Regional Energy Projects: Experience and Approaches of the World Bank Group

Background Paper for the World Bank Group Energy Strategy

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This paper was prepared as a background paper for the forthcoming World Bank Group energy strategy by Venkataraman Krishnaswamy, consultant, under the supervision of Masami Kojima of the World Bank.

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List of Abbreviations

AC	alternating current
ADB	Asian Development Bank
ARTF	Afghanistan Rehabilitation Trust Fund
BiH	Bosnia-Herzegovina
BOT	Build, Operate and Transfer
BOTAS	Turkish Pipeline and Petroleum Transmission Company
APL	Adaptable Program Loan
bcm	billion cubic meters
BP	British Petroleum
BTC	Baku-Tbilisi-Ceyhan
BTE	Baku-Tbilisi-Erzurum
CAS	Country Assistance Strategy
CASA 1000	Central Asia and South Asia Electricity Transmission and Trade project
CCGT	Combined Cycle Gas Turbines
CEB	National Power Utility of Benin
CEC	Copperbelt Energy Corporation
CIEN	Companhia de Interconexão Energética
CMH	Mozambique Hydrocarbon Company
CPS	Country Partnership Strategy
CSP	concentrated solar power
DBSA	Development Bank of South Africa
DC	direct current
DRC	Democratic Republic of Congo
EAP	East Asia and Pacific (Region of the World Bank)
EBRD	European Bank for Reconstruction and Development
ECA	Europe and Central Asia (Region of the World Bank)
ECOWAS	Economic Community of West African States
EEP	ECOWAS energy protocol
EEPC	Ethiopian Electric Power Company
EIB	European Investment Bank
ELPS	Escravos – Lagos Gas pipeline
ENH	Mozambique National oil Company
ENTRO	Eastern Nile Technical Regional Office
FYRM	Former Yugoslavian Republic of Macedonia
GCC	Gulf Cooperation Council
GMS	Greater Mekong Sub-region
GTB	Bolivian Gas Company
IBRD	International Bank for Reconstruction and Development
IDA	International Development Association
KESH	Albanian National Power Utility
IFC	International Finance Corporation
IPP	independent power producer
IsDB	Islamic Development Bank
kWh	kilowatt-hour
LAC	Latin America and the Caribbean (Region of the World Bank)

LAO PDR	Lao Peoples Democratic Republic
LNG	Liquefied Natural Gas
MIGA	Multilateral Investment Guarantee Agency
MENA	Middle East and North Africa (Region of the World Bank)
MGJ	Million giga-joules
MOU	Memorandum of Understanding
MW	megawatt
NEC	National Electric Corporation of Sudan
NTPC	Nam Theun Power Company
OMVS	Organisation pour la mise en valeur du fleuve Sénégal (Senegal River Basin Development Authority)
PAD	Project Appraisal Document
PPA	Power Purchase Agreement
PPP	public-private partnership
PRG	Partial Risks Guarantee
ROMPCO	Republic of Mozambique Pipeline Investment Company
SADC	South Africa Development Community
SAPP	Southern African Power Pool
SCADA	System Control and Data Acquisition
SOCAR	State Oil Company of Azerbaijan Republic
SIEPAC	Sistema de Interconexion Electrica para America Central (Central American Electrical Interconnection System)
SOGEM	*Societe de Gestion de I 'Energie de Manantali* (Manantali Energy Assets Holding Company)
SPT	Sasol Petroleum Temane
SPV	special purpose vehicle
STEM	Short term energy market
TBG	Bolivia Brazil Gas Transportation Company
TCF	Trillion cubic feet
TEIAS	Turkish Electricity Transmission Company
THPC	Theun Hinboun Power Company
TSO	Transmission System Operator
UCTE	Union for the Coordination of Transmission of Electricity
VRA	Volta River Authority
WAGP	West Africa Gas Pipeline
WAPP	West African Power Pool
WBG	World Bank Group
WTO	World Trade Organization

All dollar amounts are U.S. dollars unless otherwise stated.

REGIONAL ENERGY PROJECTS:

EXPERIENCE AND APPROACHES OF THE WORLD BANK GROUP

Introduction

Regional trade in energy can take advantage of economies of scale and help countries develop and gain access to low-cost energy. This would be helpful under all circumstances and particularly for small economies. For this reason, there is much interest in increasing regional energy trade, especially in Sub-Saharan Africa where achieving universal access to electricity remains a significant challenge. But designing a regional project is a complex task. Across all sectors, the World Bank processed few regional projects until the Pilot Program for Regional Projects, designed for countries eligible to receive funding from the International Development Association (IDA), was launched in October 2003. The number of regional projects increased markedly in 2004, but has remained more or less constant since despite continuing IDA support.

Traditionally the World Bank Group's energy operations have focused on the energy entities of its borrowing member countries and carried out projects within the national borders of each country. The country focus became sharper in the 1980s and 1990s with the preparation of Country Assistance Strategies and Country Partnership arrangements. Nonetheless the World Bank Group (WBG) was aware of the potential benefits from a regional approach to energy issues and cross-border energy trade in the networked sub-sectors of electricity and natural gas, and supported cross-border energy projects when there were opportunities. The World Bank's role in promoting the Indus water Treaty between India and Pakistan, paving the way for the construction of major hydropower facilities in both countries, has been widely acknowledged. A Project Performance Assessment Report of December 2006 listed only seven regional power projects (including the Itaipu Hydropower project, one of the world's largest hydropower projects) and two regional gas projects for the period 1972–2004 as having been financed by the WBG.

Fuel for Thought, the WBG's 1999 environmental strategy for the energy sector, recognized explicitly the relevance of energy trade to the objective of environmental mitigation and indicated targets for such efforts in some of the Bank's Regions. The 2001 informal WBG energy strategy, *The World Bank Group's Energy Program: poverty alleviation, sustainability and selectivity*, also promoted energy trade and regional approaches to energy development.

The objective of this paper is to inform the forthcoming WBG energy strategy by reviewing the WBG's experience with cross-border energy projects in 2000–2009 and drawing lessons to see how regional trade can be enhanced in WBG projects in the coming years. This background paper complements a separate review of World Bank regional projects being carried out by the Quality Assurance Group, which covers all sectors. While both review regional projects, this paper examines issues specific to energy trade and physical cross-border energy flows in greater detail and covers the entire Bank Group.

Rationale for Energy Trade

For many developing countries, energy trade is a logical and rational public policy choice for several reasons:

- Energy trade can help overcome the mismatch between energy demand and energy resource endowments among the countries in the region, especially among neighboring countries.
- Energy security becomes enhanced through prudent reliance on trade to meet part of the demand by diversifying the forms and supply sources, often lowering the average cost of supply.
- Energy trade would enable smaller countries with large natural resources (such as hydropower or natural gas) develop that resource exploiting economies of scale.
- Countries with little fuel or hydro resources or with markets too small to exploit economies of scale can benefit by interconnecting to the grid of neighbors with surplus capacity or resource. It may even be the most cost-effective means of increasing access and reliability (see Box 1 for the major benefits from interconnected operation of power grids).
- For resource rich smaller economies, exports of energy could be an engine of growth and development.
- Even for larger economies energy imports may help postpone, reduce, or avoid large and lumpy capital investments in new production facilities and thereby overcome temporal cash flow problems.
- As the experience of Denmark shows, the ability to trade energy across borders as a member of a large power pool helps expand supply of electricity from such variable renewable energy sources as solar and wind and absorb such intermittent supplies.
- Often energy trade projects lend themselves ideally for the use of public-private partnership arrangements, thereby enhancing private sector participation in the energy sector.

Benefits attributable to energy trade are summarized in Box 1.

Box 1: Benefits of Interconnected and Integrated operation of Electricity Grids

Apart from enabling the sale of electricity from the surplus to the deficit grids, interconnections and synchronized operations[1] of the power grids help with the following:

- Exploit differences in resource endowments and their development and operating costs.
- Exploit differences in seasonal load and supply patterns.
- Enable less expensive peak load management, especially when the interconnected grids are located in different time zones with different peak hours.
- Pool uncertainties. As demand and supply vary stochastically, the larger the system the smaller the fluctuations arising from imbalance, and hence it helps to improve the reliability of the system (and the load-following capability) at a lower cost by ensuring a better balance between hydropower and thermal power units, and among base load, intermediate load, and peak load units.
- Lower the system capital costs by lowering the reserve margins for a given level of system reliability.

[1] Many of these benefits would accrue only in the case of synchronized operation of the interconnected grids. This involves the use of common grid codes and common rules of use and procedures.

- Lower the system operating costs by enabling the substitution of generation from units with high marginal costs of one grid by generation from units in other grids with lower marginal costs.
- Lower emission levels by enabling substitution of generation from units with a high level of emissions per kilowatt-hour (kWh) of one grid with generation from units in the other grids with a much lower level of emission per kWh.
- Enable the construction of large hydropower projects, which would make better economic sense in such interconnected grids and the larger markets they provide than in the smaller individual grids.
- Attract private investment in power generation in the context of enlargement of energy markets (through interconnected operation) with transmission access.
- Usher in or increase competition. Interconnected synchronized operation of two or more grids could enable competition, which would not otherwise be possible in small grids.

Barriers to Trade

The most important barrier is the political mindset which considers 100 percent national self-sufficiency as the basis of national energy security and which regards reliance on trade as an erosion of such energy security. The second most important barrier is the lack of willingness to reach agreements with neighboring governments and sustained political commitment needed to abide by the concluded agreements. Other constraints include the following:

- Absence of adequate physical interconnection infrastructure (such as power lines and pipelines), which call for investment
- Regional conflicts and lack of friendly relations among the countries and unsettled political conditions
- Unrealistic price expectations
- Inability to conclude water sharing and water release agreements among the riparian states of trans-boundary rivers on which storage hydropower facilities are to be constructed
- Difficult transit country situations creating major risks to trade
- Lack of financial viability and high levels of operational inefficiency of the related utilities
- Absence of harmonization of standards, practices, grid codes, and regulatory arrangements
- Transmission function being bundled with generation and distribution functions in vertically integrated power utilities, making it difficult to have transparent transmission tariffs, which are necessary for power trade.

Often the countries involved in energy trade projects vary greatly in economic status, governance quality, institutional capacity, sector reform status, and legal and regulatory framework development. These differences make energy trade projects complex and difficult to implement.

Regional Energy Projects

Normally the term "regional energy projects" is taken to denote an energy project covering more than one country, as opposed to a national energy project which is within the borders of one country. Commonly used alternative terms are "cross-border project" and "electricity or energy trade project." However, for purposes of IDA special allocation beginning with IDA-13, a regional project has been defined as one with the participation of three or more countries in the region. The reason for excluding projects covering only two countries and involving bilateral trade in electricity or natural gas from this definition is not clear. To review the WBG's experience in promoting electricity and gas trade it is useful and necessary to consider such cross-border projects also. This review adopts the commonly used definition that includes energy trade between two countries.

The projects under review in this paper include power or gas interconnection projects covering two or more countries, power generation or gas production projects located in one country and constructed for power or gas exports or projects for other components (such as dispatch and communication facilities) intended to facilitate gas or power trade across the border. Transit facilities in transit countries are also included.

The Bank's Business Warehouse systems do not seem to capture fully all regional projects even when the IDA definition is adopted.[2] Using the commonly-used definition makes it even more difficult to compile a complete list of all regional energy projects including the bilateral ones. A list of regional energy projects compiled on a reasonable effort basis for the purposes of this review is given in Annex 1. Briefs on the reviewed projects are given in Annex 2.

Growth in Regional Energy Lending

The number of regional energy projects handled by the WBG and the total value of assistance provided have both been much larger since 2000 than in the earlier years, especially in the Sub-Sahara Africa Region. Annex 1, which is by no means exhaustive, lists 35 completed and ongoing projects. On the whole the regional energy project initiatives are most prominent in the Sub-Sahara African Region, followed by the Europe and Central Asia Region (ECA) of the World Bank.

In the Africa Region, a number of new projects relating to Southern Africa Power Pool, Western Africa Power Pool, Eastern Africa Power Pool, and the Nile Basin Initiatives are being prepared. The concept of Central Africa Power Pool is also taking shape.

In the ECA Region further lending and non-lending activities are planned to pursue the progress of the countries of the South Eastern Europe in power market integration. Work on similar gas market integration starting with mechanisms for promoting export of gas from Central Asia to Europe has commenced. The Central Asia-South Asia Electricity Transmission and Trade project (CASA 1000) for the export of summer surplus power from Central Asia to Afghanistan and

[2] The Quality Assurance Group plans to look into this issue and make recommendations to ensure that all regional projects are properly identified as such. It is hoped that at this time, the need for including cross-border energy projects covering two countries would also be taken into account.

Pakistan is being prepared. The feasibility of a major 3600 megawatt (MW) hydropower project in Tajikistan for increasing future export of power to South Asia is being studied.

Similar power interconnections between India and Nepal, India and Bangladesh, India and Sri Lanka, and export production initiatives in Nepal are being pursued in South Asia on the basis of a recent study, *Potential and Prospects for Regional Energy Trade in South Asia Region* (ESMAP August 2008).

The East Asia and Pacific (EAP) Region of the World Bank is cooperating with the Asian Development Bank (ADB) and other donors in supporting Greater Mekong Power Trade Initiatives.

The Middle East and North Africa (MENA) region is carrying out (or has plans to carry out) studies on a range of power and gas interconnection initiatives, including gas and power interconnection initiatives in the Mashreq and Maghreb sub-regions, initiatives related to the Gulf Cooperation Council (GCC), interconnection of Yemen and Djibouti with GCC countries, and elements of the Mediterranean Power ring and interconnections to Europe. In addition, a concentrated solar power (CSP) scale-up plan— with total cost of $6 billion including $750 million provided by the Clean Technology Fund—has been prepared to enable the construction of about 1,000 MW of CSP capacity in Algeria, Egypt, Jordan, Morocco, and Tunisia and the associated transmission lines to enable domestic and regional trade and explore the possibility of the EU green energy market being opened for solar power imports from the MENA region. MENA-EU power interconnections could be financed by the EU members under their program to achieve their renewable energy targets.

The Latin America and the Caribbean (LAC) Region of the World Bank is studying the possibility of supporting generation capacity addition and providing institutional support to the six Central American countries involved in *Sistema de Interconexion Electrica para America Central* (SIEPAC, Central American Electrical Interconnection System). It is also studying (1) the possibility of providing regulatory support for regional trade among the members of the Organization of the Eastern Caribbean States and (2) possible options for gas and power interconnections in the Caribbean.

Much of this expanded energy trade related activity has been attributed to the launch of the Pilot Program for Regional Projects in IDA-13, which has been continued through IDA-14 to IDA-15. The Regional Pilot Program requires that IDA country allocations cover one third of the regional project costs attributable to each country, with the remaining two thirds covered by the Pilot Program. In addition a separate directorate to coordinate and oversee the regional projects and programs in the Africa region was established. The Africa Region also followed the practice of preparing Regional Integration Assistance Strategy documents. These developments seem to have helped to sharpen the focus on regional projects and programs

The increased number of operations may also have been due to

- the use of the Adaptable Program lending (APL) facility, which made it somewhat easier to process a succession of investment loans/credits under an approved APL program based on triggers;

- the facility to slice the program horizontally across countries and vertically across time periods or phases of the program;
- Increased level of coordination among the World Bank, International Finance Corporation (IFC), and the Multilateral Investment Guarantee Agency (MIGA) and the use of guarantees to leverage the Bank contribution.

Status of the Projects Reviewed

Thirty-one projects are reviewed in this paper, including one by the European Bank for Reconstruction and Development (EBRD) and two by the ADB. Of the 31 operations reviewed, nine have been completed, including the Nam Theun 2 Hydropower Project which is entering into commercial operation. The remaining 22 projects are in various stages of implementation and include West Africa Gas Pipeline (WAGP) project, which was completed and went into trial operations for about a month, but was disrupted, when the insurgents blew up the pipeline in the Nigerian delta which feeds gas into the WAGP line.

Among the completed projects, six—Manantali Hydropower Project and the associated grid of Organisation pour la Mise en Valeur du Fleuve Sénégal (OMVS, Senegal River Basin Development Authority), Baku-Tbilisi-Ceyhan (BTC) Oil Pipeline, Baku-Tbilisi-Erzurum (BTE) Gas Pipeline, Southern African Regional Gas Project, Theun Hinboun Hydropower Project, and Powerlinks Project—are operating satisfactorily, resulting in considerable trade in oil, gas, and electricity as envisaged. The seventh, Brazil-Argentina Power Interconnection Project, enabled import of about 1,000 MW of thermal power from Argentina to Brazil only for a few years before Argentina banned the exports. Now the lines are used partially for the export of 750 MW of hydropower from Brazil to Argentina during the months of June to September and also partly for the export of Brazilian power to Uruguay. The eighth, Bolivia-Brazil Gas Pipeline Project, which was functioning as envisaged received a setback when Bolivia sought majority ownership and control of the oil and gas sector, but appears to have recovered from this debacle as record levels of gas exports through this line at 31.5 million cubic meters per day were reported in 2008. The ninth, Nam Theun 2, will add 5.6 terawatt-hours a year to the volume of electricity traded in the region any time now.

Among the notable results of the completed projects are the following:

- World markets had been opened for Azeri oil exports.
- Regional markets and potentially European markets had been opened for Azeri gas.
- South African gas market had been opened for Mozambique.
- Ghana, Benin, and Togo will access Nigerian gas (when the pipeline damage in Nigerian delta is repaired).
- The Thai power market has been opened for Laotian exports.
- Bolivia had been able to access the Brazilian gas markets.
- Afghanistan is absorbing increasing amounts of imported power, thus lowering its cost of supply.
- India is able to absorb large increases in the power exports from Bhutan.

Cost Overruns

Of the 31 operations reviewed, six experienced significant cost overruns.

The BTC Oil Pipeline and the West Africa Gas Pipeline Projects had cost overruns of 43 percent and 60 percent, respectively. They were sponsored by international oil and gas companies in the private sector. Additional financial needs were met mostly by increased shareholder loans.

Southern African Power Pool (SAPP) Adaptable Program Loan (APL) Phase 1, SAPP APL 1(b), and West African Power Pool (WAPP) APL 1 experienced significant cost overruns in the range of 93 percent to 220 percent, calling for substantial additional IDA credits/grants. Significant cost overrun appears likely under SAPP APL 2 (see case notes for key details). In all these cases the precise scope of the components and their costs seemed to have become clear only after completing basic engineering designs, preparation of bid documents and receipt of bids.

This raises the question of whether a two-stage lending would have been more suitable—the first stage covering engineering designs, bid documents, and bid evaluation, and the second stage covering the rest of the project implementation. Alternatively, the first stage could be covered by advance procurement authorization and retroactive financing. Since availability of adequate funds for the program is assured upfront for APLs, it is not clear why any project/credit approval needs to be rushed based on incomplete or inadequate (technical) due diligence.

The details available on the African power projects do not appear to indicate that cost overruns were caused by the cross-border nature of the projects. Actually they were discrete national projects processed as a part of the regional power pool program under the respective APLs. It is also not clear whether the cost overruns were common in most other African national projects processed during the period. Further work would be needed to ascertain this aspect; intuitively, however this is unlikely to be the case.

Private Sector Involvement

Of the 31 projects reviewed nine projects involved substantial private sector investments.

In respect of Bolivia-Brazil Gas Pipeline,[3] BTC Oil Pipeline, BTE Gas Pipeline, and WAGP, major international oil and gas companies were the sponsors and majority investors. In the Southern African Gas Pipeline Project, the main sponsor and majority investor was Sasol, the fifth largest company in South Africa. In the Theun Hinboun and Nam Theun 2 Projects, two public-private partnerships (PPPs) were formed involving Thai investors and the power utilities of France and Nordic countries and the relevant government entities of Laos and Thailand. Power Links project was based on a PPP between Tata Power Company and the state-owned Power Grid Corporation of India. The main sponsor and majority equity holder in the Argentina-Brazil Power Interconnection Project is Endesa of Spain. In addition a private sector company, Eskom Energie Manantali, was engaged to manage the Manantali Hydropower Project and the OMVS grid operations on the basis of a 15-year concession.

[3] It is, however, worth noting that the Bolivia-Brazil Pipeline Project went ahead largely because Petrobras of Brazil underwrote all major risks.

Five of these had been completed and are operating successfully. The Nam Theun 2 had been completed successfully and will commence commercial deliveries soon. WAGP had been almost completed and was disrupted during trial runs. Bolivia-Brazil Gas Pipeline and Brazil-Argentina Power Interconnection were successfully completed and operated, but faced setbacks from which they have either recovered or are recovering. The operation of the Manantali Hydopower Project and the OMVS grid through the private company has also been successful.

Prioritization of Investment Components under APLs

Energy trade is possible only when there is surplus energy to trade. Such surpluses could occur during certain hours of the day or during certain seasons or throughout the year. Clearly surplus capacity and energy that are available right through the year help sustain trade. Thus a focus on financing export generation facilities is important.

Of the 31 cases reviewed six (Manantali Hydropower, Felou Hydropower, Inga Hydropower rehabilitation, Nam Theun 2, Theun Hinboun, and Southern African Gas Pipeline Projects) financed or are financing export production facilities to produce surplus energy to trade. In the Argentina- Brazil Power Interconnection Project, the existing surplus in Argentina disappeared within two or three years and turned into a deficit on account of the change of policies. The interconnection, instead of serving exports, had to serve imports in a suboptimal fashion.[4] Most of the remaining cases finance interconnections and facilities to enable the trade of existing and future tradable surpluses.

Practically any investment in the power sector of the country forming part of an APL program of developing regional trade can be related to the trade objective through a complicated set of linkages and logic. However, given the scarcity of resources and the need to prioritize, it may be necessary and appropriate to focus on major export production projects and major grid interconnection and operation components. These can directly and immediately increase regional trade, subject always to their meeting economic and financial viability criteria. A review of the components in a number of APLs indicates that no such prioritization appears to have been undertaken. Such prioritization would make the support of the WBG to the regional market development work much more effective.

As discussed elsewhere in this report, the processing and implementation of regional energy projects are highly time-consuming and resource-intensive. In this context care should be taken to pursue only those projects with substantial economic benefits. If the benefits are marginal and the costs and risks are high, the project is unlikely to succeed.

Safeguard Issues

Significant environmental and social issues were encountered in respect of seven projects, all of which were projects with private sector sponsors. Many of them attracted widespread attention of local, national, regional and global non-governmental and civil society organizations. In five of them (Bolivia-Brazil Gas Pipeline, BTC, BTE, Nam Theun 2, Southern Africa Gas Pipeline) these issues were handled satisfactorily. In respect of the BTC project the Compliance Advisor

[4] Although not reviewed in this paper, the Central American Regional Electricity Market (SIEPAC) took nearly a decade to finalize the market arrangements, by which time there was no surplus energy to trade and construction of a major generation plant had become an urgent necessity.

Ombudsman (CAO) of IFC received about 30 complaints from the affected parties and all of them were suitably resolved. In the case of WAGP Project, resettlement and compensation issues led to the involvement of the Bank's Inspection Panel and resulted in corrective action and closer monitoring. Still disputes between the communities of the Nigerian delta region and the Nigerian Central Government remain a threat to the operation of this pipeline. Theun Hinboun Project funded by the ADB in the early years was found to have had some adverse environmental and social impacts remaining without adequate mitigation. This is being attended to as a part of the expansion of this project. The safeguard aspect had been the most time-consuming and expensive part of project supervision, the clearest evidence of which is well documented in the case of the Nam Theun 2 and WAGP Projects.

Most energy projects had serious safeguard issues and hydropower projects faced more complex and often very difficult issues.[5] On the whole the problems seem to increase quantitatively in regional or cross-border projects, because they encompass two or more countries each with its own environmental and safeguard issues and its own systems and procedures and legal framework to deal with them. Dealing with these issues in ongoing projects is proving to be both challenging and expensive.

