GUIDEBOOK FOR ECONOMIC AND FINANCIAL ANALYSIS OF REGIONAL ELECTRICITY PROJECTS

A REPORT OF THE PAN-ARAB REGIONAL ENERGY TRADE INITIATIVE

PPIAF
Enabling Infrastructure Investment

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Abbreviations and acronyms

ADB	Asian Development Bank
A/P	Accounts payable
A/R	Accounts receivable
b/b	Back-to-back (asynchronous transmission connection)
Bcfd	Billion cubic feet per day
Bcm	Billion cubic meters
BoQ	Bill of quantities
BtB	Back-to-back
BTU	British thermal unit
CAPEX	Capital expenditure
CBA	Cost-benefit analysis
CCGT	Combined cycle gas turbines
CF	Capacity factor
CIT	Corporate income tax
COD	Commercial operations date
CoUE	Cost of unserved energy
CSP	Concentrated solar power
DFI	Development finance institution
DFID	Department for International Development (U.K.)
DISCO	(Unbundled) distribution company
DSCR	Debt service coverage ratio
DSRA	Debt-service reserve account
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
EBT	Earnings before (corporate) tax
EIRR	Economic internal rate of return
ENTSO-E	European Network of Transmission System Operators for Electricity
EOCK	Economic opportunity cost of capital (see Glossary)
EPC	Equipment, procurement and construction
ERR	Economic rate of return
EU	European Union
EVN	Electricity of Vietnam
FIRR	Financial internal rate of return
FS	Feasibility study
FSRU	Floating storage and regasification unit (LNG)
GCC	Gulf Cooperation Council
GCCIA	Gulf Cooperation Council Interconnection Authority
GDP	Gross domestic product
GENCO	(Unbundled) generating company
GHG	Greenhouse gas
GWh	Gigawatt hour
HFO	Heavy fuel oil
HHV	Higher heat value (see Glossary)
HVAC	High-voltage alternating current
HVDC	High-voltage direct current (transmission)
IDC	Interest during construction
IEA	International Energy Agency
IFC	International Finance Corporation
IFI	International financial institution
IPP	Independent power producer
IRR	Internal rate of return
KfW	Kreditanstalt für Wiederaufbau (Germany)
KSA	Kingdom of Saudi Arabia
kWh	Kilowatt hour

LCOE	Levelized Cost of Electricity
LHV	Lower heat value (see Glossary)
LRMC	Long run marginal cost
LNG	Liquid natural gas
Mcf	Thousand cubic feet
MIRR	Modified IRR (see Box 2)
mmBTU	Million BTU
NICG	Net internal cash generation
NOx	Nitrogen oxides
NPV	Net present value
O&M	Operation and maintenance
OPEC	Organization of Petroleum Exporting Countries
OPEX	Operating cost expenditure
ORB	OPEC Reference Basket (of OPEC crude oils)
P/L	Profit/loss
PAD	Project Appraisal Document (of the World Bank)
PAEM	Pan-Arab Electricity Market
PA-RETP	Pan-Arab Regional Energy Trade Platform
PM	Particulate matter
PPA	Power purchase agreement
PPP	Public-private partnership
PRG	Partial risk guarantee
S/S	Substation
SCF	Standard correction factor (see Glossary)
SER	Shadow exchange rate (see Glossary)
SLD	Straight-line depreciation
SOx	Sulfur oxides
SPV	Special purpose vehicle (see Glossary)
SRTP	Social rate of time preference (see Glossary)
S/S	Substation
T&D	Transmission and distribution
Tcf	Trillion cubic feet
TRANSCO	(Unbundled) transmission company
VAT	Value added tax
VoLL	Value of lost load
WACC	Weighted average cost of capital
WTA	Willingness to accept
WTI	West Texas intermediate (crude oil)
WTP	Willingness to pay

All references to dollars, and to the symbol $, refer to U.S. dollars (unless expressly stated to the contrary). All references to "tons" refer to *metric* tons.

The spreadsheet Template for *Economic and Financial Analysis of Regional Electricity Trade Projects* is referred in the text as “the Template”. References to a table in this Template are denoted {TAB:table j} where TAB refers to the name of the worksheet, and j to the numbered table in that TAB. For example {SPV:table11} would refer to the TAB SPV, and its numbered Table 11.

