 10 MW (although, there are no known regional regulations detailing the requirements and the process to follow).

Also, under ECL regulations, to obtain a concession for hydro power generation, a sponsor has the option to request from MEM a temporary concession to develop the necessary studies of a particular project. A temporary concession gives no rights to the sponsor and is not a requirement to obtain a final/definitive concession. The ECL and its regulations contemplate also the possibility of competition of two or more sponsors/projects for a concession for a single water resource.

It is important to point out that INRENA (the National Institute of Natural Resources), under the Ministry of Agriculture, and INC (National Institute of Culture), under the Ministry of Education, participate actively in the approval of hydroelectric projects. INRENA reviews and gives its opinion on the environmental study (including the minimum river flow requirements); authorizes studies for hydropower development; approves these studies concerning river interventions and water use and restitution; and provides water rights for use in hydropower generation (once MEM gives a definitive concession and construction is scheduled).

The regulation on Archaeological Research *(Reglamento de Investigación Arqueológica, Resolución Suprema 004-2000-ED*) classifies the archaeological inheritance of Peru and establishes procedures for carrying out Archaeological Assessment of Projects and their content. The project sponsor or developer is responsible for carrying out and filing with INC an archaeological assessment report. It also requires that the INC issues a Certification of Absence of Archaeological Remains *(Certificado de Inexistencia de Restos Arqueológicos)*, or CIRA, once the archaeological assessment of the project has been completed. Construction of projects cannot begin until the CIRA has been issued. The Law also establishes that developers of projects that include partial or complete excavation of archaeological sites must carry out Archaeological Recovery Projects if the National Archaeological Commission so recommends. Although CIRAs are required for construction, project developers prefer to get CIRAs during studies.

4.3.2 Regulation of Environmental Protection with Regard to Electricity Activities

In May 2008, a Ministry of Environment was created, but the management of environmental safeguards in the case of energy remains within the environmental department of the MEM.

Environmental protection of all electricity activities (including electricity generation in all its forms) is established in two basic regulations: (a) the "Maximum Emission Limits Permitted for Electricity Activities" (R.D. No.008-97-EM) and the "Rules for Environmental Protection in Electricity Activities" (D.S. N° 029-94-EM articles 19, 20, 21, 23, 24, 29, 38, and 39). Concessionaires of electricity activities (generation, transmission and distribution) must prepare and obtain approval of an environmental study (ES) for project construction and operation. The General Directorate for Energy Environmental Matters (DGAAE) is MEM's official office in charge of reviewing and approving the ESs of energy projects. In case of hydroelectric generation, INRENA has to review and provide its opinion of the ES before it is approved. Small projects like hydro plants with capacities of less than 20 MW do not require a full ES. Instead, this type of project needs only to submit an Environmental Impact Declaration (DIA[40]) and, if some mitigation measures are required, an Environmental Management Plan (PMA[41]).

ESs should consider all the potential effects that the concerned installation or project may have on the quality of air, water, soil and natural resources. Project design, construction, operation, and retirement or abandonment should aim at the elimination or reduction of possible damaging effects to the environment. Special care must be taken in order not to create instable environmental conditions such as erosion or lack of stability of the slopes or the storage of dangerous substances.

In the case of hydroelectric generation, potential damaging effects of the project on the morphology of lakes, water flows and water uses (drinking, agricultural, aquiculture, industrial, recreational, esthetic

[40] A DIA is a document that is a sworn statement that states that the concerned project meets the regulatory environmental requirements, and that, if negative environmental impacts are generated, these are minor according to environmental regulations.

[41] The PMA is the operational plan for the implementation of environmental practices, for preparing mitigation measures, prevention of risks, contingencies and implementation of environmental information systems in compliance with environmental regulations, and to ensure that the established standards will be met.

quality, aquatic habitat, etc.), must be reduced or eliminated. River beds or shores, ravines or crossed natural rain water drainages must be protected. Installations must be built according to its natural regimes in order to avoid erosion of the river beds or shores as an outcome of the accelerated water flows. In the same way, installation or activities that may have an impact on the aquatic fauna must be avoided. Biodiversity must not be seriously affected by the project and must not have irreversible negative impacts on flora and fauna that is in an extinction risk, or on the productive quality of flora species that have a food or pharmaceutical value. Any altered and deforested areas as a result of project construction or operation should be recuperated and replanted.

The DGAAE keeps a list of professionals and consultant companies authorized/accredited in the preparation of ESs. DIAs should also be prepared and signed by these accredited professionals. Once all clarifications and explanations on the ES and the PMA, if required, have been satisfactorily responded, the DGAAE will approve the ES and PMA, within a period of 120 calendar days. DIAs should be approved within 45 days of submission.

In the period of thirty days alter the completion of project construction, the project developer must submit to OSINERGMIN, the energy regulator, a report about the compliance with the relevant measures recommended in the ES.

4.3.3 Local Requirements for Projects Under the Clean Development Mechanism

Peru signed the Kyoto Protocol in 2002, and has been participating in the clean development mechanism (CDM) and the related carbon emission reduction market, since 2005. Peru was introduced to this market through the Prototype Carbon Fund (PCF), administered by the World Bank. The *Comisión Nacional del Ambiente* (CONAM) is the Peruvian institution officially designated as focal point of the Clean Development Mechanism. In this activity, it is supported by *Fondo Nacional del Ambiente* (FONAM) as promotional agency and also in the evaluation of projects submitted for qualification for CDM validation and registration. Under the existing rules and regulations of the CDM, the "third part countries" have the responsibility of approving the qualification of projects as contributing to the sustainable development of the country involved.

CONAM has established a process that a sponsor has to follow to obtain the approval of the project as a CDM project. Annex 13 shows diagrammatically the different stages of the process, the documentation requirements and the responsibilities.[42]

4.4 REGULATORY FRAMEWORK

The Peruvian electricity regulatory system[43] is based in three main principles: (i) the segmentation of the electricity business into generation, transmission and distribution/commercialization; (ii) generation is considered a competitive segment of the business, where prices are determined mainly by "free" negotiated transactions, and transmission and distribution/commercialization are regulated; and (iii) prices to the regulated segments are determined by cost-causation and/or benefit-causation.

[42] Annex 13 contains CONAM Form P34 in Spanish, which describes in detail the different stages of the process as well as the requirements.

[43] The legal framework of the electricity sector is the Electricity Concession Law DL 25844 of 1992 (ECL), complemented by the Law 28832 of 2006, and their main regulations.

4.4.1 The Generation Market

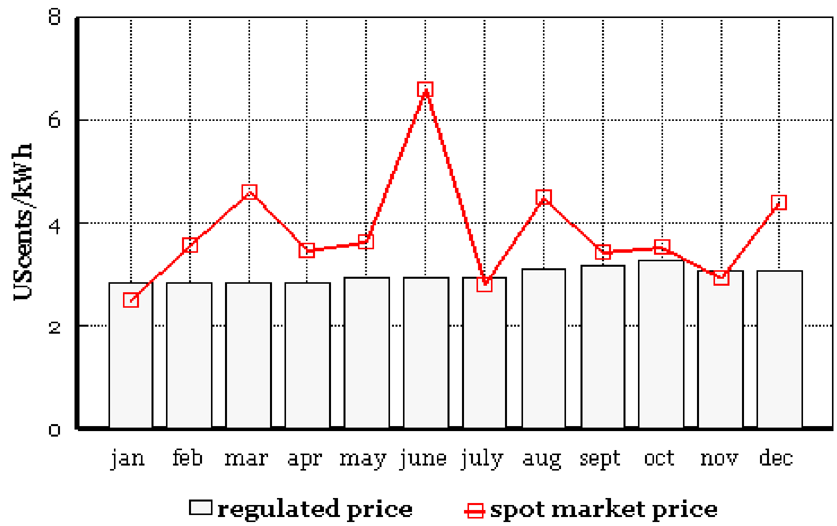
The demand side for generation transactions is divided into two categories of users in relation to their size. One category is the so called “large users”, those with power demands above 1 MW, and the other category is made up of the “small” retail or regulated users. Large users contract directly with generators or distribution companies, through bilateral, freely-negotiated contracts. Distribution companies supply electricity to retail or regulated users in their concession areas, at a regulated price. The generation regulated price is determined by the regulator every six months, according to the expected evolution of generation supply capacity, fuel prices, competitive generation auction prices (of short, medium and long-term), and other economic parameters (like price indexes and inflation). Also, the tariff system ensures that needed investments in transmission and distribution (as evaluated by the regulator) are recovered during the economic life of the assets and a rate of return, up to 12 percent on investment, is guaranteed.

Real-time dispatch of generation supply is done on a cost-based merit order procedure carried out by COES, independently of any bilateral contracts or auction prices. Hourly (in reality every 15 minutes) transactions between generators and large users in the wholesale market are done at the “marginal/spot” (last unit in the dispatch merit order) price. The wholesale market is in reality a “differences market” of quantities contracted (bilaterally or through auctions) and “demanded” by the dispatch. COES manages the wholesale market, establishing payment obligations between generators, large users and distribution companies, in accordance with individual balance of energy dispatch.

Therefore, generators face two markets. A competitive unregulated market composed of large users, dominated by bilateral contractual transactions of quantity/price, and the “distribution-captured” retail market, where the generation price is capped by regulation. Risk perception of these two markets is very different for developers of thermal and hydro plants, and between developers of small and “large” hydro. A pure hydro developer (and especially large hydro developers) needs long-term contracts to obtain a project financing.

As noted above, the small hydro projects financed to date (Santa Rosa, Poechos) have done so on the basis of a mix of relatively short-term PPAs with distribution companies at the regulated price, plus spot market prices. With spot markets often higher than the regulated price (see Figure 4-2), the latter requirement has not been of great concern. Of course the paradox is that spot markets will be especially volatile during droughts: which means that electricity prices will increase when water is scarce. This is fortuitous for the hydro developer, because during dry periods his output will be smaller, but fetch a higher price, so his revenue loss on spot market transactions will be smaller than under the fixed price of a PPA. This explains why lenders are not unhappy if developers rely on the spot market for a portion of their expected output.

Figure 4-2: Spot Market versus Regulated Price (2007)



However, since the actual financing transactions have really been balance sheet rather than project financings, the past is not necessarily a good indication of what the commercial banks would require for a true non-recourse project financing. The international experience suggests that project financings require PPAs for at least as long as the debt maturity. Indeed, as we have seen in Section 6.2, the Brazilian PROINFA program provides for 15 year PPAs with Electrobras for qualifying renewable energy projects. Therefore, the extent to which the new preferential price provides revenue certainty will be the key to the success of the new renewable energy preferential price.

4.4.2 Capacity Payments

An important characteristic of the Peruvian electricity price system is that supply charges and payments to/from final users and between wholesale market's participants are based on a two-part tariff system, very similar to the classical scheme of peak-load pricing, of capacity and energy charges. The capacity payment is based on the annualized investment and O&M costs of a peak-load generation unit, of "adequate capacity in relation to the size of the system and the reserve requirements" (this quantity is called "base price of power" in the regulations.) The regulator determines the main characteristics of this unit each year, for application in the periodic review of generation tariffs. The present reference peaking unit is a 175.6 MW open-cycle natural gas-fueled unit (reference investment requirement is taken from statistics of last five years published by "Gas Turbine World").

The capacity payment received by each unit is determined by the contribution of the unit to cover the peak demand and the "base price of power". The contribution of the unit to cover the peak demand is based on the unit's "firm capacity" adjusted by a factor necessary to "fill" the total demand of the system plus the required reserve margin, by stacking up the "reduced" (or augmented) firm capacities of generating plants (first the hydro and then the thermal plants). It should be noted that if firm capacity of existing plants equals peak demand plus required reserve (an ideal situation), no reduction of payment for full firm capacity of the units is required. If excess firm capacity exists (above required reserve), the capacity payment will be less than that corresponding to the firm capacity of a unit. The contrary happens when required reserve is less than the required amount. This means that there is a penalty in the capacity payment if the system reserve is above the requirements and an incentive if it is below.

Even though, the Peruvian electricity system is mainly hydro-based, the regulations for capacity payment are oriented towards peak demand coverage and required capacity reserve of the system. As such, capacity payment to peaking units (mostly thermal) covers most of their investments. Hydro storage for energy shortages during dry season or peaking hours is not directly recognized in the generation payment system.

4.4.3 Transmission

Electricity generated at power plants needs to reach demand centers through the transmission and distribution systems. Both generators and consumers share the responsibility to pay for these facilities. Usually there is no discussion on how this would work for the "common" network interlinking supply and demand centers. Consumers would pay their portion of the transmission costs (if the split is 50/50, then half of the common transmission network would be charge to the consumers) and generators would pay the remaining part of the costs. Generators would then add these costs to their own generating costs to charge to their customers. Instead of having generators as intermediaries in collecting common transmission costs from consumers (as part of generating costs), the Peruvian electricity regulations charge directly to consumers all the cost of the common transmission system, leaving generators to charge only for generation facilities costs.

In general, segments of transmission and substations needed to connect a generating plant to the common network are considered part of the investment of the power plant. If the national interconnected transmission system reaches most places of a country, the connection investment is a minor percentage of total investment of power plants, therefore in this circumstance transmission is not a problem when evaluating and implementing generation projects. In cases like Peru, with a large territorial area, with particular difficult topological conditions and not fully electrically connected, transmission requirements could be a serious barrier to hydropower development, large or small-size.

4.4.4 Water Rights

As reported in Section 4.3, INRENA intervenes in critical steps of project implementation, in particular: (i) it has to authorize the development of studies of water resource use for power generation; (ii) it has to approve such studies; (iii) it has to review and give its opinion on the environmental study of a hydropower generation project; (iv) it has to give the license for water use of a hydropower project, before construction starts.

Some general stipulations on implementation of these procedures are established in laws and high level regulations. However, the problem is that there are no specific rules, or a Consolidated Administrative Procedure (a TUPA), that describe in detail what are the requirements and the process to obtain authorizations or approvals. Furthermore, the intervention and responsibility of INRENA internal offices in all these activities are not clearly defined. A case in point is the determination of the ecological water flow of a river. There is no defined standard procedure for its calculation and no specific INRENA office is in charge of its approval.

Almost all project developers reported problems, mostly of administrative and procedural nature, in their dealings with INRENA, related to the required authorization for studies and the water license. One can say on this issue that there is no certainty on the specific requirements and documentation formalities needed, what payments or dues are required for initiating or obtaining official documents, what criteria would be used to qualify or evaluate a request, or what internal office(s) is in charge of qualification or evaluation, dealing with controversies or conflict resolution, etc. This relatively informal and ad hoc process produces uncertainty, delays and unexpected costs to project developers.

4.4.5 Rights-of-Way

The Peruvian Electricity Law (LCE) provides for the imposition of rights-of way for electricity activities which require a concession.[44] The meaning of "imposition" is that owners of land where facilities/installations will be located, which have an electricity concession, must provide for the right-of-way for such installations. The LCE and its regulations detail the requirements and process of this imposition of right-of-way. The legislation establishes that a just and economically reasonable price for buying (or expropriation) or renting of the required land should be negotiated. Also, the legislation stipulates that any damage caused to land or any other asset of third parties, like pass-through for construction, etc. (known as temporary rights-of-way), should be justly compensated. The owner of the land cannot refuse to provide for the right-of-way, which is why the legislation used the term "imposition" in this regard.

Usually, when the owner has documented legal registration of the land, an agreement is finally reached, and in general, payment of right-of-way is not a cost problem. If the "owner" of the land has precarious or no clearly registered rights, or with land traditionally belonging to communities, indigenous or otherwise, with communal ownership (that is not necessarily legally registered), the legal provision of imposition of right-of-way is almost impossible to enforce, if an agreement is not reached. The protracted negotiations required in these cases are the main complaint of developers.

[44] Hydroelectric generation larger than 500 kW, transmission and distribution require a concession.

5 BARRIERS AND THEIR MITIGATION

This section describes the specific barriers that must be overcome to enable larger scale development of small hydropower projects, and discusses the possibilities for overcoming them. By far the most important is the low tariff (Section 5.1): because the bulk power tariff is based on subsidized natural gas, small hydro projects have found it difficult to compete. There are other financial and technical barriers that also need to be overcome, but these are of secondary importance to the tariff issue.

5.1 FINANCIAL BARRIERS

5.1.1 Low Tariff based on Subsidized Natural Gas

An adequate tariff is an essential ingredient of a successful renewable energy program. The low price of natural gas and the resulting low tariff for power generation (which is even *declining* in real terms) has made it very difficult for most small hydro projects to compete in the marketplace.

There are two options for mitigating this problem. The first is the reduction of subsidies to Camisea natural gas, which distort capital investment in the power sector, and is desirable for broader macroeconomic reasons beyond the narrow interest of developing the small hydro potential. Whatever may have been the rationale for gas subsidies to the electric sector in the past, and whatever may have been the sunk costs associated with these subsidies, the price now charged to the power sector should reflect the opportunity cost of natural gas, which needs to be based, at a minimum, on the border price, given that the project to export LNG is now underway.[45]

The second option is to provide for a special tariff for renewable energy projects (including hydro), an approach followed in many other countries, and an approach which is now embodied in the new Renewable Energy Decree. The extent to which this preferential tariff will encourage implementation of small hydro projects will depend not just on the magnitude of the premium, but also on its certainty. A certain premium of 2 UScents/kWh over the market price is worth more to obtaining finance than a premium that may vary from 1 to 3 US cents/kWh. For the Decree to succeed, attention is needed in the development of regulations to ensure that tariff levels are adequate and predictable (see Section 7).

5.1.2 Lack of Long-Term Financing

In many countries, the most significant barrier to implementing small hydro has been the limited availability of longer loan tenors. Several programs have enabled small hydro projects though on-lending at more favorable loan tenors (e.g. Brazil, Sri Lanka, Nepal and Vietnam). While Peru has a sophisticated banking sector that has access to global capital markets, project financing in general is difficult and even more difficult in the case of small projects such as small hydropower projects. Access to finance is limited by the high transaction costs in relation to profitability of such small projects, and also by the lack of familiarity of banks with the project characteristics and issues that need to be appraised. While debt finance is available in principal, in actual fact developers would be unlikely to receive project financing for 12-15 years at competitive rates.

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[45] However, it should be noted that it is not necessarily the case that the opportunity cost of natural gas is the border price (adjusted for transportation differentials): what matters is the value of natural gas in all potential domestic uses (including use in transportation, petrochemical domestic sectors).

5.1.3 Transaction Costs of Financing

Although the commercial banking sector is competitive, it really only benefits the large projects, for which the banks are prepared to compete. Small companies with seeking debt finance for single hydro projects are in a difficult negotiating position. The project financing groups at the major banks are small, and who therefore prefer to concentrate their limited resources on larger deals (which for the power sector means large gas CCGTs (typically >100 MW) and transmission projects).

Unfortunately, the volume of potential transactions in small hydro investments is insufficient for lenders to develop standardized documentation packages -- the usual first step in lowering transaction costs for small loans. A number of World Bank projects (Sri Lanka, Vietnam) have developed such standardized documentation for small hydro projects as part of financial intermediation projects – but this involves significant effort to set up the procedures and build up the necessary technical capacity of the implementing agency,[46] transaction costs that are only warranted for large lending programs (US$100 million or more).

Nevertheless, the Brazilian example shows the potential advantages of a project aggregator (in that case an off-shore equity/guarantee facility) in being able to negotiate a single debt commitment from a large bank under reasonable terms. However, for that option to work requires that the project aggregator injects significant equity funding of his own, in an amount sufficient to provide the necessary comfort to lenders.

The challenge is to attract the attention of such potential international funds – which is much easier for Brazil with its widely publicized hydro potential than for Peru where market conditions are less favorable.

5.1.4 Unrealistic Risk Assessments Based on Large Hydropower

Neither the banks nor the asset fund managers appear to have an adequate perception of the actual completion risks for small hydro projects. Small hydro projects suffer from their association with large hydro projects, where the completion risk is clearly greater. Even though few small hydro projects involve tunneling risk, the banks and asset fund managers take the view that completion risks are sufficiently great to require the involvement of large EPCs. But this significantly increases construction costs, which are under great pressure from the low tariff. Many small hydro projects cannot afford such cost increases.

The operation of small hydro stations is a very simple matter, and requires a level of technical sophistication that is much less than that required for operating a thermal plant. The most important aspects of operating small hydro stations relate to straight forward measures (cleaning trash racks, regular flushing of sediments etc.). Routine maintenance of turbines and generators is relatively simple: the technology is well tested and understood.

Given the lack of experience in small hydro and the unwillingness of lenders to devote significant resources to completion risk assessment or to confidently assess the capacity of a small developer to manage construction himself, ways must be found to provide comfort to lenders. These could include training on risk assessment and study tours by commercial bankers to other countries, and/or the involvement of an international entity that has greater experience with small hydropower development. The strongest measure would be that the government itself would make available financing through a national development bank, as has been done in Brazil through PROINFA.

[46] Project aggregation, of the type being developed for carbon finance transactions, is another potential possibility, but it is hard to see how credit risks can be passed through the intermediary that performs the aggregation.

5.2 REGULATORY BARRIERS

Section 4 described the main characteristics and issues of the electricity legal and regulatory framework. The extents to which these issues represent barriers to small hydro power development, as well as possible needed correcting actions are examined below.

5.2.1 Capacity Payment

As noted in Section 4.4, under the existing regulatory framework, a generating unit receives payment of its electricity supply in two distinct parts: (i) contribution to the peak power demand, and (ii) energy production. All available operational generating units receive a monthly capacity payment. The generating units that have operated and supplied energy to the system receive the energy payment in accordance with their production. This is for all generating plants which belong to COES or are under COES operational dispatch administration.

Firm capacity of thermal units is relatively well defined in the technical literature (installed capacity affected by an availability factor: 1 – maintenance rate - forced outage rate). Availability factors for different types of thermal units are regularly compiled and published. Therefore, there is relatively high certainty in estimating future revenue coming from capacity payments for thermal plants. On the other hand, in the case of hydroelectric units, there is no standard procedure to calculate their firm capacity. The probabilistic nature of hydrology introduces a risk factor not present in the case of thermal plants. Therefore, the firm capacity of hydro plants is linked to the probability persistence of the available water flow.