In most private sector sponsored large regional energy projects (such as BTC, BTE, Bolivia-Brazil Gas Pipeline, and Southern Africa Gas Pipeline), association with the WBG is sought not as a major source of funds but as a major provider of comfort against country risk and as a credible certification of adherence to environmental and social norms. From this point of view, WBG practice regarding safeguard aspects appears to be a major strength. At the same time, many have expressed the view that conservative and rigid interpretation and application of safeguard rules and procedures are resulting in excessive requirements, deterring some private sponsors (pursuing energy export projects) from seeking WBG participation. Many regard such application of the guidelines relating to procurement, safeguards, transparency, and resource-curse related issues as cumulatively increasing the transaction cost of doing business with the WBG substantially. The Independent Evaluation Group is believed to be reviewing the effectiveness of the WBG safeguard practices. The outcome of the review may shed some light on the appropriate balance to be struck in this regard.

WBG Instruments Used

Among the 31 projects reviewed,

- 16 are financed under APLs,
- 7 used standard IDA investment credits or investment loans offered by the International Bank for Reconstruction and Development (IBRD),
- 4 used IDA or IBRD partial risk guarantees,
- 1 used IFC equity,
- 2 used IFC loans,
- 4 used MIGA guarantees,

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[5] For example, Yacyreta hydropower project located on the border between Argentina and Paraguay (financed by the Bank during 1980–1995 have had to operate at a reservoir level much lower than the design level on account of resettlement and compensation issues.

- 2 ADB projects were financed by its standard investment loans from its concessional funds window, Asian Development Fund, and
- 1 EBRD project was financed by a loan to Azerbaijan for its equity investment in the BTE Gas Pipeline Project.

Need for a New Lending Instrument

Bank's lending instruments were generally designed for projects within a country. Loans and credits could be given to the government of the country for re-lending to the implementing entity, or loans could be made directly to the implementing entities in appropriate cases, but only with the government guarantee. The process of adjusting them to cross-border or regional projects is still evolving.

Until about 2004, the standard investment loan instrument was used for the regional energy projects. When a project covered three countries (such as in the Manantali Hydropower Project), three loan/credit agreements were prepared, one set for each country. This led to three subsidiary loan agreements, three Implementation Completion Reports, and so on. This approach also calls for all three loans/credits to become effective, which in the case of many African countries requires parliamentary approval entailing considerable delays and risks.

Beginning about five years ago, only one Project Appraisal Document (PAD) has been prepared for each cross-border project, although credit/loan agreements are prepared for each country. This approach seems also to be followed in other international financial institutions such as the ADB (for example, Afghanistan-Tajikistan Power Transmission Project). Around 2004, the Bank embraced the concept of viewing individual cross-border projects and even projects located within each country as integral parts of an overall program of facilitating regional energy market integration and trade, and started using APLs to assure funds to support the program, and processing each component as separate APL, with relatively simplified procedures for approval.

Even here, when an asset is to be owned regionally by more than one country (such as in Felou Hydropower Project), loan/credit agreements has to be prepared for each country, though one PAD is produced. The practical problem faced (both under the APLs and under standard investment loans/credits) is the need for each loan/credit to become effective to enable the flow of funds to the project. This has often proven difficult. In the case of the Malawi-Mozambique Transmission Project, for example, the failure or inability of Malawi to sign the credit agreement and make it effective (due to parliament-related problems) is delaying the contract awards by Mozambique.[6]

The approach that is gaining ground, especially in a commercially oriented sector like energy, is to create a special purpose vehicle (SPV) to own and operate assets of the key components of the regional projects. These SPVs could be wholly private or wholly public or PPPs. In the Manantali and Felou Hydropower Projects and OMVS grid, the SPVs (OMVS and Manantali Energy Assets Holding Company, SOGEM) are jointly owned by the three governments (Senegal, Mali and Mauritania). PPP type of SPVs are common where extensive private

[6] Similarly in the case of Greater Mekong Sub-regional Power Trade project delays in commencing procurement action in Cambodia are preventing the Lao People's Democratic Republic from proceeding with the component in Lao PDR.

investments are involved (such as in BTC, BTE, Bolivia-Brazil Gas Pipeline, Mozambique-South Africa Gas Pipeline, and Nam Theun 2). In the case of SPVs with majority ownership by private investors, IFC, EBRD and ADB (private sector wing) can lend directly to the SPVs without government guarantees. When an SPV is owned entirely by the governments, the only recourse available to the World Bank until recently was to lend to that SPV against the guarantees to be provided by the respective governments in agreed proportions. The IDA special allocation mechanism for regional projects specifically allows appropriate regionally owned entities to receive IDA credits directly, if backed by guarantees of the relevant governments.

On the whole, the mechanism of APLs and the practice of creating SPVs for appropriate regional projects do not seem to pose significant limitations. However, opinions have been expressed that it is not always easy to get the governments to provide such guarantees, especially in the case of highly indebted IDA countries,[7] and that the Bank should design a new instrument for lending to such entities without requiring government guarantees. A partial answer to this demand probably lies in the WGB initiative relating to sub-national lending under which the IFC can lend to such entities without government guarantees, provided they are financially viable and bankable legal entities pursuing bankable projects (See Box 2).

Box 2: Sub-National Lending

The document entitled *Sub-national Development Program* (June 30, 2006) approved by the Board of Directors of the World Bank in August 2006 established a pilot program of sub-national lending of about $800m for the three year period FY2007–FY2009. The lending as well as equity investment is handled by the IFC, which bears the risks on its books. Eligible entities are sub-national entities such as municipalities and local bodies as well as public sector enterprises and financial intermediaries focusing on municipal portfolio. The financial assistance is on commercial terms, the risks being identified, quantified, and priced. The assistance is provided with no need for any government guarantee. The entities should clearly be bankable with demonstrated net cash flows adequate to service the debt. They must have accounting, audit, and disclosure procedures adequate for commercial lending or equity investment. The government should have no explicit or implicit obligation whatever to guarantee the debt or other obligations of the entity. They should be financially sound entities capable of accessing commercial markets and looking for an opportunity to do so with the support of IFC participation. Such entities are generally likely to be in the middle-income countries, but if such entities exist in low-income countries, they can still be considered for sub-national lending.

Unlike IDA or IBRD investment loans, disbursement under the sub-national lending is upfront after execution of the agreements. Monitoring is carried out through country systems. Processing and lending are handled by joint teams of the World Bank and IFC staff. The World Bank provides grant financed technical assistance help where needed.

Though the program is called sub-national lending, regional entities owned by several governments are also eligible for such assistance, as long as they are bankable entities pursuing a bankable project. In the case of new entities with no past record, securitization may be tighter involving such arrangements as escrowing part of the revenues for priority debt service and the like.

[7] Often such countries are under the International Monetary Fund program constraints against additional or new borrowings and guarantees.

The amount of funds available for sub-national lending appears to be limited compared to the likely demand from regional energy trade projects. Nor is it clear whether such lending could be pursued in highly indebted or debt distressed countries. In the context of continuing this pilot program, it will be worthwhile exploring thoroughly the possibilities of such financing of regional public sector entities.

Many staff members have expressed the view that two possible improvements to the existing lending policies might be worth exploring. First, the special allocation mechanism under IDA could be extended to all cross-border energy trade projects, including bilateral trade between two countries. Such bilateral trade is the essential building block for initiating trade and building confidence. Multilateral trade will have to evolve from such smaller and more practical building blocks. This appears to be a sensible suggestion and should be given serious consideration. It is also worth noting that both the Asian Development Bank and the African Development Bank, which operate similar schemes, adopt criteria for special allocations to regional projects under which projects covering only two countries are eligible. Second, in respect of countries that are not eligible for IDA assistance, some comparable and suitable incentive mechanism under IBRD lending could be designed. It is not clear whether such an incentive could be in the form of lending over and above the country lending limits or some favorable terms (such as longer maturity or a lower interest rate). The implications of this suggestion need to be carefully examined. The recent enhancements to Guarantee and IBRD Enclave Operations (discussed below) could perhaps be a partial response to this suggestion

The SPV mechanism would be suitable for power generation, or gas production and gas processing investments. It may also be used for dedicated gas transmission pipelines and dedicated direct-current (DC) power transmission lines. In most cases the alternating current (AC) lines are parts of the national grid and the SPV mechanism may be difficult to adopt in power interconnection projects. The most notable exception to this generalization is the OMVS grid covering Mali, Mauritania, and Senegal, where the lines operated by OMVS are somewhat in the nature of overlay link[8] among the three national systems.

SPVs organized as PPPs seem to provide good opportunities for the synergy among the institutions and instruments of the WBG. IBRD or IDA could lend to the governments to enable them to invest in the equity of the SPV, thus enabling the WBG to handle the environmental and social aspects effectively. IBRD or IDA guarantees, IFC equity and syndicated B loans, and MIGA guarantees can deal with SPV financial needs in a highly leveraged fashion and offer effective risk mitigation. The Nam Theun 2, Mozambique-South Africa Gas Pipeline, and Bolivia-Brazil Gas Pipeline Projects are good examples of the adoption of the elements of such an approach. Effective and intelligent use of the Infraventure Fund of IFC for project development until financial closure could be of substantial help in IDA countries, where private sponsors are reluctant to take the lead.

Effective January 2010, the World Bank has begun allowing enhanced use of IBRD and IDA guarantees and IBRD enclave operations in IDA-only countries. In IDA-only countries, only 25 percent of the guarantee amount is counted against the IDA commitment. Similarly in the case of other countries only 25 percent of the guarantee exposure will be counted against the IBRD

[8] A backbone system at a higher voltage linking grids operating at lower voltages

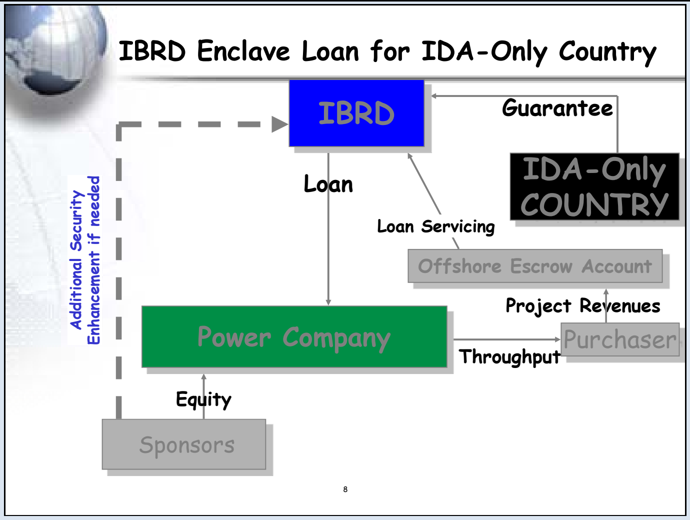
country exposure limit compared to the current practice of counting the full 100 percent. IBRD loans and guarantees have been allowed for IDA-only countries under IBRD enclave financing for projects that directly generate foreign exchange revenues adequate to service the debt (see Box 3). Starting in 2010, this facility has been extended to projects that do not by themselves generate foreign exchange revenues but have clear economic and financial benefits with strong financial flows in local currency through an off-take to a strongly creditworthy party; and also have foreign exchange-related credit enhancement, achieved by the dedication of a pre-existing alternative defined source of foreign exchange, ring-fenced into a dedicated debt service payment escrow account. A greater use of these guarantees and enclave financing could come in handy in respect of IDA-only countries handling large energy export projects (such as in Nepal or Tajikistan), especially when the SPV is organized as a PPP.

Box 3: IBRD Enclave Financing

IDA-only countries face limited IDA allocations, inadequate to enable them to handle large energy export projects. Private investors are understandably reluctant to invest in such countries without the involvement of international financing institutions. The World Bank has, in several such cases and on an exceptional basis, used IBRD loans and guarantees to support a limited number of primarily foreign exchange earning projects (for which the term “enclave projects” has been used) in IDA-only countries which are normally not eligible to receive IBRD financing..

The first enclave transaction is the loan approved for Guinea in September 1968 for developing bauxite for exports. Over the last 40 years the Bank has provided a total of about $800 million for 15 enclave loans involving 14 countries in two regions: 12 in Africa (Botswana, Cameroon, Chad, Côte d’Ivoire, Ghana, Guinea, Lesotho, Liberia, Mauritania, Mozambique, Togo, and Zaire) and 2 in Latin America (Bolivia and the Dominican Republic). By and large, these enclave operations have funded export-oriented projects in the mining sector (bauxite, iron ore, nickel, copper and cobalt), energy (gas, oil, thermal energy), and water. While the aggregate volume of lending and guarantees via enclave transactions is modest at $800 million, the total estimated investment in the underlying projects is more than $10 billion, i.e., the funding provided by the Bank has been leveraged about thirteen-fold.

Enclave projects need to conform to two key criteria. First, the projects should be discrete commercial ventures that create significant economic and development benefits for the borrowing country. Their operations and revenues should be typically separate and apart from the country’s normal activities and the projects are to be export-oriented and able to generate adequate foreign exchange to fully service both debt and equity. Second, in order to ensure that debt service payments to the IBRD will be met, credit enhancements are to be put in place. These can take a variety of forms such as (1) creation of an offshore escrow account to secure future debt service payments to IBRD, (2) a guarantee from another creditworthy entity, or (3) imposition of a risk premium over and above the standard IBRD terms.



As seen from the above figure, export-oriented power and gas projects are well suited for IBRD enclave financing. With export revenues, the first criterion is met, and all the other criteria such as payment security and off-shore escrow accounts are common in independent power projects. On occasion, additional security enhancement mechanisms maybe needed, such as sponsor guarantees to the IBRD in addition to that of the host government. It is useful to note that it is common practice in IFC financing to seek sponsors' (parent) corporate guarantees.

IFC involvement would be beneficial to ensure that the IBRD enclave operation is commercially structured. IFC presence will require sponsors to bring majority equity. This could lead to additional equity and debt financing to the project, complementing the IBRD enclave financing and enabling early financial closure. The IFC's strengths in assessing sponsors' capability and commercial viability will be complemented by the Bank's ability to assess and mitigate public policy risks and ensure compliance with safeguards policies. MIGA involvement to guarantee against political risk would also help attract investors.

Country Orientation of the Bank and Cross-Border Projects

The operations of the WB are country focused and all procedures are country oriented. Thus country directors formulate periodically Country Assistance or Partnership Strategies (CAS or CPS) from which all Bank assistance to the countries flow in the given period. In the case of a regional energy project covering two or more countries, the project needs to be considered a priority and included in the country program of each relevant country. These countries may have different country directors who have different sets of priorities in consultation with their clients and the CAS may have differing time frames. This makes it difficult to include regional energy projects in the CAS of all relevant countries and secure budget allocations for sector studies exploring regional energy cooperation and for project preparation.

For nearly a decade or so, the WBG had reduced substantially energy sector lending and in that context it was difficult to accommodate even the most urgently needed national energy projects in the country programs. The chances of a regional energy project making it to the CAS of all relevant countries were remote unless it had become regionally prominent and is pushed hard by all the countries. Preparing a regional project was perceived to be a little easier when the same country department handled all the relevant countries, but such cases are rare. Also the demands on modest country allocations under IDA are high in each IDA country and in the face of scarcity of funds regional projects do not get the attention they deserve even in the hands of IDA borrowers.

The special allocation of IDA funds for regional projects (to promote regional integration) initiated under IDA-13 under which two dollars could be added for every dollar released from national IDA allocation greatly helped in IDA countries. Much of the expanded activity in regional energy lending could properly be attributed to this initiative, especially in the Sub-Sahara Africa region where the regional integration needs are arguably the greatest. More importantly, the practice of preparing Regional Integration Assistance Strategies commenced in the Africa region, complementing CAS, and a Regional Directorate was created to coordinate and promote regional integration initiatives. These initiatives have provided some relief in IDA eligible countries.

Further efforts to be made in this direction for reducing the difficulties in increasing regional energy lending could include the following:

- Periodical preparation and updating of regional energy trade assistance strategies for each region, either separately or as a part of the overall regional/sub-regional integration assistance strategies. These will identify the potential for regional energy projects with a timeline and outline the strategy to pursue them.
- Creating a special window in the Bank budget to be operated by each regional vice presidency for funding identification of regional energy projects and preliminary project/program preparation. Further detailed project preparation has to be funded under trust funds or in collaboration with appropriate bilateral donors or other development partners.
- Introducing regional energy trade as a theme in CAS and requiring each such strategy to discuss the needs and priorities for regional energy trade from the country's perspective.
- Provision of special budget allocations for regional energy projects requiring more intense, detailed, and frequent supervision and follow-up (such as Nam Theun 2 and WAGP).

The institutional problems become even more complex and exacerbated when a cross-border project straddles two Regions of the Bank and has to deal with coordination issues which may need to be resolved at a level higher than regional vice presidencies. There are many attractive potential cross regional energy trade projects between Central Asia and South Asia, ECA and MENA, ECA and EAP, and South Asia and EAP. Some institutional coordination mechanism has to be found to arrive at consensus among the regions in respect of such projects.

Preparation and processing of many of the regional energy projects or formulating an APL is a complex and time-consuming exercise. Often these involve large investments (many of the projects reviewed for this paper had investment costs in excess of $1 billion) and involve many bilateral and multilateral donors, private investors, and commercial lenders and guarantors. Coordinating them, preparing and allocating contract packages taking into account different procurement rules and policies of the various co-financiers, structuring financing, transactions and contracts are all more complex in regional energy projects and call for teams of staff with various specialized skills. Most large regional energy projects involve substantial environmental impacts and resettlement issues and extensive environmental management programs and rapid social assessments to formulate, implement and monitor, often attracting the attention of global non-governmental organizations (see for example BTC, Nam Theun 2, Bolivia-Brazil, and WAGP Projects). Involvement of staff in successful projects of these types, both during the formulation and implementation phases, should probably receive appropriate weight in their performance evaluation and career advancement.

During the decade in which WBG lending to the energy sector greatly declined, and even earlier, the WBG lost many experienced energy/power engineers, and if the WBG were to increase its volume of lending in the energy sector, especially in the complex areas covering energy trade, there is a need to build up a pool of experienced mid-career professional power engineers who have an understanding of the complex technical issues as well as the WBG's developmental concerns. The case notes of many projects clearly point to this important need. In particular, each of the regional energy departments in the Bank and the Energy Anchor need to have at least one power engineer with adequate experience in organizing and operating energy trading systems and a clear understanding of how the competitive power pools operate in practice.

Project Supervision

The review of the several cases of the WBG involvement in regional energy projects suggests that, in respect of APL projects, each project (as a slice of the program) could be designed to be manageable in size for supervision and monitoring, while many projects handled otherwise (such as WAGP, Nam Theun 2, and Bolivia-Brazil Gas Pipeline Projects) seemed to involve heavy volume of supervision work and high related costs.

In the case of the WAGP Project, the Bank's response to the Inspection Panel report suggests the earlier inadequacy of budgets for supervision and the Bank's determination to provide more funds, staff time, and dedicated oversight mechanisms to ensure effective supervision and monitoring. For Nam Theun 2, annual supervision expenses had exceeded $1 million during FY2006–2009 and supervision will go on until 2018. For IFC-financed projects, a range of fees collected by the IFC at various stages of the transaction probably covers substantially, if not wholly, the supervision costs. There appears to be no such mechanism for projects financed by the IBRD or IDA.

Staff members interviewed for this paper have suggested that higher supervision demands of the regional energy projects and the inability to secure adequate budgets tend to discourage managers from pursuing regional energy projects. The problem, however, may be more generic pertaining to all types of projects involving serious environmental, social, resettlement, resource curse, and other transparency issues, and not confined to regional energy projects alone.

Solutions may be to (1) prioritize the key issues (among the many concerns of the WBG and global civil society) to be addressed under a project, ensuring adequate budget provisions to monitor and supervise in relation to such prioritized concerns; and (2) use standard budget allocations for staff travel and secure funding from appropriate trust funds for meeting the costs relating to the range of technical experts in environment, sociology, engineering, dam safety, and other relevant disciplines, as well as the expert panels.

Need for Realism and Clarity on Objectives

Integration Vs Trade

Energy trade, like all other trades, can take place when there are opportunities for arbitrage, when lower-cost surplus energy is available in one country for sale to another with significant supply deficits and with higher marginal economic cost of alternative supply options. Utility-to-utility bilateral trade can take place in this context, provided physical interconnections are established, under a wide range of utility and sector conditions (See Box 4).

Box 4: Interconnection Options for Electricity Trade

Bilateral electricity trade between two adjoining countries is the least complicated option from the technical point of view. If a relatively small part of one country has power shortage and needs import, that part of the grid is disconnected from the country's main grid and connected in the "island mode" to the grid of the exporting country. The frequency of the interconnected grid is then regulated by the exporting country grid. This is referred to as the synchronous island mode operation or simply as island mode operation. Trading here would be governed by bilateral trade contracts.

When the grids of the two adjoining countries are compatible and fulfill certain technical criteria (such as principles of voltage and frequency regulation, level of reserve capacities, quality standards of supply to customers, communication, and protection systems) they can be fully synchronized and operate on the same frequency and submit themselves to the unified common rules of system operation and control. This is referred to as fully synchronized operation, which maximizes the benefits of interconnection. Trading here would be governed by contracts and the bilateral agreement on grid operation and discipline.

Interconnection of two non-adjacent countries through a transit country or interconnection among more than two countries would call for synchronizing all the connected grids, with all the discipline going with such synchronous operation and would thus become more complicated, as common criteria for system operation and control will have to be agreed among several parties and observed continuously. Trading here would be governed by contracts and multilateral agreements on grid operation and discipline and continuous coordination among operators of all relevant grids.

When the systems to be interconnected are electrically incompatible, then they could be interconnected by DC transmission. Converters in the exporting country convert the AC into DC and it is then transmitted through a DC line. In the receiving country converters convert DC back to AC for normal supply. Such DC interconnections are also referred to as asynchronous interconnections. DC options used to be expensive, but in recent years costs have been coming down due to cost-effective technology upgrades. Nonetheless, the DC interconnection options are more expensive than AC interconnections and would require a much larger volume of electricity transmission to become economic than in the case of AC interconnection.