References to the “User Manual” refers to the document: *User Manual for the Template for Economic and Financial Analysis of Regional Electricity Trade Projects,* a report that accompanies the Template.

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This report was prepared by Dr. Peter Meier (Principal Author) under the Pan-Arab Regional Energy Trade Initiative[1] led by Waleed Alsuraih (Task Team Leader and Lead Energy Specialist), and comprising Alexander Huurdeman (co- Task Team Leader and Senior Energy Specialist), Emmanuel Py (Senior Energy Specialist), Mohammed Qaradaghi (Senior Energy Specialist), Debabrata Chattopadhyay (Senior Energy Specialist), Abdulaziz Al-Shalabi (Energy Specialist), Mark Njore (Program Assistant, Energy), Doug Bowman (Consultant, Senior Energy Specialist), Victor Loksha (Consultant, Senior Energy Specialist), John Irving (Consultant, Senior Power Engineer), Ilka Deluque Curiel (Consultant, Energy Specialist), and Javier Inon (Consultant, Energy Specialist).

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The report was edited by Luba Vangelova. It was designed by Cecilia Garcia and Noel Gallardo.

[1] See: https://blogs.worldbank.org/ppps/creating-second-largest-regional-electricity-market-world

1 INTRODUCTION

1.1 Background

Economic and financial analysis provides the bridge between the identification of technical options and the development of bankable interconnection project proposals to facilitate cross-border electricity trade. The overarching goal of this guidebook is to document a methodology for economic and financial analysis of potential investments to facilitate regional electricity trade, which serves to inform decision-makers on policy choices, and subsequently to inform the detailed project appraisal. This guidebook has been prepared as part of the work program of the Pan Arab Regional Electricity Trade Platform (PA-RETP).

Several World Bank and other development-bank guidebooks on the economic and financial analysis of projects provide detailed (albeit general) coverage of the methodology and application of cost-benefit analyses. These provide exhaustive discussion of the fundamental principles of the subject, for which there is no need for duplication here. These works are easily accessed on the websites of their respective institutions:

- *Handbook on Economic Analysis of Investment Operations*, P. Belli, J. Anderson, H. Barnum, J. Dixon and J. Tan, Operations Policy Department, World Bank, 1997;
- *Guidelines for the Economic Analysis of Projects*, Asian Development Bank, 1997;
- *Guide to Cost-Benefit Analysis of Investment Projects*, European Commission, 2008;
- *Cost-Benefit Analysis for Development: A Practical Guide*, Asian Development Bank, 2013; and
- *Power Sector Investment Projects: Guidelines for Economic Analysis*, World Bank, February 2017.

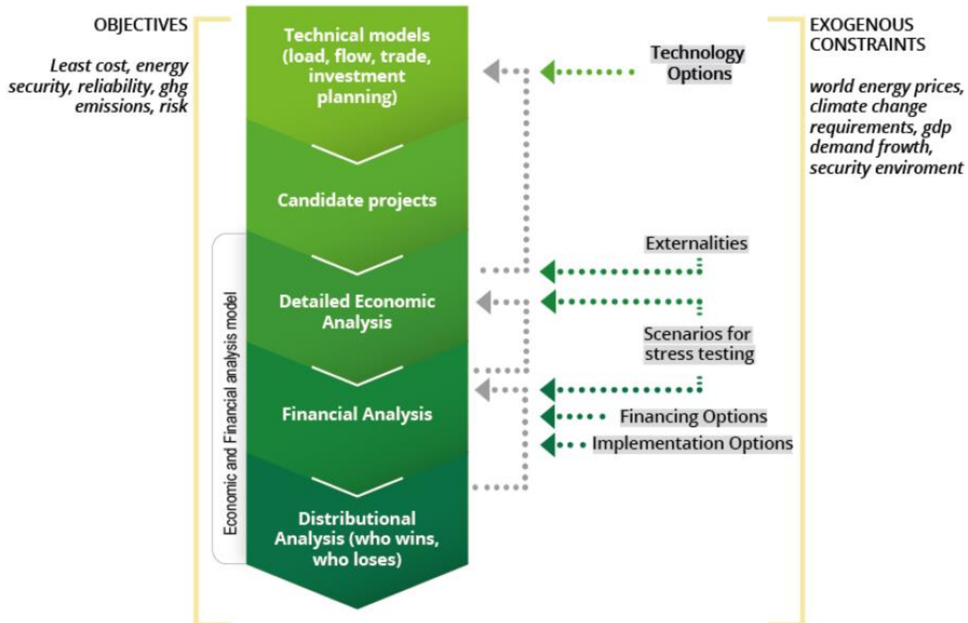
Nevertheless, most guidebooks are very general and do not address the specific problems of electricity trade. Additionally, guidelines that do concern electricity and energy trade are focused on particular institutional contexts. A typical example is the report on the cost-benefit analysis of the European Network of Transmission System Operators for Electricity (ENTSO-E)[2], which demands of its readers an extensive knowledge of the principles of economics and the rules and regulations of the European Commission. The ENTSO-E guidance is important for Pan-Arab countries wishing to interconnect to a European Union (EU) country, and some of the particular ENTSO-E requirements for presentation of the economic analysis are discussed in Section 2.14.