The Peruvian regulation establishes a level of 95 percent hydrologic probability persistence to define the firm capacity of a hydro plant. For run-of-river plants (most of the small size plants) this probability persistence level to define firm capacity, undervalues the contribution of the plant to cover peak demand (not necessarily the single day of the year when peak demand is the maximum). Furthermore, given the level of investment of a peaking thermal unit compared to a hydro plant (two to three times higher), the capacity payment for a thermal plant represents between 60 percent and 90 percent of total payment requirements (from base load to peaking units), but for a hydro plant this is no more than 30 percent.

Moreover, even if the firm capacity of a single plant were accurately assessed by the 95 percent probability level, the existing approach does not take into account the *portfolio* effect of multiple hydro plants. Studies in other countries show clearly that the seasonal variations of a portfolio of small hydro run-of-river plants is smaller than that of individual plants, and therefore the present capacity pricing approach underestimates the value of hydro capacity in aggregate.[47]

We conclude that the present two-part payment system regulation for generation (capacity and energy) favors thermal units against hydro, and should be adjusted to provide a more realistic valuation of the capacity value of hydro projects.

5.2.2 Transmission

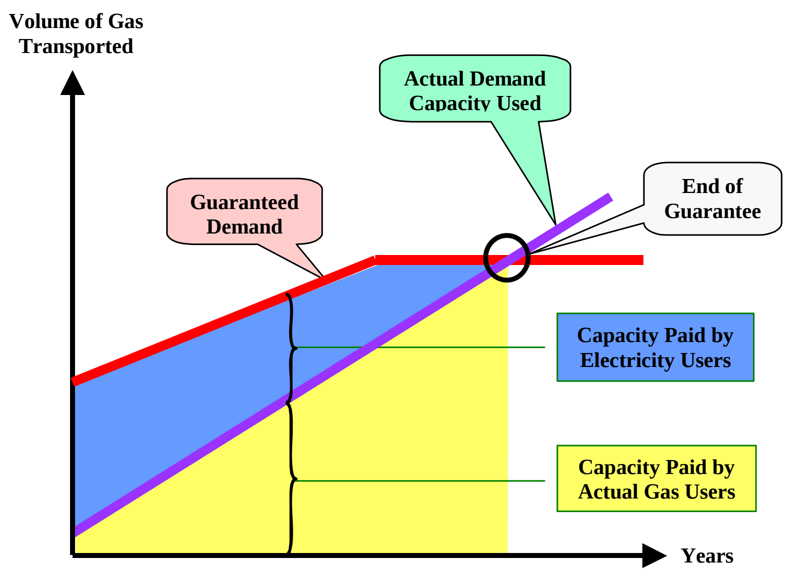
The need for longer transmission networks is an intrinsic disadvantage of hydro versus thermal plants, but in the case of Peru, there is an additional problem to consider. The natural gas field of Camisea is located

[47] In Sri Lanka, a system with several hydro plants with seasonal storage, one of the documented benefits of the small hydro program was the ability to defer releases from this storage into the later months of the dry season. See T. Siyambalapitiya, Study on Grid-connected Small Power Tariff, report to the Ceylon Electricity Board, Sri Lanka, 2001.

700 km east of Lima, the main electricity load center of the country. Thermal generators that use Camisea natural gas pay directly just a fraction of the transportation costs of gas. The remaining gas transport cost is charged to consumers in their electricity bills (under a designation of Capacity Payment Guarantee of the gas pipeline – see Box 6 below), for recovery of the gas pipeline total investment cost. This way, during the initial years of operation of the pipeline, most of the cost of the transportation of gas from Camisea to Lima is charged to electricity consumers, reducing the natural gas price for electricity generation. Therefore, the equivalent of electricity transmission for hydro plants (i.e. the transportation of gas to thermal plants), which should be included in the investment of the plant, is being paid by the consumers not the generators. This is clearly a barrier to hydro generation. The question is, if most of the cost of gas transportation for thermal generation is charged to consumers, why is the same concept not applicable to electricity transmission for hydro plants?

Box 6: Camisea Pipeline Capacity Payment Guarantee (GRP)

Studies for the pipeline indicated unattractively high tariffs, due to low demand during initial years of production. Investors required the Government to guarantee a minimum capacity usage/payment during the first ten years. MEM and OSINERG designed a payment guarantee called GRP (Garantía de Red Principal). Part of the payment is collected from electricity users. In return, a fixed natural gas price for electricity generation is guaranteed. The GRP is included in the electricity bills as a component of the transmission tariff. As seen below, initially almost all the payment comes from electricity users, diminishing as natural gas demand increases. The guarantee will cease when actual demand reaches the guaranteed demand or at the end of the tenth year.



5.2.3 Connection Requirements by Distribution Companies

A number of the hydropower developers interviewed by the Study Team cited the excessive technical connection requirements (protective relays, etc.) insisted upon by the distribution companies, significantly increasing connection costs. This is not an uncommon problem with regard to all forms on small-scale and renewable energy sources. A recent report by the European Network for the Integration of Renewables and Distributed Generation[48] documents the difficulties encountered in 18 European Union countries. Experience in other continents has been similar.

[48] ENIRDGnet (2004).

It is suggested that the MEM/DGE examine the existing national grid code (Código Nacional de Electricidad) with a view to arriving, together with the distribution companies, at a specification of connection requirements based on the principle of requiring only what is deemed to be absolutely necessary under consideration of the consequences of an outage of the connection.

A final point to mention is the use of existing distribution lines by small hydro plants. Recently approved regulations establishes that (small) hydro plants injecting supply through existing distribution lines, reducing the prevailing load of the line, will not pay for the use of the lines. This change in regulation has responded to numerous claims from small generators.

5.2.4 Water Rights

All INRENA internal procedures start at the corresponding local *Administración Técnica del Distrito de Riego* (Technical Administration of Irrigation District, ATDR in Spanish) where the project is located, which establishes its particular requirements, has its own unspecified timing and uses discretionary and arbitrary criteria for qualifying or evaluating the projects. The paperwork to go through an ATDR could take several months with complete uncertainty of the final result.

Furthermore, the existing Peruvian legislation and regulations on water resources are dated, incomplete and have gaps in some important and critical areas. Article 51 of Title III of the Water Law (Decree Law 17752, indicates that "*water uses rights could be provided for energy generation and for industrial and mining activities, giving preference to those included in promotional and development government plans.*" In the regulations of the Water Law (Supreme Decree 261-69-AP), the articles dealing with "Energy, Industrial and Mining Uses" refer to entities that have been dismantled or to inapplicable or obsolete rules. So, the legal and regulatory base of these types of water uses is very weak or inexistent.

Recently there have been changes in some regulations to clarify the role of INRENA in processing and approval of water rights, in particular for "large" hydroelectric projects, mainly by centralizing the process. But these changes have introduced new actors, such as the regional governments, in the approval of water rights in the case of small projects. Some pre-existing water rights for small hydroelectric projects are being questioned by the regional and local authorities.

A recent consultant report contracted by OSINERGMIN concludes,[49] on this specific topic, that: "…therefore, the provision of authorizations and licenses for water use of hydroelectric projects is subject to the discretionary decision of the entity in charge of such function in the Ministry of Agriculture, which is at present INRENA, with the favorable opinion of the corresponding ATDR. In this way, the public officials in charge apply existing limited norms at their own criteria and convenience, in processing the requests of the interested party.

The lack of specific regulations and the existing administrative informality reduces considerably the predictability of the legal and regulatory system, and introduces additional risks to development and final implementation of hydropower projects." The report also indicates that "INRENA intervention causes that the estimated timing for project development should be prolonged, to take into consideration the period that the institution requires to approve a petition and the time necessary to respond to its inquiries, which in many cases go beyond standard international practices."

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[49] First report of Universidad ESAN to OSINERGMIN on *Análisis de Barreras de Entrada para la Inversión en Centrales Hidroeléctricas*, February 2008.

5.2.5 Rights-of-Way and Community Intervention

As indicated in Section 4.4, most of the problems of rights-of-way for large scale hydroelectric projects are caused by "owners" of the land with precarious or no clearly registered rights or with land of communal ownership. These problems are exacerbated by the large extensions of land involved in this type of project (river side civil works, water canals, penstock, power plant, transmission lines, etc.), combined with the "ownership" (not supported by any legal right) of the water resources by communities. All this forces project developers to prolonged discussions, negotiations and deals with communities, not necessarily binding or enforceable legally. Some developers interviewed for the study have indicated that it would be better to formalize these activities through a "Social Assessment" of the project, with a defined scope, required documentation, approval process, agreements reached, implementation and monitoring plan. An approved Social Assessment of a project would be a binding document to all parties, the community, the developer and the government.

5.3 TECHNICAL BARRIERS

5.3.1 Lack of Detailed Guidelines on Required Levels of Studies

There appears to be a lack of specific requirements for the levels of studies to be submitted to the MEM/DGE in applications for concessions or authorizations. This can lead to delays in the approval of these applications or the acquisition of other permits required for implementation of the projects.

In addition, the studies carried out frequently do not adequately address all the technical and economic risks which are the concern of potential financing institutions. Inadequate socio-environmental investigations can lead to difficulties and lengthy delays in obtaining the required permits as well as the support and cooperation of regional/local authorities. Furthermore, the absence of detailed requirements can provide opportunity for speculation involving the acquisition of development rights on the basis of studies of limited scope, simply in the expectation of being able to sell these rights at significant profit. This situation can result in significant delays or even non-implementation of potentially attractive projects.

The current specifications of requirements for the issue of concessions and authorizations should be reviewed with a view to ensuring that they are sufficiently detailed and specific. The 'General Guide to Scope and Accuracy of Hydropower Project Studies' presented in Annex 7 may serve as an initial checklist for this purpose. Particular attention should be given to ensuring that the technical (e.g. hydrological, geological) and economic risks (e.g. costs) are addressed in a manner acceptable to potential financing organizations.

Particular attention should also be given to the socio-environmental assessment of the projects, ensuring that the concerns all public and private stakeholders, at national, regional and local level, are also addressed. Most of the developers interviewed by the Study Team cited opposition at regional and local level as a source of delay and expense, even though all necessary permits had been obtained at national level. The document "Environmental Due Diligence (EDD) of Renewable Energy Projects – Guidelines for Small-Scale Hydroelectric Energy Systems", produced by the United Nations Environmental Program in collaboration with the Basel Agency for Sustainable Development (UNEP-BASE, undated) could be of assistance in this respect.

In addition to the above measures, the submitted studies should be subjected to close inspection and evaluation by MEM/DGE to ensure that they fulfill all requirements.

5.3.2 Absence of Clear Guidelines Regarding Environmental Flows

A number of the developers and government agencies interviewed by the Study Team noted the absence of clear guidelines – from either the Consejo Nacional del Ambiente[50] (CONAM) or MEM/DGE - regarding the determination of environmental flows at the dam/diversion sites of hydropower projects. This flow (also variously denoted in English by expressions such as compensation flow, reserved flow, mandatory release; in Spanish by 'caudal ecológico') is an important determinant of the 'dependable' output of a hydroelectric scheme, in particular high-head plants exploiting small flows.

It is generally accepted that in the early stages of assessment of a hydropower project a tentative estimate of the environmental flow is made on the basis of the measured or estimated flow at the diversion site. In the absence of specific guidelines from CONAM or MEM/DGE an arbitrary criterion, such as 10 percent of the long-term mean flow or 50 percent of the mean dry-season flow with over 95 percent probability is often used.

It is also generally accepted that in later stages of study of the project, when all relevant baseline environmental information has been compiled, an attempt is made to establish the environmental flow on the basis of the identified environmental and social conditions in the stretch of river between the diversion site and the location at which the turbine flows are returned to the river. In a similar absence of specific guidelines from CONAM or MEM/DGE various approaches can be arbitrarily taken, often leading to delays in obtaining final acceptance and approval of the project.

Given the importance of the finally prescribed environmental flow in determining the 'dependable' output – and hence economic/financial benefit – of a project, it is suggested that CONAM and MEM/DGE collaborate in producing the following guidelines specifically for hydropower projects, possibly - at least initially – focusing specifically for small to medium-sized hydropower projects:

- Guidelines for the initial estimate of environmental flow on the basis of measured or estimated flow at the diversion site.
- The "Manual de Normas y Procedimientos para la Administración de Recursos Hídricos" issued by the Direccción Nacional de Aguas of Chile,[51] which provides four alternative definitions of environmental flow based on natural flow, could be used as an example.
- Guidelines for the establishing the environmental flow on the basis of the identified prevailing baseline socio-environmental conditions in the stretch of river between diversion and tailrace.
- There exists a plethora of procedures which have been proposed for establishing the desirable environmental flow in this manner. The European Small Hydropower Association (ESHA) has published a critical review of the numerous approaches which have been proposed in the newly expanded European Union. Guidelines specific to conditions in Peru would be of assistance to both project developers and government agencies entrusted with authorizing powers.

[50] CONAM is also the National Designated Agency for the Clean Development Mechanism of the Kyoto Protocol.

[51] DGA (2002).

5.3.3 Limited Use of Standardized Designs, Costing Procedures Specifications and Contract Documents

Notwithstanding the above-mentioned availability of national technical capacity for the design of hydropower projects, there appears to be a certain lack of awareness of standardized designs, procedures for cost estimation, standardized specifications, contract documents, etc., which have been specifically developed for small hydropower projects (of up to, say, 1 to 5 MW installed capacity).

Use of such design aids could to some extent reduce time requirements, enable an increased number of projects variants to be evaluated, and facilitate the comparative assessment of alternative projects. The MEM/DGE could disseminate information on currently available standardized procedures for design and costing. As noted in the Section 2, previous attempts to use Spanish-language versions of standard contract documents, such as those produced by the International Federation of Consulting Engineers (FIDIC), have highlighted some differences of interpretation of certain words in the context of Peruvian law. Nevertheless, it is suggested that the MEM/DGE, perhaps in collaboration with organizations such as Colegio de Ingenieros del Perú, reinitiate the discussion of the matter, with a view to promoting the use such documents.

The International Energy Agency[52] has made a review of available "Assessment Methods for Small-Hydro". Although the report is now somewhat out-of-date, many of the procedures dealt with in the report are still available, some in significantly advanced versions. Details of these methods, including ASCE Small Hydro (USA), HES (USA), Hydra (Europe), IMP (International), PEACH (France), PROPHETE (France), Remote Small Hydro (Canada) and RETScreen (International) can be obtained from the IEA website.[53]

[52] Wilson, (2000).

[53] http://www.small-hydro.com/index.cfm?Fuseaction=planning.tools

6 INTERNATIONAL EXPERIENCE

Private sector involvement in small hydropower development has taken place in a large number of countries worldwide over the previous three decades, and is steadily increasing. Often, this has occurred within programs to encourage the development of grid-connected renewable energy. Most countries, whether industrialized or developing, have initiated programs to develop renewable energy, including small hydro (though the definition of "small" varies widely, from 10 MW in Sri Lanka to 50 MW in China). Some of the reasons given for supporting renewable energy development are:

> ***Renewable energy avoids the environmental damage costs of thermal generation, especially those from greenhouse gas emissions.***
> Since these damage costs are not captured by a competitive generation market, special price support to correct for this market failure is warranted. However, large hydro results in the same avoidance of damage costs.
>
> ***Renewable energy, including small hydro, rarely has significant problems of relocation and resettlement associated with large hydro schemes.*** This is generally true, although may not apply as much to Peru where medium and large scale hydro projects tend to have limited storage,
>
> ***Renewable energy projects are able to tap sources of debt and equity not available either to large hydro projects, or to fossil generation projects.***
> World Bank loans are no longer available for thermal projects, but they are for renewable energy projects. And the equity contributed by many small companies (often construction companies) would not otherwise be available to the power sector. In countries where electricity demand is growing very rapidly, and where the most serious issue in the power sector is how the necessary capital is to be mobilized, additionality of finance can be a very strong reason for small renewable energy projects (the best example of which is Vietnam, where electricity demand is growing at 12 percent per year, and mobilizing investment capital is the main problem of the power sector).
>
> ***Portfolio benefits***
> Renewable energy plays the same role in a portfolio of electricity generation assets as treasury bonds play in a portfolio of financial assets – characterized as having low returns, but high certainty of those returns. The diversification of energy generation sources acts as a hedge against the uncertainty of international fossil energy markets. This argument is most powerful in small island countries that lack fossil and hydro resources, and are otherwise dependant upon high-cost liquid fuels for power generation – for which the best example (in the World Bank experience) is the rationale for wind power in Cap Verde.
>
> One could also argue that the dispersed locations of a small hydro project portfolio provides system support at the remote edges of the transmission system, and reduces the probability of transmission congestion. However, where there is large variation between wet and dry season output and local loads are small, then transmission lines would need to be sized to evacuate the wet season output, imposing shallow network *costs* on the system.

6.1 OPTIONS FOR PROMOTING RENEWABLE ENERGY

The international experience shows clearly that for small hydro (or renewable energy) to be developed on a significant scale requires special tariff incentives (to reflect full economic value or as a temporary measure to support technologies while achieving economies of scale) and often requires assisting promoters to gain access to long-term financing. Table 6-1 shows a classification of tariff support systems, classified according to the basis for setting the tariff (the *columns* of the table), and the method of implementation (the *rows* of the table). The system of tariff support recently proposed for Peru (in the new Renewable Energy Decree) is discussed in Section 7.

Table 6-1: Classification of Renewable Energy Tariff Support Systems

	Tariff based on costs of the:		
	Producer (Seller)	**Buyer ("Avoided Cost Tariffs")**	**Quota (Obligation) Systems, Subsidy Auctions.**
	Government Sets the Price		**Government Sets the Quantity**
Published	Most European countries ("Feed-in tariffs") Ontario Sri Lanka 2007 Brazil PROINFA	Sri Lanka (until 2006) Indonesia Hungary, most American States Vietnam (starting 2009)	
Market Price + Fixed Premium	Spain, Czech Republic		
Market Price + Auctioned Premium			Peru Proposed Discussed in Section 7
Set by Market (tradable green certificates, quotas)			Chile Romania, many Latin American countries Zhejiang
Individually Negotiated	Vietnam (present)		

In general, where the government sets the tariff (as in the German feedlaw), it is the *market* that determines the *quantity*; conversely where the government sets the quantity (as in countries that set renewables purchase obligations), it is the *market* that sets the *price.*

Worldwide, by far the most widespread approach to renewable energy tariff support is the so-called feed-in tariff, under which electricity suppliers are obliged to purchase renewable electricity at a technology specific price based on the estimate of the producer's costs. Note that this approach bears no relationship to the framework for rational pricing presented in Section 3.1 – since the price set has no direct relationship to the benefits – though advocates of the system argue that the benefits are implied in the electricity consumers' willingness to pay the incremental costs. The Government goal here is simply to promote certain technologies.

The second most common approach is for Government to provide a preferential tariff based on the avoided costs of the buyer – the most successful example of which was the renewable energy tariff provided in Sri Lanka. Although this system is economically rational (notably that the market decides which technologies should be implemented), it has its opponents among renewable energy supporters just because often the tariff does not enable the more expensive technologies.

The third approach depends upon Government setting the quantity of renewable energy that distribution companies must purchase (most often as a percentage of total purchases, increasing over time), with significant penalties for non-compliance (as in the UK). This can be economically rational if the targets are set on estimates of $\boldsymbol{Q_{SOC}}$ (see Figure 3-1), but again the difficulty is that unless the quantities are set by technology, the proponents of high-cost renewable energy technologies – notably wind – complain that the incentives do not enable their favored technology. Thus the UK has recently proposed a modification of the renewables obligation system that uses a technology banding system under which RE technologies still in the early phases of development (offshore wind, tidal energy) receive a higher number of certificates than the mature technologies. Annex 14 provides further details on the support systems in other countries.

With successful small hydro development programs in dozens of countries, this review is necessarily selective and is focused on the following examples:

(i) Countries where national legislation has provided the impetus for renewable energy investment (Brazil, Chile);
(ii) Countries where the World Bank has assisted national programs with refinancing facilities offering longer loan maturities (Sri Lanka, Turkey);
(iii) Innovative approaches that have mitigated the problems of low tariffs arising from market reforms (as in Zhejiang, China).

6.2 BRAZIL

Generation capacity in Brazil is largely dominated by hydroelectric plants, which account for 77 percent of total installed capacity, with 24 plants above 1,000 MW.

In 2002, Brazil established the Programa de Incentivos a Fontes Alternativas de Energia Eléctrica (PROINFA, Law 10,438 of 26 April), with the goal of developing 3,300 MW of renewable energy generation (1,100 MW each of wind, SHP and biomass) under 20 year PPAs with Electrobras. The projects are to be commissioned by end 2008. PROINFA defines a small hydro project as:

- 1 to 30 MW installed capacity.
- Maximum flooded are of 3 km^2.
- Use of generating units of 5,000 kW maximum each.
- Maximum flow rate of 2 m^3 per second.
- Maximum dam height of 10 meters.
- No tunnels.

Qualifying small hydro projects can obtain 80 percent financing from The National Bank for Economic and Social Development (BNDES) (some wind projects are also being financed by the Bank of Northeast Brazil). However, to qualify for the PROINFA financing, a minimum of 60 percent of the value of the project procurement must be of Brazilian-made equipment,[54] and 20 percent must be equity capital.[55] BNDES loans under the program have 12-year maturities, including a six-month grace period following completion of construction, a commitment fee of 1 percent, and lend at the TJLP (the Brazilian long-term interest rate set by the Central Bank).[56]

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[54] This domestic content requirement is similar to the wind concession bidding program in China.

[55] The original requirement was for 30 percent equity, but this was reduced in March 2004 following difficulties encountered by many project sponsors (often small companies) in meeting the guarantee requirements. Financing delays also led to the extension of the program from December 2007 to December 2008.

[56] In December 2007, this stood at 6.25 percent, compared to money market rate of 11 percent and the basic financial rate of 10.3 percent.

In the classification of price support systems of Table 6-1, Brazilian PROINFA approach is one where the main intervention is the *price* - but where the Government has also set an upper bound to the quantity that qualifies for the price.

Small hydro projects of less than 30 MW enjoy other concessions, aside from the PROINFA program:

- Size threshold for participation in the market is 500 kW (as opposed to the normal 3 MW)
- Require only an authorization from ANEEL, as opposed to a mandatory auction for a concession required under the tendering law.
- 50 percent discount on transmission and distribution fees.