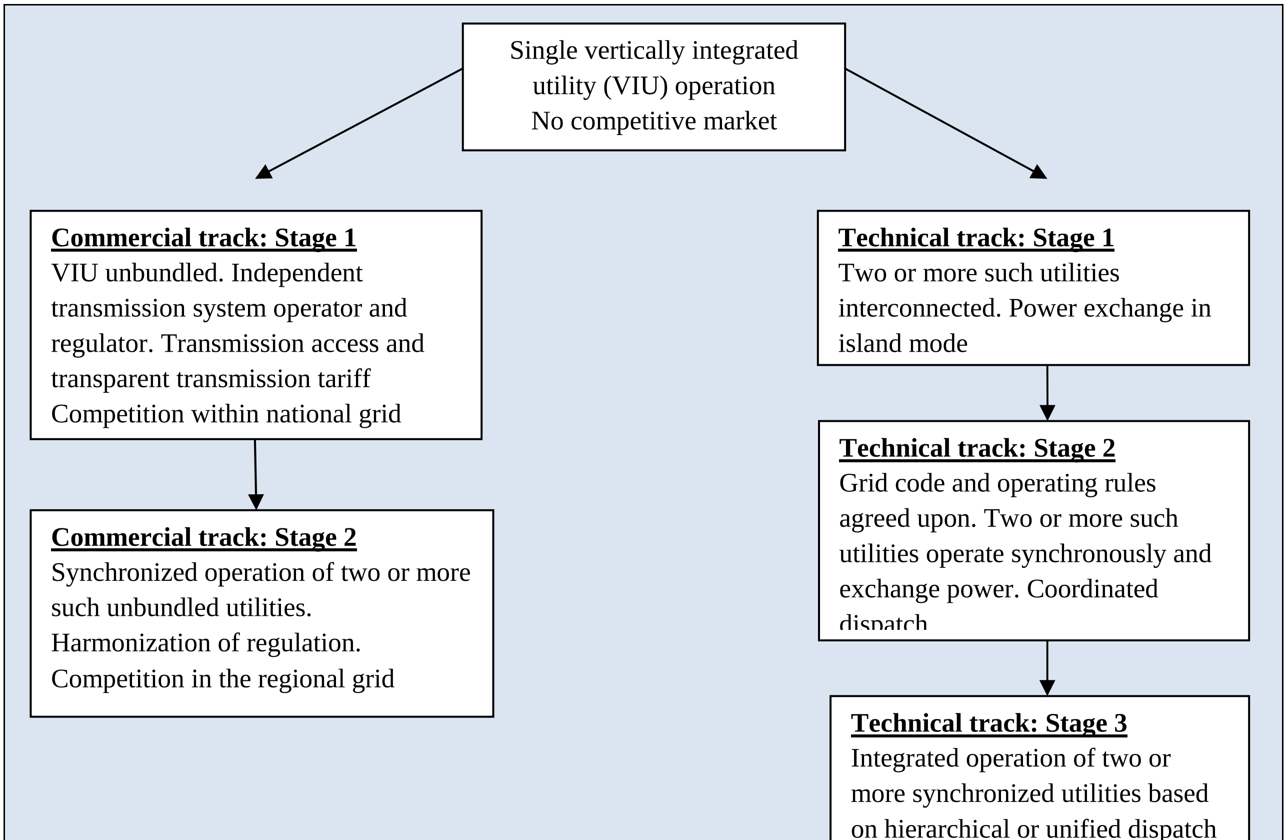
Further, when two or more grid systems are interconnected and operated synchronously, power will automatically flow to meet demand wherever it exists, since demand and supply must match at any given instant in the power system. The only way by which a constituent grid can avoid drawing more power from the interconnected system than what has been contracted or agreed upon would be to increase its own supply or to shed load. Interconnected synchronous operation of a balanced grid (in which supply and demand are broadly in balance) with a greatly unbalanced grid (in which demand exceeds supply capability substantially) is risk-prone and most often would lead to the latter grid drawing more power than agreed upon.

The common practice therefore is to use synchronized operation only among grids in which the supply and demand are broadly in balance in each system, relying on power exchanges only at the margin. For this purpose the supply for each grid would consist of the sum of its own generation capability at any given time and the volume of power imports covered by long-term contracts with take-or-pay and supply-or-pay provisions. For unidirectional export of power from a grid with surplus power supply capability to a grid with substantial supply deficits, synchronous operation of the two grids is not a good solution. Such power trade is best made in an island mode or by asynchronous DC connection (if the volumes of export warrant it). These aspects will have to be borne in mind when trying to help countries with large supply deficits through regional solutions.

However, multilateral and competitive electricity trade among more than two countries is complex and calls for sector restructuring and institutional and regulatory reform (particularly if trade were to promote private investment in new generation assets) in addition to the construction or reinforcement of the physical infrastructure for cross-border trade. Such reforms include the following:

- Separation of the transmission function from a vertically integrated utility to enable a transparent transmission tariff and third-party transmission access and technical coordination among the transmission system operators for network operation and dispatch
- Horizontal unbundling of generation and distribution functions to enable the creation of multiple sellers and buyers to enable competition
- Choice of suppliers at least for large consumers and distribution entities, which, among other things, would increase the number of buyers in the market
- Licensing energy traders who could aggregate smaller demands and supplies to reasonable sized transactions by matching demand profiles and supply profiles
- An independent regulator to ensure transmission access and approve transmission tariffs
- Harmonization of grid codes, regulatory rules and principles, and settlement mechanisms as well as cooperation among the regulatory organizations on cross-border transmission
- Coordinated regional energy planning for capacity expansions and demand-side management
- Financial viability of market participants, especially of distribution entities, and enforcement of payment discipline
- A dispute resolution mechanism.

A fully interconnected multilaterally trading competitive power pool among three or more countries takes decades to evolve and calls for high levels of institutional sophistication and governance excellence, which are not available or possible in most developing countries in the short run. Development of power/gas trade may have to commence in the simplest form of trade based on bilateral contracts for long-term supply (perhaps initially on island modes of supply) and gradually develop into synchronized operation between the two grids and later move into synchronized operation of more than two grids and into competitive trade, based on sector and institutional reform progress. Figure 1 illustrates the technical and commercial tracks for the evolution of competitive regional power markets).



Source: Author.

Figure 1: Evolution of Electricity Markets

Casual use of the phrases “regional energy integration” and “competitive power pools” conjures up unrealistic expectations, which are unlikely to be achieved except in the long term. While this should remain a long-term goal in many parts of the developing world, substantial benefits of energy trade can be gained by pursuing the opportunities for the simpler forms of trade in the short to medium term.[9]

Introduction of competitive markets may not be possible in many small countries or countries with small systems lacking economies of scale needed to bear the high transaction costs involved. In between simple bilateral utility-to-utility trade and fully competitive power pools,

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[9] “Integration” of power grids carries with it the connotation that there would be a *hierarchical control of dispatch systems* and this may be rarely possible except within national borders. Even in large countries with several provincial grids such integration is not always possible. Central authorities have to use economic incentives to influence dispatch decisions. Interconnected and synchronized systems (such as the UCTE in Europe and a few others in the world) operate on the basis of *coordination of dispatch systems*, based on agreed common rules. Developing competitive markets in such systems has taken two decades or more and is still largely a work in progress in many places. In this context it may be best to avoid the use of the phrase “integration of power systems” when dealing with the objective of promoting electricity trade.

there are intermediate solutions for introducing some element of competition. If an independent power producer (IPP) generating unit were to have freedom to export power to other interconnected grids, the conclusion of bilateral contracts between the IPP and the interconnected utilities will have an element of competition. Under such conditions the IPP's perception of demand risk and payment risk may be less, resulting in better terms for the investment and consequent lowering of costs.

Among the regional competitive power market initiatives pursued by the Bank, those relating to the South East European countries and the Southern African Power Pool appear to be somewhat more advanced than the rest. The grids of the South Eastern Europe (except those of Albania and Turkey) are members of the Union for the Coordination of Transmission of Electricity (UCTE) and operate in synchronism with the European systems. Sector reforms are proceeding (although slowly) under the Energy Community Treaty of October 2005 to create competitive structures, market opening and competitive trade. The pursuit of competitive power market integration under these circumstances could be somewhat meaningful even though it may still be a very long, drawn out process. Similarly most of the grids in SAPP operate synchronously and a "day-ahead market" on a competitive basis is under a trial-operation phase which is nearing completion. The pursuit of further development of a competitive market here too would be appropriate, provided additional generating capacities are quickly added. In most other cases such pursuits may have to await the development of simpler forms of bilateral trade based on long-term contracts, development of the grids, and the ability to operate them synchronously, as well as further sector reforms.

It may be more appropriate, meaningful, and practical to specify a target increase in the volume of electricity trade (which connotes unidirectional exports and imports or bidirectional exchange of electricity at different points in time among the power systems) as the key immediate objective of regional energy initiatives, with the understanding that, over the long term, such trade should desirably be enabled to evolve into multilateral competitive trade. Such an approach would enable setting practical goals that are achievable in a reasonable time frame.

In technical terms the progression will be from island mode of bilateral trade to synchronized operation of two or more grids; and in commercial terms the progression will be from utility-to-utility trade to trade among many sellers (generators and traders) and buyers (large users, distribution companies, and traders), based on long-term contracts and a balancing market based on competitive bids. The whole process may take a decade or two.

Even in respect of the simpler bilateral energy trade initiatives, it takes years of dialogue and intense negotiation among the countries and the international financing institutions to formulate a practical and reasonable project. Such dialogues should aim at building confidence among parties and should be opportunistic, taking advantage of whatever entry point is available.

Governments Changing Their Minds and Political Risks

Consistency of the commitments by the governments is a key determinant for the success of regional energy projects. Of the 31 cases reviewed, four involved a lack of sustained commitment, causing setbacks to the project.

- In the Brazil-Argentina Power Interconnection Project, four years after the completion of the first line and successful operation, Argentina banned the export of gas and power, thereby adversely impacting not only this investment, but future regional energy cooperation related investments in Latin America. The Argentinean ban on gas exports harmed not only the investors in the transmission lines to Brazil, but also Chile to a much greater extent, as it was dependent on gas imports from Argentina for its power generation needs.
- In the Bolivia- Brazil Gas Pipeline Project, after a few years of successful operation, the Bolivian government decided to acquire by force majority stakes in the oil and gas sector, thereby adversely affecting the interests of Petrobras in Bolivia and Bolivian gas exports. By 2008 the project seems to have recovered from this development.
- In the Greater Mekong Sub-regional Power Trade Project, the Government of Cambodia is planning to withdraw the component for power interconnection between Cambodia and Lao PDR, because of its disagreement with the Bank on procurement related issues. It may perhaps pursue it under alternative bilateral financing.
- Under SAPP APL 2, Malawi has not yet been able to sign the credit agreement, although the credit was approved in July 2007, owing to the problems associated with parliamentary approval of the loan. News reports indicate that the President may no longer be interested in the project, as he considers it to be an expensive option for the country. If true, it will jeopardize the chances of Malawi interconnecting with SAPP.

Experience of the kind encountered in Argentina or Bolivia tends to discourage large reliance on trade and create the impression that such trade is an erosion of energy security. However, complete energy independence is most often not possible for most countries (and may not even be desirable in terms of cost and lack of the needed diversity). A reasonable approach in such a political milieu, at least in relation to the electricity sector, is to have adequate domestic *capacity* to meet domestic demand and rely on electricity exchange or trade essentially for cost reduction of supply through fuel cost saving, reserve margin capacity saving, better capacity utilization, and other similar benefits of interconnected operation.

Such political risks are inherent in all regional energy projects and related investments. Mitigation mechanisms against such risks arising from changes in governments and their policies are not always easy or effective. In addition to the various types of guarantees and insurance that are designed to compensate the affected party when the risk occurs, possible mitigation mechanisms could include the relevant countries (desirous of attracting private investment, especially for regional projects) becoming members of Energy Charter Treaty (see Box 5 and Figure 2).

The investment agreements, trade agreements, and power purchase agreements between the parties could benefit from the Energy Charter Treaty obligations of the host governments and from the treaty provisions for international dispute resolution. Membership of the treaty could be yet another significant restraint to arbitrary decisions to renege on agreements. The synergy between the treaty and the standard commercial agreement may provide a greater level of comfort to the investors. Membership in formal treaty-based regional political and economic cooperation organizations could also serve a similar purpose. WBG guarantee mechanisms could also offer similar protections. Such memberships could enable the involvement of multilateral financing institutions in related regional energy projects without the cumbersome array of covenants.

Box 5: Energy Charter Treaty

International trade is carried out under the framework of the treaty, rules, and regulations of the World Trade Organization (WTO), which supplement and influence the national rules. In order to accede to the WTO, each country has to harmonize its laws, rules, and regulations with the WTO framework.

A similar organization to provide the multilateral framework specifically for the energy sector cross-border trade and investment has been in existence since 1991 when the Energy Charter Declaration was made. The Energy Charter Treaty provides a broad multilateral framework of rules governing energy cooperation. The fundamental aim of the Energy Charter Treaty is to strengthen the rule of law on energy issues by creating a common set of rules to be observed by all participating governments, thereby minimizing the risks associated with energy-related investments and trade and creating a level playing field.

The Treaty's provisions focus on five broad areas: (i) the protection and promotion of foreign energy investments, based on the extension of national treatment, or most-favored nation treatment (whichever is more favorable); (ii) free trade in energy materials, products, and energy-related equipment, based on WTO rules; (iii) freedom of energy transit through pipelines and grids; (iv) reducing the negative environmental impact of the energy cycle through improving energy efficiency; and (v) mechanisms for the resolution of state-to-state or investor-to-state disputes.

The Energy Charter Treaty and the Energy Charter Protocol on Energy Efficiency and Related Environmental Aspects were signed in December 1994 and entered into legal force in April 1998. To date the Treaty has been signed or acceded to by 53 signatories, consisting of 51 states, the European Communities, and Euratom. The Treaty was developed on the basis of the Energy Charter Declaration of 1991. Whereas the latter document was drawn up as a declaration of political intent to promote energy cooperation, the Energy Charter Treaty is a legally-binding multilateral instrument, the only one of its kind dealing specifically with inter-governmental cooperation in the energy sector.

The Treaty is open for accession by any country that wishes to participate, that is ready to take on the obligations in the Treaty, and whose application is accepted by the Energy Charter Conference. In order to join the Energy Charter Treaty, a country has to take the first step of signing the 1991 Energy Charter Declaration, thus committing itself to the principles of the Charter. By doing so the country becomes an observer to the Energy Charter with access to all its meetings and documents. There are 23 countries and 10 international organizations (including the World Bank and EBRD) with observer status at present. The next step is the actual accession for which the country and the Energy Charter Secretariat must assess the compatibility of its domestic legislation with the provisions of the Treaty. Once the assessment reports are found satisfactory by the Energy Charter Conference, the country is invited to accede to the Treaty and become a full member.

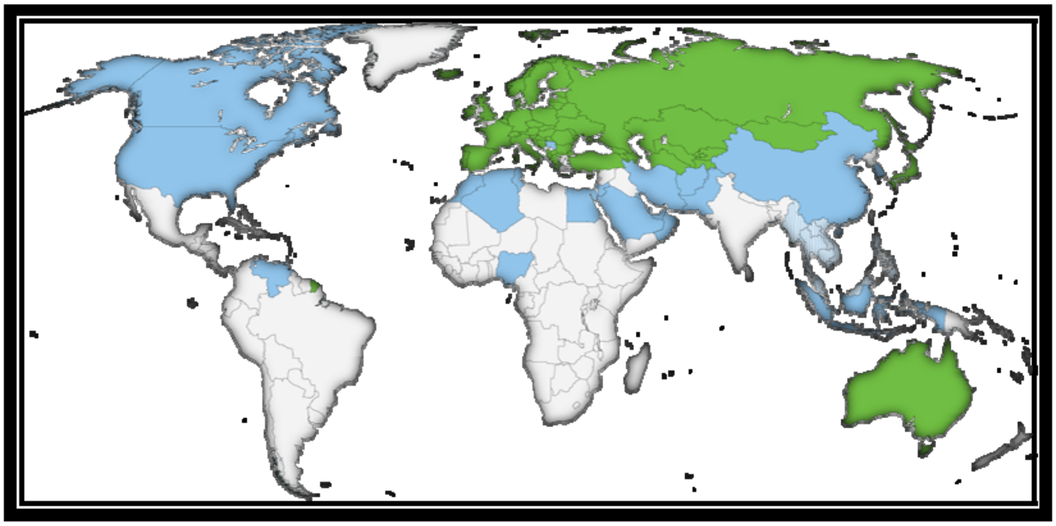

Figure 2: Participation in the Energy Charter Treaty
Countries marked in green are signatories to the Energy Charter Treaty, and members of the Energy Charter Conference. Countries marked in blue are observers
Source: www.encharter.org

Outlook and the Way Forward

The elements that are conducive to successful development of regional energy markets[10] in electricity and gas appear to include the following:

- A mismatch between energy resources, energy production, and demand, and an uneven distribution of energy resources in the region
- Evolution of political and economic communities seeking to find answers to their development needs on the basis of regional cooperation
- Existence of competently staffed and well-funded regional organizations or secretariats to turn the desire to cooperate into a concrete set of actions and to monitor progress
- Major project initiatives sponsored by the private sector to overcome the inertia of governments and sustain their interest and complete projects and commence production and trade in a timely manner
- The ability of the governments to avoid regional and local conflicts and maintain peaceful conditions.

The first element is prevalent in various regions, and the second has sprung up also in many regions. The third is effective only in one or two regions, and very many regions badly needing regional cooperation are involved in intractable regional conflicts. The approach of governments to private investment in the power sector and the approach of the private sector towards different developing countries also vary widely.

There is a great deal of scope and need for regional energy projects in most regions of the Bank. However, unlike the case of national energy projects, the regional energy projects evolve in the

[10] Simple bilateral export projects such as the Mozambique-South Africa gas pipeline project or the earlier Mozambique-South Africa power transmission project managed to proceed without the assistance of regional secretariats, largely because of the political will of the governments and private sponsor support.

context of political decisions of the governments to cooperate among themselves and creating organizations to pursue and facilitate such cooperation. Their desire to cooperate and willingness to enter into the various agreements and abide by them need to be consistent over the long term. Such opportunities do not come by often. For these reasons dramatic increases in regional energy projects are probably unlikely.

Further, the key contribution of the WBG to cross-border projects is to play the role of an honest broker. This role will be possible and credible only in the context of the close and continuous involvement of the WBG in the energy sector of all the relevant countries participating in a regional project. In the context of a notable decline in energy lending over a decade and also due to a variety of other reasons, the WBG had not been involved in the energy sector operations of many countries in certain regions such as Middle East and North Africa. This is perceived as a significant constraint.

However, in the context of climate change mitigation efforts, many countries are studying the potential scope for low carbon growth with World Bank support. Such studies (in countries such as India) could enable the opening of dialogue on regional energy trade as enabling low carbon growth. The Bank needs to be alert to such opportunities. The CSP scale-up effort in MENA region is one example that promotes trade.

Many of the environmentally friendly major regional energy resources are in the form of potential for large storage hydropower projects across trans-boundary rivers. They tend to be tied up in long-standing riparian disputes, discouraging any water sharing and water release agreements. Given these constraints, attempts need to be focused on those regions where the governments are open to cooperation.

Promoting regional cooperation and trade is only one of the many (competing) objectives pursued by the WBG. These considerations as well as the long lead times and high cost involved in preparing, processing, and supervising regional projects suggest that the increases in the volume of such lending are likely to be modest.

This implies that the WBG needs to be alert to the available opportunities and pursue those effectively, making suitable institutional and organizational adjustments to promote such a pursuit.

The WBG could consider the following to ensure that it is taking maximum advantage of opportunities for regional trade:

- Adopt an increase in electricity trade in the medium term as a realistic target outcome of regional power projects. It should be recognized that the evolution of simple utility-to-utility trade between two countries into a competitive power market pool among many countries in the region with multiple buyers and sellers and operating in synchronism is a very long, drawn-out process, lasting possibly a few decades.
- Review the possibility of making energy trade projects between two countries eligible for special allocation support.
- Screen projects for suitability for the WBG guarantees and IBRD enclave financing in energy export projects in IDA-only countries.

- Explore the financing of regional energy projects under the sub-national financing scheme.
- Periodically update regional energy trade promotion strategies for each region, either separately or as a part of an overall regional/sub-regional integration assistance strategy.
- Consider special allocation in each regional vice presidency for identification of regional energy projects and preliminary project/program preparation.
- Examine problems specific to inter-regional energy projects and consider mitigation options.
- Where appropriate, include energy trade in Country Assistance Strategies and Country Partnership Strategies, including the needs and priorities for regional energy trade from the country's perspective.
- Review budget allocations for regional energy projects requiring more intense, detailed, and frequent supervision and follow-up (such as Nam Theun 2 and WAGP).
- Review the design of APLs and assess when it would be appropriate to have the first loan cover the costs of basic designs, bid documents, bidding, and bid evaluation and associated consulting services, and other steps to enable reliable cost estimates of regional energy projects.
- Review the skill mix to ensure that there are enough mid-career professional energy engineers with adequate hands-on experience in energy trade and power pool operations.

Annex 1: List of Regional Energy Projects (2000-2009)

Africa Region

(a) Completed Projects:

Product #	Title	Approval	Status	Remarks
P046648	Regional Hydropower Development (Senegal)	1997	Closed in June 2004	Three IDA credits totaling $38.7m
P046650	Regional Hydropower Development (Mauritania)	1997	Closed in June 2004	
P046651	Regional Hydropower Development (Mali)	1997	Closed in June 2004	
P082308	Mozambique-South Africa Regional Gas Project	Nov 2003	ICR under preparation	IBRD PRGs $30m IFC equity $18.5m
P076499	Nile Basin Initiative--Shared vision program (Includes a Nile Basin Regional Power Trade component t be funded under NBI Trust Fund)	April 2003		Master TA program for 8 components ($131.5 m)
P075945	Nile Basin Initiative –Regional Power Trade Project (Grant of $5.71 m from NBI TF for Phase 1 and $7.39 m for Phase 2	May 2004		Institution Building of NBI secretariat and basin studies
MIGA 3323	MOTRACO – Mozambique Transmission Company project. Transmission line to supply power from South Africa to Aluminum smelter in Mozambique, parts of Mozambique and Swaziland.	FY 2000	Project completed in 2003	MIGA Guarantee of $69.40m Guarantee holder is SA Power Utility

(b) Ongoing Projects

Product #	Title	Approval	$m	Remarks
P069258	South Africa Power Market APL 1—Phase 1 of the SA Power Market Program (DRC-Zambia)	Nov 2003	178.6	
P105654	South Africa Power market APL 1-Additional Financing (Project Paper of June 2009)	June 2009	180.6	
P097201	Southern Africa Power Market APL 1(b)-Regional and domestic power market development project-Rehab of Inga Hydropower Project in DRC and 400 kV line to Kinshasa and distribution expansion in Kinshasa	May 2007	296.7	
P084404	Southern Africa Power Market APL 2 Mozambique-Malawi Power Transmission	July 2007	93.0	
P075994	WAPP APL 1- Phase1: Coastal Transmission Backbone : 330 kV line rehabilitation and new line in Benin, Ivory Coast, Ghana, Nigeria and Togo	June 2005	40.0	
P094916	WAPP APL2 Felou Hydropower Project, which will supply power to WAPP (Mali, Mauritania and Senegal)	June 2006	75.0	
P114935	Additional Financing for Felou Hydropower Project	July 2009	85.0	
P094917	WAPP APL 1-Phase 2: Coastal Transmission Backbone – second phase of 330 kV Rehab and new lines Benin, Ivory Coast, Ghana, Nigeria and Togo	June 2006	60.0	
P074011	Nile Basin Initiative: Ethiopia-Sudan power transmission line	Nov 2007	41.5	
P082502	West Africa gas pipeline project- a new pipeline system **(678** km long) to transport natural gas from Nigeria to Ghana, Togo, and Benin (Guarantee Operation)	Nov 2004	PRG 50.0 MIGA 75.0	

Product #	Title	Approval	$m	Remarks
P093806	Niger basin water resources Development and sustainable Ecosystems management program-APL Phase 1 (Phase 1 $186m and Phase 2 $314m Total program $ 500 m) Loans and grants to five governments are re-lent to Niger Basin Authority	July 2007	$186m Five Credits and 2 grants to 5 countries	$115.88 m of the IDA financing relates to rehabilitation of two dams and hydropower units in Nigeria

(c) Projects under Preparation

Further Projects under SAPP and WAPP

Nile Basin Initiative related Projects

Central Africa Power Pool Program

East Africa Power Pool Program

Europe and Central Asia Region

(a) Completed Projects:

Product #	Title	Approval	Status	Remarks
11251 (IFC)	Baku Tbilisi- Ceyhan oil pipeline ($250 m loan)	Nov 2003	Completed	
EBRD	Baku- Tbilisi-Erzerum gas pipeline ($65m loan)	March 2004	Completed	

(b) On-going Projects

Product #	Title	Approval	Amount $m	Remarks
P090656	Energy Community of SEE APL-2 Albania	June 2005	27.0	
P110481	EC SEE APL-5 Albania dam safety	June 2008	35.3	
P090666	EC SEE APL-3 Bosnia Herzegovina	June 2006	36.0	
P106899	EC SEE APL-3- Montenegro	June 2007	9.0	
P082337	EC SEE APL-3-FYRM	Jan 2006	25.0	
P086694	EC SEE APL-1 (CRL) Romania	Jan 2005	84,3	
P094176	EC SEE APL-2 Turkey (CRL)	Apr 2005	66.0	
P096400	EC SEE APL-3- Turkey	Mar 2006	150.0	
P088867	EC SEE APL-2 Serbia	Jun 2005	21.0	
P075046	Geothermal Fund ECA	Nov 2006	4.1	

(c) Projects under preparation:

CASA 1000 for export of Power from Kyrgyz Republic and Tajikistan to Afghanistan and Pakistan

Rogun Hydropower Project in Tajikistan 3600 MW mainly for export to South Asia

P116337 Caspian Development Corporation for gas exports from Central Asia to Europe

P096208 SEE Gas APL -1

South Asia Region
(a) Completed Projects

Product #	Title	Approval	Status	Remarks
IFC # 20350	Powerlinks Transmission Project IFC debt was in local currency. ADB gave a similar debt to Powerlinks India Ltd	Oct 2003	completed	IFC equity of $75m

(b) on-going projects:

Product #	Title	Approval	Amount $m	Remarks
P083908	Emergency Power Rehabilitation Project	June 2004	125.0	
P106654	The Kabul -Aybak -Mazar-e-Sharif Project	Oct 2007	57.0	
P111943	Afghanistan Power Sector Development Project	Oct 2008	35.0	
ADB project	Tajikistan-Afghanistan Power line	2006	56.5	

(c) Projects under preparation

India—Nepal Transmission Line
India—Bangladesh Transmission Link
India--Sri Lanka transmission lines

East Asia Pacific Region
(a) Completed projects: None

(b) On-going Projects:

Product #	Title	Approval	Amount	Remarks
P105329	Greater Mekong Sub-Regional Electricity Trade Project: Cambodia--Laos and Cambodia--Viet Nam transmission lines	May 2007	$33.5m	Two IDA credits $18.5 m to Cambodia & $15 m to Laos
P076445	Nam Theun 2 Hydropower Project Construction of a new Hydropower Project and power export to Thailand (Nam Theun 2 Environmental and social project)	March 2005	$20m IDA grant, IDA PRG $50m, MIGA Guarantee $200m	www.worldbank.org/laont2 see this website for updates

LAC Region
(a) Completed projects:

Product #	Title	Approval	Amount	Remarks
P006549	Brazil Gas sector Development project (Bolivia- Brazil Gas pipeline)	Dec 1997	IBRD loan $130m and IBRD PRG $180m	Closed on Dec 2000 ICR June 2001, PPAR Dec2003
Project No.628	Brazil-Argentina Power Interconnection project (MIGA guarantee of $28m to Endesa and $37 million to Banco Santander Central Hispano)	FY 2000	MIGA Guarantee $65m	Project completed in 2002

(b) On-going Projects

None

<u>(c) Projects under Preparation</u>.