[2] ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, February 2015.

1.2 Policy analysis and project appraisal

The process of project development is illustrated in Figure 1. The first task of any policy, pre-feasibility or appraisal study is to define the objectives.

Figure 1: Project Development



Each objective must be accompanied by a defined indicator, which will be used for quantification and, where plausible, monetization (see Table 1). Some of these objectives imply trade-offs, notably the trade-off between risk and economic returns; others are difficult or highly controversial to quantify and monetize.

Table 1: Objectives and Indicators

Objective	Indicator	Quantification
Maximize total economic benefits	Total economic returns	NPV and ERR
Assure financial sustainability	Financial internal rate of return debt service coverage ratio	FIRR, debt service cover ratio
Equity	Share of the net economic benefits that accrue to each party	Display in the distributional analysis
Minimize local environmental impacts	Emissions of NOx, SOx and PM_{10}	Monetization as per World Bank guidelines for the power sector Investments
Minimise greenhouse-gas (GHG) emissions	Lifetime change in GHG emissions	Monetization based on social value of carbon
Maximise energy security	Index for supply diversity in importing country	Difficult to monetize; best treated in a scenario analysis
Minimise risk	Probability of not meeting the hurdle rate	Derived by Monte Carlo simulation
Maximise reliability	Change in unserved energy	Assign value of VoLL

1.3 Prior Work

Several studies of energy trade in the Pan-Arab region underpin these guidelines. The most important of these are:

- *Feasibility Study of Electrical Interconnection and Energy Trade Between Arab Countries*, by CESI and Ramboll for the Arab Fund for Economic and Social Development, 2014 (cited in these guidelines as the CESI-Ramboll report*);*
- *Pan-Arab Regional Gas Pricing*, by A. Smirnov for the World Bank, 2016;
- *Analytical Foundation for Increased Pan-Arab Regional Gas Trade,* Ramboll, 2017;
- *The Potential of Regional Power Sector Integration: Gulf Cooperation Council Countries Transmission & Trading Case Study,* by Economic Consulting Associates (ECA) for the World Bank, 2010.

1.4 Institutional Models

This guidebook is focused on the appraisal of power-transmission-line investments to facilitate regional electricity trade. While the economic appraisal is largely independent of the specific institutional arrangements for implementing projects, the financial analysis necessarily depends upon the institutional arrangements to deliver the interconnection project. A bankable investment project requires a power purchase agreement (PPA), whose tariff schedules need to be informed by the financial analysis. Consequently, the design of the model needs to include a variety of different models under which transmission investment projects can be realized.

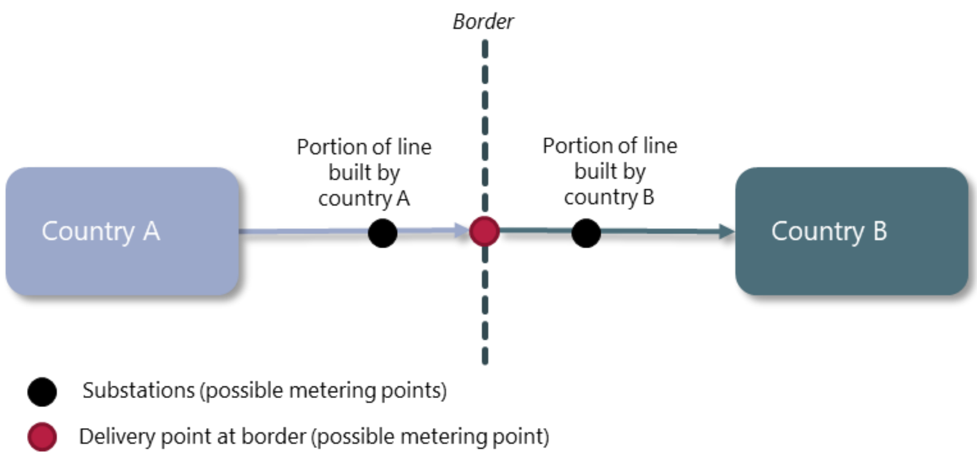
Interconnectors Built by the Trading Countries' Utilities