The most important feature of PROINFA is the fixed tariff, available for approved projects up to the limits specified in the law (Table 6-2).[57]

Table 6-2: 2006 PROINFA Tariffs

	Euro/MWh	UScents/kWh
Small Hydro	47.80	7.36
Wind	73.60-83.46	11.33-12.85
Sugar Bagasse	39.30	6.05
Rice Husk	42.15	6.49
Woodchips	41.40	6.38
LFG	69.05	10.63

Source: Brazil Ministry of Mines and Energy

The second phase of the program will require that a minimum of 15 percent of the annual increment of electricity must be contracted from these renewable sources (excluding large hydro), under 15-year PPAs.

The PROINFA program has attracted the attention of international equity funds. For example, a private US$91 million equity/guarantee facility for small hydro development began operation in the second quarter of 2006. Registered with the Brazilian Securities and Exchange Commission (Comissaio de Valores Mobiliarios), and supported by an American Foundation (Fiorello La Guardia Foundation), 80 percent of the capital is subscribed by Brazilian pension funds. An additional US$18 million is being sought from investors in OECD countries. The fund is looking for IRRs of 13-14 percent plus inflation (about 4.5 percent in 2006), that is 17-19 percent.

The fund plans to support 200 MW of new small hydro capacity in 13 projects in the states of Mato Grosso and Minas Gerais. Construction has begun on the five Mato Grosso plants, which are scheduled to be on-line in early 2008. The financing facility has negotiated US$275 million in debt from the Brazilian National Development Bank (BNDB), and negotiations are underway with BNDB to replace their current requirement for real asset guarantees with financial guarantee structures.

As of April 2007, 55 percent of the 3,300 MW target (1,809 MW) was either in operation or under construction, and a further 18 percent had been contracted:[58]

- SHP: 1,077 MW SHP (90 percent of target) in operation or under construction
- Wind 218.5 MW (15 percent of target) in operation or under construction
- Biomass: 514 MW biomass (75 percent of target) in operation or under construction

[57] The wind tariff is based on a sliding scale (on the model of the German feed-in tariff) dependant on load factor: projects with annual load factors of up to 32 percent receive 9.783 UScents/kWh, decreasing linearly to 8.626 UScents/kWh at 42 percent load factor.

[58] "Energias Renováveis", Laura Porto, São Paolo, April 24, 2007.

PROINFA was extended until end December 2008, in order to achieve the targets.

6.3 CHILE

As in Peru, the use of hydropower in Chile has a long tradition, mainly in the form of micro- and mini-hydropower plants in the southern regions. These plants were usually privately owned and operated either as stand-alone systems or in small local grids together with diesel plants. In the second half of the last century larger hydropower plants began to be constructed, mainly in the Bio-Bio region south of Santiago, and regional interconnected networks were formed.

Compared with the hydropower evolution in Peru, Chile has been somewhat more successful in developing its hydropower resources since deregulation and privatization in the 1990s. However, in the face of rapidly increasing demand, Chile has been itself forced to implement significant thermal generating capacity, mainly fuelled by imported natural gas. Hydropower as a proportion of total installed capacity has fallen from 57 percent in 1995 to just 38 percent in 2007.[59] Hydropower capacity grew at an annual total growth rate of over 4 percent, compared with Peru's 2.8 percent, and small to medium-sized hydropower capacity (< 30 MW) grew a 1.8 percent, comparable to Peru's.

The legal base for hydropower development is the 1981 Código de Aguas (Water Law), which privatized the water rights and, for the first time in Chile, separated water rights from land rights. This law defines water as a national good for public use whose user rights are granted by the Dirección General de Aguas (DGA), a unit within the Ministry of Public Works. After granting these water rights, the State does not intervene further.

One of the objectives of the Government's PER, initially launched in 1994, is the promotion of the use of renewable energies. In 2004, the Government initiated a series of incentives affecting small to medium-sized hydropower.

2004 Short-Law No. 19-940

In 2004, the Ministerio de Economía, Fomento y Construcción introduced Law No. 19-940, "Regulation of Transmission Systems, Establishment of a New Tariff Regime for Medium-sized Power Systems and Introduction of Adaptations to the Electricity Supply Law".[60] The law applies to all generators, but includes some measures specifically affecting small hydro:

- Right of energy sale on the spot market is ensured for any generator, regardless of size.
- Equal treatment conditions entail a simplified business treatment (price stabilization and ensured access to trunk networks if connected).
- Price paid to generator includes not only a marginal energy cost component but also recognition for installed capacity or the backup capacity available during peaks of demand.

In addition, specifically for producers employing Non-Conventional Renewable Energy (NCRE) technologies, including hydropower under 20 MW installed capacity, the law provided for:

- Access rights to the power grid at either transmission or distribution level are legally secured for NCRE producers under 9 MW.
- NCRE producers under 9 MW are exempt from transmission tolls, while NCRE producers between from 9 MW to 20 MW pay transmission tolls proportionately. These effective subsidies are borne by the other generators in proportion to their supply capacities.

[59] Tokman (2007).

[60] In Spanish: "Regula Sistemas de Transporte de Energía Eléctrica, Establece un Nuevo Régimen de Tarifas para Sistemas Eléctricos Medianos e Introduce Las Adecuaciones que Indica a la Ley General de Servicios Eléctricos".

2008 Short-law No. 20-018
In 2005 the Ministerio de Economía, Fomento y Construcción introduced Law No. 20-018, "Modification of the Regulatory Framework of the Electricity Sector",[61] which included further provisions favoring NCRE producers:

- 5 percent of the total electricity demand to regulated clients is to be supplied by NCRE generators.
- Provides for the Economic Development Agency (CORFO) to offer financial and technical support to investors and entrepreneurs interested in developing NCRE projects (see next bullet point).

In the tendering process prices are determined by a payment mechanism based on stable long-term (marginal) costs and are indexed to the input costs of each bidder.[62] The capacity price is fixed and corresponds to the node price prevailing at the time of the call for bids, while the maximum energy price is capped at 20 percent greater that the prevailing average free-market price.[63]

The first auction under the above mechanism was held in October 2006, involving supplies to five distribution companies of around 11,000 GWh/a, requiring about 2,750 MW installed capacity, over the period 2010 to 2024. Bids were received covering about 90 percent of the auctioned supplies, with a mean energy price of US$52.6 per MWh, significantly lower than the cap of US$62.7 per MWh.[64] The capacity price was set at US$7.86 per kW per month, applicable to effective capacity (which generally amounts to around 65 percent of installed capacity in the case of run-of-river small hydropower projects).[65]

In the second auction, held in October 2007, offers were received from only one of the three distribution companies issuing tenders, the mean energy price offered being only just under the price cap.

Subsequently, the Ministerio de Economía, Fomento y Construcción, issued Decreto Supremo Num 244, "Regulations for Non-Conventional and Small Generators",[66] which provided for various administrative and technical manuals and standards to support NCRE generators.[67]

CORFO-CNE Co -Financing of Studies
In 2005 the Economic Development Agency and the National Energy Commission (CNE) initiated a program of financial support to NCRE projects:

- Subsidies of up to US$60,000 per project (selected competitively) are provided for pre-investment studies, specialist investigations, detailed engineering design and studies required for the Clean Development Mechanism (CDM), on a 'matching fund' basis up to a maximum of 50 percent of total cost of studies and investigations, and up to 2 percent of total investment cost.

[61] "Modifica Marco Normativo del Sector Eléctrico" (2005a).

[62] Comisión Nacional de Energía, (2006).

[63] Benarion, P., (2006).

[64] Rudnick, H., Moreno, R. and Barroso, L., (2007).

[65] United Nations Development Program (UNDP) and EndesaEco, (2007).

[66] Ministerio de Economía, Fomento y Construcción, (2005b).

[67] The documents included: (i) 'Technical Standards for Connection and Operation' of NCRE generators, (ii) 'Manual for Evaluation of the Environmental Impact of NCRE Projects', to be made available on the website of National Energy Commission (Comisión Nacional de Energía - CNE)., (iii) A Cooperation Agreement between the CNE National Irrigation Commission (Comisión Nacional de Riego – CNR) to promote development of NCRE (hydropower) projects by irrigation entities, (iv) 'Guide to the Clean Development Mechanism (CDM) for NCRE Projects'.

- In the first two annual bidding processes carried out in 2005 and 2006 CORFO-CNE selected a total of 91 projects- including 40 hydropower projects- with an estimated total installed capacity of 550 MW and total investment cost of US$850 million. The total amount of subsidy funds provided by CORFO-CNE was US$2.6 million.[68]

2008 Renewables Obligation Law

In March 2008 a law was passed requiring the generating companies in Sistema Interconectado Central (SIC) and the Sistema Interconectado del Norte Grande (SING) with total installed capacity greater than 200 MW to generate at least 5 percent of annual energy production through NCRE by the year 2010. This percentage will rise to 8 percent by 2024. Companies failing to meet the obligation will pay penalties from US$4,300 to US$6,400 per MWh. Presidential approval of the law is expected in 2008.

The CNE and the National Irrigation Commission (CNR) carried out an inventory of small to medium-sized hydropower projects (2 to 20 MW capacity), which could be constructed in existing irrigation systems in 8 regions covering approximately 97 percent of the irrigated area in the country. The results of the inventory[69] show possibilities to implement 290 projects with a total installed capacity of around 860 MW. CNR-CNE highlighted the need to bring together the irrigation entities and the generating companies in order to implement the projects.

At a recent investors meeting in Santiago it was noted that, as result of the various government measures described above, a substantial pipeline of NCRE projects has been established, including 23 small hydropower projects with total installed capacity 193 MW for which social and environmental impact assessments have been submitted for approval.[70]

6.4 SRI LANKA

Sri Lanka's power sector is dominated by hydroelectricity (54 percent of total generation in 2007). Since 1996, the modern small hydro power (SHP) industry has commissioned over 100 MW of privately owned, small-scale (less than 10 MW), grid-connected projects. As at 30 June 2006, Ceylon Electricity Board had 141 SHP projects accounting for 270 MW.[71]

The World Bank financed 1997 Energy Services Delivery Project (ESDP) in Sri Lanka was one of the first refinancing facilities established expressly to support renewable energy projects.[72] The main objective was to provide loans at much longer maturities than previously available (10 years rather than the typical 3-7 years), and to familiarize the commercial banking system with lending to renewable energy facilities. The facility is available to grid-connected SHPs, as well as to off-grid village hydro schemes.[73] Funds are provided to the Government of Sri Lanka (GoSL) as an IDA credit under typical terms, for which the GoSL carries the exchange risk. The Government of Sri Lanka in turn nominated the Development Finance Corporation of Ceylon (DFCC) to administer the program through a special

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[68] Further details of the two bidding processes – including problems encountered – are to be found in presentations by CORFO (2007) and CNE (2007b).

[69] CNR-CNE (2007).

[70] Tokman, M., (2007).

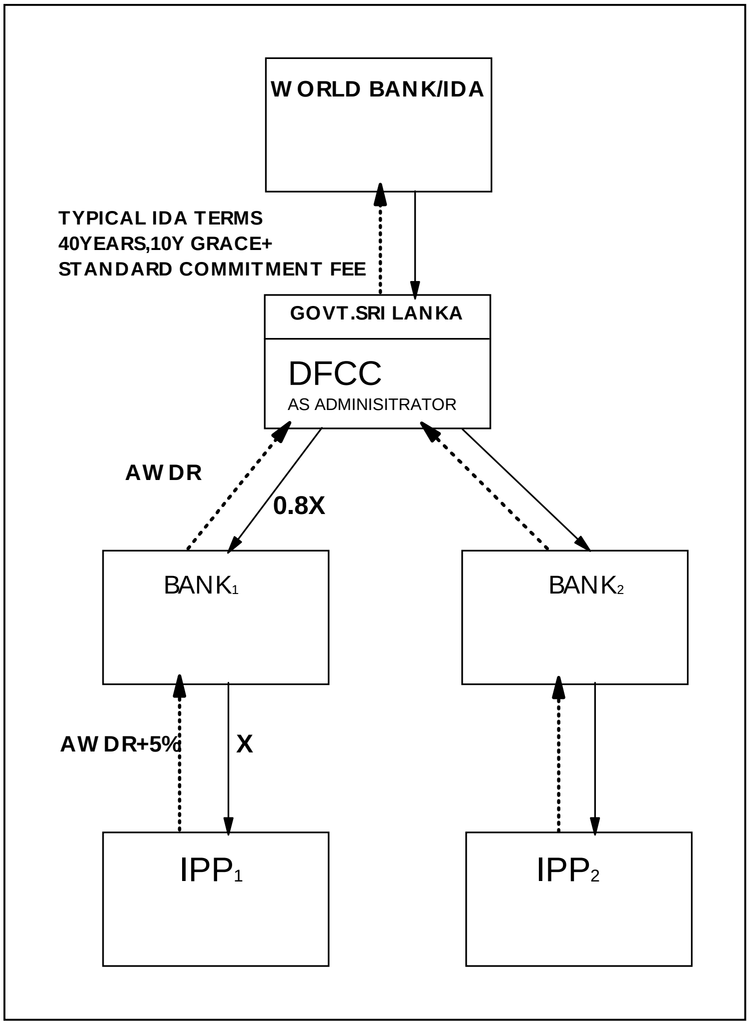
[71] World Bank, (2008).

[72] World Bank, (2003), (2007b).

[73] 147 off-grid village hydro schemes (average size 10 kW) have also been financed, and the refinance facility is also available to microfinance institutions for financing household PV solar home systems.

account set up in the Central Bank of Sri Lanka. Developers (IPP_1, IPP_2 in Figure 6-1) obtain finance from qualified commercial banks ($BANK_1$, $BANK_2$, etc.) under normal lending terms,[74] with interest at the normal bank + 5 percent.[75] The commercial banks then refinance, at normal lending rates, with the administrator of the program, some portion (typically 75-80 percent) of this loan.

Figure 6-1: The Sri Lanka Energy Services Delivery (ESD) Project Arrangements



Source: World Bank, (2003).

Prior to the ESDP there was no interest in commercial financing of renewables. Under the original ESDP (1999-2003), US$24 million was disbursed through two development banks and three commercial banks; under the follow-on project (2004-2007) one development bank, one commercial bank, and two leasing companies joined the program: in addition, two finance companies and a rural development bank have

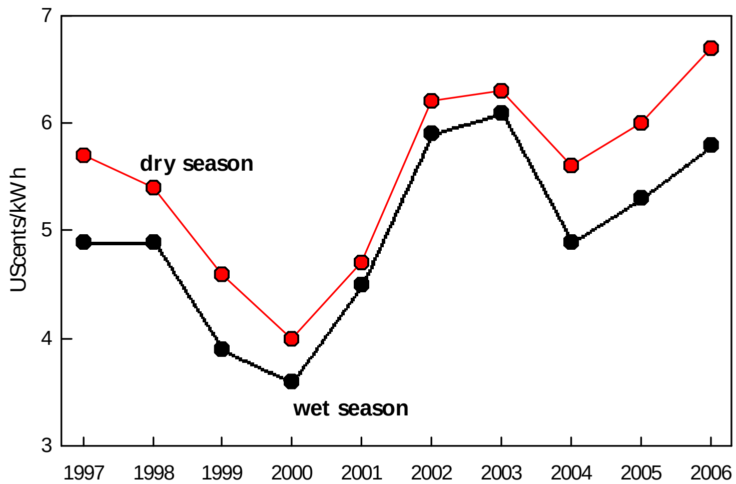
[74] However, these sub-loan maturities are limited to 10 years including a maximum of 2 years grace, and no more than $3 million to any individual project.

[75] Six banks were appointed under the original program, namely DFCC Bank, National Development Bank, Sampath Bank, Hatton National Bank, Commercial Bank, and Sarvodaya Economic Enterprises Development Services [SEEDS] (a microfinance institution).

started lending to renewable energy projects *outside* the World Bank project. The Sri Lanka ESDP has been successful not only in serving as a catalyst to the establishment of a viable, private-sector small hydro industry, but has also been successful in establishing a broader basis for commercial financing for renewables. By the end of 2006, some 95 MW in 38 small hydro projects had obtained finance under the program, and 17 further projects, bringing the total to 137 MW, are in progress.

However, the most important difference between Sri Lanka and Peru is in the tariff. Renewable energy projects in Sri Lanka below 10 MW have benefited from an avoided cost tariff which is quite high because Sri Lanka has no natural gas or domestic oil resources, and the marginal thermal projects are auto-diesel fueled combustion turbines: the tariff (which varies by wet and dry season) is shown in Figure 6-2.

Figure 6-2: Avoided Cost Tariff, Sri Lanka



Source: www.energyservices.lk

Thus, with tariffs of between 5 and 6 UScents/kWh, and capital costs of US$1,100- US$1,300, it is no surprise that so many small hydro schemes have been built. To be sure, recent capital cost increases have also affected Sri Lanka, with more recent capital costs reported in the US$1,200- US$1,500/kW range. In early 2007 the avoided cost tariff was replaced by a fixed feed-in tariff of around 7 US cents/kWh (the avoided cost tariff under the old system would have been over 12 US cents/kWh as crude oil prices have risen to US$100/bbl).

6.5 TURKEY

Like Peru, Turkey is well endowed with hydropower resources, but unlike Peru, lacks gas and other fossil fuels. A total of 88 small hydro projects less than 30 MW are in operation, the bulk of which are private BOT projects, and a further 10 are under construction. There are a further 344 identified projects. Unlike thermal and wind projects for which many opportunities for financing though export credits exist, long-term financing of the local costs of small hydro projects remains a major problem.

In response to this problem, in 2004 the Turkey Renewable Energy Project was approved by the Government and the World Bank, including a debt facility to provide long-term lending.[76] The World Bank loan will be on-lent by the Treasury to two financial intermediaries, the private Turkish Industrial

Development Bank and the Government Development Bank.[77] These entities will appraise sub-projects, make loans to sub-project sponsors and supervise project implementation.

The Turkey Renewable Energy Project includes financing of US$250 million from IBRD and US$250 million from commercial banks and four components: (a) a Debt Facility that combines World Bank funds with funds from two commercial banks to provide long-term loans to private sponsors of projects. It is intended to leverage equity from local private investors, export credit financing and other financing for construction and operation of renewable facilities between 10 and 50 MW; (b) capacity building to support development of a potential pipeline of projects; (c) technical assistance to develop the legal and regulatory arrangements to facilitate such projects, including the development of renewable energy legislation and models public-private development of large hydropower development, improvement of dam safety regulation and introduction of modern techniques for dam safety monitoring and disaster mitigation, and the preparation of technical standards to lower the present transaction costs of project approval; and (d) support for project implementation and monitoring.

The Turkey Project is similar to the Nepal US$35 million World Bank-assisted Power Development Fund Project, also designed to provide long-term financing for private-sector small and medium-sized hydropower developments in Nepal to overcome the lack of sufficient debt financing for private-sector hydropower projects and the inadequate maturity of available debt financing. The Fund is managed by a Fund Administrator, a private Nepalese commercial bank selected by the Government through a competitive bidding process. A Board formed by the Government is responsible for approving loans in accordance with the recommendations of the Fund Administrator.

6.6 ZHEJIANG PROVINCE, CHINA

China is the World Leader in small hydro, with more than 25,000 MW in place.[78] The bulk of this capacity was installed in the 1960s and 1970s, and the driving force has been its historical role in rural development in areas not served by the grid. However, under extensive power sector reforms in China, past models of investment in small hydro by local governments are being replaced.

The province of Zhejiang, on the East Coast, is one of the more advanced in introducing market reforms into the power sector, and has instituted an innovative competitive process for the development of small hydro projects. Zhejiang presently has some 1,690 MW of small hydro in place, and about 200 MW per year is expected to be added over the next five years under a new incentive system. Renewable energy projects in China also benefit from a number of tax concessions (Box 7).

The first part of the bidding system is a guaranteed fixed price for small hydro generation that provides for a premium above the prevailing market price: the guaranteed price assures a revenue stream that makes for a bankable project.[79]

The second component is a bidding system under which the county government has the authority to award the development rights through tenders or auctions: developers pay an up-front fee. Recently a pilot auction of development rights for the Wencheng project had 30 bidders, with the winner paying Y3.5

[77] World Bank, (2004a).

[78] In China, the definition of "small" hydro is now projects less than 50 MW.

[79] There is no special pricing provision at the national level for small hydro. However, for biogas and wind, special pricing rules were implemented in early 2006 (National Development and Reform Commission of the People's Republic of China, Document No.: NDRC Price Decision No. 7, 2006.) For example, biogas is given a fixed subsidy of 0.25 Y/kWh (for 15 years) above the reference price for a coal project with FGD.

million (US$425,000) for the development rights. The Provincial Water Resources Board is responsible for approval of project design and future safety management after commissioning. In return, a small hydropower management fee, 1 percent of power revenue, is paid by the developer to the grid operator, who in turn disburses the proceeds to provincial, prefecture and county Water Resource Boards.

Box 7: Tax Incentives in China

Renewable energy benefits from a range of tax incentives and special subsidies in China. Although small hydro does not enjoy an income tax reduction, it does benefit from a preferential VAT rate.

	VAT (percent)	Corporate Income Tax
General	17 %	33
Small hydro	6 %	33
Biogas	13 %	15
Wind	8.5 %	15
Landfill gas	0 %	33

There are also special incentives for small hydro in the poor western provinces: the Western China Cropland Conversion Program and the Western China Energy Development Program, provide special funds derived from Government bonds for small-scale hydropower development. The Ministry of Water Resources has also provided interest rate subsidies.

With an extensive domestic small hydro equipment manufacturing capability, equipment imports are not an issue in China (though other renewable energy technology imports, where classified as "high technology" (such as wind turbine) benefits from preferential customs duty rates.

Source: Li et al (2006).

6.7 CONCLUSIONS ON INTERNATIONAL EXPERIENCE

Table 6-3 summarizes the discussion in the text. The international experience shows clearly that for small hydro to be developed on a significant scale requires special tariff incentives. These can be provided in several different ways, but the most successful in Latin America have been fixed technology-dependant tariffs as exemplified by the Brazilian PROINFA program.

It is too soon to gauge the success of the Chilean approach of a renewable obligations requirement, the law having been passed just a few months ago. However, it may be noted that this law is much stronger than the new Peruvian regulation. In Chile there are penalties on the distribution companies if the obligation is not met, where as in Peru, the 5 percent is merely an upper bound for the amount of renewable energy that the system dispatcher must take.