Possible Generation and institutional Support to SIEPAC
Regulatory improvements and support for regional trade for the Organization of Eastern Caribbean States
Gas and or power Interconnection options in the Caribbean Islands to facilitate sub-regional energy markets

Annex 2

Annex 2: Case Notes on Regional Energy Projects

1	Regional Hydropower Development Project
2	Southern African Regional Gas Project
3	Southern African Power Market Program
4	West Africa Power Pool Program
5	West Africa Gas Pipeline Project
6	Ethiopia Nile Basin Initiative: Ethiopia-Sudan Interconnection Project
7	Baku-Tbilisi-Ceyhan Pipeline
8	Baku-Tbilisi-Erzurum Gas Pipeline Project
9	South Eastern Europe Energy Community Program
10	Power Projects in Afghanistan
11	Powerlinks Project India
12	Nam Theun 2 Hydropower Project
13	Theun Hinboun Hydropower Project
14	Greater Mekong Sub Regional Power Trade Project
15	Bolivia-Brazil Gas Pipeline Project
16	Brazil Argentina Power Interconnection Project

MANATALI HYDROPOWER PROJECT

(P046648, P046650, P046651)

This is one of the early regional power projects financed by the Bank in June 1997 covering Mali, Mauritania and Senegal. It involved the installation of a 200 MW hydropower generating station (in the existing Manantali Reservoir across the Bafing River, a tributary of the 1,800 km long Senegal River—one of the largest rivers in Africa) and about 1300 km of 225 kV transmission lines to feed the annually generated power of about 807 GWh to the capital cities of Mali, Mauritania and Senegal and other towns and settlements on the way.[11] This project enabled the interconnection of the power systems of the three countries and their operation in a cooperative manner.

Senegal River basin had an area of 290,000 square km in these three countries and Guinea and about 10 percent of their population (or about 2 million people) lived there.[12] The countries got together in 1972 and established the Senegal River Basin Development Organization (OMVS) to manage on behalf of the member governments, construction and operation of facilities for flood control, irrigation and hydropower development, and navigation. Twelve donors funded in 1981 the construction of the Manantali dam upstream in western Mali (to store water and regulate river flows) and Diama dam in the deltaic area to prevent the intrusion of salt water into the valley. These dams were completed in 1988 at a cost of around $620m, facilitating the irrigated agriculture of 100,000 ha and the cultivation of another 50,000 ha through the process of "artificial flooding".

The operating costs of OMVS are shared equally by the three governments and the capital expenditures are shared in agreed proportions, based on benefits. The only income it generated was the water use fee, which was modest and inadequate to service the debts incurred for the dams.

The construction of the hydropower station and the transmission systems was considered necessary: (a) to lower the long term power supply costs; and (b) to generate revenues to service the debt incurred for the dams.

Mali, Mauritania and Senegal had in 1995 relatively small power systems (with peak demands of 50 MW, 31 MW and 276 MW respectively) and with low electricity access to the population (7, 20, and 25 percent, respectively) and high average tariffs (14 to 17 US cents/kWh), which still did not cover supply costs.

OMVS handled the power project preparation assisted by several donors and coordinated by French Development Fund (CFD). The project cost was estimated at $445.5m (including capitalized interest) and was financed by contributions from the three governments ($31.5m) and by three IDA credits to the three governments (totaling $38.7m) and loans and grants from 10 donors ($375.3m). The donors included bilateral (France, Germany, Canada) and multilaterals (African Development Bank, Islamic Development Bank, Arab Fund for Economic and Social Development and West African Development Bank).

[11] The project also included a modern load Dispatch Center and communication systems

[12] Guinea had only been an observer most of the time.

The project costs were agreed to be divided among the three countries in the following proportions: Mali 35.3 percent, Mauritania 22.6 percent and Senegal 42.1 percent. Generated power was agreed to be shared as follows: Mali 52 percent, Mauritania 15 percent, and Senegal 33 percent.

As a part of the implementation arrangements for the project, the countries agreed with the Bank and created Manantali Energy Assets Holding Company (SOGEM) to construct the power plant, transmission lines and the associated facilities, to obtain on concession the Manantali dam and the constructed facilities from the governments which owned the undivided assets and to have the facilities operated by a professional private management contractor on the basis of a 15 year concession. The private Management Contractor had the responsibility to collect the power sales revenues and pass them on (after deducting his fees and contract expenses for operation, maintenance and minor replacements) to SOGEM for servicing the project debt and for other purposes. SOGEM was also responsible for servicing 43.8 percent of the debt relating to the construction of Manantali dam as it was the percentage of the total cost attributed to the power operations.

$30.8 m of the IDA credits were on-lent by the governments to SOGEM with 7 percent interest and 20 year maturity. The remaining $7.9m was passed on as grant to OMVS which had the responsibility for the implementation of the environmental impacts monitoring and mitigation program, part of which related to the adverse effects of the two dams constructed earlier.

The project was completed at a cost lower than estimated ($242.6m) mainly as a result of exchange rate gains. It was however delayed by a year. The hydropower units became fully operational by June 2003. By November 2002 the transmission lines had been completed and the three systems were interconnected. Eskom Energie Manantali[13] was retained as the management contractor to operate and maintain the facilities on the basis of international competitive bidding.

The project succeeded in providing lower cost power supply thereby moderating the high cost local supply the three utilities have. SOGEM is operating as a solvent and cash-rich utility able to meet its costs and service its debts. It is however to some extent subject to the non-payment problem by the utilities which are not solvent because of operational inefficiency and tariffs not being adequate to cover the cost of supply. Nonetheless payment to SOGEM is reported to be improving significantly.

There are several noteworthy features to this project. This is one of the earliest regional power projects in West Africa creating very credible regional operational entities such as SOGEM and OMVS for power development and river valley basin management on a regional basis. The bank gave three credit to the three countries and produced three appraisal reports, three sets of credit documents and three ICRs, though they all seem to be almost like carbon copies. The Bank's involvement in the project preparation seems to be modest, but seems to have been very fruitful in terms of institutional and implementation arrangements, which made the project possible and commercially oriented. Bank's environmental contribution seems to be significant.

[13] A private firm belonging to the Eskom Holdings group of South Africa

While the three governments did cooperate and got everything done, it had not been easy to get their commitments or concurrence for various steps in the time frame envisaged. There were considerable delays is securing their agreement to the reservoir operation regimes and the so called “water charter”, which inter alia sought to protect the interests of downstream riparian activities.

There were far too many financiers (with differing procurement, payment and disbursement procedures) and it proved difficult to coordinate with them effectively for making efficient procurement packages and arrangements. This proved to be a source of major delay.

The OMVS model has been followed to create a similar basin organization for Gambia River (OMVG). OMVS has pursued other regional hydro projects such as Felou based on the earlier experience and it is playing an important role in the deliberations of the ECOWAS and is also serving as the secretariat of African Network of for Basin Organizations.

It is expected that the OMVS network will be interconnected to zone A of WAPP through Mali by 2012. Additionally two hydroelectric power stations (Felou and Gouina downstream of Manantali) are expected to commence operation between 2011 and 2013.

SOUTHERN AFRICA REGIONAL GAS PROJECT

(P082308)

This project was intended to help Mozambique to develop its substantial natural gas reserves and export it to the adjoining Republic of South Africa and also eventually promote natural gas use within Mozambique.

Mozambique was a low-income country with per capita incomes around $230, growing rapidly at about 8 percent per year during 1992-2003 after pronged periods of unrest. It was a country with abundant energy resources, undeveloped energy markets and very low energy demand. The country had the second largest hydroelectric potential (14,000 MW) in Southern African region, substantial coal reserves estimated between 2 billion and 5 billion tons, and significant natural gas reserves (discovered as early 1961) both onshore and offshore. Yet only 6 percent of the population had access to electricity and the domestic power demand was only about 200 MW. The energy strategy of the country thus focused on attracting foreign investment for development and export of energy and develop the domestic energy market and supply capabilities in that context. Its known gas resource at that time was modest and not large enough for liquefaction and export. There was no domestic demand. Development of the gas fields by a South African investor and export of gas to South Africa was thus seen as a good fit for this policy.

The project consisted of an upstream and a downstream component. The upstream component was to produce gas from Temane and Pande gas fields by putting down several production wells, gathering the gas by a network of 177 km of pipes to a central gas processing unit to dehydrate the gas, remove the condensate from it and compress it for transport through pipeline. The downstream component was the construction and operation of a 865 km gas pipeline with a diameter of 26 inches from the central gas processing plant to the petrochemical plant of Sasol in Secunda of South Africa. The pipeline's initial transportation capacity was 120 million gigajoules (MGJ) of gas per year and this could be doubled by adding three compressor stations at appropriate intervals. About 525 km of the pipeline was in the territory of Mozambique and the design included five take off points for possible future supply to the consumers in Mozambique. The natural gas imported into South Africa would replace gas produced from coal which was: (1) being used to produce chemicals, and (2) also being distributed to about 600 industrial customers through a pipeline network of 1,500 km.

The project cost was estimated at $721m. The total financing required was $ 1,001m including $130m for interest during construction and $150m to cover exchange rate variations, as the South African Rand, the main currency for project expenditures was appreciating against US dollar.

The objective of the project was to commence export of gas in 2004 and reach the full capacity level of the pipeline (120 MGJ/yr or 3.24 billion cubic meters per year) by 2009.

The main private sector project sponsor was Sasol the fifth largest South African company, with market capitalization of over $8 billion. Starting with the business of synthetic fuels from coal it had diversified into several fields including hydrocarbon exploration. It had acquired exploration interests in Temane and Pande fields in the late 1990s. As a result of the confidence in the proven reserves of the fields Sasol conceptualized the project and pursued the conclusion of several agreements with Mozambique government and its entities[14], arranged for the bridge financing and commenced implementing the project. A MIGA guarantee of $72m was also obtained by Sasol in December 2002 for the bridge financing

The earlier assistance of the World Bank group to Mozambique through the Gas Engineering Project (IDA Credit 2629 closed in June 2003) providing for a review of the adequacy of gas reserves for commercialization, assistance in negotiation of agreements for the commercialization of the gas fields and institutional strengthening of gas sub-sector entities led to the evolution of the project concept and the needed agreements.

The project components were structured as follows: the upstream part was to be implemented by an unregistered joint venture among Sasol Petroleum Temane (SPT) – a subsidiary of Sasol with 70 percent interest, Mozambique Hydrocarbons Company (CMH) –a subsidiary of Mozambique National Oil Company (ENH) with 25 percent interest and IFC with 5 percent interest. The Joint Venture designated SPT as the operator of the gas fields and the gas processing facility. The gas export pipeline was to be constructed, owned and operated by Republic of Mozambique Pipeline Investment Company (ROMPCO in which Sasol has 50 percent interest, I-Gas , a South African Government gas agency has 25 percent interest and Mozambique Gas Company (CMG) a subsidiary of ENH has the remaining 25 percent interest.

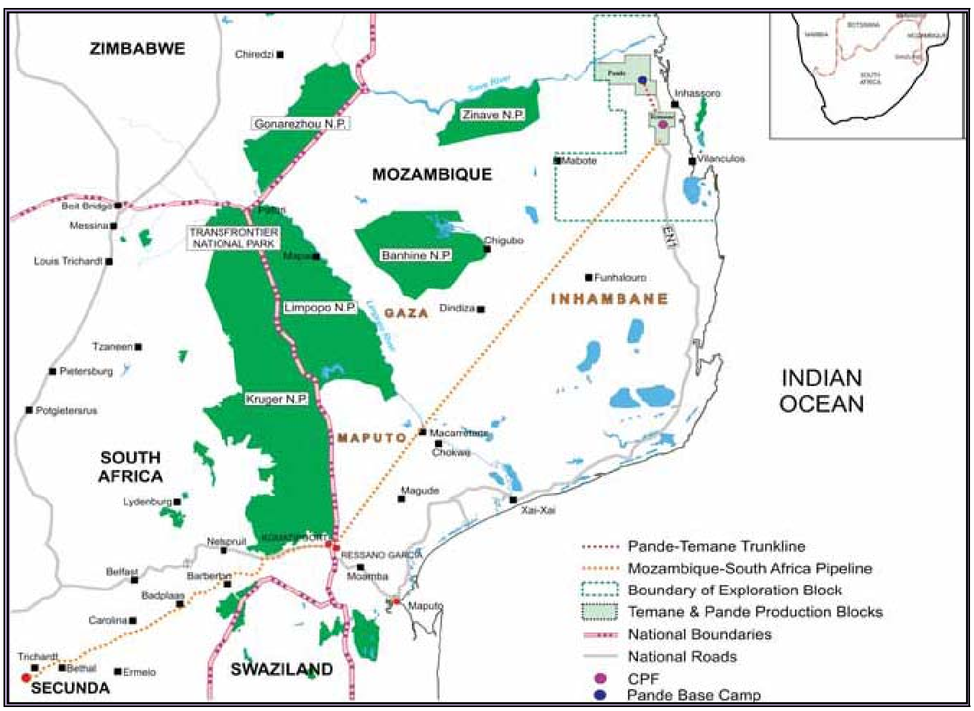

Figure 3: Mozambique –South Africa Gas Pipeline Project

Of the total cost of $ 396m of the upstream project, equity contributions (70 percent by SPT, 25 percent by CMH and 5 percent by IFC) financed $176m. Debts financed $220m. Of the total cost of $605m for the downstream component equity contributions (50 percent by Sasol, 25 percentby

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[14] There were 11 agreements in all including Petroleum Production Agreement, Pipeline Agreement, Joint Operation Agreement, Gas Sales Agreement and Gas Transportation Agreements.

I-Gas and 25 percent from CMG) financed $285m and debts financed $320m. Bridge loan was raised by Sasol from the Development Bank of South Africa (DBSA) and political risk cover of $72m for this was provided by MIGA in December 2002 covering Sasol's equity contribution to SPT (up to $27m) and Sasol Gas Holdings equity to ROMPCO (up to $45m). For financial closure Sasol obtained assistance from export credit agencies of Australia, South Africa, and Italy, as well as European Investment Bank. The bridge loan from DBSA was rolled over into a long term loan and Standard Commercial and Merchant Bank of South Africa (SCMB) was to syndicate a loan from commercial banks for the rest of the debt. Guarantees for the debts were provided by the export credit agencies. While DBSA assumed Mozambican political risk, commercial lenders desired a robust political cover such as from the WBG. Thus IBRD enclave PRG of $20m provided such a cover in respect of the SCMB syndicated loans to SPT and IBRD enclave PRG of $10m provided cover in respect of the syndicated commercial loans to ROMPCO (WBG assistance was approved in October 2003). In addition, a part of the equity guarantee of $72m provided by MIGA was to be rolled over as debt guarantee.

The project facilities were commissioned and gas supply to South Africa commenced on 26 March 2004. The export in 2004 amounted to 50MGJ and it has risen to 120.4 MGJ in 2008, thus hitting the target level one full year ahead. Gas exploration in the given fields as well as in other offshore and onshore blocks have led to larger discoveries and at present the outlook is that annual exports by the pipeline could increase to 183 MGJ and eventually to 240 MGJ.

The success of the project had attracted other oil companies such as Petronas (Malaysia), Norsk Hydro (Norway), ENI (Italy), Andarco (US), Mitsui (Japan) and Artumas (Canada) for exploration of oil and gas to the same general area. The project is slowly opening the domestic market for gas. The government of Mozambique is selling the royalty gas they get from the Petroleum production Agreement to Matola Gas Company which constructed a 75 km pipeline from the off-take point on the export pipeline at Ressano Garcia and has started distributing gas to about 15 industrial consumers in the suburbs of the capital city of Maputo. Also a gas distribution system has started operating in the North Inhambane area.

Apart from the dividends the Mozambique national oil and gas companies get from the profits made by the Joint venture and ROMPCO, the government gets significant sums by way of royalties and taxes. The project sells gas and condensate. Gas price is linked to those of certain crude oil prices with floor and a ceiling, while the condensate price is market based moving with world crude oil prices without any cap or floor. Originally it was estimated that over the period of 25 years the project will yield $498m in nominal terms to the government by way of royalties and taxes. Based on the current oil and gas prices and the price forecasts it is presently estimated that such royalties and taxes will amount to $177m and $1.3 billion respectively. Dividend incomes to Mozambique entities could be as high as $1.5 billion.

IFC had also helped CMH to sell 10 percent of its shares to the public of Mozambique through a successful public issue in May 2008.

The participation by the WBG has also ensured that the project was carried out and is being operated in an environmentally and socially sound manner. On-going exploration and development for additional gas is also carried out on a similar basis. Sasol maintains and operates a social development fund. The Bank's supervision had focused on environmental and social aspects.

Preparation of the sector through such projects as Gas engineering Project, strengthening sector institutions through such projects as Energy Reform and Access project helped the evolution of this project. The ongoing economic cooperation efforts among the South African Development Community (SADC) countries and the creation of South African Power Pool established an overall political environment conducive to cooperation. The use of a highly solvent private sector sponsor in conjunction with significant participation by Mozambican government entities reduced the sovereign risks to the project and provided with initial capital resources. Price expectations were moderate and realistic. With modest exposure the Bank leveraged its assistance substantially and was able to bring added value in the areas of political risk mitigation, and environmental and social risk mitigation.

Mozambique has relatively modest gas reserves (more may be found) but with little local demand and too little gas for an LNG plant, Sasol and South Africa were the only option for gas development.

SOUTHERN AFRICAN POWER MARKET PROGRAM

Among the members of the SADC, those in the north—Democratic Republic of Congo (DRC), Mozambique and Zambia—had significant hydropower resources, those in the south—such as South Africa mainly and to some extent in Botswana and Zimbabwe—had significant coal resources. Realizing that electricity trade among the member countries would be beneficial to all members SADC established the Southern Africa Power Pool (SAPP) in 1995, through an Inter Governmental Memorandum of Understanding (MOU) and an Inter Utility MOU. The member countries signed an Energy Protocol in 1996 and it entered into force in April 1998. The Energy Commission of SADC prepared an Energy Sector Activity Plan (2000-2005) focusing on energy trade, investment and finance, capacity building and exchange of information and experience. SAPP emerged a sa vehicle to foster regional electricity trade.

SAPP has the national power utilities of 12 countries as its members.[15] Nine of them are interconnected and are designated as operating members and three (Angola, Malawi and Tanzania) are yet to be interconnected to the regional grid. The pool covers an area of 9.09 million square km and a population of about 230 million and about 7.2 million electricity customers (2008). During the FY 2007-08, the twelve member-utilities had a combined total installed capacity of 52,835 MW, of which the available capacity was 45,579 MW to meet their cumulative peak demand of 43,829 MW. Their total net energy generation amounted to 276 TWh.

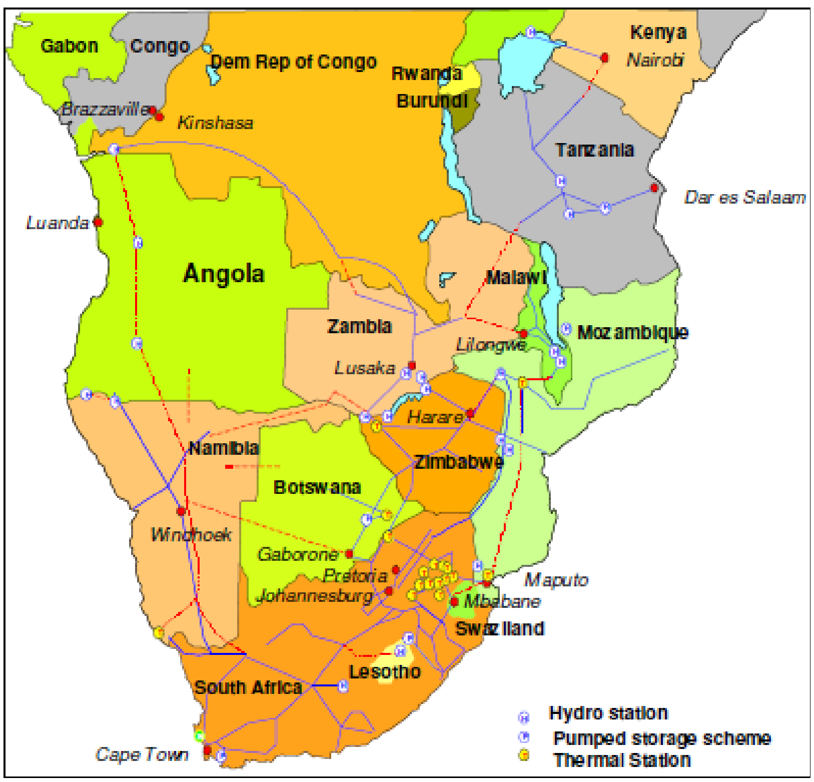

Figure 4: Countries in the Southern Africa Power Pool

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[15] They are Angola, Botswana, Democratic Republic of Congo, Lesotho, Malawi, Mozambique, Namibia, South Africa, Swaziland, Tanzania, Zambia and Zimbabwe.