Worldwide, this is by far the most common arrangement: Country A sells power to Country B. A PPA signed between the two governments sets the price; most often this is denominated as a simple energy charge in USc per kWh, and subject to minimum and maximum quantities to be delivered and taken. Often the power supplied to the importing country is islanded (i.e., synchronized to the system of the exporting country). Typically, each country builds and operates the transmission facilities on its side of the border. Power generally flows largely in one direction. Examples include:

- **Vietnam exports to Cambodia**. The Phnom Penh grid so supplied is synchronised to the Vietnamese grid (Electricity of Vietnam, or EVN). On the Cambodian side, the transmission line was built with Asian Development Bank (ADB) assistance.
- **Yunnan (China) exports to Vietnam**. Certain areas in the northwestern provinces of Vietnam are connected at 110 kV to the Yunnan grid and islanded.
- **Turkmenistan imports to Afghanistan**. Turkmenistan will export gas-generated electricity to Afghanistan. The transmission interconnection is being financed by the ADB.

The typical arrangement is shown in Figure 2. The delivery point is typically at the border, and not necessarily at one of the substations at either end of the interconnection.

Figure 2: Utility Implementation (Type 1 Project)

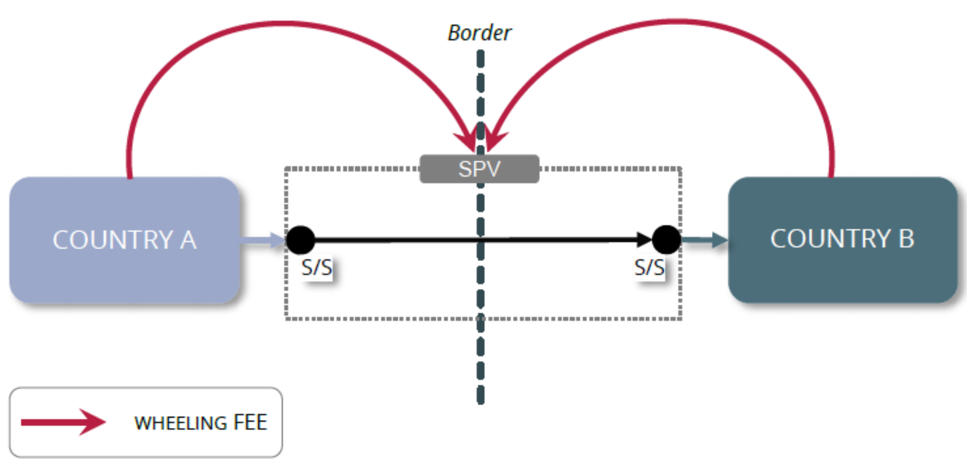


The spreadsheet Template refers to this arrangement as "Type 1". It requires an identification of what parts of a proposed interconnection are financed by each party.

Export Trade Facilitated by a Special Purpose Vehicle

The CESI-Ramboll report has proposed that all electricity interconnections in the pan-Arab region be implemented by special purpose vehicles (SPVs), whose income is provided by a wheeling fee (see Figure 3). The SPV could be entirely private or could include either or both the trading countries as equity holders. To date we know of no such arrangement for a cross-border power-trading project, though a number of transmission lines have been built on this basis within countries (see Box 8 for an example from Cambodia). The Template describes this arrangement as "Type 2".