The problem of small developers with development rights not being able to obtain financing is also not unique to Peru. As we have seen in Section 3, financing will always be difficult where tariffs are inadequate, and the international experience seems to confirm this. Competitive bidding is another approach to solving this problem, but concession bidding only works if there are profits worth bidding for, and with a revenue stream that is easily predicted: high transaction costs are also an issue. Brazil's experience shows that concession bidding for small hydro projects is not practical, and it works in Zhejiang because transaction costs are low (and because the tariff is adequate).

In countries where the World Bank has provided a refinancing facility offering loans of much longer tenor than previously available (Turkey, Sri Lanka, Nepal), there is evidence that the benefit is not just one of reducing financing costs, but that the involvement of the Bank has provided comfort to the commercial banks with renewable energy project lending and the necessary capacity building for risk assessment.

Table 6-3: Summary of Barriers to Renewable Energy Development and Solutions in Other Countries

COUNTRY	MAIN BARRIER	BARRIER OVERCOME BY
Brazil	Lack of PPA; Inadequate tariff Lack of long-term financing	PROINFA law: feed in tariff, access to low cost loans, 15-year PPAs with PROINFA law (less than 30MW)
Chile	Limited investment High pre-investment costs	Binding renewables obligation with penalties for non-compliance; Pre-investment grants
Sri Lanka 1998	No preferential tariff Lack of long-term finance	Published tariff based on avoided cost of buyer World Bank assisted financing facility provided long-term loans
Turkey	High transaction costs, lack of standard contracts Lack of long-term finance	TA for regulation, development of standard contracts, tariff World Bank assisted financing facility
Zhejiang, China	Difficulties in site allocation and licensing; Desire to introduce market-based approaches	Competitive bidding for sites plus feed in tariff World Bank assisted financing facility for small hydro under CRESP (China Renewable Energy Scale up Project)
Vietnam, 2006	Lack of standardized PPA, tariffs through *ad hoc* negotiation; many small hydro projects held up for lack of finance	Avoided cost tariff published by regulator; standardized, non-negotiable PPA; World Bank assisted financing facility for renewable energy small power producers (below 30MW)

7 RENEWABLE ENERGY DECREE OF MAY 2008

7.1 THE MAIN POINTS OF THE DECREE

On 2 May 2008, the Government issued a new legislative decree for the promotion of investment in electricity generation using renewable energy (*Decreto Legislativo de Promoción de la Inversión Para la Generación de Electricidad con el Uso de Energía Renovable*). The key provisions of this decree are as follows:

- Every five years MEM is charged with issuing a target ceiling for renewable energy. For the first five years (i.e. until 2013), the ceiling is set at 5 percent of total national electricity consumption (Article 2)

- Wind, solar, geothermic, biomass and tidal/wave energy are considered renewable energy sources, as well as hydro not greater than 20 MW (small hydro) (Article 3)

- Small hydro is not accounted for in the ceiling of 5 percent, therefore this type of technology will benefit of the incentives of this new legislation regardless of the percentage of its participation in the total national electricity consumption (Article 2)

- Renewable energy will have priority in the daily dispatch, meaning that COES will consider as zero its production variable cost. Renewable energy plants will sell their energy production to the spot market (Article 5)

- Renewable energy plants will receive the marginal (spot) price of energy plus a “premium” in case the spot price is lower than the tariff, both established by OSINERGMIN (Article 5)

- The premium and tariff will be calculated taking into account the type of technology and other characteristics of the installations, and will “guarantee” a rate of return on investment of no less than that established in Article 79, Law Decree 25844 for electricity concessions, which is currently 12 percent.

- The premiums will be “auctioned” by OSINERGMIN (Article 7.1).

- Transmission cost to connect the renewable energy plant to the interconnected grid are considered as part of the investment cost of the plant for the premium calculation (Article 7.1)

- The incremental costs will be recovered by a user charge (Article 7.2)

7.2 THE FUNDAMENTAL APPROACH

Government seems to have chosen to set a target ceiling for a share of renewable energy (excluding small hydropower which is not subject to this ceiling), in combination with a premium price. The financial analysis indicates that a price in the range of 5-6 US cents per kWh for hydro could unlock significant investment in small hydropower. In 2007, total generation was 27,255 GWh, so the 5 percent target ceiling would require 1,362 GWh from renewable energy sources. At an annual load factor of 60 percent, this corresponds to 260 MW. Although, small hydro will not be considered in the indicated amount, this type of projects should compete in the auctions with other technologies for the premium. In the short term, wind power appears as the other renewable technology in competition for the premium. We may note that 14 of the 16 identified projects listed in Table 2-3 meet the 20 MW size threshold, totaling 143 MW.

The Decree raises three fundamental issues of approach chosen by the Government. The first concerns the introduction of a renewable energy ceiling. The numerical ceiling is not really a *renewable energy* target but rather a limit on the amount of energy that must be taken by COES at the premium price. Also, according to MEM, small hydro will qualify for the preferential tariff but will not be subject to the ceiling. This is unusual, most countries include small hydro in the renewable energy target, and many countries, including those of the EU, now include large hydro in their country-specific renewable energy targets. More importantly, since the decree sets no penalties upon any entity in the case of non-compliance (unlike, say, in Chile), the decree is much weaker than in other countries that have set specific targets.

The second relates to the general principle of enacting subsidies. The economically rational approach (suggested in the framework of Section 3.1) argues that the generation tariff be set on the basis of economic avoided costs – meaning gas would be valued at its opportunity cost rather than at its presently subsidized price. Elimination of the gas price subsidies would therefore enable not just all hydro, whether small or large, but would also eliminate the perverse incentives for open cycle gas generation (rather than the more efficient combined cycle). Unless the ceiling set for the preferential price is close to $\boldsymbol{P_{SOC}}$, there is a risk that the Renewable Energy Decree simply compounds the distortions of one subsidy (on gas) with another (on renewable energy). Indeed, if the gas price subsidies were eliminated, there would be no need for a preferential tariff for renewable energy (or small hydro in particular) except to reflect the value of the avoided environmental damage costs of thermal generation ($\boldsymbol{V_{L.ENV}}$).

The third issue relates to technology choice. The moment one introduces technology banding (i.e. different prices for different renewable energy technologies), there can be no pretense about the system being economically efficient. For example, there is no *economic* justification for paying 9 UScents/kWh for wind, rather than 6 UScents for hydro, unless one believes that the social costs of small hydro exceed the social costs of wind by 3 UScents/kWh. There are no studies that show differences in social costs of this order of magnitude.[80]

Nevertheless, the Decree represents an important step forward. If the implementing rules provide some degree of certainty in the preferential tariff, then one can expect that many small hydro projects currently stalled for lack of an adequate tariff and the related financing difficulties move to implementation.

Clearly, this decree is weaker than the corresponding Chilean regulation (see Section 6.3), that imposes a renewables *obligation* (rather than just a target), with penalties on the generating companies for failure to meet the obligation. Nevertheless, the Decree represents is an important step forward. If the implementing rules provide some degree of certainty in the preferential tariff, then one can expect many small hydro projects currently stalled for lack of an adequate tariff and the related financing difficulties to move to implementation.

[80] The only circumstances under which one could argue for a special consideration for wind power in countries where there is a potential for large-scale domestic turbine manufacture. For example, in China (and Brazil) there is an argument for wind power insofar as only the development of a large domestic market will induce the development of a domestic manufacturing capability, which (as has been true in China) brings the prospect of long-run cost decreases that may outweigh the short run costs of subsidy. That argument has no merit for Peru (or other small countries where there is no chance that a commitment to wind power will affect the future supply price).

7.3 IMPLEMENTATION OF THE DECREE

While the Decree has not yet been regulated, the language of the decree raises a number of questions that need to be resolved.

- It is unclear upon what set of principles the tariff calculation is to be based. The reference to "allowable profitability" suggests that what is intended in a cost-based feed-in tariff that allows for a "fair" rate of return not to exceed the statutory maximum. However there are other tariff options more in harmony with the existing tariff principles – for example, the tariff could be based on marginal costs using the *unsubsidized* natural gas price – i.e. based on the avoided economic costs of the buyer, which has no need to be technology specific.
- Article 7.2 *implies* that tariffs will be calculated for each renewable energy technology. The wording says "taking into account the different renewable energy forms." But exactly what is intended here is unclear. More detail is needed. For example, in Germany the current feed-in law provides a tariff for wind power that is also a function of the load factor. In many jurisdictions there are different tariffs for small hydro according to their size.
- It is unclear whether the premium applies just to the energy payment or to the capacity payment as well.
- There is a conflict between the apparent requirement that premiums will be "auctioned" and that technology specific tariffs will apply. It may be that the tariffs are meant to be an upper bound to the auctions.
- The presumption is that the Decree introduces a must-take obligation on COES up to 5 percent. If the premiums are to be auctioned, then the realities of the costs of different renewable energy forms is that the winners of the auctions will always be the cheapest technology, other than small hydro which is excluded from the ceiling. The Brazil PROINFA program resolved this problem by setting targets for each technology (1000 MW each for small hydro, biomass and wind). However the Decree is silent on this matter.
- The list of qualifying renewable energy technologies excludes specific mention of biogas: most regulations (e.g. EU directive) on renewable energy make express mention of bio*gas* as an eligible category, thereby making eligible landfill gas projects.

It is clear from this list of issues that there are many practical details to be settled as part of the process of developing the regulations that will permit implementation of the Decree 1002. Only after these details are decided would it be possible to make judgments about the extent to which the new tariff regime will significantly assist small hydro (and renewable energy) producers. Thus whether the decree will in fact encourage small hydro projects depends critically on the implementation details, including:

- The entire 5 percent target could be taken up by two or three wind farms if there are no separate targets by technologies, crowding out smaller projects (of whatever other technology).
- At what point does the premium tariff become a bankable off-take commitment by COES. If the premium is to be considered as a secure revenue stream for project financing, then that commitment must be in place at financial closure – several years ahead of the first premium payment.
- If a two-part tariff is intended (which raises the important issue of the basis of the capacity charge, and how to ensure that capital cost recovery (which accounts for the bulk of costs for a renewable energy facility) is assured.

Based on informal discussions with MEM, there appear to be three main issues in the implementation of the preferential tariff.

- Technology banding

- Determination of the tariff
- Auction of the premium

The basic concept seems to be that candidate technologies are to be banded by type (wind, biomass, small hydro), and a tariff issued for each category, and perhaps even by projects with longer and shorter transmission connections. The premium to be paid over the market price will be determined through auction, but would be capped by the difference between this tariff and the market price. For technologies other than small hydro, the auction will be only for an amount equal to the energy target set in the decree. MEM has indicated that the process cannot be "first-come first served", so even if there is less capacity (energy) offered than the cap, an auction process would still be needed in the interests of efficiency. MEM also expressed the view that the premium should have separate energy and capital charges.

But it is hard to see why the possible differentiation by length of transmission connection fosters economic efficiency: all other things equal, surely the public interest is to build those small hydro plants that have as short a transmission connection as possible.

Nor is it clear what economic efficiency interest is served by setting individual technology targets. What is important is that the energy for which the consumer pays the premium is simply a properly qualified renewable energy type: whether that comes from wind, small hydro or biomass does not really matter: all bring the same benefit of avoided local and global air emissions from thermal emissions. The economic efficiency interest is surely best served by letting the market make decisions about which technology is offered and built.

7.3.1 Technology Banding

While banding by technology has been adapted by several countries (as in the case of Brazil, see section 6.2, where there are three bands, 1,000 MW for each of wind, biomass and small hydro below 30 MW), the degree of technology differentiation varies widely. For example in the Eastern European countries that has adopted feed-in tariffs, the banding is relatively simple, as shown in Table 7-1. Small hydro is at most divided into two categories (less than 1 MW, more than 1 MW, and in Slovakia with a special rate for small hydro rehabilitation).

Table 7-1: Feed-in Prices in Eastern Europe (€cent/kWh)

	Hungary		Slovakia		Bulgaria		Slovenia		Czech Republic	
	€	US	€	US	€	US	€	US	€	US
Avoided Cost Peak	10.0	15.8								
Off-Peak	6.3	9.9								
Wind <1 MW			6.46	10.2			6.10	9.6	8.74	13.8
>1 MW			6.46	10.2			5.90	9.3		
Geothermal			9.01	14.2			5.90	9.3	15.98	25.2
Small Hydro			5.94	9.4	4.09	6.5			8.49	13.4
Small Hydro <1 MW							6.20	9.8		
1-10 MW					6.14	9.7	5.90	9.31		
Small Hydro rehab			6.20	9.8					7.71	12.2
LFG							5.30	8.4	8.09	12.8
Biogas			6.46	10.2					10.80	17.0
Biomass Co-Firing			5.17	8.2						
Biomass Plantation			7.75	12.2						
Biomass			5.17	8.2					8.31-12.00	13.1- 18.9
<1 MW							9.36	14.8		
>1 MW							9.11	14.4		

Source: World Bank, Serbia*: Analysis of Policies to Increase Renewable Energy Use,* 28 Sept. 2007

However, at the other extreme, the German feed law is very finely differentiated, as shown in Table 7-2. The 2004 rates decrease by 1 percent per year (a plant built in 2004 receives the payment shown during its lifetime; but a plant built in 2005 gets 1 percent less, and a plant built in 2005 gets 2 percent less, etc., the so-called "digression": the idea is to incentivize early investment and reflect expected technological progress. [81]

Table 7-2: German Feed-in Tariffs for Small Hydro (2004)

	€cents/kWh	UScents/kWh
less than 500 kW	7.7	11.5
500 kW-10 MW	6.7	10.0
10 MW-20 MW	6.1	9.2
20 MW-50 MW	4.6	6.8
50 MW-150 MW	3.7	5.6

Source: Federal Ministry for the Environment, Nature Conservation and Nuclear Safety

There is a similar differentiation for biomass projects, but for wind, the differentiation is based not on size, but on load factor.

In the case of Peru, the size of overall renewable target being limited (estimated at 565 MW - assuming a load factor of 27.5 percent), it is not advised to set up too many technology bands. For instance, in the case of Brazil PROINFA, three technology bands were established (small hydro, wind and biomass), with a size of 1,100 MW each.

[81] However, the expectation of a decline in capital costs has not come to pass. Over the past few years, the strong market for wind turbines has led to a sellers market, with upward pressure on prices – some smaller wind farms in developing countries have had no bidders at all. This is similar to the situation for PV, where surging demand in Japan and Europe has created a worldwide shortage and again higher rather than lower prices.

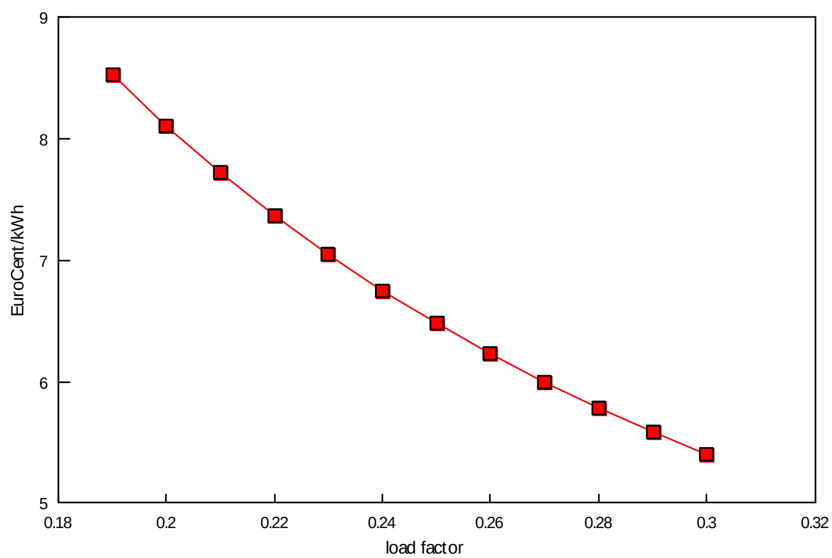
7.3.2 Determination of the Tariff

There are several different approaches for setting technology-specific tariffs. The German feed-in tariff illustrates the basic principle for renewable energy projects: the most important assumptions are the capital cost and load factor. For example, the calculation of the wind power tariff makes the following assumptions:

- Capital cost (equipment), €895/kW (US$1,412.66/kW)
- Capital cost (site), 30 percent of power plant
- Operating cost in years 1-10 (4.8 percent of the power plant cost)
- Operating cost in years 11-20 (6 percent of the power plant cost)
- Inflation over 20 years: 2 percent
- Debt: Equity ratio: 70:30
- Interest rate 5.5 percent
- Return on equity 12 percent

This results in a price that varies by load factor, and in effect rewards wind energy producers at poorer inland sites: the better the site, the lower the feed-in tariff (Figure 7-1). This is not economically rational, but was introduced in the latest version of the law in response to equity concerns to achieve more uniform development of wind energy across Germany, rather than being concentrated in the coastal areas of northwestern areas characterized by the highest wind speeds. The differentiation may also be seen as an attempt to limit scarcity rents at the highest wind speed sites.

Figure 7-1: Wind Energy Price versus Load Factor



But such feed-in tariffs come in many other forms. As of January 2007, Sri Lanka introduced cost based and technology-specific (replacing the avoided cost system described in Section 6.4). Two options are provided: a three-tier tariff, and a flat rate tariff.

Tariff option 1: Three-tier tariff. The tariff in the first six years is front-loaded, and set in such a way as to allow 20 percent post-tax return for developers. The tariffs for the first tier (i.e. years 1-6) are as follows.

Table 7-3: Inclusive Tariffs for SPPA 2007 (LKR/kWh): Years 1-6

Year of Operation		**1**	**2**	**3**	**4**	**5**	**6**
Mini-Hydro	Non-scalable	7.99	7.99	7.99	7.99	7.99	7.99
	Escalated O&M	0.48	0.52	0.56	0.6	0.64	0.69
	Total	8.47	8.51	8.54	8.59	8.63	8.68
Wind	Non-scalable	13.88	13.88	13.88	13.88	13.88	13.88
	Escalated O&M	1.67	1.80	1.93	2.08	2.23	2.40
	Total	15.55	15.68	15.81	15.95	16.11	16.27
Biomass	Non-scalable	5.22	5.22	5.22	5.22	5.22	5.22
	Escalated fuel	5.00	5.25	5.51	5.78	6.07	6.37
	Escalated O&M	0.84	0.90	0.97	1.04	1.12	1.20
	Total	11.06	11.37	11.69	12.04	12.4	12.78

Source: Sri Lanka Sustainable Energy Authority

The tariffs for the second tier (years 7 to 15) are substantially lower:

Table 7-4: Inclusive Tariffs for SPPA 2007 (LKR/kWh): Years 7-15

Year of Operation		**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
Mini-Hydro	Non-scalable	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79	2.79
	Escalated O&M	1.48	1.59	1.71	1.84	1.97	2.12	2.28	2.45	2.63
	Total	4.28	4.39	4.50	4.63	4.77	4.91	5.07	5.24	5.42
Wind	Non-scalable	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85	4.85
	Escalated O&M	2.57	2.76	2.97	3.19	3.43	3.68	3.96	4.25	4.57
	Total	7.43	7.62	7.82	8.04	8.28	8.54	8.81	9.10	9.42
Biomass	Non-scalable	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82
	Escalated fuel	6.68	7.01	7.36	7.73	8.11	8.51	8.93	9.37	9.84
	Escalated O&M	1.29	1.39	1.49	1.60	1.72	1.85	1.98	2.13	2.29
	Total	9.80	10.22	10.67	11.15	11.65	12.18	12.74	13.33	13.95

Source: Sri Lanka Sustainable Energy Authority

And in years 16 to 18 fall even further, as follows:

Table 7-5: Inclusive Tariffs for SPPA 2007 (LKR/kWh): Years 16-18

Year of Operation		**16**	**17**	**18**	**19**	**20**
Mini-Hydro	Non-scalable	2.06	2.17	2.27	2.39	2.51
	Escalated O&M	2.82	3.03	3.26	3.50	3.76
	Total	4.89	5.20	5.53	5.89	6.27
Wind	Non-scalable	2.06	2.17	2.27	2.39	2.51
	Escalated O&M	4.90	5.27	5.66	6.08	6.53
	Total	6.97	7.44	7.94	8.47	9.04
Biomass	Non-scalable	2.06	2.17	2.27	2.39	2.51
	Escalated fuel	10.32	10.84	11.37	11.94	12.53
	Escalated O&M	2.46	2.64	2.84	3.05	3.27
	Total	14.85	15.64	16.48	17.37	18.31

Source: Sri Lanka Sustainable Energy Authority

A Bank Guarantee will be required to ensure that the SPP operates in years 7-12 of the second tier, in return for the high tariffs paid in the first tier. The guarantees have to be provided to the utility over years 1-6, and they will be returned from year 7 onwards.

Tariff Option 2 (Flat Tariff): Selection between the three-tier tariff and this flat tariff would be entirely at the discretion of the developer. There will be no requirement for bank guarantees by SPPs opting to be on this flat tariff.

Table 7-6: All Inclusive Rate Years 1-20

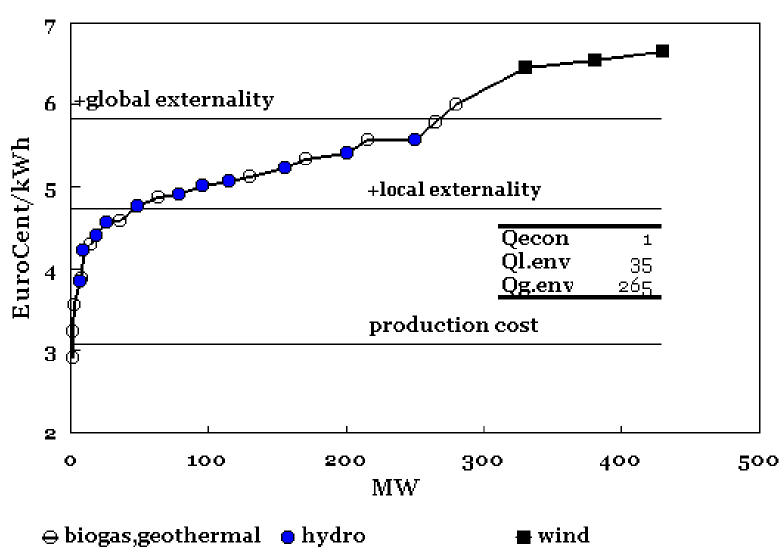
Technology	All inclusive rate (Rs/kWh) for years 1-20
Mini-Hydro	7.10 (6.6 UScents/kWh)
Wind	12.83 (11.9 UScents/kWh)
Biomass	11.87 (11.0 UScents/kWh)

Source: Sri Lanka Sustainable Energy Authority

The flat tariff will not be escalated for any reason over the entire 20-year period. It may be noted that all of these systems are one-part tariffs, with the capitals costs covered in a single kWh charge. This means that the seller assumes hydrology risk (or in the case of wind power, the risk of low wind years)[82] because in dry years, few kWh will be sold.