South Africa was clearly a dominant member of the group. Its share of the total installed capacity of the interconnected grid was nearly 87 percent and its peak demand was about 83 percent of the interconnected system peak demand. Its share in total power generation is more than 80 percent. SAPP started as a loose cooperative pool and facilitated trade largely on the basis of long term bilateral contracts in the context of the existence of a large amount of surplus capacities in the system especially in South Africa. For more than a decade preceding 2007, there had been no new capacity addition and the available surplus capacity had come down sharply on account of increased demand. A country like Botswana which has substantial coal resources and chose to run its small power system (peak demand 500 MW) based mostly on imports from South Africa for more than a decade had to scramble and start building domestic coal-fired capacity to meet its demand and possibly for exports.

In 2000, a Coordination Center was established in Harare to facilitate the Short Term Energy Market (STEM) which allows members of the SAPP to trade using monthly, weekly, daily and hourly contracts for energy. This had been functioning since April 2001. In the context of surplus capacities in the region STEM became popular and about 5 to 7 percent of the total volumes of traded energy went through this market. Since 2004 SAPP is moving towards the concept of a competitive pool and, in the first instance, is implementing on a trial basis the “Day Ahead Market”. There is as yet no balancing market.

The Southern Africa Power Market Development APL Program of the Bank was developed in this context to support the operations of SAPP and its Coordination Center to administer electricity trading efficiently, to remove transmission bottlenecks, to connect Malawi and possibly Tanzania to the rest of the SAPP grid and to provide institutional support. So far three operations have been funded under this APL.

P069258 SAPP APL-1 and (P105654) Additional Financing: This consisted of four parts. Part A related to the support of the Coordination Center of SAPP (estimated cost $3.36 million) to be financed by Norway, Sweden USAID and other donors. Part B related to the rehabilitation of the 2,280 km long HVDC transmission link from Inga Hydropower Project to Kolwesi in Democratic Republic of Congo (DRC) and the construction of 220kV AC transmission line from Kolwesi to Kasumbalesa at the Zambian border (278 km) with the objective of enabling transfer of about 500 MW of power from Inga to SAPP with 95 percent dependability estimated at $186.11 million to be funded mostly under the IDA credit. Part C related to the construction of 220 kV double circuit AC lines from Kasumbalesa to the Luano substation in Zambia at a cost of $ 9.7 million. This line was to be funded and constructed by a private company in Zambia, Copperbelt Energy Corporation. Part D related to a feasibility study for a transmission link between Zambia and Tanzania and the reinforcement of the transmission link between Tanzania and Kenya at a cost of $1.01 million to be carried out by the government of Zambia under IDA credit financing.

The total project cost of $ 200.19m was financed by two IDA credits (to DRC and Zambia) totaling $178.6 million, Copperbelt Energy Corporation financing of $9.7m and financing from European Investment Bank (EIB) and bilateral donors as well as borrowers’ own financing covered the balance. The IDA credits were approved in November 2003 and became effective in May 2004. Part A and Part D of the project were completed satisfactorily before the original closing date of December 31, 2007. Internal conflicts in DRC delayed implementation of Part B and Part C. According to the Project Paper for additional financing, the Bank had not also been able to provide efficient supervision and monitoring owing to staff transitions and inadequate budgets.

Recruitment of consultants and prequalification of bidders for major contracts were greatly delayed due to procedural problems. Three of the six major contracts for goods and works covering 61 percent of the original credit amount for Part B have been awarded or were about to be awarded by mid 2009. Based on a review of the bids and the need for additional components to help achieve the initial development objectives, a revised cost estimate was prepared covering Part B and Part C. Compared to the original estimate of $195.3 m, the revised estimate amounted to $ 430.0 million creating a financing gap of $234.17m. The reasons cited for this increase include: (a) scaling up of some components and addition of new elements; (b) increase in the cost of materials and equipment; (c) increases in the scope of rehabilitation works based on subsequent deterioration; and (d) currency fluctuations. These cost increases for Part B were financed by an additional IDA grant of $180.62 million and EIB assistance of $47.02 million. The increases in Part C of $8.30 million was to be absorbed by Copperbelt Energy Corporation. The additional IDA grant was approved in June 2009 (P105654). The closing date had been revised as 31 December 2012.

The Project is excellently conceived since DRC is a major supplier to the SAPP and a potential supplier to CAPP and removal of constraints in the transmission corridor from DRC to SAPP deserves high priority. However, it would appear that this case illustrates inadequate project preparation in terms of properly defining project components, estimating costs with any degree of accuracy, and appreciation of the institutional inadequacies of the DRC power utility and making appropriate ring fencing arrangements for such a major project.

<u>P097201 SAPP APL-1(b): Regional and Domestic Power Marketing Development Project</u>
In the second operation under the APL program, an IDA grant of $ 296.7 million to DRC was approved in May 2007 for financing: (a) Rehabilitation of the Inga 1 and Inga 2 Hydropower Projects; (b) construction of a 400 kV transmission line from Inga Hydropower Project to the major load center Kinshasa; (c) Distribution rehabilitation in Kinshasa area; (d) Capacity building for the national power utility and for the sector governance; and (e) Consulting services for project execution and for environmental and social aspects of the project. The total project cost was estimated at $499m to be financed by IDA Grant ($296.7m), African Development Bank ($189.5m) and the borrower ($12.8m). The original closing date was June 30, 2013. The grant became effective in April 2008. So far there had been negligible disbursements (about 1.5 percent of the grant amount).

Much of DRC’s large hydropower potential is concentrated in one location Inga. The site has a total potential of 45,000 MW of which 1,775 MW had been developed in the form of Inga 1 and Inga 2 Hydropower Projects. Together they have 14 units and are in need of extensive rehabilitation as their reliable output now is of the order of 700 MW only. Inga is a crucial facility for supply to SAPP and CAPP and the development of electricity trade in both regions depend to a large extent on the proper development and use of this large resource. The rehabilitation funded by IDA aimed to increase the operating capacity to 1300 MW.

The engineering consultants and the utility have carried out further studies on the rehabilitation of Inga 1 and 2 and seem to have indicated a total revised cost estimate of $547m calling for additional iDA financing of the order of $120 m to $140m. The strategy proposed for the rehabilitation of all units indicates that it is likely to go on till 2020.

This project is also conceptually an excellent one, but seems to have suffered from inadequate preparation. In the APLs there is no special need to commit funds without appropriate engineering and cost estimation. The program assures the availability of funds and therefore there should be no special reason to hurry to commit funds based on inadequate preparation.

<u>P084404 SAPP APL-2 Mozambique Malawi Transmission Interconnection Project:</u> In the third operation under the APL program IDA credits of $48m to the government of Malawi and $45m to the government of Mozambique were approved in July 2007 for financing an electricity interconnection between the two countries, thereby linking Malawi grid to SAPP. The project consisted of: (i) construction of a 72km long 220 kV double circuit transmission line with associated substation and facilities on the Malawi side and the construction of a 135 km long 220 kV double circuit line and associated substation(s) and facilities on the Mozambique side; (ii) Capacity building and technical support for both national power utilities –ESCOM and EDM— for system upgrade, expansion and power trade; and (iii) improved infrastructure to both utilities to support power trading. The line will be from Matambo substation in Mozambique to a new substation in Malawi at Phombeya and will be capable of transmitting 300 MW. The line will enable Malawi to meet its peak demand power deficits through imports from Mozambique and will also enable Malawi to export energy from its run-of-river hydropower stations to SAPP during off-peak hours.

The total project cost was estimated at $109.7m to be financed by IDA credits ($93m) and the two borrowers ($16.7m). To ensure coordination, credit conditions included: (i) that as a condition of effectiveness of the credits, both the utilities formally sign an Implementation Agreement, a Maintenance Agreement, a System Operation Agreement and a Wheeling Agreement (all of which had been already negotiated) and (ii) that disbursements in any country can take place only after the credit had become effective in the other country. A joint Steering Committee and a Coordination Committee had also been established to monitor and oversee the activities of the two Project Management Units. There is only one Design and Project Supervision firm for the entire project spanning both countries, hired jointly by both utilities, which share the cost equally.

The neat and clean conceptually sound project, however, has made little progress since its approval. The credit agreement had not been signed by Malawi, as the government could not secure the needed parliamentary approval. After the elections held in May 2009, there is a new parliament and the government hopes to secure its approval. Because of this Mozambique utility cannot disburse funds from the credit in respect of the few contracts it has concluded. Further, the design work for the Matambo substation expansion in Mozambique by the consultants resulted in the cost estimate of this work being increased from $6.2m to $15.1m. The bids received were even higher at $17.9m. The additional financing to meet this increased cost is being arranged from Norwegian trust funds. It is possible similar cost increases might occur as other contract designs are finalized and bids are invited. However there are news reports indicating that the President of the country is no longer interested in the project considering it an expensive option for the country.[16]

The experience in this project and two earlier operations makes one wonder whether each operation should have been divided into two operations one for design, engineering and bidding and the second for construction. Such a division might enable better cost control. The project also highlights the potential political risks involved in regional projects.

[16] Source: http://www.nationmw.net/newsdetail.asp?article_id=3586

WEST AFRICA POWER POOL PROGRAM

The Economic Community of West African States (ECOWAS), founded in 1975, has fifteen member states[17] with a total area of five million square kilometers and a population of 250m, projected to grow to 380m by 2020.The aim of the Community is to establish an open, unified regional economic space in West Africa.

Despite its substantial energy resource endowments, the development of the electricity sector had been modest and the average per capita annual electricity consumption was of the order of 160 kWh. The Community believed that past approaches based on national self-sufficiency had been expensive and not very successful and desired to adopt a regional approach to the energy development needs. Thus in 1999, the Community resolved to support the concept of integrating their national grids through the mechanism of cooperative West African Power Pool (WAPP). The overall objective of securing for the people, in the medium to long term, stable and reliable power supply at affordable prices was sought to be achieved mainly through; (a) the optimal operation of the several large existing hydropower stations (Akosombo, Kainji, Manantali) on Niger, Volta and Senegal Rivers; (b) developing the untapped hydropower potential in the region, such as that of Guinea River; (c) exploiting the 3000 billion cubic meters of natural gas reserves of Nigeria, transporting the gas to several member countries to generate thermal power, so that the regional system could have an optimal hydro-thermal mix to ensure greater system reliability; and (d) increasing the interconnections among member systems fourfold by 2020 to facilitate regional trade flows.

During the next several years, the Summit of the Heads of States and Governments[18] approved the overall concept, the ECOWAS Energy Protocol (EEP), a revised Master Plan for Power generation and transmission of the region, as well as an Emergency Power Supply Security Plan. It also approved organizational arrangements to implement the program.

EEP is a key document seeking to produce a level playing field to facilitate the balanced development of the diverse energy resources of member states for their collective economic benefits, through long term cooperation and increased cross-border power trade unimpeded by energy transit constraints. It seeks to enable a transparent and harmonized policy, regulatory and commercial framework in the energy sectors across the region. It deals with a whole range of energy cooperation and trade issues including investment protection, taxes, non-discriminatory access to the networks and dispute resolution. Having been ratified by nine members the EEP entered into force in 2006.

The WAPP organization consists of (a) the General Assembly comprising representatives of all public and private electricity utilities in the region[19]; (b) the Executive Board which has six elected members and the Secretary General; (c) the WAPP Organizational Committees comprising technical experts from member utilities to provide advice to the Executive Board on engineering, operations, strategic planning, and human resources; and (d) the WAPP Secretariat headed by the Secretary General. Further the ECOWAS Regional Regulatory Authority was established in January 2008 with jurisdiction over cross-border exchanges of electricity. Also

[17] These are Benin, Burkina Faso, Cape Verde, Cote d'Ivoire, Gambia, Ghana, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leon and Togo.
[18] This is the highest decision making body of ECOWAS
[19] There are 19 such member utilities

regional projects are sought to be implemented, owned and operated by Special Purpose Vehicles rather than by national entities.

The implementation of the WAPP infrastructure program for 2005-2020 is based on pursuing five distinct mutually reinforcing subprograms the realization of which will converge to facilitate the unified well coordinated WAPP operation. These five subprograms are: (a) Coastal Transmission Backbone to provide robust interconnection among the power systems of Cote d'Ivoire, Ghana, Benin/Togo, Nigeria; (b) Inter-zonal Transmission Hub (Burkina Faso and Mali via Ghana, *OMVS* via Mali, Liberia-Sierra Leone-Guinea via Cote d'Ivoire) --these interconnections would help to displace expensive diesel based generation by low cost power; (c) OMVG/OMVS power System Development covering Gambia, Guinea, Guinea Bissau, Mali and Senegal will help securing access to the low cost power from Hydropower Projects to be built on Gambia, Senegal and Konkoure River basins; (d) North-core Transmission (Nigeria, Niger, Burkina Faso, Benin); and (e) Cote d'Ivoire - Liberia-Sierra Leone-Guinea Power Network (Cote d' Ivoire, Liberia, Sierra Leone, and Guinea) (See Figure 5).

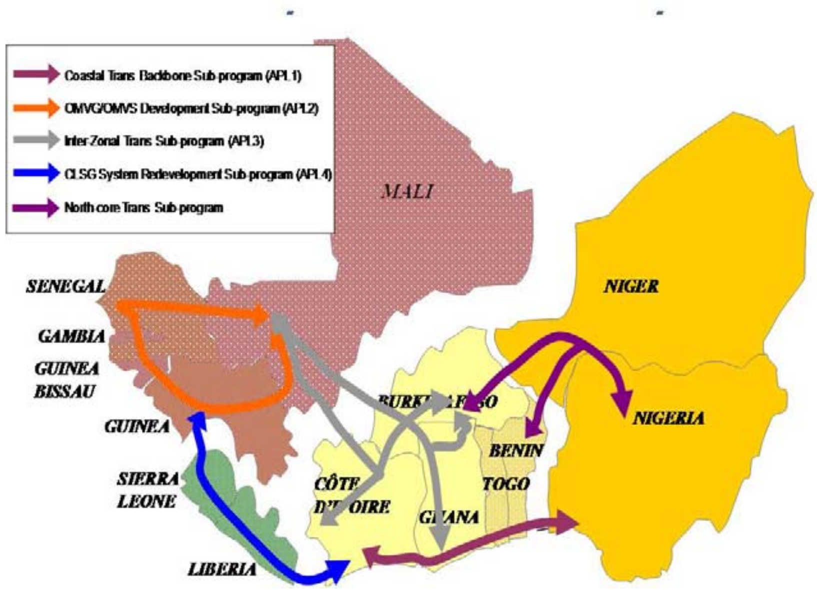

Figure 5 : The Five Subprograms under the WAPP program

The Emergency Power Supply Security Plan envisages the construction of: (a) 200-400 MW CCGT facility in Benin near the West Africa Gas pipeline terminal; (b) 400 MW CCGT facility near Takoradi gas terminal in Ghana; and (c) 150-250 MW CCGT facility near Nouakchott using offshore gas in Mauritania. Financing from various bilateral sources is being organized by WAPP.

The WAPP program is being financed by a range of multilateral and bilateral donors. The World Bank has agreed to meet the financing gaps, initially to the extent of $350m from IDA resources in the form of Adaptable Program Loans. The World Bank's mixed APL program closely follows the five subprograms of WAPP and has corresponding tranches (APL 1, 2, 3, 4) each with appropriate phases. So far APL 1-phase 1, APL 1-phase 2, APL 2 and additional financing for APL 2 have been approved. The eligibility criterion for borrowing from the APL facility is the ratification of the EEP. Policy triggers are derived from the core principles of EEP and the projects need to be part of the revised Master Plan approved by ECOWAS.

The preparation time for the APL operation was spread over nearly four years from October 2001 to April 2005. The cost of preparation excluding the PPF has been indicated at around $875,000. Estimated annual supervision cost was $100,000.

Brief details and status of these operations are given below:

<u>P075994 WAPP APL 1- Phase1: Coastal Transmission Backbone:</u> $40 m credit from IDA was approved in June 2005 to finance in Ghana: (a) the 330 kV transmission segment Abodze-Volta[20]; (b) upgrade of the System control center with modern SCADA system; (c) upgrade of the switchyard of Akosombo Hydropower Project; and (d) consulting services for project engineering and implementation, for the preparation of the "operational mitigation and security plan" for the 330 kV Coastal transmission system, and for re-optimizing the operation of Akosombo and Kpong Hydropower Projects to increase the volume of peaking support to the regional system. The total project cost of $83.5m was financed by IDA ($40m), Kuwait Fund for Arab Economic Development ($17.5m) European Investment Bank ($12m) and the Borrower ($14m). IDA credit to government of Ghana was on-lent to the implementing agency Volta River Authority of Ghana. After initial delays the project appears to be proceeding well. All major contracts (except that of the SCADA) representing 80 percent of the IDA credit have been awarded. The transmission line is expected to be commissioned by end 2009 and the rest by 2011.

<u>P094917 WAPP APL 1-Phase 2: Coastal Transmission Backbone:</u> $60m IDA credit was approved in June 2006 to finance (a) New SCADA systems and metering systems and associated technical assistance in Benin; (b) substation and switch yard upgrades, generating station rehab and associated technical assistance in Ghana. The total cost of $75m was financed by IDA ($60m) and by Ghana ($15m). $45m of the IDA credit was given to Ghana for being re-lent to the Volta River Authority (VRA) the implementing agency in Ghana and $15m of the IDA credit went to the government of Benin for being re-lent to the national power utility of Benin (CEB). The credit to Benin became effective only on November 29, 2007 among other things, on account of the need for the legislature to approve the foreign agreement. Even after this, progress in Benin appears to very slow. The progress in Ghana is relatively better—most of the contracts have been awarded or about to be awarded soon. The closing dates may have to be extended. The financial fragility of VRE and CEB seems to have become a cause for concern. Donor coordination in funding the other components of Coastal Transmission Backbone Project in a timely manner seems to have become important.

<u>P094916 WAPP APL 2: Felou Hydropower Project and P114935: Additional financing for Felou Hydropower Project:</u> Three IDA credits of $25m each were approved in June 2006 for Senegal, Mali and Mauritania for the construction of a 59 MW (350 GWh/year) run-of-river hydropower project about 200 km downstream of the Manantali Hydropower Project on the Senegal River, making use of the existing weir (after reinforcing it) and associated transmission facilities.

[20] Other segments of the Coastal Transmission Backbone, such as Volta to Mome Hague to Sakete to Lagos are being financed by other donors

Manantali Hydropower Project was constructed by OMVS, owned by SOGEM—both regional entities owned by the three governments—and operated by a private sector firm Eskom Energie Manantali. This firm operates not only the Manantali Hydropower Project but also the extensive transmission system (known as the OMVS system) interconnecting the national grids of the three countries (See Regional Hydropower development Project --Manantali--case notes for details). Felou Hydropower Project is to be built, owned and operated similarly and feed the OMVS system. The three governments have to re-lend the proceeds of the credit to OMVS/SOGEM for implementing the project. The project included consultant support for project implementation and technical assistance to SOGEM for the optimal operation of the OMVS grid and the related national grids. The total cost was estimated at $125m to be financed by IDA ($75m) and EIB ($40m) and by the borrowers ($10m). Felou Hydropower Project was to be built on the basis of a single responsibility contract for designing and building the project. Credits became effective by end April 2007.

Two stage bidding done for the Felou Hydropower Project contract resulted in the lowest bid being about 61 percent more costly than the original estimate. This and the increased interest during construction resulted in the total project cost going up from $125m to $241m. Two additional IDA credits of $42.5m each to Mali and Senegal were approved in July 2009 to meet the cost overrun. Due to exchange rate gains the EIB assistance now amounted to $45m. The remaining $36m was expected to be met by the implementing agency SOGEM. The closing date had been extended by three years to June 30 2013 and SOGEM had been made the sole implementing agency. The power utilities of Mali, Mauritania and Senegal to whom SOGEM sells power from Manantali continue to be financially fragile and build up periodically very large arrears of payment to SOGEM. A good solution to this problem is yet to be found. Under the most recent arrangements, SOGEM is authorized to reduce supplies by 30 percent to 100 percent to the utility which does not settle its bills within the time allowed.

WEST AFRICAN GAS PIPELINE PROJECT

(P082502)

IDA approved a partial risk guarantee of $50m for Ghana and MIGA approved a guarantee of $75m for the sponsors' equity in November 2004 in respect of the West Africa Gas Pipeline (WAGP) project, intended to transport Nigerian gas to Ghana, Benin and Togo.

The project consisted of a 678 km long 20 inch diameter pipeline from Nigeria to Ghana (most of the length being a submarine pipeline laid close to the sea coast) with spurs with diameter of 8 inches to supply gas to the power plants near Cotonou (Benin), Lome (Togo), Tema and Takoradi (Ghana) and associated facilities. Natural gas produced in the Nigerian delta was to be gathered and transmitted to the starting point of WAGP through the Escravos-Lagos gas pipeline (ELPS) existing since 1989. The cost of the project was estimated at $589m and it was financed by equity contribution of the shareholders of the West African Gas Pipeline Company (WAPCO) and shareholder loans to the Company as follows: (a) Government of Ghana ($96m); (b) Nigerian National Petroleum Corporation ($147m); (c) Chevron Nigeria ($216m); (d) Shell Production Development Nigeria ($106m); (e) Benin Gas Company ($12m); and (d) Togo Gas Company ($12m). [21]

Nigeria has gas reserves exceeding 125 trillion cubic feet (TCF) and annual gas production of about 1.3 TCF. About 75 percent of this was associated gas and it was simply being flared for want of any market. Nigeria was pursuing several options to find markets for the gas (such as LNG exports and promotion of domestic consumption) and eliminate gas flaring. At the same time many of the other ECOWAS countries had power systems relying mostly on hydropower stations and were greatly in need of inexpensive thermal power support to improve their system reliability and to increase electricity access to their population. They also needed gas in the first instance to replace the very expensive liquid fuels they were using in their existing thermal generation units. The Gas pipeline project was thus a perfect fit in the region and a major support to the aims and objectives of the WAPP (see case notes on WAPP).

The initial capacity of the pipeline was 200 million cubic feet of gas/day capable of being increased later up to 470 million cubic feet/day depending on the demand growth.

Contracting arrangements were complex. Gas producers in the Nigerian delta entered into gas sales contract with a newly established entity for shipping, called N-Gas, a Bermuda registered company of the relevant producers and affiliates, which entered into gas transportation contracts with pipeline companies ELPS[22] and WAPCO and gas sales agreements with the two buyers in Ghana, Benin and Togo namely VRA and CEB (the power utilities of Ghana and Benin). WAPCO will operate only as a transporter of gas and will not be a buyer or seller of gas.

Under the gas sales contract and under the gas transportation contracts, when supply is terminated on account of payment default by VRA, the latter needs to pay certain amounts to WAPCO and N-gas. These payments are guaranteed by the government and the IDA guarantee provides the cover to the performance of the government obligation. IDA guarantee is

[21] These two gas companies were expected to promote distribution of gas to new consumers in Benin and Togo.
[22] ELPS is owned by Nigerian National Petroleum Corporation and operated by its subsidiary Nigerian Gas Corporation.

complemented by MIGA Guarantee and Zurich/OPIC insurance which cover political risks and risks relating to breach of contracts from Benin and Togo as well.

The sponsors produced over a two year period comprehensive Environmental Management Plans and Resettlement Action Plans. WAPCO was obliged to hire international consulting firms to carry out periodic independent audits to verify compliance with Environment Management Plans. It was also obliged to provide fixed financial support for a three man Environmental and Social Experts Panel to oversee the safeguard aspects.