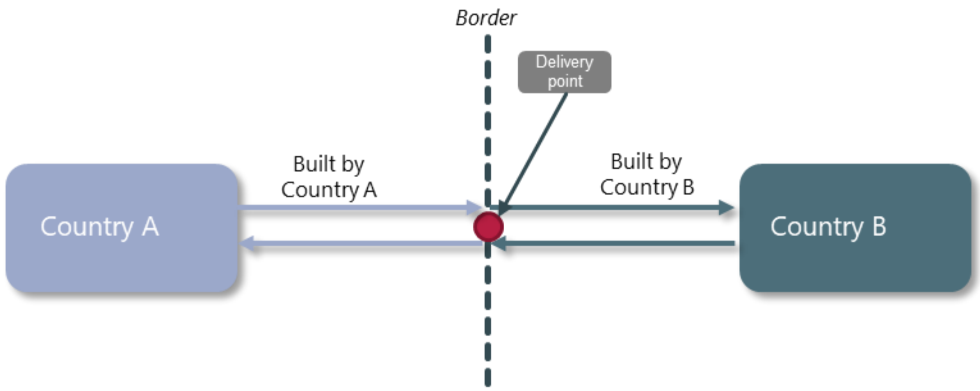
Figure 3: Interconnection Built by an SPV (Type 2 Project)



The Gulf Cooperation Council Interconnection Authority (GCCIA) is an example of an SPV created to build and operate the interconnector (Box 1). However, because the capital costs were provided to GCCIA by the six member states (in proportion to their share of benefits, see Table B1.1), there is no wheeling fee to recover the capital costs.

The above implementation-option schematics assume that the flow of power is in one direction only. However, some interconnections may serve power flows in both directions (see Figure 4); this could occur under either type of project. The spreadsheet Template accommodates such bi-directional flows.

Figure 4: Bilateral Trade (Type 1 Project)

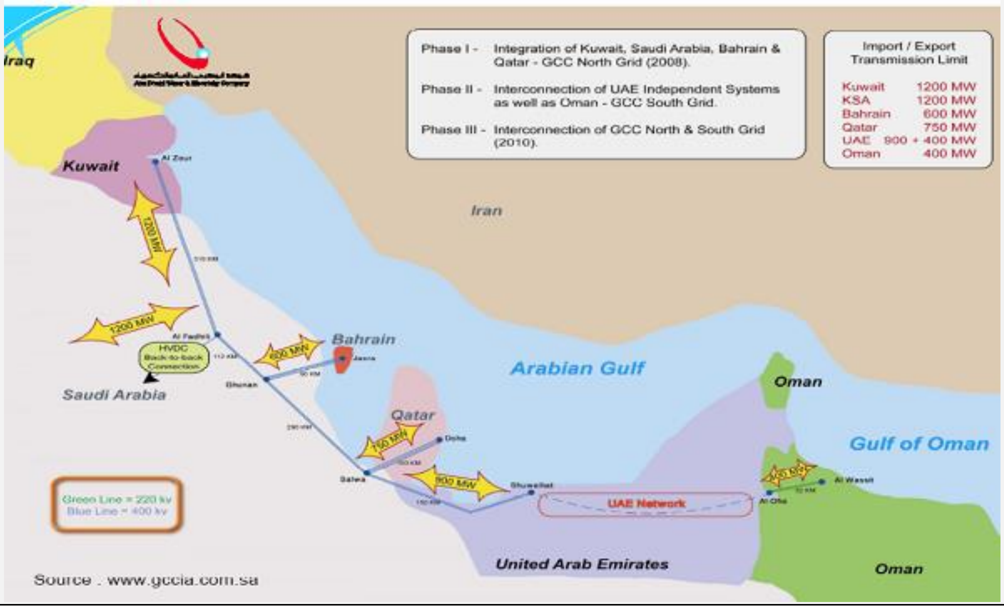


Bi-directional flows exploit the differences in the daily, monthly or seasonal demand curves. For example, in the case of the illustrative interconnection between the Arab Republic of Egypt and Jordan, if the peak demand occurs at different times of day, then it may be cheaper for Jordan to import from Egypt during Egypt's off-peak hours rather than generate from its own high-cost thermal units (and vice versa). For the economic and financial analysis, this requires information about peak and off-peak variable generation costs in both countries, and an estimate of the kWh per year that would be exchanged in each direction.