An alternative approach to tariff setting is based on avoided cost of the buyer, plus such adders that reflect the avoided damage costs of thermal generation. The concept is illustrated by a recent study for Serbia[83] The first step is to derive a so-called supply curve, which takes the inventory of renewable energy projects, sorts them by production cost, and then displays the project in increasing order of cost showing the cumulative generation (or MW) available as a function of cost (Figure 7-2). This follows precisely the rational framework for renewable energy pricing presented in Section 3.1.

Figure 7-2: Renewable Energy Supply Curve for Serbia



[82] A study of annual variations in wind output in Sri Lanka showed that the resulting variation in annual generation cost was higher than the variation in cost of auto-diesel based CCGT power generation due to volatility of Singapore spot prices. Studies of Danish wind farms suggest annual variations of 20 percent around the mean.

[83] World Bank, (2007d).

Economic theory states that the economically efficient quantity of renewable energy is given by the intersection of the supply curve with the avoided cost of the buyer. In Serbia, the marginal production cost is set by low-cost lignite based generation, with a cost of slightly over 3 EuroCents/kWh (4.5 UScents/kWh). As shown in the figure, only 1 MW (a small biomass project) is economic at this cost (denoted $\boldsymbol{Q_{ECON}}$ in the figure). If one now adds the avoided environmental damage costs of thermal generation (which is high in eastern Europe in areas where lignite is used without FGD systems), the social cost of thermal generation is 4.75 Eurocents/kWh (7 UScents/kWh) – a level that the supply curve intersects at 35 MW – a mixture of biomass and small hydro projects ($\boldsymbol{Q_{ENV}}$). If one adds to this the avoided global externality cost, resulting in a cost of 5.75 Eurocents/kWh (9.07 UScents/kWh), the economic quantity of renewable energy is 265 MW ($Q_{G.ENV}$). Note that the wind projects in Serbia would require a social cost of thermal generation of 6,5 Eurocents/kWh (10.25 UScents/kWh) – in other words, even if one were to include the avoided global externality cost into account, wind would not be economic in Serbia.

Note that knowledge of the supply is only required if one wishes to set an economically efficient target, for a technology that is more expensive than the avoided economic cost of generation (e.g. windpower). From the point of view of overall economic efficiency, it suffices to set the tariff on the basis of the avoided economic costs of the buyer this will automatically provide whatever renewable energy is economic – though that will unlikely enable wind power. Such avoided cost systems have been effective in many countries (as noted, for example in Sri Lanka from 1998-2006, as discussed in Section 6.4).

7.3.3 Auction of the Premium

Several countries provide for a premium over the market price to be paid to qualifying renewable energy producers, and the closest appears to be Thailand, where developers bid for a subsidy, subject to a maximum amount of subsidy per kWh generated. This (fixed) subsidy is provided for a 5-year period. However, the bidding process is technology neutral, and there is no separate auction by technology. There is a single cap that applies to all.

The "green bonus" system adopted in the Czech Republic is another relevant model for Peru, which was introduced in a 2005 law on electricity from RE. Producers of electricity can choose from two support schemes, namely fixed feed-in tariffs or a "green bonus" under which the producer sells his electricity at the wholesale market price plus a premium from the distribution system operator. Green Bonuses are fixed one year ahead for individual types of RE in such a way that the expected total revenue is higher than that for the fixed feed-in purchase prices, to reflect for the risk in the price uncertainty of the wholesale market. However, in this system the bonus is fixed, and there is good certainty about the revenue stream because the expected value of revenue is higher than the published feed-in tariffs

In any event, the details of what precisely is being auctioned are unclear. Because of year-on-year variations in output (true of both small hydro and wind), the auction cannot be for a fixed number of kWh each year; in the case of small hydro, there have to be carry-over provisions from drought years to wet years; and possibly even a cap on wet year generation. Nor can the auction be conducted each year: the premium revenue available to any developer must be known at the time of financial closure if the premium revenue is to have any benefit for on financing.

The advocates of renewable energy auctions -- whether for price subsidies or the right to develop specific sites (as in the case of the Chinese Wind farm concession program) -argue that such auctions encourage efficiency thorough competition, and secure for consumers some part of the benefits of low cost renewables. This may have some merit where concessions involve thousands of MW. But this has very little merit in the case of Peru, where at best a few hundred MW would be auctioned. In fact, the auction is simply a way for consumers to capture part of the producer surplus (site rents). This may indeed have merit from the perspective of keeping tariffs low, but should not be confused with the optimal allocation of resources (the latter being best served if $\boldsymbol{P_{ECON}}$ is available to all producers).

7.4 POTENTIAL IMPACT OF IMPLEMENTATION OF THE DECREE

Table 7-7: Summary of Barriers to Small Hydropower and Potential Impact of Renewable Energy Decree

	Options for Mitigation	Responsible	Role of Renewable Energy Decree
Major Barriers			
Lack of remunerative tariff	(a) Reduce subsidies on natural gas for power generation (b) Introduce a preferential tariff. Government has elected option (b) in Renewable Energy Decree.	OSINERGMIN	Regulation must ensure premium is predictable and adequate. Recommend basing tariff on avoided economic cost of generation based on opportunity cost of gas.
Capacity charging methodology	Revise methodology to properly reflect capacity contributions of hydro (and to reflect the portfolio benefits)	OSINERGMIN	Regulation must ensure this. If the premium tariff is two-part, capacity charge should reflect capacity costs of SHP.
Transmission costs	Include costs of gas transmission in generation price of CCGT.	OSINERGMIN	Not affected by Decree
Security of water rights	New Water Act is under discussion		Not affected by Decree
Lack of clear regulations & norms when land is under "traditional" settlement ownership	Formalize a "Social Assessment" for hydro projects, with a defined scope, required documentation, approval process, agreements reached, implementation, & monitoring plan.	CONAM and MEM in collaboration with stakeholders	Not affected by Decree
Inappropriate requirements for connections	Existing national grid code should be revised and abbreviated version prepared for small generators.	MEM/DGE	Not affected by Decree
Financing problems- unrealistic risk assessment, lack of long term loans and project finance, and high transaction costs.	Financing facility using national development bank, commercial banks, or international finance facility Training and outreach to commercial banks can supplement but not replace facility.	MEM, MoF	Not affected by Decree
Other Barriers			
VAT recovery discriminates against small hydro	Reduce construction period eligibility from 4 to 2 years for renewable energy projects	MEF	Not affected by Decree
Lack of guidelines on environmental flows	Draft and implement guidelines	CONAM and MEM/DGE	Not affected by Decree
Lack of standardized guidelines for design, feasibility studies, business and financial plans	Prepare guidelines, conduct training programs	MEM	Not affected by Decree

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 CONCLUSIONS

Peru's significant small hydropower potential, conservatively estimated at over 1,600 MW, merits development as part of a renewable energy development program on economic and environmental grounds. The fundamental constraint to developing Peru's hydro potential has been the low tariff faced by hydro generators, which is a consequence of the subsidies to natural gas. With gas costs for power generation cif Lima of only US$2.15/mmBTU among the lowest anywhere in the world outside the Middle East), CCGT generation costs are little more than 3.5 UScents/kWh.

However, the Government has now decided to provide small hydro projects less than 20 MW with a premium on the tariff under the proposed new Renewable Energy Decree. If the tariff resulting from the Renewable Energy Decree is adequate and predictable, and similar to small hydro preferential prices in other countries (roughly 5–7 UScents/kWh), the main barrier to small hydro development would be overcome.

The New Renewable Energy Decree

The new Decree, once it is regulated and effective, is an important first step to unlock the small hydro potential of Peru. However, whether the tariff premium to be given to qualifying facilities unlocks financing problems will depend not just on its magnitude, but upon its certainty at the time of financial closure.

Attempts to promote renewable energy while regulating rates of return of renewable energy projects, as suggested by the language of the decree, have often failed in other countries. This will be especially difficult for small hydropower in Peru, because of the need to predict the price of imported equipment that has been subject recently to steep price increases due to increasing material costs, increasing demand for hydropower equipment, and the decline of the dollar. In the case of wind and biomass, where production costs are likely to be significantly higher than the avoided economic cost of the buyer, there may be no alternative but to issue a technology specific tariff. However, because small hydro is economic if market prices reflected the opportunity cost of natural gas, the preferential small hydro tariff could be set on the basis of avoided economic costs of the buyer, i.e. at the unsubsidized price of gas generation. This avoids the need for a profusion of different sub tariffs (for projects at existing irrigation infrastructure, greenfield projects, projects less than 1 MW, less than 10 MW etc), and the need to estimate costs for "typical" small hydro projects.

The problem of low generation tariff resulting from the subsidized gas price is compounded by two further distortions in the tariff environment. The first concerns the allocation of transmission costs. In the case of hydro projects at distant locations, the incremental transmission connection costs are charged to the hydro generators. That is perfectly reasonable, and should indeed be taken into consideration in an economic comparison of generation options. However, the corresponding capacity costs of gas transmission to CCGT plants located in and around the Lima area should also be taken into consideration in such an economic analysis. But under the present arrangements, these costs are carried directly by consumers and paid as part of the transmission charge. This further favors gas generators.

The second issue concerns the methodology for determination of capacity charges. Again, given the significant variations of seasonal output from run-of-river projects, it may not be unreasonable to base the capacity charge for a particular project on the 95 percent probable availability. A single small hydro project may well add little to dry season capacity. However, studies of the capacity credit of renewable energy generation in other countries clearly show the diversity effects of a *portfolio* of projects, such that the capacity benefits to the system of the portfolio is much greater than the sum of individual capacity benefits. These benefits should be estimated and recognized in the premium tariff system.

The Financing Environment

The commercial banking sector in Peru is relatively competitive, and Peru has weathered the present international liquidity crisis much better than most. To date, however, very few non-recourse deals for infrastructure have actually been completed – and the only such power generation project was for a thermal project.

At the same time, private equity funds are eager to invest in infrastructure, and the private Peruvian pension funds would like to rebalance their investment portfolios toward such projects, recognizing that the very high returns achieved over the past decade in the stock market are unsustainable. However, in the past tariff environment, financially strong entities have had no interest in small (or even large) hydro (except for small projects dedicated entirely for own-use of mining companies) because there is no money to be made, while financially weak developers who have the concession/water rights have unrealistic expectations about the value of these rights with the result that both debt and equity providers discount their technical acumen as well. Indeed, over the past few years the commercial banks have seen no big hydro projects at all, and just one or two small hydro projects.

The proposed preferential tariff under the new Renewable Energy Decree may improve the fundamental requirement of a remunerative tariff, and therefore increase the interest of potential equity investors in the sector. However, it is far from clear that this alone would also transform the debt market to enable project financing at long loan maturities.

Indeed, the commercial banks have limited project finance capacity (project finance groups are small - though very well qualified), so they tend to divert their internal resources to big deals, not small projects. With no large hydro projects being proposed, the banks have limited interest in doing project financings for the small number of projects that are presented to them, and under these circumstances they have even less interest in developing the necessary in-house risk assessment capability – particularly for projects that are in locations far from Lima.

The Santa Rosa project required 100 percent collateral for the first unit. The desire of lenders to impose expensive EPC contracts with "name" firms on small projects may well mitigate lenders' risks, but the incremental costs of such an approach simply makes many small projects non-remunerative. None of the Banks, fund managers or potential equity providers saw higher rates of return (FIRR) as offsetting risk concerns. Their view is that completion risk is mitigated by EPCs, not an extra 2-3 percent on FIRR.

Assistance from the Government is needed to enable access to long-term financing for investors other than large corporations that can finance on the balance sheet. This financing could be done in many different ways, e.g. through a development bank as in the case of Brazil, or through a project that involves an international finance institution, like the cases of Turkey, Sri Lanka and Zhejiang. International financial institutions (IFIs) are more experienced than national commercial banks in assessing the unique risk profiles of hydro projects, and can assist in building confidence. This cannot be achieved just by technical assistance and lectures about the need to upgrade risk assessment techniques, but needs to be coupled with meaningful financial participation of the IFIs.

This may be of lesser importance to the larger companies likely to sponsor medium to large hydro projects, whose financial strength enables them to raise debt from the commercial banks. But for small hydro projects – and for renewable energy projects in general, assistance for access to financing will be an important advantage.

Peru in the International Marketplace- Carbon Finance and Other Incentives

Section 3 has shown the potential value of carbon finance and longer loan tenors to improve financial returns. With recent increases in carbon prices, and future expectations of yet further increases, carbon finance makes a significant difference to developers' cash flows and enhances debt service cover ratios required for non-recourse financing.

To get the attention of the increasing number of international *private* equity funds interested in clean energy investments requires clear Government interest and commitments – for which there is no substitute for targeted legislation to assist small renewable energy projects. If the new Renewable Energy Decree is successfully implemented, this could trigger such interest. If the new preferential tariffs for small hydro are in the range of 5-7 UScents/kWh (the Brazilian PROINFA tariff is more than UScents 7/kWh), and provide reasonable tariff certainty, then one may be confident that Peru will attract the interest of specialized international equity funds.

Water Rights

Security of water rights is a major concern, and there have been instances where uncertainty in water rights has led to significant delays and costs for large hydro projects. Many call for a new Water Act or major revisions to the present law. Tensions between project developers and local communities, intervention of the various levels of Government and regional differences in the capacity of the legal system to address complex technical matters create difficulties.

Although it seems unlikely that small hydro development would spark the sort of major legal confrontation as may be encountered in the case of large hydro projects, as noted in the discussion of Section 4.4, the biggest problem faced by small hydro developers is the uncertainty of the process and its duration, one that relies heavily on administrative discretion. The hassle, risks and difficulties of this process doubtless influences the developer's perceptions of the value of securing these water rights, which is perhaps insufficiently appreciated by the commercial banks.

The Case for Hydro Projects in the 20-200 MW Size Range

Many of the arguments for small hydro are in fact shared with medium and even large-sized hydro – such as the avoidance of the environmental damage costs of thermal generation (which constitutes a market failures in that these costs are not captured in the market price), and the portfolio and diversity benefits of an energy source not subject to the volatility and supply security issues of internationally traded fossil fuels.

This study finds that small hydropower in the particular circumstances of Peru (<20 MW), except in the case of projects that have the ability to use existing irrigation infrastructure, has no particular economic or environmental advantage over medium sized hydro in the 20-200 MW. The latter projects are generally run-of-river projects (with minimal storage sufficient for daily peaking operation in the dry season) and with minimal numbers of project affected households and little impact on forests and agriculture.

As shown in Section 2, the probable potential for hydro projects is much greater than for small hydro of less than 20 MW, and projects in this size category therefore have the potential for making a more significant aggregate contribution to meeting the fast growing power demands.

However, the case for a more active Government role to promote such larger projects is much greater, since the potential for issues over water and land rights are more likely; and feasibility studies are more expensive, so there will be a greater reluctance of private companies to undertake them, and prepare them to a stage where entities of more substantial financial strength (mining companies, existing generating companies) would finance, construct and operate them.

8.2 RECOMMENDATIONS

A number of main barriers have been identified for small hydro power and main recommendations follow below. It is important to note, however, that there are secondary barriers, and while not essential would help small hydro developers. We recommend, therefore, that the government proceed on addressing these secondary barriers and recommend: improving access to hydrology data, clarification of requirements and approval process for studies, clarification for environmental evaluation, social approval and ecological flows, relaxation of rigid connection requirements, and standardization of specifications and contract documents.

1. Implementation of the Renewable Energy Decree

The key to unlocking the small hydro potential will be a remunerative and predictable tariff. Implementation of the price premium and auction provisions in such a way to minimize uncertainty on the premium received is particularly important. Unless the preferential tariff is predictable, and the transaction costs minimized, the decree will have little impact. Part of the success of the Brazilian PROINFA program has been the simplicity and clarity of its implementation.

Key specific suggestions for the implementation of the Decree are set below:

- It is recommended that a simple and economically justified method be used to set the tariff—such as using avoided economic cost of gas-based generation when gas is priced at opportunity cost.

- It is suggested that technology bands not be used or that number of technology bands be limited because of the small scale of target.

- Many details of the auction process need to be decided—e.g. what exactly is being auctioned (presumably the premium price), over what time period, how variations in output will be handled. The key is that the auction provides certainty of the premium price for sufficient time to enable financing of the Project (e.g. 15 or 20 years).

It will also be very important for OSINERGMIN to have access to experts with renewable energy tariff experience in other countries, technical assistance that could be provided through a Workshop in Peru with the participation of such experts.

The timetable provided by the decree for OSINERGMIN to develop the implementation details of the decree is only 90 days. Experience in other countries suggests that much more time is required to do this well.

2. Capacity Charge Methodology

OSINERGMIN should review the methodology of setting capacity charges. It is clear that the portfolio benefits of hydro (small or large) are not properly captured in the present approach. If the implementation of the preferential tariff for small hydro is based on a German-style feed-in tariff, in which capital outlays are recovered in a one-part tariff, then the general methodology of capital cost recovery for the regulated market is not relevant. But if the preferential tariff for renewables is to be based on a two part tariff (with separate remuneration for capacity), the present approach will not provide for adequate recovery of investment costs.

3. Long-Term Financing Facility

As noted in the assessment of barriers, a range of financing problems will face developers even if an adequate tariff is provided under the new Decree. These problems include unrealistic risk assessments by the commercial banks, high transaction costs, and lack of long-term loans. These would all be mitigated by a long-term financing facility from domestic resources like a national development bank or entity such as COFIDE, or with support from an international financial institution, such as the World Bank, along the lines of similar facilities in Sri Lanka, Vietnam and Turkey. Absent such a facility, it is very unlikely that non-recourse project financing can be achieved for small hydro projects, and the present 100 percent collateral/corporate guarantee requirements of the commercial banks will remain a major barrier to all but large corporate sponsors.

A major long-term goal of such a facility is to demonstrate to the commercial banks that lending for small hydro (and other small renewable energy projects) is viable, and that whatever risks as are actually an issue can be mitigated by less draconian requirements than 100 percent cash collateral. The necessary technical assistance to the banking system is an integral part of all of such projects in other countries.

4. Water Rights

Despite some attempts to improve and clarify regulations regarding the requirements and procedures to obtain the necessary approvals and permits to carry out studies and water use rights for power generation, the situation at present is still not quite satisfactory. Most developers indicated that the main problem is not excess of requirements but the unpredictable process. The lack of a specific TUPA (Consolidated Text of Administrative Procedure) is the main complaint. What is needed is a TUPA that describes in detail the documentation requirements; who could submit a solicitation, its format and if a payment is necessary or not; the intervention of different internal units or offices, specifying their specific roles in the process and timing; type of official document and person(s) who sign the authorization or approval of the petition; if petition is rejected a full explanation of reasons for rejection; and finally specifying the maximum duration of the whole process, after which the petition is considered approved if there is no official rejection.

5. Rights-of-Way and Community Intervention

The Peruvian electricity legal framework provides for the imposition of rights-of-way for hydropower generation and other electrical activities like transmission and distribution. This legal framework and its specific regulations contain the necessary requirements and process to obtain, in a formal way, the necessary temporal and definitive use of the required land to develop a hydropower project. This systems works well in case land property is clearly defined and legally registered. In most cases an agreement is reached between the owner of the land and the project developer, either buying or renting the required land. If an agreement could not be reached in these cases, a legal imposition of the right-of-way is possible, although not desirable due to the time required to settlement.

When land belongs to communities, legally registered or otherwise ("traditional" settlement ownership), the right-of-way problem, compounded with water use rights, is much more complicated. An agreement is more difficult to obtain due to the interventions of many people acting as leaders of the community, and the requirement that the majority of the community approves the final agreement. Also this type of agreement is not legally enforceable and is subject to change of opinion of leaders or the community.

To deal with the indicated problem, we agree with the recommendation made by some developers, to formalize a "Social Assessment" of hydropower projects, with a defined scope, required documentation, approval process, agreements reached, implementation and monitoring plan. The approved Social Assessment of a project, including rights-of-way and water use agreements, would be a binding document to all parties, the community, the developer and the government.

6. Early Recovery of VAT

The early recovery of VAT is limited to projects with construction periods of four years or more. At the same time, thermal projects, which are less capital intensive, can be financed as lease deals, one of the principal advantages of which is immediate recovery of VAT. But lease deals cannot be done for small hydro projects (because the tariff cannot support the high payments implied by the typically much shorted lease terms). The net effect of these provisions is an unfair disadvantage for small hydro. We recommend that this discrepancy be eliminated (perhaps as part of the implementing regulations for qualifying renewable energy facilities under the new law).

6. Larger Hydro Projects

A similar study is underway on hydro projects in the 20 MW-200 MW size range. As noted above, such projects have a much larger potential role to meet the fast growing power demand of the country (with required capacity additions of several hundred MW annually). At the same time, the case for a more active Government role in overcoming the institutional and regulatory barriers is at least as great. The special tariff incentives that the new decree provides to small projects will not be available to these larger projects under the 20 MW threshold set in the draft decree, which therefore implies the need for: (a) removal of the gas subsidy, which is desirable on macro-economic grounds; (b) raising of the 20 MW limit of the Renewable Energy Decree to higher levels; or (c) another approach to overcome the distortion of the low tariff based on the subsidized cost of gas.