A formal WAGP Treaty was entered into among the states in January 2003 agreeing to establish a single harmonized regulatory and fiscal regime for the project and also to harmonize other important elements of the investment regime. Following the Treaty the four governments signed with the sponsors an International Project Agreement (IPA) in May 2003 outlining various project related arrangements, and created a regional regulatory authority, called West Africa Gas Authority (WAGA) to monitor compliance by WAPCO of its obligations under the IPA, the pipeline Access Code and other project related agreements, agree on changes to the tariff methodology, and also make best efforts to ensure that all four states conformed to the provisions of the IPA and related legislation. The Project was expected to be in commercial operation by early 2007.

The project suffered a number of setbacks due to violence in the Niger delta, construction problems, and a prolonged dispute with one of the contractors. Based on the reviews carried out in July 2009, it appears that the project had been substantially completed and is expected to be fully completed and placed in commercial operation in the first quarter of 2010. Gas producers had been supplying the line pack gas in late 2008 and early 2009. One of the generating units at Takoradi power station in Ghana had been commissioned in end April 2009 using the free flow of gas in the WAGP. It went on till May 16, 2009, when the insurgents in the Nigerian delta vandalized the ELPS pipeline in Nigeria thereby disrupting the flow of gas into the WAGP. The supply had not yet been resumed due to the tense situation in Nigeria. Nigerian government is believed to be taking steps to improve the situation and resume gas flow. The steps include grant of amnesty to the insurgents, securing a cease-fire, allocating substantial sums from the federal budget for social development works in the delta and attempting to ensure that as required by law at least 13 percent of the revenues derived from the resources of the related provinces is ploughed back for their benefit.

Meanwhile in Benin, two gas turbines running on Jet fuel have been upgraded for the use of natural gas. Benin has also acquired eight new gas turbine units of 10 MW each also running on jet fuel to be commissioned by end 2009 and they could run on gas if additional gas supplies are made available. In Togo an IPP owned generating unit capable of running on gas, heavy fuel oil or diesel oil is expected to be commissioned in early 2010 as it has a PPA for 780 GWh a year. In Ghana power plants at Takoradi and Tema are ready for use of gas and await resumption of gas supply.

The Project is also believed to have experienced significant cost overrun, the total cost now being estimated at around $1.0 billion.

WAGA (the regulatory agency) seems to be suffering from lack of funding from the governments.

In April 2006 ten communities in the southwest Nigeria complained to the Bank's Inspection Panel that the project did not comply with some of World Bank guidelines for public consultation, compensation, economic evaluation and supervision. The Panel investigation concluded that compliance with guidelines on social assessment and involuntary resettlement was not adequate (lack of baseline socio-economic data, inadequate disclosure of information, inadequate compensation payments.etc). While the EIA's were of good quality their disclosure in a form and language understandable by the groups being consulted was poor. The World Bank Board of Directors discussed Panel's report and the Management response on 6 August, 2008, and approved an Action Plan to address the issues identified by the Panel, such as actions to improve management of resettlement and compensation, creation of an effective grievance mechanism, enhanced disclosure of information and strengthened field base supervision, to complete the remedial steps already taken since 2006. These relate in particular to the compensation payments for land acquisition. Independent experts have been hired to review actual payments and assess the current values of each asset lost to the project. The sponsors recognized that under-compensation occurred and approved a budget for the additional compensation payments. The Bank made institutional changes and additional budget allocations for strengthening Bank supervision.

This project seems to highlight the risks of regional trade. The supply and line security risks have probably been underestimated. Hopefully its problems would be overcome.

Preparation time for this project was about 7 to 8 months and the cost was around $1.0m. Annual supervision cost was estimated at $100,000 a year.

ETHIOPIA: NILE BASIN INITIATIVE

ETHIOPIA - SUDAN INTERCONNECTION PROJECT (P074011)

An IDA credit of $41.05 million was approved in December 2007 to the government of Ethiopia for being on-lent to the national power utility Ethiopia Electric Power Corporation (EEPC) for financing an electricity interconnection between Ethiopia and Sudan. The total project cost was estimated at $43.1m. The project consisted of (a) the creation of a 296.5 km long double circuit 230 kV transmission link (partly by constructing a new double circuit line and partly by converting an existing single circuit line into a double circuit line) between Bahir Dar substation in Ethiopia and Sudan border along with associated substations and facilities; and (b) Institution strengthening and capacity building for regional development, covering such aspects as project implementation , implementation of EMPs and RAPs, load dispatch for cross-border power exchanges, other regional trade aspects and promotion of export oriented generation projects based on competitive bidding.

The155 km 230 kV double circuit link from the Sudan-Ethiopia border to Gedaref Substation in Sudan (along with associated substation and facilities) is being constructed by the Sudanese National Electric Corporation (NEC) at a cost of $25.5m with financing from Export-Import Bank of India.

Ethiopia is endowed with significant hydropower potential and it follows a strategy of developing a number of cost effective medium and large sized hydroelectric projects on the basis of public private partnerships both for meeting its domestic demand and for monetizing its energy resource through export of hydropower to Djibouti, Sudan, Kenya and other countries in the region. Also the hydro power dominant Ethiopian system will be able to secure the badly needed thermal power support to improve its system reliability through interconnections to thermal power dominated neighboring systems.

Three hydropower projects – Gilgel Gibe 2 (420 MW; 1500 GWh), Tekeze (300 MW; 980 GWh) and Beles (460 MW;1833 GWh)—under construction at a total cost of $1.4 billion are nearing completion[23] and the interconnections to Sudan, Djibouti and Kenya were considered necessary to export the surplus energy from these projects.[24] The interconnection to Djibouti funded by African Development Bank earlier is expected to be completed in the first half of 2010. The line to Kenya is yet to be funded.

Ethiopia is part of the Nile River basin. Riparian states of Nile River[25] have formed a partnership called Nile Basin Initiative (NBI) seeking to develop the river in a cooperative manner, share the socioeconomic benefits equitably and promote regional peace and security. They agreed on a vision for NBI and a Strategic Program for its realization. The latter includes subsidiary action programs at the sub-basin levels. The Ethiopia-Sudan interconnection project was part of the Eastern Nile Subsidiary Action Program. The implementation of this Action Program is sponsored and advanced by Eastern Nile Technical Regional Office (ENTRO). Promoting power

[23] Gilgel Gibe 2 has four units of 105 MW each; two of them have become operational already and the other two are undergoing trial runs and will become operational by mid December 2009.

[24] A supplementary credit was approved by AfDB in 2008.

[25] Burundi, Democratic Republic of Congo, Egypt, Ethiopia, Kenya, Rwanda, Sudan, Tanzania and Uganda with Eritrea as an observer

trade through regional cooperation to increase access to electricity and lower costs is a key part of the Action Program. Several major hydropower projects are being studied under the program for facilitating energy trade among Ethiopia, Sudan, Kenya and Egypt. Further, countries belonging to the East African Community are promoting East African Power Pool, which will be greatly facilitated by the interconnections and studies pursued under the above Action Program.

Project segments in each country are being implemented by the respective national power utilities EEPCO and NEC. Coordination is provided by a Steering Committee set up by the two utilities and it is assisted by ENTRO in monitoring and facilitating progress especially in relation to EMPs and RSAs. The two utilities have also entered to a Construction Agreement and an Operation and Maintenance Agreement. Under the former, the Steering Committee nominates one project manager, who supervises the project implementation in both countries. For the operational phase there will be a permanent Interconnection Committee with two working groups, one for operation and the other for planning

In addition they have negotiated and initialed in mid 2009 a formal PPA valid for10 years. Under this PPA firm power supply would be 100 MW priced at 5 cents/kWh for the first 3 years. Additional power supply (to be annually agreed and scheduled) would be 75 MW to 100 MW priced at 50 percent of the firm power price. In addition there could be monthly scheduled and agreed supply of about 25 MW during the rainy months of June, July and August priced at 30 percent of the firm power price. At the end of 3 years prices levels would be renegotiated. Formal signing of the PPA is awaited.

The credit became effective on July 31, 2008, and after some initial delays all key contracts have been awarded. The line and substations are expected to be completed by June 30, 2010. Construction of the Sudan segment is also proceeding well. Under the Construction Agreement between the two utilities, the party delaying completion of the line beyond June 30, 2010 will have to pay a liquidated damage of $100,000 a day. This has proven a powerful mechanism to ensure completion of the line before the target date. Disbursements are at around 17 percent of the credit with a lag of about 38 percent

Project preparation time was slightly less than 3 years at a cost of around $550,000. Annual supervision cost is estimated at $100,000. The project was handled as a separate investment credit operation rather than as a part of the APL program, as it was believed that the subsequent phases of the market development had not been sufficiently developed.

BAKU-TBILISI-CEYHAN PIPELINE

(IFC PROJECT ID 11251)

This project involved the construction and operation of a 1,768 km long oil pipeline with a diameter of 42 inches and an ultimate capacity of 1.0 million barrels per day to transport crude oil from the Azeri Chirag Gunashi oil field near Baku in Azerbaijan to the new oil export terminal at Ceyhan on the Mediterranean coast of Turkey transiting through the Republic of Georgia. About 443 km of the pipeline is in Azerbaijan, 249 km in Georgia and 1,076 km in Turkey.

The project was developed by BTC Company –a special purpose vehicle established by a consortium of public and private sponsors. It comprised the affiliates of BP Corporation of North America (30.10 percent), SOCAR of Azerbaijan (25 percent), Unocal (8.9 percent), Statoil (8.71 percent), Turkish Petroleum AO (6.53), ENI (5 percent), TOTAL (5 percent), ITOCHU (3.4 percent), Conoco Phillips (2.5 percent), INPEX (2.5 percent) and Amerada Hess (2.36 percent).

A BP affiliate, BP Exploration Ltd, was responsible for the overall management and operation of the Sangachal Terminal in Azerbaijan and the pipeline sections in Azerbaijan and Georgia, while the state-owned enterprise BOTAS was responsible for the pipeline section and the Ceyhan terminal in Turkey. BP was responsible for the overall coordination of the construction and operation of the pipeline.

The pipeline was intended to complement two other existing pipelines, the Northern Route pipeline to the Russian port of Novorossiysk on the Black Sea and the Western Route pipeline to the Georgian port of Supsa also on the Black Sea. The new pipeline, apart from helping the land locked Azerbaijan overcome the capacity limitations of the earlier two pipelines, would enable it to bypass the environmentally sensitive Black Sea and the highly congested Bosphorus Straits and access the European and world oil markets through the Mediterranean port of Ceyhan in Turkey.

The project was perceived to be of considerable geo-political significance, creating a direct East-West energy corridor from the hydrocarbon rich but landlocked Central Asian countries to the West. The pipeline could be used to transport oil from other Central Asian countries, such as Kazakhstan, when the oil production from the Azeri fields declines.[26]

The total project cost was estimated at $3,637m including capital expenditure of $2,931 m, line-fill cost of $255m and financing costs of $451m.[27] The construction of the pipeline which began in 2003 was expected to be completed by early 2005.

It was financed by $1,274m of sponsors' equity and $2,363m of debt from eleven lenders including IFC ($250m), EBRD ($250m), export credit agencies of Europe, Japan and USA ($914m), political risk insurers ($92m) and senior debt from sponsors ($857m). Both IFC and EBRD gave 50 percent as A loans and 50 percent as B loans (commercially syndicated).

[26] Actually Kazakhstan and Azerbaijan have recently concluded agreements in terms of which they are implementing a project to transport Kazakh oil by barges across the Caspian Sea to feed into the BTC oil pipeline. This will further improve the economics of the line while Azeri oil production is building up.
[27] The line-fill needed 10 million barrels of oil. (see www.bp/caspian)

The project was approved by IFC in October 2003. Funds were committed in Jan 2004 and disbursements were made in March 2004. BTC began to fill the pipeline in May 2005, oil reached Ceyhan in June 2006 and project completion was in December 2007. At the beginning of 2008 the pipeline was operating at about 50 percent of the design capacity, somewhat below the 60 percent level originally anticipated. The Project experienced substantial cost overrun of $1,564m (in capital costs and line-fill costs) and the operating expenses had increased on account of gas price increases.[28] These in turn have led to an increase in the oil transportation costs through this line, which however continues to be economically and financially robust, inter alia, on account of the oil price increases.

The participation of IFC in the project was expected to: (1) assist in mitigating the political risk perceived by international investors in such cross-border projects and ensure stability of the project arrangements and operation; (2) provide long term financing through A and B loans; (3) provide a framework for the development and operation of the project in an environmentally and socially sound and sustainable manner and credibility to the efforts of sponsors in this regard; and (4) help in the transparent accounting of the receipts to the Azeri government from this and from other oil projects and management of the Azeri Oil Fund in coordination with the World Bank and IMF.

Inter Governmental Agreements among the three countries and host government agreements between the pipeline company and each of the three governments were concluded in a reasonable time as the Project was perceived to be of strategic importance by all three countries and therefore political commitment and cooperation were generally forthcoming. The project actually helped to cement relationship among them.

The environmental and social issues relating to the project traversing over such a long distance through three countries attracted the attention and concern of a wide variety international and local NGOs and, ensuring credibility of impacts assessments, mitigation and monitoring arrangements proved a major task consuming a great deal of time and cost. IEG evaluation rates IFC performance in this regard as excellent

Comprehensive alternative routing exercises were undertaken over several years to avoid all kinds of places with any potentially significant environmental, social or archeological problems. The finally selected pipeline route still had to pass through difficult terrains including several waterways calling for riparian notifications to many countries, several ground water areas including Borjomi in Georgia which feeds the world famous Borjomi mineral water park, many communities with a total of about 750,000 people, over 21 archeological sites, and also a small corner of the Gobustan cultural reserve in Azerbaijan.

Oil spill prevention and response planning was a major component of this.

Comprehensive ESIAs and resettlement Action Plans (RAPs) and Public Consultation and Disclosure Plans were prepared for each of the three countries. Based on these an Environmental and Social Action Plan outlining the mitigation plans and monitoring mechanisms was prepared. This plan included Contractor Control Plans which outlined the environmental and social measures, which each contractor was obliged to meet. No work was allowed to proceed without

[28] The pumps associated with the pipeline use gas a fuel

approved plans meeting these obligations. All these documents were made available to public by June 2003.

In addition IFC got BTC Company to prepare, publish and widely disseminate a comprehensive Regional Review dealing with the social, economic and development issues relating to the project in all three countries.

Over 98 public consultation meetings were held in the three countries covering the village communities, national and international NGOs, as well as the governments and the media. In addition 46 meetings were held in Turkey for all the stakeholders.

IFC staff and specialists visited at least 20 of the project sites and met all stakeholders during 2002-2003. These were resource intensive, but helped to design and implement meaningful and effective environmental and social protection arrangements for the project.

The nine layered monitoring plan for the project includes monitoring by NGOs and communities and independent monitoring by the Caspian Development Advisory Panel comprising internationally recognized experts.

About 30 complaints were received by the Compliance Advisor Ombudsman of IFC from affected parties and all of which were satisfactorily resolved.

Due diligence by IFC lasting over 2 to 3 years were needed especially in the environmental, social and other safeguard areas. To some extent IFC benefited from its earlier experience in financing the Baku-Supsa oil pipeline. Also IFC's practice of charging various kinds of fees from the project company for its services helped to meet a good part of the extra costs involved in such extended processing.

The Project is designed as a BOT project. At the end of 20 years the pipeline would be handed over to the Azerbaijan shareholder.

IFC also pursued in the context of the project the efforts to enhance development impact of the project by designing and implementing small and medium enterprise linkage programs and community development programs complementing the programs of sponsors in this regard. These involved supply chain development, improving access to finance, and business development services. The small and medium enterprise related disbursements amounted to $0.8m while the disbursements under the community development programs amounted to $66m during 2003-2005 benefiting 530 communities along the line. Local spending through BP contracts to local medium and small enterprises amounted to $337m during 2003-2007. BTC Company plans to spend annually $250m with SMEs and $250m with local joint ventures.

All three governments derive substantial revenues by way of transit fees, taxes. Transit revenue flows during the 20 year operation of the pipeline (2005-2024) has been estimated at $0.6 to $0.7 billion for Azerbaijan, $0.6 to $0.9 billion for Georgia and $1.2 to $1.8 billion for Turkey. As a result of the pipeline Azerbaijan is able to export the oil it produces and thus derive much more substantial benefits.

The preparation and implementation of this project was greatly supported and facilitated by a number of complementary lending and non-lending operations of the WBG in all three countries, including notably (1) Georgia-Energy Transit Institution Building Project (P072394) and (2) Turkey- Baku-Ceyhan Oil export pipeline TA project (TR-PE-45073).

BAKU-TBILISI-ERZURUM GAS PIPELINE PROJECT

(EBRD financed)

The experience of implementing the BTC project in an environmentally and socially sound manner came in handy for sponsors to build the Baku-Tbilisi-Erzurum gas pipeline to export natural gas from Azerbaijan's Shah Denis field to Turkey via Georgia in the same corridor as that of the oil pipeline. This is another example of a high profile and high impact regional energy project, which was done in a sound manner. The WBG did not participate in financing this 690 km 42 inch diameter gas pipeline with an annual transport capacity of 20 bcm of gas and with a capital cost of $1,024 million. EBRD gave a loan of $60 m in March 2004 to the State Oil and Gas Company of Azerbaijan Republic (SOCAR) to finance its equity investments in the project. The consortium of sponsors for this project included many of the partners of the Shah Denis field in Azerbaijan notably BP, SOCAR, Statoil and Total. The sellers of gas were the partners of Shah Deniz Gas Production venture and the buyer was primarily BOTAS of Turkey. The operator of the gas pipeline is Statoil.

This had also been successfully completed in 2007 and is being operated satisfactorily enabling Azerbaijan to export its gas to Turkey and providing 5 percent of the gas as transit fee to Georgia. In addition Georgia is entitled to buy another similar amount of gas at discounted prices.

It took nearly a decade for the sponsors to realize these two projects. The IFIs were involved in one form or other for nearly 75 percent of the period.

SOUTH EASTERN EUROPE ENERGY COMMUNITY PROGRAM

By signing the Athens memorandum of December 2003, South East European states (Albania, Bosnia-Herzegovina, Bulgaria, Croatia, Macedonia, Romania, Serbia-Montenegro, Turkey and Kosovo) agreed with EU to integrate their electricity markets in terms of EU directives (governing, market structure and liberalization, competition, harmonization of regulation, and environmental approaches) and eventually to integrate their regional market with that of the EU. Later in October 2005 an Energy Community (EC) Treaty was signed for this purpose by all of them (except Turkey) and ratified by their respective legislatures. The Treaty entered into force on July 1, 2006.

Before 1991 the Balkan states with the exception of Albania were part of the UCTE operating synchronously with the rest of European network and got disconnected on account of conflicts and war damages. After the rehabilitation of war damaged facilities they started operating synchronously among themselves as UCTE 2 and after the rehabilitation of certain key substations UCTE2 achieved back its connectivity to UCTE and synchronous operation with the whole UCTE network was restored in 2006. Bulgaria and Romania were also connected to the UCTE meanwhile and the connection of Turkey to the UCTE is expected within a year.

Presently the membership of the EC consists of (a) Contracting states (Albania, Bosnia-Herzegovina, Croatia, Macedonia, Serbia Montenegro, and Kosovo); (b) Participant states (EU Member States Austria, Bulgaria, Cyprus, Czech Republic, Germany, Greece, Hungary, Italy, Romania and Slovenia -any other EU Member States can also request to become a participant; and (c) Observers (neighboring Non-EU Member States Moldova, Turkey, Norway, Ukraine and Georgia. The observers are likely to become contracting states in the near future.

The implementation of the EU directives by the contracting states is being facilitated, coordinated and monitored by the EC secretariat funded by EU (98 percent) and by the members (2 percent) and was governed by a Council of representing Ministers and a permanent High Level Group of representative senior officials. It has also a Regulatory Board and a regulatory secretariat to handle matters related to regulatory harmonization and developments.

The Bank's set of APLs were aimed at supporting and supplementing this process of integration through investments which would contribute to the achievement of the objectives of the EC Treaty.

<u>P086694 EC SEE APL-Phase 1 Romania</u>: An IBRD loan of $84.3 m loan to Hidroelectrica SA of Romania with the Government guarantee was approved on 27 Jan 2005. This proposed an APL program assistance of $1.0 billion to nine countries over a five year period. It will finance investments which will enable the countries to participate effectively in the regional electricity market. The signing and ratifying the EC treaty were the qualifications to borrow under the APL program and adherence to the targets (for various activities) contained in the EC treaty provides the triggers under the APL for subsequent loans/credits.

The first loan was to Romania. This was for Rehabilitation of Lotru Hydropower Project (510 MW) which provides key ancillary services to the national and regional grid. In addition Hidroelectrica was given a TA for twinning arrangements with a Utility with substantial hydropower capacity and experience in operating electricity markets under the EU liberalization approach.

Disbursement under this loan as of 12 June 2009 was $35.56 m with a disbursement lag of 55.44 percent compared original schedule. Closing date of 30 June 2010 may have to be extended as project completion may go up to 2011.

<u>P094176 EC SEE APL-2 Turkey</u>: A loan of $66m to TEIAS with a Guarantee from the Government for financing (1) market management system—hardware, software and training for implementing balancing and settlement systems (2) strengthening of National Load dispatch, and (3) Substation renovations and system improvements. Disbursement was at $35.48 m (or with a lag of 35 percent) as of 23 June 2009. Project components are proceeding generally as planned with minor changes and delays.

<u>P096400 EC SEE APL-3 Turkey</u>: A loan of $150 m to the Turkish Electricity Transmission Company (TEIAS) with the government guarantee approved on 24 March 2006 with closing date of 30 June 2011 for financing transmission upgrades to improve system reliability. The components were: (1) Transmission Network Strengthening-- Construction o f new GIS substations and a new 380 kV underground cable to strengthen the transmission networks in Istanbul and Izmir; and (2) Urban Transmission Network Upgrading--Construction o f underground cables to replace existing 154 kV overhead transmission lines in the densely populated areas of Istanbul and Izmir. Disbursement as of 21 February 2009 was at $105.07m some 37 percent ahead of the initial projection.

Turkey had not signed the EC treaty on account of its negotiations of the energy chapter for the EU accession, but remains committed to the principles of the Treaty and been implementing the key elements of the related EU directives and provisions of the treaty. As of January 2006, the substantial aspects of Turkey's Compliance with common rules for the internal market in electricity per the EC Directive 2003/54/EC and the 2003 Athens Memorandum include:

- Complete functional and corporate restructuring o f the sector. The integrated utility has been entirely replaced by a distribution company, several generation companies, and a transmission company with both the distribution company and the government owned generation company scheduled t o be split up and privatized.
- An independent Transmission System Operator which is separate from generation and distribution.
- An independent Energy Regulatory Authority which is functioning has its own independent sources of revenue and has the authority to set retail electricity and gas prices. Eligibility (to choose their supplier) for consumers with annual consumption exceeding 6.0 GWh with plans to extend this further (this is more than 30 percent o f the total Turkish market). Turkey is perhaps only second to Romania, in the degree of market opening amongst all SEE countries.
- Ongoing development of an electricity market in Turkey with assistance from the Bank.
- Ongoing effort to synchronize its grid with UCTE—On September 28, 2005, a technical study was initiated jointly by TEIAS and UCTE to complete technical assessments to synchronize with SEE network.
- Construction o f a transmission link to Greece, which will support connection with other ECSEE countries (this link was completed by June 2006).