Box 1: The Gulf Cooperation Council Interconnection Authority (GCCIA)

Six Arab countries—Kuwait, Saudi Arabia (marked as KSA in the map), Bahrain, Qatar, United Arab Emirates (marked as UAE in the map) and Oman—constructed the interconnection of the 50-Hz systems of Kuwait, Bahrain, Qatar, United Arab Emirates and Oman, with a back-to-back (BtB) interconnection to the 60 Hz Saudi Arabian system. The interconnection was justified solely on the basis of sharing of generation reserves, and was built in three phases, as shown below (Figure B1.1)

Figure B1.1: The GCCIA. AC Interconnection Spanning Six Arab Countries



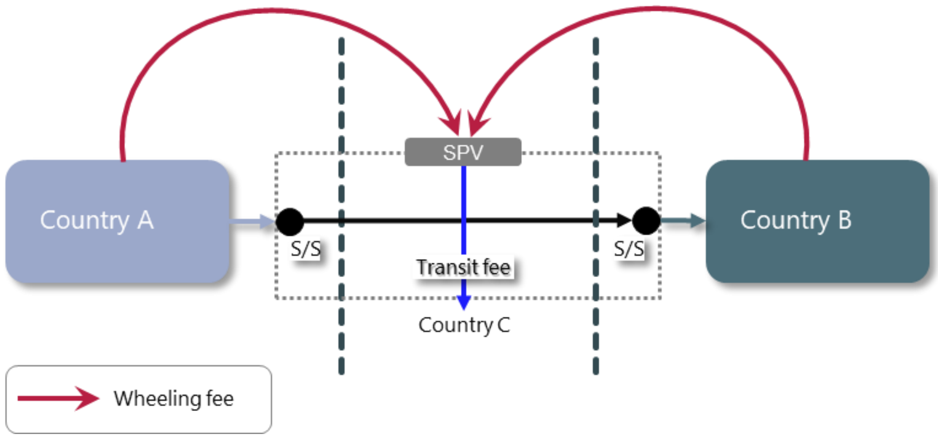
The GCCIA was created to construct this interconnector. It took responsibility for overseeing its construction (under competitive tenders), and now operates the interconnector from its dispatch center in Ghunan (Saudi Arabia). Each government contributed capital for construction in proportion to its share of the net present value (NPV) of estimated capital-expenditure (CAPEX) savings; the capital structure is as shown in Table B1.1.

Table B1.1: Capital Shares on the GCCIA

Country	Share of Capital
United Arab Emirates	15.4%
Bahrain	9.0%
Saudi Arabia	31.6%
Oman	5.6%
Qatar	11.7%
Kuwait	26.7%

Finally, electricity trade may require transit of an interconnector through a third country, which may require the payment of a transit fee (in Figure 5 this is assumed to be paid by the SPV, but it could also involve direct payments from the trading countries). As defined in this guidebook, such transit fees would not include reimbursement for actual construction costs across the territory of the transit country (which constitutes a real economic cost), but only any additional payment required to secure permission for the passage of the interconnection across its sovereign territory (which constitutes a so-called transfer payment).[3]

Figure 5: Electricity Trade Requiring Transit Through a Third Country



1.5 Modelling approach

Integration of Economic and Financial Analyses

Economic and financial analyses are sometimes conducted as separate exercises, each with its own methodology, spreadsheets and format. The approach of this guidebook and the economic- and financial-analysis spreadsheet Template is different, presenting economic and financial analysis in a single, integrated model. The main reasons for this are:

- Economic and financial analyses share many key assumptions. There is little point in conducting the analyses in different spreadsheets when so much information is common.
- Particularly in the pan-Arab region, where subsidies for gas and electricity are widespread, the magnitude and hidden costs of subsidies can only be made transparent by reconciling the economic and financial costs, which demands an integrated analysis.
- How the net economic benefits of trade are distributed among the stakeholders is a central question. But stakeholders perceive costs and benefits in financial terms, so the distributional analysis is necessarily presented in nominal terms. It also follows that, in the first instance, the economic benefits must also be expressed in nominal terms (rather than the usual presentation at constant prices). If one wishes also to report economic returns at constant prices, that is easily achieved by applying appropriate deflators and providing an additional table of economic flows at constant prices.

[3] See Section 2.4.

Risk Assessment and Allocation

Economic analysis may well show robust economic returns when assessing the underlying economic flows. However, what is economic may not be financially feasible, and what may appear to be financially feasible may be so only under a specific apportionment of risks and benefits.