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Annex 2: Hydropower Projects Existing in 1976

Listed in order of descending installed capacity

No.	Project	River Basin	Year Start of Operation	Installed Capacity (MW)	Average Annual Energy Production (GWh)
1	Stgo. Antuñez de Mayolo	Mantaro	1965	342.0	2,640
2	Huinco	Rimac	1964	258.0	921
3	Matucana	Rimac	1971	120.0	665
4	Yaupi	Tambo	1956	108.0	693
5	Cañon del Pato	Santa	1964	100.0	700
6	Callahuanca	Rimac	1938	67.0	501
7	Moyopampa	Rimac	1951	63.0	475
8	Malpaso	Mantaro	1926	54.0	189
9	Cahua	Pativilca	1967	40.0	293
10	Macchu-Picchu	Urubamba	1957	40.0	280
11	Huampani	Rimac	1960	31.4	192
12	Aricota I	Locumba	1967	24.0	138
13	Charcani IV	Chili	1962	14.4	87
14	Pachachaca	Mantaro	1929	12.0	45
15	Aricota II	Locumba	1967	12.0	in Aricota I
16	Oroya	Mantaro	1930	9.0	56
17	Charcani VI	Chili	1978	9.0	67
18	Carpapata II	Perene	1970	6.3	in Carpapata I
19	Charcani III	Chili	1939	4.6	33
20	Sicay-Huarisca	Mantaro	1970	3.8	11
21	Carpapata I	Perene	1958	3.0	37
22	Ingenio	Mantaro	1950	1.8	7
23	Charcani I	Chili	1909	1.5	10
24	Charcani II	Chili	1913	0.8	5
	Others	-	-	80.3	-
			Total :	**1,405.8**	**8,046**

Source : Lahmeyer-Salzgitter-MEM [1979], Vol 2, Tabla 2.3

Annex 3: Hydropower Projects with Concessions and Authorizations

Table 1: Hydropower Projects with Definitive Concessions

No.	Name	Project Sponsor	Design Capacity (MW)	Estimated Annual Production (GWh)	Estimated Investment (US$ Mio.)
1	Centauro I y III	Corporación Minera del Perú S.A. - Cormipesa	25.0	Not estimated	14.0
2	Cheves	Empresa de Generación Eléctrica Cheves S.A.	158.0	Not estimated	160.4
3	G1 El Platanal	Compañía Eléctrica El Platanal S.A.	220.0	1100	155.0
4	Huanza	Empresa de Generación Huanza S.A. - Emghuanza	86.0	338	56.2
5	La Virgen	Peruana de Energía S.A.A.	64.0	385	54.9
6	Marañón	Hidroeléctrica Marañón S.R.L.	96.0	425	78.0
7	Macchu Picchu (Extension)	Empresa de Generación Eléctrica Machu Picchu S.A.	71.0	Not estimated	85.0
8	Morro de Arica	Cementos Lima S.A.	50.0	248	128.0
9	Pías 1	Aguas y Energía Perú S.A.	11.0	82	13.4
10	Poechos (2nd Powerhouse)	Sindicato Energético S.A. - Sinersa	10.0	Not estimated	9.0
11	Pucará	Empresa de Generación Hidroeléctrica Del Cuzco	130.0	900	136.4
12	Quitaracsa I	Quitaracsa S.A. Empresa de Generación Eléctrica	112.0	720	78.5
13	San Gabán I	Empresa de Generación Macusani S.A.	120.0	725	132.2
14	Santa Rita	Electricidad Andina S.A.	173.5	1000	134.1
15	Tarucani	Tarucani Generating Company S.A.	49.0	418	46.9

Source : Ministerio de Energía y Minas, Dirección General de Electricidad, October 2007.

Annex 3: Hydropower Projects with Concessions and Authorizations (continued)

Table 2: Hydropower Projects with Temporary Concessions

No.	Name	Project Sponsor	Design Capacity (MW)	Estimated Annual Production (GWh)	Estimated Investment (US$ Mio.)
1	Copa	Empresa de Generación Eléctrica Cahua S.A.	92.0	Not estimated	Studies: S/. 33,000
2	Chaglla (Variante)	Empresa de Generación Huallaga S.A.	240.0	Not estimated	Studies: S/. 309,382
3	Cheves II	Empresa de Generación Eléctrica Cheves S.A.	75.0	Not estimated	Studies: S/. 60,000
4	Cheves III	Empresa de Generación Eléctrica Cheves S.A.	123.5	Not estimated	Studies: S/. 60,000
5	El Caño	Electroandes S.A.	100.0	726	119 Studies: US$ 399,692
6	La Guitarra	Electroperú S.A.	220.0	1831	235 Studies: S/. 81,050
7	Llaclla 2	Empresa de Generación Eléctrica Cahua S.A.	71.0	Not estimated	Studies: S/. 33,000
8	Napo-Mazan	Iquitos Hepp S.A.	154.1	Not estimated	Studies: US$ 1,059,725
9	Quiroz-Vilcazán	Junta de Usuarios Del Distrito de Riego San Lorenzo	18.0	Not estimated	Not estimated
10	Rapay	Empresa de Generación Eléctrica Cahua S.A.	90.0	Not estimated	Studies: S/. 33,000
11	San Gabán II (Refurbishment)	Empresa de Generación Eléctrica San Gabán S.A.	-	Not estimated	Not estimated
12	San Gabán III	Empresa de Generación Eléctrica San Gabán S.A.	To be determined	1219	153 Studies: S/. 130,000
13	Santa Teresa	Empresa de Generación Eléctrica Machu Picchu S.A.	108.8	821	103 Studies: S/. 955,800
14	Tablachaca 2	Iesa S.A.	200.0	850	Not estimated
15	Uchuhuerta	Electroandes S.A.	30.0	235	36 Studies: US$ 342,192
16	Pías II	Aguas y Energía Perú S.A.	16.0	Not estimated	Studies: US$ 462,612

Source : Ministerio de Energía y Minas, Dirección General de Electricidad, October 2007.

Annex 3: Hydropower Projects with Concessions and Authorizations (continued)
Table 3: Hydropower Projects with Authorizations

No.	Name	Project Sponsor	Design Capacity (MW)	Estimated Annual Production (GWh)	Estimated Investment (US$ Mio.)
1	Caña Brava	Duke Energy Egenor S. En C. Por A.	5.65	Not estimated	6.05
2	Carhuaquero IV	Duke Energy Egenor S. En C. Por A.	9.67	Not estimated	5.36
3	Gratón	SIIF Andina S.A.	5.00	Not estimated	4.72
4	Ispana-Huaca	Inversiones Productivas Arequipa S.A.C.	9.60	Not estimated	Not estimated
5	La Joya	Generadora de Energía del Perú S.A.	9.60	Not estimated	9.57
6	Pátapo	Generación Taymi S.R.L.	1.02	Not estimated	0.77
7	Roncador	Agroindustrias Maja S.A.C.	3.80	Not estimated	2.50
8	San Diego	Duke Energy Egenor S. En C. Por A.	3.24	Not estimated	2.93
9	Shali	ABR Ingenieros S.A.C.	8.95	Not estimated	8.10

Source: Ministerio de Energía y Minas, Dirección General de Electricidad, October 2007.

Annex 3: Hydropower Projects with Concessions and Authorizations (continued)

Table 4: Hydropower Projects with Studies (No Concession or Authorization)

No.	Name	Project Sponsor	Design Capacity (MW)	Estimated Annual Production (GWh)	Estimated Investment (US$ Mio.)
1	Aricota III	Empresa de Generación del Sur - Egesur	19	66	21
2	Ayapata	Empresa de Generación Eléctrica San Gabán S.A.	80	491	183
3	Camana	Plan Maestro	3	23	8
4	Chaglla	Electroperú S.A.	420	2,811	586
5	Culqui	Electroperú S.A.	20	133	54
6	Cumba	Electroperú S.A.	825	4,524	974
7	El Chorro	Ex Corporación del Santa	150	491	48
8	Huascarán	Heracles	55	99	56
9	La Guitarra	Electroperú S.A.	220	1,831	235
10	Lluclla II	Peruana de Energía S.A.	90	121	112
11	Lluta	Plan Maestro	280	1,604	417
12	Mayush	Electroperú S.A.	100	695	207
13	Molloco I	Electroperú S.A.	200	1,014	235
14	Molloco II	Electroperú S.A.	110	558	95
15	Olmos I	Proyecto Especial Olmos - Tinajones	300	1,116	239
16	Pampa Blanca	Chavimochic	66	514	60
17	Paquitzapango	Electroperú S.A.	1379	10,734	1,775
18	Puerto Prado	Plan Maestro	620	4,764	1,250
19	Quishuarani I	Electroperú S.A.	90	467	125
20	Rentema	Electroperú S.A.	1500	6,509	750
21	San Gabán IV	Empresa de Generación Eléctrica San Gabán S.A.	130	845	183

Source : Ministerio de Energía y Minas, Dirección General de Electricidad, October 2007.

Annex 4: Candidate Hydropower Projects for Addition to the National Interconnected Power System

Project	Region	Installed Capacity (MW)	Investment (US$ Mio.)	Specific Capacity Cost (US$/kW)
C.H. Olmos I	Norte	120	80.02	667
C.H. Olmos II	Norte	120	89.83	749
C.H. Quitaracsa I	Norte Media	112	94.79	846
C.H. Santa Rita	Norte Media	174	137.60	791
C.H. Cheves	Centro	158.6	146.50	924
C.H. Huanza	Centro	86	84.10	978
C.H. G1 El Platanal	Centro	220	246.21	1119
C.H. La Virgen	Centro	58	56.40	972
C.H. Macchu Picchu (Extension)	Sur	71	73.95	1042
C.H. Santa Teresa	Sur	110	72.30	657
C.H. San Gabán I	Sur	120	141.51	1179
C.H. Tarucani	Sur	50	55.59	1112
C.H. Lluclla II	Sur	380	307.97	810
C.H. Pucará	Sur	130	136.40	1049

Source : From Ministerio de Energía y Minas [2006], Plan Referencial 2006-2015, Tabla 3.3.

Annex 5: Catalogue of Hydropower Projects up to 100 MW Indentified in 1979 'Hydropower Potential' Study (Part 1)

No.	Project	Mean Flow (m^3/s)	Net Head (m)	Installed Capacity (MW)	Annual Energy (GWh)	Price level : January 1979			Price level : 2007[3/]		
						Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)	Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)
1	JEQUE70	33.5	105.1	29.4	164.8	14.4	1.03	408	22.4	1.60	634
2	PISCO70	30.2	359.7	90.5	721.3	102.0	1.22	939	158.3	1.90	1,458
3	JORGE10	31.8	332.7	88.2	651.5	112.3	1.16	1,061	174.3	1.80	1,647
4	CHICA30	51.9	67.3	29.1	168.7	102.8	1.55	2,944	159.6	2.41	4,570
5	ANDA20	6.5	687.9	37.3	186.3	19.1	1.20	427	29.7	1.87	663
6	ICA10	23.6	179.9	35.4	254.9	148.7	2.04	3,501	230.8	3.17	5,434
7	CHIN20	77.2	73.4	47.3	384.8	73.3	2.23	1,291	113.8	3.47	2,005
8	ANDA30	6.5	875.8	47.5	237.2	28.6	1.41	502	44.4	2.20	779
9	OTOCA10	9.6	754.4	60.4	529.0	56.6	2.42	781	87.9	3.76	1,212
10	VNOTA10	104.0	108.4	94.0	706.7	147.1	2.44	1,304	228.4	3.79	2,025
11	PER20	259.7	31.0	67.1	416.1	58.6	1.65	728	91.0	2.56	1,130
12	HUA40	30.0	287.8	72.0	473.6	78.2	1.94	905	121.4	3.01	1,405
13	CHICA20	50.6	105.5	44.5	269.7	256.8	2.37	4,809	398.7	3.68	7,466
14	LAMB10	17.2	346.7	49.8	315.8	37.9	1.41	634	58.8	2.19	985
15	TACNA30	4.3	976.3	35.0	240.0	44.7	2.19	1,064	69.4	3.39	1,652
16	LUCUM20	4.6	372.1	14.3	125.0	32.0	3.01	1,865	49.7	4.67	2,895
17	MARA150	104.0	61.8	53.6	286.4	49.4	2.02	768	76.7	3.14	1,192
18	PALCA30	23.1	286.4	55.2	338.2	47.4	1.64	716	73.6	2.55	1,111
19	APUR25	57.3	56.7	27.1	161.3	39.2	2.85	1,205	60.9	4.43	1,871
20	URAB10	9.6	1228.8	98.4	861.6	230.3	3.14	1,950	357.5	4.87	3,028
21	VNOTA200	109.0	53.5	48.6	291.8	55.4	2.23	950	86.0	3.46	1,475
22	MARA160	107.3	68.3	61.1	398.6	70.6	2.08	963	109.6	3.22	1,495
23	MARA120	93.6	104.4	81.5	443.4	88.5	2.34	863	137.4	3.63	1,340
24	CHON10	24.1	220.6	44.3	295.5	72.4	2.87	1,362	112.4	4.46	2,114
25	OTOCA20	11.6	713.9	69.1	576.6	157.9	3.08	1,904	245.1	4.79	2,956
26	CHIR10	26.0	264.1	57.3	456.0	80.8	2.08	1,175	125.4	3.23	1,824
27	HUAL150	236.0	26.7	52.5	325.2	49.3	1.78	783	76.5	2.76	1,215
28	TAB10	75.0	86.9	54.3	424.8	95.4	2.63	1,464	148.1	4.09	2,273
29	HUA10	10.2	898.2	76.7	524.9	102.9	2.30	1,118	159.7	3.57	1,736
30	TACNA50	4.3	321.5	11.5	79.1	17.8	2.65	1,290	27.6	4.11	2,002
31	CHIN10	69.3	99.8	57.7	469.0	130.3	3.26	1,882	202.3	5.06	2,921
32	ANDA10	6.5	786.7	42.6	373.5	111.2	3.49	2,175	172.6	5.42	3,377
33	TACNA40	4.3	357.6	12.8	88.0	20.3	2.71	1,322	31.5	4.20	2,052
34	MAN130	74.5	88.0	54.7	324.3	78.9	2.86	1,202	122.5	4.43	1,866
35	SANTA60	52.0	214.8	93.2	646.4	194.7	3.06	1,741	302.3	4.75	2,703
36	MAN60	56.1	64.0	29.9	184.9	41.3	2.62	1,151	64.1	4.06	1,787
37	OLMOS20	32.4	269.8	73.0	501.1	103.9	2.43	1,186	161.3	3.78	1,841
38	JEQUE10	8.5	674.5	47.8	277.9	73.8	3.11	1,287	114.6	4.83	1,997
39	TACNA20	4.3	482.9	17.3	118.7	29.8	2.94	1,435	46.3	4.57	2,228
40	CHIL130	12.9	645.3	69.5	348.5	90.0	2.90	1,079	139.7	4.51	1,675

Annex 5: Catalogue of Hydropower Projects up to 100 MW Indentified in 1979 'Hydropower Potential' Study (Part 2 continued)

No.	Project	Mean Flow	Net Head	Installed Capacity	Annual Energy	Price level : January 1979 Investment Cost[1/]	Specific Energy Cost[2/]	Specific Capacity Cost	Price level : 2007[3/] Investment Cost[1/]	Specific Energy Cost[2/]	Specific Capacity Cost
		(m^3/s)	(m)	(MW)	(GWh)	(US$ Mio)	(US¢/kWh)	(US$/kW)	(US$ Mio)	(US¢/kWh)	(US$/kW)
41	CHANC10	9.2	1093.4	84.3	536.5	110.8	2.42	1,095	172.0	3.76	1,700
42	LAMB20	30.2	269.3	67.9	426.4	119.2	3.28	1,463	185.1	5.09	2,271
43	SANTA90	73.5	86.2	52.8	331.5	97.7	2.82	1,542	151.7	4.37	2,394
44	MAN70	58.8	44.3	21.7	134.1	37.0	3.23	1,421	57.4	5.02	2,206
45	JEQUE20	8.5	360.8	25.6	155.0	46.4	3.24	1,510	72.0	5.03	2,345
46	CHFC10	6.6	1246.0	68.4	472.9	136.5	3.39	1,663	211.9	5.26	2,582
47	CHAN30	77.1	150.6	96.8	669.2	191.5	3.36	1,649	297.3	5.21	2,559
48	MAN80	92.5	87.8	67.7	413.4	120.8	3.43	1,487	187.5	5.32	2,308
49	MANTA10	9.8	954.6	77.9	423.6	92.4	2.56	988	143.4	3.97	1,534
50	PUZ20	48.6	237.4	96.2	733.8	261.6	4.18	2,266	406.1	6.49	3,518
51	COLCA10	11.2	171.0	16.0	105.4	36.1	4.02	1,880	56.0	6.24	2,919
52	CASMA50	24.3	269.8	54.7	375.8	125.5	3.80	1,912	194.8	5.90	2,968
53	TOTOR10	14.8	179.9	22.2	127.4	27.5	2.53	1,032	42.7	3.93	1,603
54	SANTA30	32.3	151.0	40.7	286.0	112.9	3.60	2,312	175.3	5.60	3,589
55	TABLA10	27.5	421.1	96.6	576.3	182.2	3.54	1,530	282.9	5.50	2,375
56	CHAMA50	87.0	54.6	39.6	262.4	84.6	3.78	1,780	131.3	5.87	2,764
57	JEQUE30	8.5	359.7	25.5	159.5	68.1	3.79	2,226	105.7	5.88	3,455
58	JEPF10	123.0	53.3	54.7	339.1	85.4	2.27	1,301	132.6	3.52	2,020
59	CASMA60	24.3	80.9	16.4	113.6	54.6	4.09	2,774	84.8	6.34	4,307
60	PISC020	9.1	756.9	57.4	254.6	56.8	2.62	783	88.2	4.06	1,215
61	CHANC20	15.7	719.4	94.0	593.2	153.8	3.04	1,364	238.8	4.72	2,117
62	MOCHE10	5.8	1512.3	73.5	384.3	163.7	4.22	1,856	254.1	6.54	2,881
63	SANTA40	18.3	524.0	80.1	623.1	2,717.3	4.82	2,885	4,218.4	7.49	4,479
64	MARCA70	64.0	179.9	96.0	595.0	138.5	2.73	1,202	215.0	4.24	1,866
65	HUABA20	141.4	65.7	77.4	482.9	146.0	3.55	1,572	226.7	5.50	2,440
66	PISC040	16.9	361.4	50.9	229.6	50.7	2.59	830	78.7	4.02	1,289
67	SANJU20	20.0	533.9	89.1	395.8	114.2	3.38	1,068	177.3	5.25	1,658
68	PAUC270	61.0	157.4	80.1	656.1	297.4	5.32	3,094	461.7	8.25	4,803
69	CHICHA10	17.8	614.9	91.4	457.1	149.0	3.82	1,359	231.3	5.93	2,109
70	QUIRO10	13.0	151.7	16.4	100.9	39.6	4.61	2,012	61.5	7.15	3,124
71	SANTA10	7.2	238.1	14.4	120.5	85.8	5.46	4,965	133.2	8.48	7,708
72	CHAN10	13.0	648.9	70.4	438.7	186.9	5.00	2,212	290.2	7.76	3,435
73	PAMI10	44.8	64.7	24.2	140.0	56.3	2.66	1,939	87.4	4.13	3,010
74	CHAMA30	51.6	129.4	55.7	361.8	128.3	4.16	1,920	199.2	6.46	2,980
75	SANJU10	14.3	530.6	63.3	280.9	89.0	3.71	1,172	138.2	5.77	1,819
76	URUM15	21.2	563.4	99.6	695.1	312.3	5.26	2,613	484.8	8.17	4,056
77	VNOTA60	91.1	97.6	74.1	538.4	258.8	5.64	2,911	401.8	8.75	4,518
78	SAMA30	30.0	314.8	78.8	361.5	104.6	3.39	1,106	162.4	5.27	1,717
79	UTC30	50.0	131.1	54.7	387.4	186.3	5.64	2,838	289.2	8.76	4,406
80	JEQUE60	33.0	144.9	39.9	209.3	133.7	5.04	2,792	207.6	7.83	4,335

Annex 5: Catalogue of Hydropower Projects up to 100 MW Indentified in 1979 'Hydropower Potential' Study (Part 3 continued)

No.	Project	Mean Flow (m^3/s)	Net Head (m)	Installed Capacity (MW)	Annual Energy (GWh)	Price level : January 1979 Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)	Price level : 2007[3/] Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)
81	JFQUE50	32.5	196.3	53.2	314.9	189.2	5.41	2,964	293.7	8.40	4,601
82	RIMAC10	5.1	1253.1	53.3	421.3	199.6	5.56	3,121	309.9	8.63	4,845
83	CANET90	31.8	283.3	75.2	373.4	122.4	3.84	1,356	190.0	5.97	2,106
84	MARA50	32.4	346.2	93.4	514.8	227.9	5.19	2,033	353.8	8.06	3,157
85	SAMA20	30.0	314.8	78.8	361.5	109.0	3.54	1,153	169.2	5.49	1,789
86	APUR90	69.6	73.7	42.7	213.9	31.8	4.48	1,596	49.4	6.96	2,478
87	CHILL20	8.4	359.7	25.3	161.2	54.5	3.97	1,795	84.6	6.16	2,787
88	RIMAC20	27.0	224.8	50.6	266.1	95.7	3.94	1,576	148.6	6.12	2,447
89	CHILI20	8.3	223.8	15.5	97.6	122.3	5.95	6,575	189.9	9.24	10,208
90	JEQUE40	17.2	171.0	24.5	133.8	114.7	5.49	3,901	178.1	8.52	6,057
91	SGAB60	75.0	109.3	68.3	432.5	175.5	4.76	2,141	272.5	7.39	3,324
92	YANA10	32.0	274.9	73.4	478.5	172.5	4.23	1,958	267.8	6.56	3,040
93	CANET40	20.3	481.9	81.7	410.5	167.9	4.69	1,713	260.7	7.28	2,659
94	PAM84	36.6	59.4	18.1	104.9	48.3	5.24	2,224	75.0	8.14	3,452
95	ICHU20	13.2	352.4	38.8	207.0	94.0	5.33	2,019	145.9	8.27	3,134
96	CHAL10	20.2	294.8	49.8	275.9	135.3	5.75	2,264	210.0	8.93	3,515
97	VIL10	21.6	275.6	49.6	330.0	167.3	5.95	2,811	259.7	9.23	4,364
98	CHILL10	8.4	940.6	66.2	353.4	123.7	4.10	1,557	192.0	6.37	2,417
99	TAMBO30	31.5	359.7	94.5	751.5	231.1	5.89	2,038	358.8	9.14	3,164
100	SAMA40	30.0	107.9	27.0	236.5	68.8	7.04	2,123	106.8	10.92	3,296
101	PISCO30	12.0	539.6	54.0	239.3	79.3	3.89	1,224	123.1	6.04	1,900
102	OYO10	5.7	1879.0	89.3	337.1	175.8	6.12	1,641	272.9	9.50	2,547
103	SAMA50	33.2	60.9	16.9	147.8	30.5	7.06	1,504	47.3	10.96	2,335
104	MALA20	16.0	539.6	72.0	319.1	106.7	3.92	1,235	165.6	6.09	1,917
105	CHOTA10	17.2	108.0	15.5	108.3	57.1	6.19	3,070	88.6	9.60	4,766
106	QUIRO20	20.4	257.6	43.8	276.9	148.4	6.29	2,823	230.4	9.76	4,383
107	CHON20	37.6	214.8	54.8	363.7	193.4	6.24	2,941	300.2	9.68	4,566
108	VIL20	37.2	94.0	29.2	163.7	75.2	5.39	2,146	116.7	8.36	3,332
109	COTAH20	30.3	359.7	90.8	316.7	105.1	3.89	965	163.2	6.03	1,497
110	HUAN10	19.1	343.1	54.8	446.4	284.4	7.47	4,325	441.5	11.60	6,714
111	OXA30	16.1	264.5	35.5	249.6	141.9	6.67	3,331	220.3	10.35	5,171
112	TAMBO20	24.2	302.6	61.1	533.5	235.0	7.87	3,205	364.8	12.22	4,976
113	OCONA80	89.7	127.9	95.7	442.8	203.2	5.51	1,813	315.5	8.56	2,814
114	TAMBO90	54.3	179.9	81.5	557.9	170.9	6.14	1,747	265.3	9.54	2,711
115	MALA10	16.0	584.5	78.0	345.6	142.1	4.58	1,518	220.6	7.11	2,357
116	COLCA60	46.4	89.9	34.8	187.8	70.5	4.40	1,688	109.4	6.84	2,621
117	SANJU30	20.0	359.7	60.0	265.3	104.6	4.62	1,453	162.4	7.18	2,255
118	BLANC10	3.9	390.1	12.7	81.7	89.5	7.94	5,873	138.9	12.32	9,117
119	CANET10	5.4	1022.2	45.6	353.8	290.2	8.39	5,303	450.5	13.02	8,233
120	CHILL30	8.4	179.9	12.7	80.6	37.0	5.39	2,428	57.4	8.36	3,769