<u>P090656 EC SEE APL-2 Albania</u>: An IDA credit of $27m to the Government of Albania for being on-lent to the national power utility KESH was approved on 28 June 2005 for financing: (1) replacement o f high-voltage equipment in six transmission substations, and control and protection systems in six transmission substations; and (2) technical assistance for: (a) strengthening of the transmission system operator (TSO); (b) Procurement activities and supervision of project implementation; (c) an electricity tariff study; and (d) improving procurement procedures for importing electricity. The original closing date was 31 July 2009. Disbursement as of 29 June 2009 was only 0.92 m SDRs lagging behind the original schedule by 94 percent. Major procurement delays were the cause. Since a TSO had been established the responsibilities under the project agreement are being transferred from KESH to the TSO. Loan closing date has been extended to 31 January 2011. Albania is not a member of the UCTE

<u>P110481 EC SEE APL-5 Albania Dam Safety :</u> An IDA credit of $35.3 m to the government of Albania for being on-lent to KESH was approved on 30 June 2008 for financing: (i) water alarm systems in the Drin and Mat River basins, and specification of an Emergency Action Plan; (ii) Rehabilitation of spillways on Fierza, Koman and Vaui Dejes dams on the Drin river; (iii) rehabilitation of electromechanical equipment in the Koman dam; and (iv) implementation of Load Frequency Control system in Vaui Dejes and Fierza Dams. The project also included technical assistance components relating to: (i) hydrology studies and water management; (ii) implementation consultants; (iii) studies for new hydropower development; (iv) financial management systems capacity building; and (v) international panel of experts on Safety of Dams. The closing date was 31 December 2013. Dam Safety Panel has reviewed and approved the dam safety related proposals. Implementation consultants are being recruited. The project is co-financed with Swiss and EBRD. Other donors are now coming forward to finance further dam safety elements in the KESH system. Albanian dams with hydropower units, when rehabilitated, could provide valuable ancillary services to the SEE grid.

<u>P088867 EC SEE APL-2 Serbia</u>: An IDA credit of $21m to the Government of Serbia-Montenegro was approved on 30 June 2005 for being on-lent to the Electric Power Company of Serbia and Electricity Transmission company for financing the following project components: (1) 110 kV Substations and Related Activities for construction of five new 110 kV Substations; (2) 110 kV Interconnecting Transmission Lines and Related Activities. The project will be carried out in two phases. The closing date was 28 Feb 2010. Disbursement as of 20 March 2009 was only 3.4m SDRs with a lag of about 65 percent from the original schedule. Delays in loan effectiveness (caused by the need for the parliament to approve the loan) and in the separation of the transmission company from the Electric Power Company through sector unbundling and delays in procurement were the reasons. The first phase of the project is nearing completion and the key procurement actions for the second phase have been accomplished. Closing date may have to be extended by a year or so.

<u>P082337 EC SEE APL-3 FYR Macedonia</u>: A loan of $25m to Macedonia Transmission System Operator with a government guarantee was approved on 10 January 2006 for financing: (1) expansion of the 400/110kV substation at Skopje; (2) construction of a 400 kV interconnection to Greece by upgrading the 19 km long 150 kV line (within FYRM territory) and construction of two other 110 kV lines of 54 km and 12 km respectively; (3) Upgrading o f the existing Energy

Management System and System Planning Software; (4) upgrading and rehabilitation of 110 kV substations; (5) Consulting services for upgrading the financial management of MEPSO and purchase of a Financial Management System. The Greek Public Power Corporation is financing and constructing the 22 km section of the 400 kV interconnection based on the EU funded feasibility study and ESIA in full coordination with the Macedonian transmission system operator. Disbursements as of 24 December 2008 at $14.39 m were 15 percent ahead of the schedule.

After initial delay due to change in management of the Macedonian transmission system operator, the project is now proceeding normally.

P090666 EC SEE APL-3 Bosnia and Herzegovina: An IDA credit of $36m was approved on 16 June 2006 to the government of for being on-lent to the three power utilities serving three parts of the country for financing a wide range of investments—rehabilitation of several hydropower and thermal power generating facilities, distribution rehabilitation, provision of SCADA systems, provision of financial management system hardware and software for the three utilities, provision of a market operating system to the Independent System Operator —and technical assistance for emission reductions in a thermal power plant. The overall project cost was estimated at $286 m and co-financing came from EIB and EBRD. Loan became effective on 13 April 2007 and procurement activities started moving only by October 2008. Independent System Operator and Transmission Company were established through sector unbundling and in order for them to become fully operational several steps such as allocation of assets and personnel and ensuring role clarity are to be completed. Cumulative disbursement as of January 2009 was negligible and was lagging behind by 98 percent from the original schedule. The closing date currently is 31 December 2010 and it may have to be extended.

P106899 EC SEE APL-3 Montenegro: An IDA credit of $9 m was approved on 6 July 2007 to the government of Montenegro for being on-lent to the state power utility for financing: (1)Development of a modern telecommunications network, including links with regional utilities; (2) Construction of transmission line circuits from the transmission network to the Andrijevica substation and to the Mojkovac substation; and (3) Installation o f a new trash rack and trash rack cleaning equipment, and supply of spare turbine runners for Perucica Hydropower Plant. The loan became effective on 28 January 2008, and the state power utility was unbundled and the Transmission Company was set up in March 2009. Disbursements at 2.14 m SDRs as of September 2009 were ahead of the projections by 16.6 percent

Overall in all countries laws have been amended or new laws have been enacted in the electricity sector enabling the implementation of the thrusts of EU directives. Vertically integrated utilities have been unbundled into generation, transmission and distribution and independent transmission system operators and or market operators have been established. Regulated third party access has been provided. Independent national energy regulatory bodies have been established. In most countries non-household consumers with significant monthly consumption levels have become eligible consumers with a right to choose their supplier. The eligibility threshold is being lowered every year. However effective switching of suppliers is still relatively modest. Tariffs are being raised to cost recovery levels for captive consumers of public supply, but still there is quite some distance to go in this respect. Trading is mostly national and regional trading is yet to make significant impact. Because of interconnected synchronized operation in the UCTC power exchanges among utilities take place based on system needs. Within this overall framework, actual degree of progress varies from country to country. Croatia, Bulgaria and Romania are leading followed by Turkey and others.

POWER PROJECTS IN AFGHANISTAN

(P083908, P106654 AND P111943 of IDA and an ADB Project)

The modest sized and fragmented power system in Afghanistan was extensively damaged during to the prolonged periods of war. In 2004 only 6 percent of the population had access to electricity and even in the capital city of Kabul, supply could not be for more than three hours a day. A number of bilateral and multilateral donors got together and helped the government to evolve a strategy the key elements of which were: (1) to improve the existing interconnections (at 110 kV and lower levels) to the adjoining countries—Tajikistan, Uzbekistan, Turkmenistan and Iran and secure as much imported power as possible; (2) to rehabilitate the transmission and distribution systems to be able to receive and distribute the imported power; (3) to rehabilitate the damaged hydro and thermal generation facilities to augment domestic generation; and (4) to build 220 kV interconnections to the four neighbors to increase the volume of imports. Thus the strategy relied heavily on power imports in the short and medium term, while the existing generation facilities would be rehabilitated.

Afghanistan has some natural gas and coal resources and significant hydropower potential, but it will take considerable time and large financial resources to develop them. Thus for a considerable number of years, power imports would play a key role in Afghanistan and the activities of all donors aim to facilitate these imports and their absorption by the Afghan system.

IDA, ADB, IsDB, USAID, KfW, and India as well as the Afghanistan Rehabilitation Trust Fund (ARTF) (to which many other donors have contributed) are involved in integrating the northern and eastern power system fragments (regions) and creating the North East Power System (NEPS) through a double circuit 220 kV line, which will convey the imported power from Tajikistan, Uzbekistan and Turkmenistan to the load centers in the northern and eastern regions (including the Kabul area) (see Figure 6).

Emergency Power Rehabilitation Project (P083908 and TF 054718) ($105m from IDA and $20m from ARTF) approved in June 2004 was for transmission and distribution rehabilitation in Kabul area and also for the rehabilitation of Naghlu Hydropower Project. All the funds had been contracted and about 61 percent had been disbursed. The project is nearing completion. The recent completion of certain components enabled the connection of Kabul area to the NEPS resulting in the flow of about 40 MW of power from Uzbekistan to Kabul. Thus Kabul area now has 16 to 24 hour power supply. The power utility is being converted into a corporate commercial entity.

The Kabul-Aybak -Mazar-e-Sharif Project (P106654) approved in October 2007 with an ARTF grant of $57m seeks to rehabilitate the low voltage system in the Kabul area, the distribution system in the Mazar-e-sharif area, and the transmission substations in Aybak and Mazar-e-sharif areas. About 65 percent of the funds had been contracted and 20 percent of the funds had so far been disbursed.

The Afghanistan Power Sector Development Project (P111943) approved in October 2008 (with an ARTF grant of $35m) seeks to rehabilitate and expand the distribution systems around Pul-e-Khumri, Jabal-es-Saraj, Charikar, and Gulbahar areas and also rehabilitate the transmission facilities associated with Naghlu, Mahipar and Sorobi Hydropower Projects. It has also institution building components. About 70 percent of the funds have been contracted and disbursements are yet to commence.

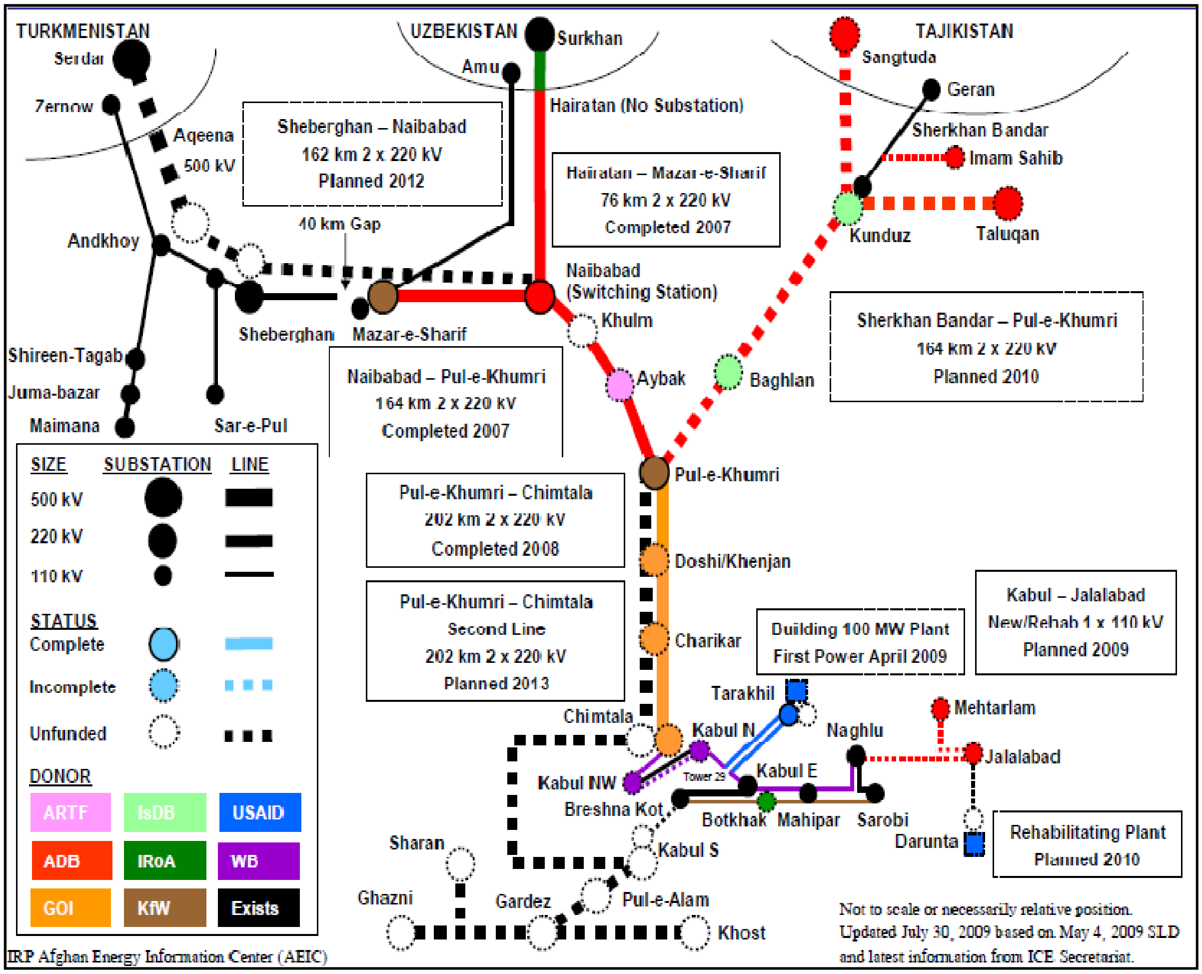

Figure 6: North East Power System (NEPS) in Afghanistan as the main conduit for imported Power

These projects are part of the strategy based on power imports from neighbors. Afghanistan has now installed hydropower capacity of 261 MW and thermal power capacities of 137 MW and power import capacity of 370 MW. A good portion of the installed capacity is still not available for reliable supply. The overall supply position in the last three years had been as follows:

Table 1: Share of Imports in the Total Power Supply in Afghanistan

Year	Total supply (GWh)	Share of Hydro (%)	Share of Thermal (%)	Share of Import (%)
2006	1289.5	49.9	16.5	33.5
2007	1574.8	48.0	13.4	38.6
2008	1566.5	39.4	12.6	48.0
2009 (Jan-July)	1124.7	42.3	5.5	52.2

Source: www.afghaneic.org

It may be seen that the overall supply level and the share of the imports are increasing, as the rehabilitation works are being completed. The share of the very expensive domestic thermal generation is going down steeply.

ADB Project --Afghanistan-Tajikistan 220 kV Power Interconnection Project: Afghanistan has already signed a power purchase agreement with Tajikistan for 300 MW (about 590 GWh a year in the summer months) and plans to have PPAs for 300 MW each from Uzbekistan and Turkmenistan. ADB has funded (December 2006) the 220 kV double circuit transmission line from Sangtuda Hydropower station in Tajikistan to Pul-e-Khumri in Afghanistan and power flow is expected from this new line from 2010. Uzbekistan-Afghanistan link is being strengthened for 300 MW supply under IsDB and ADB financing. Turkmenistan has agreed to build 410km of a 500 kV line from to the border of Afghanistan. USAID and other donors are planning to fund the Afghan portion from the border point at Aqeena to Mazar-e-sharif (partly as a 500 kV line and partly as a 220 kV line). Iran has already built its lines to the western part of Afghanistan.

Thus the three power projects of the WB and the projects of other donors, though they appear as national projects, are underpinned by the electricity trade concept among the five neighbors enabling them to sell their surplus power and enabling Afghanistan to absorb it. Thus the WB and other donor also focused on commercialization of the Afghan power sector, institutional and management upgrade of the Afghan utility and the exposure of the Afghan officials to the concepts of power purchase agreements and related international commercial transactions and protocols associated with them.

The ADB project (which provides for a 220 kV double circuit interconnection between Tajikistan and Afghanistan) is handled under one appraisal document for a loan each to the two countries. The financing plan is as follows:

Table 2: Financing Plan for the Tajikistan-Afghanistan 220 kV Link Project ($m)

Financier	Afghanistan	Tajikistan	Total
ADB concessional loans	35.0	21.5	56.5
OPEC Fund for International Development	-	8.5	8.5
Islamic Development Bank	-	10.0	10.0
ARTF /other (Grant)	16.5		16.5
Governments/Utilities--own financing	4.0	14.0	18.0
Total	55.5	54.0	109.5

The ADB loans are relent by the respective governments to the Afghan and Tajik utilities which will own and operate the portions of the line in their territories as a part of their national grid. The power imports through the completed line will be on the basis of a PPA which had been entered into in 2008. The conclusion of such a PPA was a condition of contract awards. The project is proceeding with substantial delays.

Apart from the usual formidable problems, which one faces in processing and implementing any project in Afghanistan or Tajikistan, these operations of the WB and ADB do not seem have met with any new major problem on account of bilateral trade orientation of the project.

POWERLINKS PROJECT

(IFC #20350)

IFC approved in October 2003 a loan of $75m (in Indian Rupees) to Powerlinks Transmission Ltd for building a 400 kV double circuit AC power transmission link with a capacity of 3000 MW between the eastern and northern regions of the Indian national power grid. The link consisted of five 400 kV sections and one 220 kV section and covered a distance of 1,200 km. It starts at Siliguri in the state of West Bengal and end at Mandaula near Delhi. The total cost of the project was $265m, which was financed by equity of $79.5m and debt of $185.5m.

Tata Power Company of India had 51 percent share and the state-owned Power Grid Corporation of India had 49 percent share in the equity of Powerlinks Transmission Ltd. It was the first public private partnership in the transmission sector of India and the project was carried out on a 30 year BOOT basis. IFC provided a loan of $75m and Asian Development Bank provided a loan of $66.3m (from its private sector window) and the domestic financing institutions and banks provided loans of $$44.2m. The project was completed by September 2006 and has been operating successfully since then. The entire transmission capacity was assigned to Power Grid Corporation under a Transmission Service Agreement for a regulated transmission fee. Powerlinks Transmission Ltd had the responsibility to construct the line and maintain it to ensure its availability at contracted levels.

The line was meant to transfer surplus power from the eastern to the northern region of India. The eastern region had in 2003 a power surplus of 2,100 MW which was expected to grow rapidly in The Afghanistan Power Sector Development Project (P111943) approved in October 2008 (with an ARTF grant of $35m) seeks to rehabilitate and expand the distribution systems around Pul-e-Khumri, Jabal-es-Saraj, Charikar, and Gulbahar areas and also rehabilitate the transmission facilities associated with Naghlu, Mahipar and Sorobi Hydropower Projects. It has also institution building components. About 70 percent of the funds have been contracted and disbursements are yet to commence.

the next three years. At the same time the northern region had a power deficit of 2,500 MW expected to grow rapidly to 7,500 MW in the following three years. About a 1000MW of this increase was expected to come from the Tala Hydropower project in Bhutan.

Government of India provided 60 percent grant and 40 percent concessional loan to finance the full cost of Tala Hydropower project of Bhutan with an installed capacity of 1,020 MW and an annual generation of 4,900 GWh, about 80 percent of which was meant for export to India. This project was being commissioned in FY 2007 and power was being fed by two short 220 kV lines to Siliguri. Total import from Bhutan including this was of the order of 5,700 GWh which could not be absorbed in the eastern region.[29] Thus the construction of the 400 kV link between the

[29] The earlier projects in Bhutan which were exporting power to India were: (1) Chuka HPP (336 MW), Kurichu (60MW), and Basochu (64 MW) with a cumulative level of imports of 1,764 GWh in FY 2006

eastern and northern region before the expected commissioning of Tala Hydropower Project was necessary to facilitate this regional trade in electricity. The project achieved this purpose fully.

The capital cost of Tala hydropower project at $1,080m was larger than the GDP of Bhutan. Power exports to India at an agreed price of around 4.65 cents/kWh amounted to about $265m or about 25 percent of Bhutan's GDP.

The involvement of IFC and ADB in this project, apart from facilitating regional electricity trade also helped the project secure better terms from local commercial lenders, and ensured adherence to environmental and social guidelines, appropriate for the project.

NAM THEUN 2 HYDROPOWER PROJECT

(P076445)

This is a 1070 MW storage hydropower project across Nam Theun River in Lao PDR to export 995MW of power to Thailand and to provide 75 MW of power for Laotian domestic power market. The average annual electricity generation is estimated at about 5700 GWh. The project involved the construction of 39m dam, a reservoir with an area of 450 square km, diversion of the water from Nam Thuen River to Xe Bang Fay River (which joins Mekong River downstream), a power house with a capacity of 1070 MW, a dedicated 138 km long 500 kV double circuit transmission line to the Thai border[30] and a 70 km long 115kV single circuit transmission line to the Laotian grid. Since the Laotian and Thai grids are not synchronized, the generating units serving Laotian market are segregated from the rest of the plant and are served by separate penstocks and switch yard.

It is designed as a BOT project to be carried out and operated by the Nam Theun Power Company (NTPC), the shareholders of which are: (1) EDF of France (35 percent); (2) Electricity Generating Public Company of Thailand (25 percent); (3) Lao Holding State Enterprise of the Laotian government (25 percent); and (4) Italian Thai Development Public Company (15 percent).

The base cost of the project was estimated at $1.25 billion, 28 percent of which was to be financed by equity and the rest by debt. Contingencies were estimated at $200m to be financed by equity and debt in equal proportions. Total financing for $1.45 billion[31] was arranged from 27 sources including multilateral and bilateral sources, commercial sources, export-import banks, and Thai commercial banks. Lao PDR financed its equity contribution by securing a $20m grant from IDA, $20 m concessional loan from ADB, $40 m loan from European Investment Bank, a $6.25m grant from the French development Agency and a reimbursement of $28 m by NTPC to the Government for project preparatory expenses and facilities extended. International commercial debt of $ 205 m was guaranteed by the Export Credit agencies of France, Norway, Sweden and Thailand. International commercial debt of $135 m was guaranteed by IDA, ADB and MIGA. In addition, loans totaling $160m were provided by ADB, French Development Agency, Nordic Investment Bank, Thai Export-Import Bank and Proparco (The French Investment Promotion Company). Thai commercial banks provided a Thai local currency debt equivalent to $500m.

The World Bank Group assistance consisted of: (1) $20 m grant to Laotian government for its equity investment (and this would be spent on the expenses relating to the environment and social project for implementing the project in an environmentally and socially sound manner); (2) $50m Partial Risk Guarantee by IDA for the syndicated commercial borrowing; and (3) MIGA guarantees up to $200m covering commercial borrowing, equity risks and other risks.

Project construction is nearly complete and commercial operation of the facilities is expected to commence on schedule in the last quarter of 2009. Initial reservoir filling is complete and 60 MW of power was actually exported to Thailand, while testing the generation facilities in June

[30] Thai portion of the transmission line is constructed by Thai power utility using its own funds.
[31] It is worth noting that the total cost of the project was equivalent nearly to 75 percent of the country's GDP in 2003.

2009. Presently it is anticipated that the completed project costs would be $1290 million, using only a small part of the contingency funds.

Power sales to Thailand is covered by 25 year power purchase agreement for an annual delivery of 5,636 GWh of which 95 percent will be governed by take or pay provisions. About 4,406 GWh (to be delivered between 6 AM and 10 PM from Monday to Saturday) would be priced at 4.24 cents/kWh in 2009 (50 percent to be paid in US dollars and the rest in Thai local currency) and will be subject 1.4 percent escalation per year. Another 948 GWh (deliverable at other times) would be priced at 1.95 cents/kWh in 2009 (50 percent payable in US dollars and the rest in Thai local currency) and subject 1.4 percent escalation per year. The remaining 252 GWh is not covered by take or pay obligations and is priced at about 1.43 cents/kWh payable only in Thai currency and with no escalation. Power sales to Laotian grid is covered by another PPA and power is priced at 3.53 cents/kWh in 2009 (50 percent payable in US dollar and the rest in Thai currency) and is subject to the same 1.4 percent annual escalation.

The project will bring revenues to the government by way of dividend, profit taxes and royalty. Such annual income will be about $30 m during the first 10 years, and will increase thereafter sharply to $110m, thus generating an income of $1.95 billion over the 25 period (2009-2034).

Excluding the time the earlier Australian project sponsors spent, the project preparation extended well over a decade. The project gave rise to major environmental and social concerns as the reservoir would cover forest areas, human settlements, wild life habitat, reduce river flows substantially in Nam Theun River downstream and increase substantially the flow in Xe Bang Fay river, thus affecting the lives of humans, flora and fauna in a variety of ways. It took several years and substantial costs to assess the impact of the project on various fronts, taking into account the concerns of a wide range of environmental and social NGOs (local, regional and international) and devise monitoring, mitigation and oversight mechanisms. Over 6200 people were displaced, given alternative places to live and work. Thus the project called for extensive resettlement of residents, restoration of their livelihood, wildlife management in the Nakai Plateau, protection of the Nam Theun 2 watershed area and mitigation of downstream impacts in the two rivers.