Annex 5: Catalogue of Hydropower Projects up to 100 MW Indentified in 1979 'Hydropower Potential' Study (Part 4 continued)

No.	Project	Mean Flow (m^3/s)	Net Head (m)	Installed Capacity (MW)	Annual Energy (GWh)	Price level : January 1979 Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)	Price level : 2007[3/] Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)
121	TACNA10	4.3	472.0	16.9	138.2	100.2	8.50	4,941	155.6	13.19	7,670
122	OYO20	7.9	972.5	64.2	164.3	61.0	4.35	792	94.7	6.76	1,229
123	SANJU40	20.0	354.1	59.1	267.1	118.4	5.20	1,670	183.8	8.07	2,592
124	MOCHE20	5.8	582.8	28.3	125.7	50.0	4.67	1,472	77.6	7.24	2,286
125	TAMB0100	54.3	179.9	81.5	557.9	212.6	5.91	2,170	330.0	9.17	3,368
126	CONAS10	14.2	180.5	21.4	160.2	114.7	8.40	4,467	178.1	13.03	6,934
127	PUCH10	15.4	223.7	28.7	154.3	85.0	6.46	2,468	132.0	10.03	3,832
128	SANTA20	13.1	303.7	33.3	223.8	161.0	7.43	4,029	249.9	11.54	6,255
129	CHAMA10	29.2	169.9	41.4	321.0	239.7	8.76	4,825	372.1	13.60	7,490
130	SANTA70	52.0	170.9	74.1	456.7	236.6	6.08	2,661	367.3	9.43	4,131
131	TAMBO110	56.5	107.5	50.6	373.7	167.9	8.15	2,765	260.7	12.66	4,293
132	SONDO30	13.2	583.2	64.2	393.1	293.7	8.76	3,812	456.0	13.61	5,918
133	STOM30	25.7	300.2	64.4	368.3	238.0	7.58	3,080	369.5	11.77	4,781
134	PISC050	*16.9*	539.6	76.1	342.8	140.5	4.81	1,539	218.1	7.46	2,389
135	CHOTA30	17.5	105.8	15.4	113.9	86.6	8.92	4,686	134.4	13.84	7,275
136	SUNDO20	6.8	458.7	26.0	154.7	109.8	8.32	3,519	170.5	12.92	5,463
137	ARMA20	9.4	1164.0	90.8	232.1	97.4	4.67	894	151.2	7.25	1,388
138	CHAMA40	51.6	89.9	38.7	251.1	127.4	5.95	2,743	197.8	9.24	4,259
139	VIZCA10	15.6	248.0	32.4	168.3	121.4	8.46	3,122	188.5	13.14	4,847
140	SANJU50	20.0	171.5	28.6	148.1	104.7	8.29	3,051	162.5	12.88	4,736
141	ARMA30	9.4	1217.5	94.9	242.8	115.9	5.60	1,018	179.9	8.69	1,580
142	TAMBO80	54.3	179.9	81.5	557.9	356.0	8.62	3,640	552.7	13.39	5,651
143	APU10	11.8	171.0	16.8	135.6	133.0	11.49	6,597	206.5	17.83	10,242
144	HUAN20	23.4	129.4	25.2	179.6	143.1	9.34	4,732	222.2	14.51	7,346
145	VILCA70	26.4	344.2	75.9	406.3	283.6	8.19	3,114	440.3	12.71	4,834
146	COLCA30	32.1	128.8	34.5	251.4	221.8	10.02	5,358	344.3	15.56	8,317
147	HUAN35	29.3	45.0	11.0	75.7	57.9	8.99	4,386	89.9	13.96	6,810
148	PISC010	9.1	353.1	26.8	145.2	143.0	11.00	4,447	222.0	17.07	6,903
149	PARA20	7.2	765.8	46.3	153.7	71.0	5.42	1,278	110.2	8.41	1,984
150	MARCA40	32.4	156.9	42.4	282.5	248.6	10.32	4,886	385.9	16.02	7,585
151	CHICA10	7.0	527.9	30.8	173.8	178.2	12.02	4,821	276.6	18.67	7,485
152	OCONA05	19.6	351.0	57.4	256.0	236.4	10.83	3,432	367.0	16.81	5,328
153	CHOTA20	6.3	236.3	12.4	73.5	*59.0*	12.60	5,302	91.6	19.56	8,232
154	TAMBO10	19.0	172.1	27.3	238.8	300.3	14.12	9,167	466.2	21.92	14,231
155	COLCA40	32.1	89.9	24.1	164.6	181.3	10.75	6,269	281.5	16.69	9,732
156	CAJA10	14.7	65.6	8.1	55.3	59.2	12.54	6,091	91.9	19.47	9,455
157	YAUCA20	7.4	699.5	43.2	153.3	148.1	11.26	2,857	229.9	17.48	4,435
158	MOCHF30	9.9	216.5	17.8	96.9	143.7	12.90	6,728	223.1	20.03	10,444
159	CONDF10	7.5	306.4	19.2	125.8	176.7	16.49	7,669	274.3	25.59	11,906
160	LLAU10	8.4	332.9	23.2	174.5	345.4	23.22	12,407	536.2	36.04	19,260
161	YAUCA40	7.4	197.8	12.2	35.3	41.2	13.69	2,814	64.0	21.25	4,369
162	PARA10	3.5	1030.9	30.4	71.3	110.4	18.15	3,026	171.4	28.18	4,698
163	YAUCA10	5.4	507.3	22.8	73.7	182.7	28.41	6,678	283.6	44.10	10,367

Annex 5: Catalogue of Hydropower Projects up to 100 MW Indentified in 1979 'Hydropower Potential' Study (Part 5 continued)

No.	Project	Mean Flow (m³/s)	Net Head (m)	Installed Capacity (MW)	Annual Energy (GWh)	Price level : January 1979 Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)	Price level : 2007[3/] Investment Cost[1/] (US$ Mio)	Specific Energy Cost[2/] (US¢/kWh)	Specific Capacity Cost (US$/kW)
	Total			8,377.5	51,084.8						
	Ave	32.9	359.9	51.4	313.4	141.7	5.44	2,460	220.0	8.44	3,819
	Min	3.5	26.7	8.1	35.3	14.4	1.03	408	22.4	1.60	634
	Max	259.7	1879.0	99.6	861.6	2,717.3	28.41	12,407	4,218.4	44.10	19,260

Source: Lahmeyer-Salzgitter-MEM [1979], "Evaluación del Potencial Hidroeléctrico Nacional", Vol II (Metodología y Resultados), Tabla 6.6.

Notes:

1. Investment costs include:
   - engineering and administration (developer's own costs),
   - contingencies,
   - in the case of multipurpose projects, deduction of present value of net benefits other than from electricity (mainly irrigation).

   Investment costs do not include:
   - transmission costs,
   - 'interest during construction', approximated in the Hydropower Potential study IDC = T + DR/2, where T = construction period and DR = discount rate.

   For the above table IDC has been deducted from the investment cost assuming a 4-year construction period and 10percent discount rate.

2. In the original Table 6.6 the projects are listed according to increasing specific energy costs (sum of i) annualized investment costs (over the project useful/economic life) and ii) annual operation, maintenance and repair (OM&R) costs, divided by the average annual energy production.) whereby the specific energy cost was computed using a weighting factor of 0.5 on 'secondary' energy. The order of listing is maintained in the above table, but the indicated specific energy cost has been re-computed on the basis of total energy production (without weighting of secondary energy).

3. Investment costs include have been updated from January 1979 to 2007 price level using the Manufactures Unit Value (MUV) index prepared by the Development Prospects Group (DECPG) of the World Bank [2007c].

Annex 6: Specific Capacity Costs of Projects with Concessions and Authorizations

a) Concessions

No.	Project	Installed Capacity (MW)	Investment Cost (US$ Mio.)	Specific Capacity Cost (US$/kW)
	Definitive Concession			
1	Centauro I y III	25.0	14.0	560
2	Cheves	158.0	160.4	1,015
3	G1 El Platanal	220.0	155.0	705
4	Huanza	86.0	56.2	653
5	La Virgen	64.0	54.9	858
6	Marañón	96.0	78.0	813
7	Macchu Picchu (Extension)	71.0	85.0	1,197
8	Morro de Arica	50.0	128.0	2,560
9	Pías 1	11.0	13.4	1,218
10	Poechos (2nd powerhouse)	10.0	9.0	900
11	Pucará	130.0	136.4	1,049
12	Quitaracsa I	112.0	78.5	701
13	San Gabán I	120.0	132.2	1,102
14	Santa Rita	173.5	134.1	773
15	Tarucani	49.0	46.9	957
	Average	91.7		1,004
	Minimum	10.0		560
	Maximum	220.0		2,560
	Temporary Concession			
1	Copa	92.0	-	-
2	Chaglla (Variante)	240.0	-	-
3	Cheves II	75.0	-	-
4	Cheves III	123.5	-	-
5	El Caño	100.0	119.0	1,190
6	La Guitarra	220.0	235.0	1,068
7	Llaclla 2	71.0	-	-
8	Napo-Mazan	154.1	-	-
9	Quiroz-Vilcazán	18.0	-	-
10	Rapay	90.0	-	-
11	San Gabán II (Refurbishment)	-	-	-
12	San Gabán III	-	153.0	-
13	Santa Teresa	108.8	103.0	947
14	Tablachaca 2	200.0	-	-
15	Uchuhuerta	30.0	36.0	1,200
	Average	117.1		1,101
	Minimum	18.0		947
	Maximum	240.0		1,200

Annex 6: Specific Capacity Costs of Projects with Concessions and Authorizations

b) Authorizations and Studies

No.	Project	Installed Capacity (MW)	Investment Cost (US$ Mio.)	Specific Capacity Cost (US$/kW)
	Authorizations			
1	Caña Brava	5.7	6.1	1,071
2	Carhuaquero IV	9.7	5.4	554
3	Gratón	5.0	4.7	944
4	Ispana-Huaca	9.6	-	-
5	La Joya	9.6	9.6	997
6	Pátapo	1.0	0.8	755
7	Roncador	3.8	2.5	658
8	San Diego	3.2	2.9	904
9	Shali	9.0	8.1	905
	Average	6.3		849
	Minimum	1.0		554
	Maximum	9.7		1,071
	With studies only			
1	Aricota III	19.0	21.0	1,105
2	Ayapata	80.0	183.0	2,288
3	Camana	2.8	8.0	2,857
4	Chaglla	420.0	586.0	1,395
5	Culqui	20.0	54.0	2,700
6	Cumba	825.0	974.0	1,181
7	El Chorro	150.0	48.0	320
8	Huascarán	55.0	56.0	1,018
9	La Guitarra	220.0	235.0	1,068
10	Lluclla II	90.0	112.0	1,244
11	Lluta	280.0	417.0	1,489
12	Mayush	100.0	207.0	2,070
13	Molloco I	200.0	235.0	1,175
14	Molloco II	110.0	95.0	864
15	Olmos I	300.0	239.0	797
16	Pampa Blanca	66.0	60.0	909
17	Paquitzapango	1,379.0	1775.0	1,287
18	Puerto Prado	620.0	1250.0	2,016
19	Quishuarani I	90.0	125.0	1,389
20	Rentema	1,500.0	750.0	500
21	San Gabán IV	130.0	183.0	1,408
	Average	317.0		1,384.8
	Minimum	2.8		320.0
	Maximum	1,500.0		2,857.1

All (Concessions, Authorizations and Studies)			
Average	179.8		1,157.5
Minimum	1.0		320.0
Maximum	1,500.0		2,857.1

Annex 7: A General Guide to Scope and Accuracy of Hydropower Projects Studies

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Level: INVENTORY	Level: PREFEASIBILITY	Level: FEASIBILITY
Objective: Establish a comprehensive catalogue of project options for the candidate reach or site(s).	**Objective:** Determine provisional ranking of options taking into account optimal integrated development of river reach.	**Objective:** Demonstrate technical, environmental, economic and financial feasibility of project.
Topography: Minimum requirement aerial photography at least 1:60,000, preferably 1:25,000, for stereoscopic interpretation (geometric, geologic, and agronomic). Vertical control and river profiles by surveying altimeter. Contour maps by photogrammetric interpretation covering possible dam sites and reservoir areas (for elevation/area/ volume curves). Field surveys of cross-sections at dam, powerhouse and other hydraulic works for topographic maps at 1:5,000 with 5 or 10 m contours. **Hydrology:** Historical discharge series of about 30 years, either recorded at (or near) site or reconstituted by regression with records at nearby locations and/or by catchment model. Probabilistic assessment of severity of stream flow deficiency periods included in series. Estimated probability curves of flood peaks and volumes, possibly from regional analysis. Evaluation of regionally available data on sediment transport for estimation of accumulation rates in reservoir. Approximate assessment of precipitation/evaporation balances in reservoir area. **Geology:** Surface reconnaissance to enable inferences to be made on depth of alluviums, tectonic features, availability of construction materials, pervious formations and slope stability at dam site and reservoir area. Possibly some sub-surface investigation by geophysical methods for larger project after preliminary screening of options. **Socio-environment:** Sufficient agronomic and demographic information to quantify loss of agricultural land and commercial enterprises, number of families or persons to be resettled, etc. Qualitative evaluation of impacts relating to biodiversity, erosion, forest habitat, aquatic ecology, health, archaeology, legal aspects, etc.	**Topography:** Photogrammetric survey of reservoir area, altimetric precision corresponding to 1:5,000 up to 1:25,000 scales with 2 or 5 m contours. Verification of 1:5,000 topography at sites by additional cross-sections. Linkage of surveys (and water level gauges) with regional or national geodetic network. **Hydrology:** Verification of stream flow series established at inventory level. Derivation of design flood hydrographs at various probabilities for spillway and diversion works. Detailed analysis of any sediment load measurements made since inventory, for better estimation of deposition rates and design of any trapping and separating structures. De-termination of stage discharge relation-ship at dam sites and powerhouses based on staff gauge readings and discharge measurements. **Geology:** Sub-surface investigation by geophysical methods (seismic and/or electrical resistivity) to yield more accurate interpretation of foundation conditions for major hydraulic structures. Verification of previous assessments of slope stability and perviousness formations in reservoir area and at dam site. In special circumstances, limited mechanical drilling at specific sites of larger projects. **Socio-environment:** Field surveys to improve inventory level estimates of resettlement and inundation of agricultural lands and business enterprises. Re-assessment of potential social and environmental problems for IEE report to development bank requirements.	**Topography:** Field surveys at structure sites and compilation of 1:2,000 maps with 2 m contours. Surrounding areas at 1:5,000 with 2 or 5 m contours. Verification of profiles, reservoir area/volume curves and maps prepared during earlier studies. **Hydrology:** Updating of previously derived stream flow and meteorological series, flood hydrographs and sediment deposition rates by incorporating any further data obtained since previous study. **Geology:** Comprehensive sub-surface investigations by mechanical drilling at sites of major surface structures and underground works (tunnels, caverns), supplemented by trenches and exploration audits at dam abutments, along tunnel alignments and in area of underground powerhouse. Complementary investigations by geophysical methods if necessary. Detailed verification of previous evaluations of slope stability, perviousness of formations and availability of construction materials. **Socio-environment:** Verification of pre-feasibility estimates of resettlement and inundation of agricultural lands and commercial enterprises. Detailed evaluation of socio-environmental benefits and potential problems, with recommendations for solutions. Preparation of detailed plans and costing for measures to be undertaken during construction and operation of project. EIA report to bank requirements.

(cont.)

Annex 7: A General Guide to Scope and Accuracy of Hydropower Projects Studies

(Page 2 of 2)

Level: INVENTORY	Level: PREFEASIBILITY	Level: FEASIBILITY
Design: Consideration of several project layouts, including variations of dam axis location, waterway alignment and power-house location. Use of generalized types of dam (earth fill, rock fill, concrete gravity dam, etc.), hydraulic structures and electro-mechanical equipment, avoiding non-conventional designs intended to reduce costs. Standard criteria for selection of nominal installed capacities and reservoir operating levels. Presentation as single drawing showing general layout and sections through principal structures, supplemented by technical data sheet.	**Design:** Consideration of various project layouts (maximum operating levels and powerhouse locations), for optimum develop-ment of river reach or site. Variations around pivotal design (dam height/installed capacity) to permit optimization. Use of specific solutions for major project features such as diversion works, dam, spillway, waterways, powerhouse.	**Design:** Economic optimization of principal project features such as flood surcharge (trade-off spillway capacity and dam crest elevation), diversion works size, waterway dimensions, etc. Preliminary stability analysis of major structures. Particular consideration of construction methods and schedules and their influence on project cost. Details of drawings sufficient for offtake of volumes and costs, including access roads and construction site installations.
Costing: Consistent criteria and standard procedures to obtain homogenous cost estimates of project components, indirect costs and contingencies. Individual unit or total costs represented as functions of specific project variables, on basis of information from suppliers and actual civil works costs incurred on completed projects. Estimates of operation and maintenance costs based on experience in existing projects. Breakdown of costs into labour, equipment and materials, foreign and local currency.	**Costing:** Standard cost estimating procedure similar to that used at inventory level, possibly with greater desegregation into project components.	**Costing:** Use of standard procedures applied during inventory and prefeasibility studies as a basic reference for detailed cost estimate. Determination of unit cost composition of main construction items, taking into consideration capability of local labour, performance of construction equipment, costs of supply and handling of materials, meteor-ological conditions, access, etc. Combination of cost estimates with construction schedule to yield investment schedule.
Evaluation: Computation of energy production and capacity availability over period of recorded or reconstituted streamflow series, taking into account reservoir elevation area/volume relation-ships, evaporation and seepage, turbine performance characteristics, existing and planned river basin developments and other uses (irrigation, water supply, flood control), using simplified i.e. system independent operating policies. Assessment of power and other benefits to yield estimates of net benefits and unit values of kW and kWh for projects and alternatives, applying cost allocation procedure to multi-purpose projects	**Evaluation:** Assessment of energy production, capacity availability and power and other benefits for project variants (range of dam heights and installed capacities), applying procedures similar to those used during inventory study, possibly incorporating in some form an optimization model, to arrive at a development of the river reach or site which maximizes total net benefits. Refinement of the scheme, in particular more detailed assessment of installed capacity based on system approach or assumed PPA terms and conditions.	**Evaluation:** Demonstration of technical feasibility of constructing project. Economic evaluation and detailed financial analysis based on estimated investment schedule and possible sources of finance. All assumptions to be stated and sensitivity testing of plausible adverse outcomes included. Benefits, risks and returns for participants to be clearly identified.

All three levels of investigation provide input data to the continuously on-going planning process which in turn yields technical and economic bases for:

i) identifying river basins or reaches for study at prefeasibility level;

ii) selecting individual projects for study at feasibility level;

iii) deciding to construct a project.

Annex 8: National Consulting Engineering Companies involved in Hydropower and Water Resources Projects

Company	Services	Example Hydropower Projects
S&Z Consultores Asociados S.A.	Studies, design and construction supervision	- Feasibility study and tender design Quitaracsa (200 MW) - Construction supervision Yuncán (130 MW) - Detailed design and construction supervision Monzón (360 kW)
CESEL Ingenierios	Studies, design and construction supervision	- Feasibility study Mollepata (592 MW) - Final design 36 mini-hydropower schemes (Prodeis Norte) - Construction supervision Charcani IV (135 MW)
Proyectos Especiales Pacífico S.A. (PEPSA)	Studies, design and construction supervision	- Studies, design and construction supervision Macchu Picchu (90 MW), Centauro (10 MW), Huanchór (15 MW)
Julio Bustamante y Asociados	Studies and design	- Prefeasibility and feasibility studies Copa (92 MW) and Rapay (90 MW) - Prefeasibility study Cheves I (158 MW)
GCZ Ingenieros S.A.C.	EPC, operation and maintenance	- Turnkey projects Lucanas (250 kW), Maca (2.5 MW), Santa Rosa (3 MW)

Annex 9: National Civil Engineering Contractors Involved in Hydropower and Water Resources Projects

Contractor	Example Water Resources Development Projects
G&M S.A.	- Cañón del Pato (50 MW) – dam, desander, tunnel, powerhouse - Yanango (40 MW – intake, tunnel, penstock
JJC Contratistas Generales S. A.	- El Platanal – 15 km tunnel, vertical shaft - Chavomochic – river crossing siphon - Jachacuesta – 7 km tunnel
Cosapi	- Mantaro (360 MW) – installation of electromechanical equipment - Río Chillón groundwater recharge – intake, wells, transmission line - San Gabán II (110 MW) – intake dam, desander
GCZ Ingenieros S.A.C.	- Turnkey projects Lucanas (250 kW), Maca (2.5 MW), Santa Rosa (3 MW)

Annex 10: Hydropower Turbine Manufacturers in Peru

Company	**Turbines Manufactured**			**Total Capacity Installed[1/]**		**Other Equipment / Services**
	Type	Head (m)	Max. Capacity (kW)	Peru (kW)	Other Countries (kW)	
GCZ Ingenieros SAC	Pelton	100 – 1,000	5,000	5,750	1,140	Control systems
	Francis	10 – 250	5,000	8,725	525	Valves
				Total : 16,140 kW		EPC
ITDG / Tepersac	(Axial	4 -12	60			
	Pelton		600			
	Mitchell-Banki		20	ca. 10,000		
Ing. Jorge Gutiérrez	Mitchell-Banki					
SAMMYCO – S&Z						
Ing. Villanueva						
3HC S.A.C.	Mitchell-Banki	10 - 320	0.5 - 150	ca. 750		
Hidrosatur S.A.C.	Francis		300			

1/ For GCZ Ingenieros, principal installations since from 1995 to date.