Towards the end of 1990s the Asian financial crisis created a brief lull of over two years in the activities. The activities soon revived with the new set of sponsors who had acquired the interests of the earlier ones

In addition, the Bank evolved a decision framework under which it set for itself the task of ensuring that the project revenues accruing to the state from the export of power would be properly accounted for and spent through a transparent budget process on poverty reduction schemes in terms of the National Growth and Poverty Eradication Strategy of the government.

Thus the attempt was to demonstrate that highly complex and large hydropower project with considerable capital cost can be implemented in a small low income country in an environmentally and socially responsible and sound manner to export power and benefit its poor people.

The Project Appraisal Document indicates that the costs of preparation from FY 2002 till Board approval in March 2005 were $6.809 million. If costs incurred in the earlier years by the Bank were also included this amount could be substantially higher. Expenses incurred by other agencies could further add significantly to the costs of preparation.

The PAD estimated the supervision costs at $1.1 m per year for the period FY 2006-FY 2010. Compared to this the actual supervision costs during FY 2006-FY 2009 have varied from $1.012 m to $1.411 m. This compares with $80,000 which is the allocation for supervision in LAO PDR for most standard projects.[32] The supervision of the project will go on till FY 2018, the closing date being December 31, 2017. It is being examined whether the supervision costs could be contained at the annual level of $0.4 m to $0.5 m for the remaining years.

The project involved extensive and intensive consultation and coordination with wide range of development partners (IFIs, Bilateral aid agencies) and financiers and civil society.

Surprisingly for a storage hydropower project located on a trans-boundary river, riparian consultations did not assume the complexity and delays which are usual in such cases. During the preparation period of over a decade less than 5 percent of the time was needed for such consultations. Consultation and notification letters were sent through Mekong River Commission Secretariat to the members of the 1995 Agreement on the Development of the Mekong River Basin (Thailand, Cambodia and Vietnam). Letters and notifications were sent directly to China and Myanmar. These documents demonstrated that the project will not cause any substantial change in the discharge pattern of the Mekong River. All gave no objections except Cambodia which called for some additional studies and information. After receiving these Cambodia also concurred with the execution of the project. These consultations took place during 2001-2004.

Nam Theun 2 project is part of the Greater Mekong Sub-region (GMS) Initiative (supported by the World Bank and the ADB) to increase electricity interconnections and trade among the member countries (Cambodia, China, Lao PDR, Myanmar, Thailand and Vietnam –all riparian states of Mekong River). In 2002, the six GMS member countries signed an Intergovernmental Agreement on Regional Power Trade, culminating years of collective effort in conceptualizing a Regional Power Market. The electricity trade is expected to develop in stages beginning with bilateral export contracts and moving gradually towards the goal of a competitive regional market. Lao PDR and Thailand governments had signed a Memorandum of Understanding in 1996 for the development of about 3000 MW of hydropower in Lao PDR for export to Thailand.[33] Nam Theun 2 Hydropower Project was the largest of the several projects pursued under this MOU.

Lao PDR was one of the less developed countries in South East Asia with per capita income of $340 (2003) and with a small power sector with modest access rates, despite its large hydropower potential estimated at 26,500 MW. It operated four small isolated grids. In 2003 its power demand was of the order of 250 MW (906 GWh) and the country's electrification ratio was only 43 percent. The strategy for development for Lao PDR was to develop its large hydropower potential exploiting the economies of scale mainly for export and partly for domestic use. Its immediate neighbor Thailand was a much larger and more developed economy with an installed generating capacity of 25,705 MW and peak demand of close to 20,000 MW in

[32] The Bank collected $5 million from the project sponsors as reimbursements of the costs of project preparation and this was "attributed" to project supervision expenses for the period FY 2006 to FY 2009.
[33] Lao PDR also signed and MOU with Vietnam for development and export of 1500 MW of hydropower

2004-2005. Further additions to meet the growing demand there could come mainly from lignite fired plant options. The idea of importing hydropower from Lao PDR was appealing to Thailand as it could reduce resort to fossil fuel fired options. The Nam Theun 2 Hydropower Project as an export project was an excellent fit under these circumstances and received firm and continuous political support and commitment from both governments.

In this project the electricity trade aspects proved manageable partly because of the high level of commitment on the part of both governments and partly because of the well designed commercial arrangements. The problem of doing a project costing nearly the equivalent of 75 percent of the country's GDP was difficult to handle. To attract private investment on that scale for the project and to handle the numerous financiers involved extensive efforts. However the environmental and social aspects and the objective of ensuring that the project related government revenues must be spent on poverty reduction schemes, made the handling of the project time consuming and the effort expensive.

THEUN HINBOUN HYDROPOWER PROJECT

(ADB Financed Project)

Theun Hinboum hydropower project (210 MW; 1,645 Gwh/year) was constructed in 1990s on the Nam theun River at a site downstream of the Nam Theun 2 Hydropower Project site mainly for exporting power to Thailand on the basis of a public private partnership arrangement. The special purpose vehicle for constructing and operating the project—Theun Hinboun Power Company (THPC)—was owned by the Government of Lao PDR (60 percent), Nordic Hydropower AB (20 percent) and GMS Laos Company (a Thai private investor) (20 percent). The project was completed at a cost of $240m some 11 percent below the estimated cost. Asian Development Bank worked with the sponsors to realize this project.

Project expenditures were met by equity of $110m and debt of $130 m. The government's equity contribution was financed by a concessional loan of $57.7m from ADB, and grants from Nordic Development Fund, Norwegian agency for Development Cooperation and UNDP. Long term debts were raised from Export Credit agencies and commercial banks. The Company implemented the project on the basis of a 30 year BOT arrangement. It concluded a 25 year PPA with EGAT of Thailand in 1996 for the guaranteed off-take of 95 percent of the annual output of the project (sales during the last 6 years for example ranged 1,358 GWh to 1,521 GWh). The project was commissioned in 1998 and the sale price for the first year was 4.84 cents/kWh. After 1999 the price was subject to an annual escalation of 1.0 percent At the end of 10 years the tariff would be renegotiable. Payment was to be made 50 percent in US dollar and 50 percent in Thai baths, the exchange rates being fixed at 25.35 Thai baths to a dollar. THPC has been operating profitably with annual sales revenues increasing from $42m in 1998 to $72.35m in 2008. Cumulative income during 2003-2008 was $189.80m out of which $155.40 was paid out as dividends. Dividends paid to the Laotian power utility EdL (holding the equity on behalf of the government) was $93.24m. Royalty payment to the government at 5 percent, for example, amounted to $3.78m in 2008. Similarly profit taxes paid in 2007 and 2008 were at $3.17m and $5.46m respectively.

The problem in the otherwise successful project was that some of the adverse environmental and social impacts had remained without mitigation. Post construction reviews showed the need for remediation. On the basis of thorough reviews, a 10 year comprehensive mitigation plan has been agreed upon and being pursued and monitors in conjunction with the activities concerning the expansion of the project capacity to 440 MW. For the expansion project feasibility studies had been completed in 2007. PPAs for the additional output of power had been concluded with Thai power utility and concession agreements with the Laotian government had been executed in 2008. All contracts have been awarded and construction had commenced with a planned completion date in 2012.

The environmental and social aspects of the expansion project and the remaining mitigation plan of the first project are closely monitored based on arrangements somewhat similar to those adopted for Nam Theun 2 project.

The Nam Theun 2 project arrangements have learnt from this experience and have focused on environmental and social impacts and their mitigation under several layers of close monitoring. It also differed from the earlier project in one other aspect. In Theun Hinboun project the government equity was held by the Laotian power utility EdL which tended to use the substantial dividend income to cross subsidize its domestic operation and distort electricity prices in Laos. In the Nam Theun 2 project government equity is held by a separate government holding company enabling transparent account of receipts and its expenditure by the government on agreed poverty mitigation schemes.

GREATER MEKONG SUBREGIONAL (GMS) POWER TRADE PROJECT

(P105329)

Greater Mekong Sub-region (GMS) comprises Cambodia, Lao PDR, Thailand, Viet Nam, Myanmar and the Guangxi and Yunnan provinces of China. With a population of 315 million and a combined GDP of more than $350m, it is one of the fastest growing regions in the world. However considerable diversity exists among the countries posing major challenges to be overcome through regional cooperation and trade. Cambodia, Lao PDR and Myanmar still face high poverty rates. The GMS Economic Cooperation Program was launched in 1992 with the support of the Asian Development Bank. The World Bank had been playing a complementary and supportive role to the lead taken by ADB. The cooperation focuses on a number of sectors such as transport, telecommunication, tourism, energy, water resources, environment and agriculture. The World Bank's approach is outlined in the "Strategy Note on Economic Cooperation across the Mekong Sub-region" of April 2007. It emphasizes that regional measures planed or initiated should complement and reinforce country level activities and programs. The two areas selected by the strategy for World Bank's focus are: (1) continued support for the development of regional power trade; and (2) enhancing collaboration on Mekong water resource management.

GMS has considerable energy resources, but the distribution of those resources is skewed and does not match the demand in each country, thus creating the basic rationale for cooperation and trade. There is considerable diversity in terms of access to electricity and annual per capita consumption. The per capita annual electricity consumption in Cambodia and Myanmar were 63 kwh and 108 kWh compared to that in Thailand at 1,900 kWh. Access rates in Cambodia, Myanmar were 18 percent and 5 percent compared to 45 percent in Lao PDR and 90 percent or above in Vietnam and Thailand. Cambodia, Lao PDR and Myanmar have substantial resources far in excess of their modest needs. The countries of GMS have agreed on a cooperation program of strengthening power interconnections, cross-border investments in large generation facilities and promotion of regional electricity trade in a phased manner, with the objectives of enhancing energy security, reducing oil dependence, exploitation of economies of scale, optimization of investments, and environmental benefits.

Several studies have attempted quantification of benefits of cooperation. One study estimated that the pursuit of a "full trade scenario" compared to the pursuit of "minimal trade scenario" will result in cost savings of over $10 billion over the next 15 years and a reduction in airborne pollutants valued at $120 million a year. In 2002 ADB sponsored study *Indicative Master Plan for the Power Interconnection in GMS Countries* estimated that the proposed interconnections would reduce the capacity required to meet the peak demand by 2.5 percent. The operating reserve costs would fall by 3 percent. The study also estimated that investment in about 10,400 MW of fossil fuel fired units would be displaced by investment in 8,900 MW of hydropower and that there could be an overall capacity reduction of 1,400 MW by 2020.

Beginnings have been made is constructing major hydropower projects in Lao PDR (Nam Theun 2, Theun Hinboun) with associated transmission lines substantially for export of power to Thailand. Small transmission interconnections are planned to connect the remote areas to the adjoining country grids so that less expensive imported grid power could replace the expensive power from diesel generating sets. The cooperation is still largely in the phase of construction of interconnections. It has considerable distance to go before we see the operation of an integrated competitive power market in the region.

A GMS forum was established in 1990s which was followed by the signing of MOUs between various member countries for power trade. The long term vision of a regional electricity market was incorporated in the Intergovernmental Agreement on Regional Power Trade in 2002. This was ratified by the respective legislatures during 2004-2005. While regional power market remains a long term goal, the consensus is to focus in the short to medium term on system interconnections and augmenting generation capacity on a regional basis. The institutional framework for pursuing GMS power trade objectives comprises: (1) the Ministerial Council for Economic Cooperation; (2) Energy Ministers Council; (3) Regional Power Trade Coordinating Committee; (4) Focal Group for the planning and operation of power trade initiatives; (5) Planning Working Group for cross-border planning and for operational standards.

GMS Power Trade Projects (P105329 and P105331) funded by IDA grants in FY 2007 are the first set of interconnection projects under this regional framework. They consist primarily of 115 kV interconnections (a) between Cambodia and Vietnam, and (b) Cambodia and Laos to enable the import of grid power from Vietnam and Laos to Kampong Cham and Stung Treng provinces of Cambodia to displace the highly expensive diesel power generation there. IDA grant of $18.5m to Cambodia will finance the 64 km 115 kV line and associated substations to Vietnam border and the 56 km 115 kV line to the Laos border and associated substations along with consulting services for project implementation and for institutional strengthening. IDA grant of $15m to Lao PDR will finance the 25 km of 115 kV line to Cambodia border and associated substations as well as other components such as (a) a modern load dispatch center which will help manage the Laotian grid and enable better integration with the regional market (b) feasibility study for a hydropower project (60 MW) and (c) a tariff study. The short stretch of the 115 kV line from Cambodia border to Tay Ninh substation in Vietnam will be financed under an IDA Credit of $225m for System Efficiency Improvement, Equitization and Renewable Project approved in FY 2002.

Though there were two grant finance agreements and two project agreements, both projects were handled in one Project Appraisal document. Supervision will be done as for two projects but in coordination. The two IDA grants were approved in June 2007. The financing agreement for Lao PDR became effective in December 2007 and that for Cambodia became effective in February 2008. Cambodia is under an obligation to use an independent procurement agent for all IDA financed projects including this one. The Cambodian utility (EDC) finds this arrangement unacceptable, as it is feared to cause delays. The Government has therefore proposed that the urgently needed cross-border transmission components be removed from the project and be implemented with funds from some other financing source. No progress has been made so far on account of this. The projects may still proceed with alternative financing.

It is worth noting that the problem in this project does not relate to trade issues or disputes among governments, but to the mechanics of procurement arrangements and disagreement with the Bank.

BOLIVIA-BRAZIL GAS PIPELINE PROJECT

(P006549)

Bolivia is a relatively small country with a population of 9.5 million, but with substantial oil and gas resources far in excess of the modest domestic needs. One of the poorer countries in Latin America, it was relying, among other things, on its income from export of gas to Argentina. About 80 percent of Bolivia's gas production was being exported to Argentina. When Argentina discovered in the mid 1990s large volumes of its own gas, Bolivia was keen to develop its gas exports to neighboring Brazil, a large and fast growing economy with huge energy demand met in part by increasing imports. Brazil was trying to develop its gas market in the southern and south eastern parts to increase the share of natural gas in the country's total energy consumption from 2 percent to a much higher level to diversify energy sources and improve energy security. Bolivia- Brazil gas pipeline project carried out towards the end of 1990s was thus designed to help Bolivia diversify its natural gas exports to Brazil. The two national oil companies concluded a gas sales contract and Petrobras the Brazilian national oil company became the key sponsor for the project.

The project involved the construction of a 3,150 km long mostly 32 inch diameter gas pipeline from Rio Grande in Bolivia to Porto Alegre in Brazil with an initial capacity of 18 million cubic meters/day, capable of being expanded to 30 million cubic meters/day by the addition of eight compressors at suitable intervals (see Figure 7). About 557 km of the pipeline was in the Bolivian territory and the rest was in Brazil.

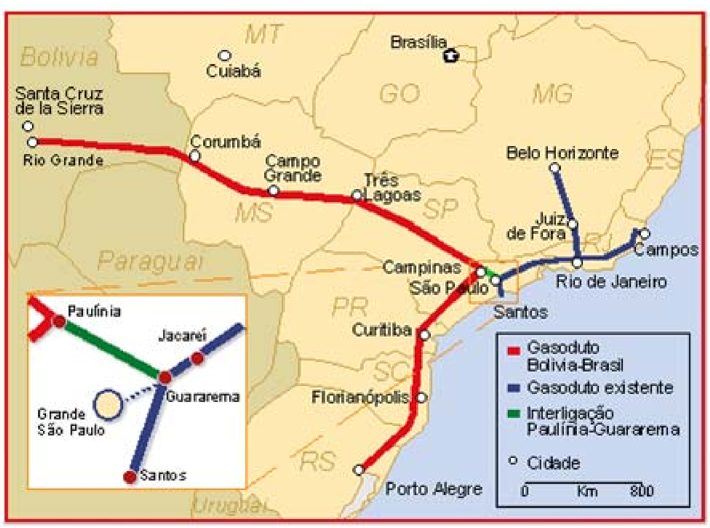

Figure 7: Bolivia-Brazil Gas Pipeline

It was estimated to cost $2,086m and was planned to be completed by June 1999. It was actually completed at a slightly lower cost and commercial deliveries began in March 2000.

The pipeline portion in Bolivia was to be owned and operated by Bolivian Gas Company (GTB), in which 85 percent of the equity shares were by Bolt JV – a joint venture among Shell, Enron and Bolivian pension funds, followed by Petrofertil, a subsidiary of Petrobras of Brazil (9 percent) and BTB – a consortium of BHP, El Paso and British Gas (6 percent). The Brazilian portion of the pipeline was to be constructed owned and operated by Bolivia-Brazil Gas Transport Company of Brazil (TBG) in which 51 percent of the shares were held by Petrofertil, followed by BTB (25 percent) and other private investors (24 percent). In order to reduce project risks, Petrobras a executed the Bolivian portion of the pipeline on the basis of a fixed price contract and also arranged for its financing through competitive bidding.

The project was financed by equity (19 percent), debt (63 percent) and by a special device called transport capacity option (TCO) (18 percent). Under the gas sales agreement sales will commence with a volume of 9.1 million cubic meters per day in year 1 and increase to 18 million cubic meters/day by year 8 and remain at that level for the remaining 12 years. Petrobras agreed to purchase the additional capacity rights in the pipeline of 6 million cubic meters per day for 40 years by paying a sum of $383 million upfront. For the transport of this additional gas Petrobras will not pay transportation charges to GTB and TBG. The Bolivian portion was financed by equity of $75m, share of the TCO payment of $ $81m, and by a debt of $280m provided by Petrobras secured from Japanese Exim Bank and the suppliers through competitive bidding. The Brazilian portion was financed by equity of $310m, share of the TCO payment of $302m, and debts amounting $1,038m. They came from IBRD ($130m), IDB ($240m), Andean Development Corporation –CAF-($80m), EIB ($60m), Petrobras secured Eximbank and supplier credits ($348m) and a Bond issue by Petrobras guaranteed by IBRD partial credit guarantee ($180m).

Though till about 2003 the actual export volumes slightly lagged behind projected levels, exports seem to have picked up a great deal since then. A new contract was signed between Brazil and Bolivia increasing the volumes from 19 million cubic meters /day to 31 million cubic meters/day and adopting a price of $8/million BTU.[34] According to the information in the website www.eia.doe.gov Brazil imported in 2008 a total volume of 395 billion cubic feet which corresponds to 30.5 million cubic meters per day, indicating near full utilization of the line capacity. The imports which reached a record level of 31.5 million cubic meters/day towards the end of 2008 started declining in 2009 and came down to 21 million cubic meters/day by end July 2009, largely as a function of all Brazilian Hydropower reservoirs being filled to capacity, and increased availability of domestic gas.[35]

The project succeeded in attracting foreign investments to Bolivia, the proven oil reserves of which jumped from 117 million barrels in 1997 to 440 million barrels in 2005. Similarly Bolivian proven gas reserves increased to 24.7 trillion cubic feet (or 678 billion cubic meters).

The gas consumption in Brazil increased considerably and several gas distribution companies came into existence in the southern and eastern parts of Brazil.

The environmental and social aspects of the project were highly complex as the line passed through some of the world's most ecologically sensitive regions, settlements of indigenous populations and archeological sites. The project involved the implementation of an Environmental Management Plan which included social compensation programs, indigenous peoples' development plan and an ecological compensation program. TBG and GTB actually

[34] Source: http://www.globalpost.com/dispatch/bolivia/090109/brazil-slashes-bolivian-gas-imports

[35] Source: http://www.americasquarterly.org/node/808/

received 2001 award from the International Association of Impact Assessments for excellence in environmental management and the use of impact assessments in the design and construction of the pipeline. It also included improvements to 13 national parks in Brazil and the Kaa-Iya National park in Bolivia. At the instance of international and local NGOs, community participation in compliance monitoring was successfully adopted. Both WB and IDB focused considerably on these aspects. It is worth noting that though the loan was given to Brazil, the legal documents provided coverage for the commitments for the execution of the environmental and social management program in Bolivia.

Essentially Bolivia was helped by giving a loan and guarantee to Brazil in this regional energy project. Because of the numerous financing agencies involved and the need for close coordination with them, and because of the significant environmental concerns, the project took considerable resources to prepare and supervise. According to the PPAR (2003) the project required 275 staff-weeks for preparation and supervision. Preparation seems to have lasted from February 1995 to May 1997, taking up about 48 percent of the total staff-weeks. However the project closed without any extension of the closing date.

Clearly the commitment of the two governments to cooperate was firm and lasting. It is worth noting that the gas trading arrangements have held well, despite the nationalization of the oil and gas sector by the Bolivian government, in which Petrobras, like many other international oil and gas companies, was adversely affected.

Earlier World Bank lending to Brazil for the Sao Paulo Gas distribution project, Hydro Carbon Transport and Processing project had helped the Bank to develop an understanding of the sector reform needs that came in handy for pursuing such reforms successfully through this project in Brazil.

There seems to have been a continuity of the task team leadership from the stage of preparation to the stage of implementation completion report of the project, which may have contributed to the success of the project.

BRIZIL-ARGENTINA POWER INTERCONNECTION PROJECT

(Project No.628 of MIGA)

MIGA provided two guarantees totaling $65m in FY 2000 in respect of the above project. The project was for the construction of two 500 kV AC power transmission lines[36] between the substations of Rincón de Santa Maria (RSM) in Argentina and Itá in Brazil with a power transfer capacity of about 2,050 MW. It also included two HVDC back to back convertor stations located in Brazil close to the border with Argentina, since the system frequency of Brazil was 60 Hz, while that in Argentina and other adjoining countries was 50 Hz. The objective of the project was to enable the export of 2,050 MW of thermal power from the gas fired thermal power stations of Argentina to Brazil to balance the seasonally variable hydropower generation in the latter. Supply of about 1000 MW of firm power was covered by a 20 year power purchase agreement between the Brazilian Ministry of Mines and Energy and the government of Argentina. [37]The rest of the line capacity was to be available for export of power from the IPPs of Argentina to Brazilian distribution companies and to the Brazilian spot market.

In 1997 the Brazilian government carried out competitive bidding for the construction and operation of a transmission line between Argentina and Brazil to enable the import of about 1000 MW of power from Argentina. The bidding was won by Endesa of Spain, which actually undertook the construction of two parallel lines with total capacity of 2,050 MW Endesa of Spain established Companhia de Interconexão Energética (CIEN) as the special purpose vehicle for owning, implementing and operating the project. The total cost was estimated at $700m and Inter American Development Bank provided equity and debt assistance to the extent of $394.5m. The rest of funds came from various commercial sources. MIGA issued guarantees for $28 million to Endesa and $37 million to Banco Santander Central Hispano for their investments and loans in CIEN to expand its power distribution capabilities in Brazil. The guarantees covered the investors against the risks of transfer restriction and expropriation.

The first of the two transmission lines was completed in 2000 and the second was completed in 2002. In the initial period export of power from Argentina to Brazil took place as envisaged, supply from Argentina being made by various IPPs including Tractabel and Furnas. From 2001/2002, a gas crisis and gas shortage developed in Argentina which affected the power and gas export capability of Argentina and by 2004 the Argentinean government formally banned the export of power to Brazil, thus abrogating the export contracts. The resulting disputes and claims still appear to remain unresolved.

However the line capacity is being used to some extent in the subsequent years for export of about 750 MW of hydropower from Brazil to Argentina during the months of June to September In return Argentina is to supply 1.2 million cubic meters of gas /day during October to May. The convertor stations are also being used by routing Brazilian power exports to Uruguay through them.

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[36] The first line had a length of 125 km in Argentina and about 375 km in Brazil. The second line was slightly shorter with total length of 489 km

[37] The transmission entity CIEN was also a party to the contract.

Argentina’s ban on gas exports caused harm not only to the investors in the transmission line, but also to Chile, the power sector of which was greatly dependent on gas imports from Argentina and had to make major changes and adjustments at considerable cost to overcome the effect of the Argentinean ban. The developments in relation to this project had, on the whole, notably dampened the enthusiasm for regional project investments in this part of the world and proved a major setback to the regional energy market integration efforts.