Annex 11: Agreement Between InterAmerican Development Bank and Instituto Nacional de Electrificación, Guatemala, on Feasibility Studies of Small to Medium-Sized Hydropower Projects

LEG/OPR/RGII/IDBDOCS#927659

Source: http://idbdocs.iadb.org/wsdocs/getdocument.aspx?docnum=927659
Date: 16 March 2007

ANEXO ÚNICO

Estudios de Factibilidad para Apoyar el Desarrollo de Pequeñas y Medianas Centrales Hidroeléctricas

I. **Objeto**

1.01 El Programa tiene por objeto coadyuvar al proceso de desarrollo de proyectos de pequeñas y medianas centrales hidroeléctricas (PMCH´s) en Guatemala, específicamente para: (a) seleccionar un conjunto de proyectos elegibles para realizar estudios de factibilidad; (b) elaborar para algunos de los proyectos elegibles los estudios requeridos hasta completar la fase de factibilidad; (c) identificar y plantear al INDE un conjunto de estrategias que permitan propiciar la participación municipal y/o privada en proyectos hidroeléctricos, entre otros, mediante el uso de nuevos modelos de asociación público-privada que movilicen recursos privados hacia proyectos impulsados por el sector público; y (d) llevar a cabo una evaluación de los resultados del Programa y los estudios llevados a cabo.

II. **Descripción**

2.01 Para el logro del objeto anterior, el Programa comprende los siguientes componentes:

Componente 1. Analizar los proyectos de la lista corta existente y escoger los proyectos que serán llevados a factibilidad.

2.02 Bajo este componente, se financiará la contratación de servicios de consultoría para integrar un equipo multidisciplinario de consultores (Equipo de Consultores) para revisar los perfiles de proyecto de la lista corta acordada con el Banco y realizar labores de campo y gabinete para escoger, utilizando métodos de decisión multicriterio (tomando en consideración factores técnicos, políticos, sociales y ambientales, entre otros), cuales proyectos de la lista serán sujetos de estudios hasta llevarlos a factibilidad.

Componente 2. Estudios de Factibilidad.

2.03 Bajo este componente, el Equipo de Consultores llevará a cabo los estudios para los proyectos escogidos. Los estudios comprenderán para cada proyecto, entre otros aspectos: (a) análisis de la información disponible y visitas a los sitios; (b) estudios topográficos; (c) estudios hidrológicos; (d) estudios geológico-geotécnicos y de riesgo sísmico; (e) estudios socio-ambientales preliminares; (f) estudio de alternativas y proyecto recomendado en cada caso; (g) prediseños hidráulicos de las obras; (h) análisis de costos y beneficios esperados; y, (i) análisis económico-financiero.

Componente 3. Promoción de Proyectos.

2.04 Bajo este componente se financiará la contratación de servicios de consultoría para desarrollar y proponer estrategias para lograr la integración del sector privado y municipal a los proyectos que impulsa el INDE. Específicamente se propondrán alternativas de asociación público-privada que permitan movilizar recursos del sector privado hacia proyectos impulsados por el sector público.

III. Costo del Programa y plan de financiamiento

3.01 El costo estimado del Programa es el equivalente de quinientos mil dólares (US$500.000), según la siguiente distribución por categorías de inversión y por fuentes de financiamiento:

Costo y financiamiento
(en US$)

	Rubro	Infrafondo	Contraparte	Total
1	**Componente 1**. Selección de proyectos candidatos	60.600	25.000	85.600
2	**Componente 2**. Estudios de factibilidad	279.500	75.000	354.500
3	**Componente 3**. Promoción de Proyectos	44.900		44.900
4	Evaluación final y revisión estudios de factibilidad	10.000		10.000
5	Auditoría Externa	5.000		5.000
	TOTAL	**400.000**	**100.000**	**500.000**
	Porcentaje	**80%**	**20%**	**100%**

IV. Ejecución

4.01 El Equipo de Consultores trabajará en el INDE en estrecha coordinación con la Oficina de Promoción de Proyectos Hidroeléctricos (OPPH); oficina que será la encargada de administrar integralmente el Programa y actuar como canal de comunicación formal con el Banco. Todos los movimientos de recursos que se efectúen (desembolsos y pagos) serán registrados contablemente por la unidad correspondiente del INDE.

4.02 El Programa contará con un coordinador que será responsable de la ejecución técnica. El coordinador tendrá entre sus principales actividades las siguientes: (a) liderar el equipo multidisciplinario estableciendo y velando por el cumplimiento de las metas y objetivos del Programa; (b) trabajar en estrecha coordinación con el Director de la Oficina de Promoción de Plantas Hidroeléctricas (OPPH) del INDE, buscando por medio de las actividades a realizar, reforzar la capacidad de la OPPH, de modo que pueda seguir desarrollando estudios de proyectos en PMCH´s una vez finalizado el Programa; y (c) programar, coordinar y velar porque las actividades necesarias para llevar a cabo los estudios, tanto a nivel de oficina como a nivel de campo, se realicen siguiendo un orden y secuencia lógica y debidamente programada.

4.03 El INDE tendrá además a su cargo la coordinación interinstitucional del Programa en particular con el Ministerio de Agricultura y Ganadería, el Ministerio de Energía y Minas, las municipalidades en las que se sitúan los proyectos a ser estudiados y el sector privado.

Annex 12: Requirements to Obtain an Authorization or Concession for Hydropower Development
Requirements and Procedure to obtain an Authorization for Hydropower Generation

The Decree of May 2008, described in Section 4.2 above, included several articles modifying the existing electricity law, among them changes to the modified authorization and concession requirements for hydropower generation, eliminating in practice *Authorizations* for plants larger than 500 kW of installed capacity. So, now hydroelectric plants with installed capacities larger than 500 kW will require a concession. Although there is no disposition in this new legislation regarding requirements for plants smaller than 500 kW, it follows from the general electricity law that this type of plants are unregulated (this does not prevent compliance with environmental and other sectors' regulations.

Requirements and Procedure to obtain a Temporary Concession for Hydropower Generation

Development and operation of hydropower plants larger than 20 MW require a *concession.* The concept is that the use or exploitation of a public property, like natural resources (river water in this case), should be permitted only through a concession from government to the interested party. In the Peruvian electricity regulatory framework, there are two stages or levels, in the concession process of hydro plants, a *temporary* for studies and a *definitive* (or final) for construction and operation.

The requirements and procedure to obtain a *temporary concession* for hydro power generation are established in article 23 of the ECL, articles 30 and 33 of its regulations and in item CE02 of Annex N° 1 of the Consolidated Text for Administrative Procedures of MEM (the TUPA). Main requirements are:

a) Presentation of project documentation with a general description and main design parameters of the project and a location map of main works and installations, and other relevant project information.
b) INRENA authorization to carry out studies for the use of water resources for electricity generation.
c) General description, schedule and budget of project studies to be carried out; specific requirement of possible rights of way on third party properties.
d) Security bond in favor of MEM, valid for the period of *temporary concession* requested, in an amount equivalent to 1percent of the budget of proposed studies, up to 25 UIT.
e) Legal documentation of public registration of sponsor/developer as a commercial company. Companies must be established in Peru and register according to the Peruvian law.

MEM should verify compliance of all required paperwork and documentation within thirty (30) calendar days of submission. Then, the request of *temporary concession* should be published in the official newspaper "*El Peruano*" during two consecutive days (the cost of this publication is paid by the interested party).[84]

MEM issues *temporary concession* for a maximum period of two years. During this period the project studies should be completed. If the project sponsor/developer (the petitioner of the *temporary concession*) is not able to complete the studies in time, it can request an extension. If concession terms as outlined in the application, with regard to the studies and the relevant schedule, are not complied with during the concession period (and any extensions), the *temporary concession* will cease and the guarantee bond will be cashed. All ministerial resolutions regarding granting, renewal and revocation of *temporary concessions* are published in the official newspaper "*El Peruano*."

[84] UIT: Unidad Impositiva Tributaria: a monetary amount to be paid for some rights or obligations. For example, if the UIT is S/.3,000, then 500UITs is S/.1,500,000.

Requirements and Procedure to obtain a Definitive Concession for Hydropower Generation

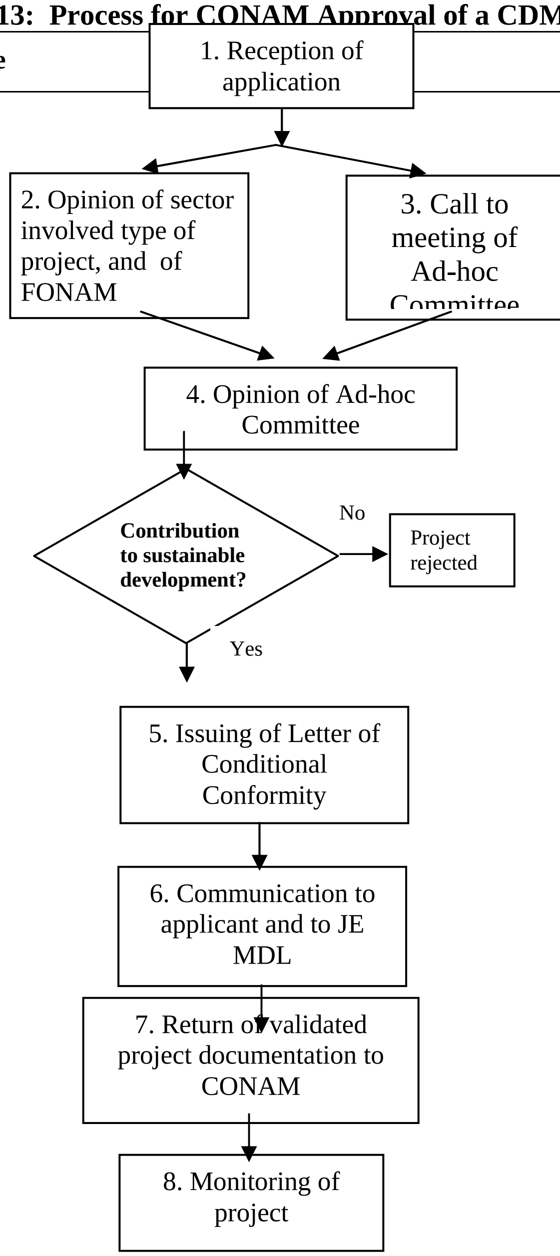
The requirements and procedure to obtain a *definitive concession* for hydro power generation are established in articles 3, 6, 22, 25, 26 and 28 of the ECL, articles 37, 43, 53 and 54 of its regulations and in item CE01 of Annex N° 1 of the Consolidated Text for Administrative Procedures of MEM (the TUPA). Main requirements are:

a) Submission of request, addressed to the General Director for Electricity, and payment of the corresponding right of one half of a UIT.
b) INRENA approval of the required studies for hydropower generation. The study should be at pre-feasibility level and cover the project area relevant to the water retention and intake and the water return to the natural or artificial river water source, as applicable.
c) General project description consolidated design and full set of engineering drawings and maps of all project installations; delimitation of the concession area, indicating UTM coordinates; project implementation schedule and project costs estimation and budget.
d) Specification of the required rights of way of project facilities;
e) Approval of the Environmental Impact Study of the project by the General Directorate for Energy Environmental Matters of MEM, or receipt of the request for approval.
f) Security bond in favor of the MEM, in an amount equivalent to 1percent of the estimated project costs, up to an amount of 50 UITs.
g) INC certification of absence of archaeological (the CIRA).
h) Legal documentation of public registration of sponsor/developer as a commercial company, according to the Peruvian law.

MEM should verify compliance of all required paperwork and documentation within ninety (90) calendar days of submission. MEM issues *definitive concessions* for an undefined period of time.

Annex 13: Process for CONAM Approval of a CDM Project

Responsible	**Stage**	**Registration**
CONAM Executive Secretary		Letter of request for project approval. CONAM format 34.3, Clean Development Mechanism (CDM) Project Document.
Executive Secretary and Chief of Climate Change Unit		CONAM format 34.1: Guidelines for Facilitating Project CDM Evaluation. Report of field visit to Project site.
Executive Secretary		Citation for meeting
Executive Secretary		Minutes of meeting of Ad-hoc Committee.
Executive Secretary		Letter of Conformity
Executive Secretary		Letters to applicant and CDM Executive Committee (JE MDL)
Executive Secretary and OAF Director		Letter communicating validation and receipt of payment
Chief of Climate Change Unit		Annual report of CDM projects



Annex 14: Comparison of International Renewable Energy Policies (1/5)

Country	Objective (RE as % of electricity or MW)	Program(s)	Prices	Auctions	Technology bands	Future
Australia	- 2010: 9,500Gwh - 2020: 20%	Mandatory Renewable Energy Target (MRET) - through a Renewable Power Percentage (RPP), which is updated yearly to ensure 2010 target is reached.	Renewable Energy Certificates (RECs) are created by generators accredited by the Office of the Renewable Energy Regulator (ORER), with each certificate equivalent to 1MWh of renewable generation. The RE generator is responsible for negotiating a price for those RECs.	No auctions. Registered RECs are traded with notification to the REC registry.	No technology bands.	The system was extended until 2020.
Brazil	3,300MW capacity from RE (1,100MW each of wind, SHP and biomass) under 20 year PPAs	Proinfa (Incentives Program for Renewable Sources of Energy)	Maximum prices: Wind: 9.783-8.626$c/kwh, Small hydro: (<30MW) 5.602$c/kwh, Bagasse: 4.489$c/kwh, Wood: 4.852$c/kwh	2 auctions were held by Electrobras, with only those having a license of installation able to participate.	Maximum tariffs for each technology (see prices)	Program has encountered some delays so the deadline for contracting capacity (3300MW) has been extended
Chile	- 2010: 5% of the regulated demand supplied to come from Non-Conventional Renewable Energy (NCRE) and hydro<20MW - 2024: 8%	NCRE Program (short laws 19-940, 20-018)	Prices are determined by a payment mechanism based on stable LT (marginal) cosrs and indexed to the input costs of each bidder; capacity price fixed and maximum price capped at 20% above prevailing free-market price (cap at 2006 auction was: USc6.27/kWh). Future prices are expected to be around US$c7/kwh.	2 acutions were held in October 2006 and October 2007.	No	Program is ongoing, with final objective for 2024.

Annex 14: Comparison of International Renewable Energy Policies (2/5)

Country	Objective (RE as % of electricity or MW)	Program(s)	Prices	Auctions	Technology bands	Future
England	- 2010: 10% - 2020: 20%	1. UK non fossil fuel obligation (x-2000) 2. Renewables Obligation (2000 on)	1. Guaranteed price: function of power pool wholesale price plus technology-specific premium paid by electricity consumers 2. The Obligation requires suppliers to source an annually increasing percentage of their sales from renewables (The current level is 7.9% for 2007/08 rising to 15.4% by 2015/16). For each Mwh of RE generated, a tradable certificate called a Renewables Obligation Certificate (ROC) is issued. Suppliers can meet their obligation by: (i) acquiring ROCs, (ii) paying a buy-out price equivalent to £34.30/Mwh in 2007/08 and rising each year with retail price index;or (iii) a combination of ROCs and paying a buy-out price.	1. Competition for lowest bid for each category separately. Each scheme that passed a “will-secure” test submitted a final bid and the government then selected the cheapest schemes to secure the required capacity within each technology band. The renewables capacity was secured through contracts with generators at premium prices. 2. ROCs are traded	1. Renewable technologies are separated into different technology categories and competitive bidding rounds are organised for each category separately. 2. From 2009, the Government wants to include banding of the RO; the new Renewable Obligations 2007 (to be voted in 2008) introduced the obligation to amalgamate output by technology groups.	Multiple ROC approach1 from 2009 with 4 bands: (1) technologies in the Established Band will receive 0.25 ROCs/MWh; (2) technologies in the Reference Band 1 ROC/MWh; (3) technologies in the Post-Demonstration Band 1.5 ROCs/MWh; and (4) technologies in the Emerging Technologies Band 2 ROCs/MWh. Microgeneration projects will be placed in the same bands as large scale generation using the same technology
France	- 2010: 21%	Orientations of energy policy (2005)	Feed-in tariffs by technology, which covers capital and O&M costs and a premium - total tariff cannot exceed a "normal rate of return", taking into account technology risks and guarantee for the generator to sell the whole production at a given tariff (Small hydro: 9.5 to 16.1USc/kwh based on season; PV: USc30/kWh +USc39/kWh construction premium; wind: USc12.9/kWh during 10 years and then btw USc4.4-12.9/kWh the five following years depending on site)	Over 4.5MW, the generator needs to obtain a concession, through a bidding procedure which looks at: (i) energetic content (investments, operating modalities) ; (ii) proposed redevance rate that the concessionary will pay to the State, (iii) environmental mitigation plan.	Technology specific.	

Annex 14: Comparison of International Renewable Energy Policies (3/5)

Country	Objective (RE as % of electricity or MW)	Program(s)	Prices	Auctions	Technology bands	Future
Germany	- 2010: 12.5% - 2020: 20%	Renewable Energy Law (EEG) - Erneuerbare Energien Gesetz	Feed-in tariff, depending on the energy source, the size of the installation and the date of commissioning (the later an installation begins operation, the lower the tariff). The grid operators and energy supply companies can pass on the difference in costs for electricity from renewable energies to the final consumer. For 2005, fees under the new EEG range from 6.70$c/kWh for electricity from wind energy (basic payment) and 8.27$c/ kWh for electricity from hydropower, to 73.99$c/ kWh for solar electricity from small façade systems (see attached table) In principle the guaranteed payment period is 20 calendar years, for hydropower 15 or 30 years.	No	Tariffs differ according to technology.	
Ireland	- 2010: 15% - 2020: 33%	1. Ireland Alternative Energy Requirement (AER):1995- 2005 2. From 2006, Renewable Energy Feed In Tariff (REFIT)	1. The additional cost of electricity procured under the AER schemes is spread across all electricity consumers: the Public Service Obligation (PSO) levy. 2. Under REFIT, project developers are free to negotiate with any electricity suppliers in the liberalised electricity market. The purchase price is negotiated between the generator and supplier directly. Contracting suppliers will be compensated for the net additional costs incurred (up to some price caps) from the PSO levy funded by electricity consumers.	1. Winning bidders are entitled to a 15-year PPA whereby the ESB buys the electricity output of the winning facility at the bid price. 2. No auction.	1. For each competition a quota is set for the amount of electricity to be sourced from each technology, e.g., wind, hydro, biomass/waste. 2. Price support caps: Large Scale Wind category: 7.78$c/kwh, Small Scale Wind category:$8.05c/kwh, Hydro: $9.83c/kwh, Biomass Landfill Gas: $7.0c/kwh, Other Biomass: $9.83c/kwh.	

Annex 14: Comparison of International Renewable Energy Policies (4/5)

Country	Objective (RE as % of electricity or MW)	Program(s)	Prices	Auctions	Technology bands	Future
Spain	- 2010: 29.4% - 2020: 37%	Plan for renewable energy	For RE (<50MW), choice between: selling energy at a regulated rate, or selling the energy directly into the spot market/forward market/bilaterally, receiving in this case the price on the market plus a premium. Recently cap and floor prices were introduced for certain technologies, and premium is eliminated if market price is too high vs costs (for hydros, 2 groups of tariffs: <10Mw, 10 to 50MW).	No	Tariffs and premiums by technology (see attached table).	Plan for renewable energy for 2011-2020 is currently in elaboration to help Spain reach 2020 target of 37% electricity from RE.
USA	Case study: California - 2010: 20% - 2020: 33%	Renewable Portfolio Standard (24 States + DC) - hydro: <30MW Example: California	1. When RE facilities are certified, they receive and IOU in their contract. Tariffs are based on the Market Price Referents (MPRs), which are the cost of a long-term contract with a combined cycle gas turbine facility, levelized into a cent-per-kWh value. 2. Since February 2008: Feed-in tariffs (for RE of less then 1.5 MW): fixed base rate determined by the MPR table for a period of 10, 15, or 20 years. The rates are set and adjusted by Time of Use (TOU) factors as authorized by the Commission.	California's three large investor owned utilities are required to issue annual solicitations for renewable energy, until they reach the 20% requirement. - Bid prices at or below the MPR may be accepted by the California Public Utilities Commission (CPUC). - Bids priced above the MPR may face a stronger burden of proof in justifying the reasonableness of their contract price. Above market costs are then covered by Supplemental Energy Payments (SEPs).		The Amended Scoping Ruling of the Assigned Commissioner projects a proposed decision on whether the CPUC will authorize Tradable RECs for RPS compliance in the second quarter of 2008.

Annex 14: Comparison of International Renewable Energy Policies (5/5)

Notes

1. UK ROC multiple band approach: 4 bands

- Established: sewage gas, landfill gas, cofiring of non-energy crop (regular) biomass;
- Reference: Onshore wind; hydro-electric (<20MW); co-firing of energy crops; EfW with combined heat and power; other not specified;
- Post demonstration: offshore wind; dedicated regular biomass;
- Emerging technologies: Wave; tidal stream; advanced conversion technologies (anaerobic digestion, gasification and pyrolysis); dedicated biomass burning energy crops
(with or without CHP), dedicated regular biomass with CHP; solar photovoltaics; geothermal.

Sources:

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8. Benarion, P., “Avances en Materia de Regulación del Sector Eléctrico”, Presentation at Seminar ‘Abastecimiento Energético Futuro - Los Cambios a la Legislación y la Importancia de la Norma T
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