This is well illustrated by the potential for electricity exports from Saudi Arabia to the Republic of Yemen. The economic returns are driven by the massive power deficit in the Republic of Yemen and the very large benefit of reducing diesel self-generation; post-conflict economic recovery will be strongly dependent on restoring reliable grid supply. But in a situation where the financial capacity of the Yemen power company is very limited, the only hope of implementing such a project is for the government of Saudi Arabia to assume the bulk of the construction and payment risk. Moreover, the proposed pricing mechanism for the Pan-Arab Electricity Market (PAEM) is not applicable in this case, because its presumption is the equal sharing of net benefits. But in this Yemen case, the bulk of the benefit accrues to the Republic of Yemen, and the bulk of the cost and risk to Saudi Arabia.

Counter-Factuals

The cost-benefit analysis methodology requires comparison with a counter-factual, consistent with the idea of economic costs being expressed as opportunity cost—the value of the resource being consumed for a proposed project in its next-best use. At the very least, especially in the absence of other alternatives to deliver the same benefits, one should look at the "no-project" alternative.

In the case of cross-border power trading, the importing country may have a range of alternatives to a proposed interconnection. It can generate the equivalent energy by one of the following means:

- Import electricity from the source proposed by the interconnection under evaluation;
- Import electricity from another source (for example, in the case of a proposed interconnection between Saudi Arabia and Jordan, imports from to Jordan from another country, e.g., from Egypt)
- Generate electricity from domestic resources (and from imported fuels other than gas);
- Import gas for power generation by pipeline, rather than the equivalent amount of electricity (Jordan could import gas for power generation from some other country); or
- Import liquid natural gas (LNG).

The distinction between LNG and pipeline gas is important, not just as a matter of cost, but because the energy security implications of LNG imports are quite different. Importing LNG does not require locking into a fixed pipeline supplier, and in the case of FSRU, the availability of five- or 10-year leases provides additional flexibility.

1.6 Scope of the Guidebook

The scope of this guidebook is as follows:

- Section 2 presents the principles of economic analysis, including an overview of the cost-benefit analysis (CBA) methodology, and an elaboration of the most important principles of economic analysis that are relevant to the analysis of interconnection investment projects;
- Section 3 discusses the benefits of electricity trade, and explains how the different types of benefits can be valued;
- Section 4 discusses the calculation of economic returns;
- Section 5 presents a discussion of power pricing;
- Section 6 discusses the principles of financial analysis;
- Section 7 deals with the financial assessment, and the financial flows that result for both importing and exporting countries;
- Section 8 discusses the distributional analysis (based on a reconciliation of economic and financial flows), which shows how the net economic and financial benefits are distributed among the various stakeholders; and
- Section 9 discusses risk assessment.

2 PRINCIPLES OF ECONOMIC ANALYSIS

2.1 The methodology of cost-benefit analysis (CBA)

Cost-benefit analysis is a well-established methodology. The main features of the approach are as follows:

- **An agreed-upon numeraire**: Both costs and benefits must be quantified and monetized to some common unit of measurement (the so-called "numeraire"). In the case of international trade, the numeraire should be in the currency that will be used in the tariff schedules of a PPA; the Template assumes this would be in United States dollars. All power trade transactions in the GCCIA are in U.S. dollars.
- **An agreed criterion for evaluation**: The most common criterion is the internal rate of return (IRR). In the case of financial analysis, this is either the financial return to equity or the project financial return. In the case of economic analysis, one speaks of the economic rate of return (ERR). Particularly in economic analyses, the World Bank requires calculation of the net present value (NPV) of benefits.
- **Comparison to a counter-factual**: A proposed investment project needs to be evaluated at least against a "no-project" alternative, but preferably also against alternative technical options for achieving the same benefits. For example, the CESI-Ramboll report considers an HVDC alternative to the proposed upgrading of the Egypt-Jordan high-voltage alternating current (HVAC) 400 kV interconnection.
- **An agreed-upon value of the discount rate**: The discount rate is a proxy for how society trades off present costs and benefits against future costs and benefits. In financial analyses, that trade-off is provided by the market rate of interest, but in economic analyses, this trade-off is a policy variable, and hence inevitably controversial. The problem is that governments in developing countries inevitably put greater weight on poverty alleviation in the short term (which leads to higher discount rates), while developed countries put greater weight on inter-generational equity (which leads to lower discount rates). In general, lower discount rates favor capital-intensive projects (e.g., renewable energy, transmission), while higher discount rates favor projects with lower initial capital costs (notably thermal power generation with low CAPEX but high operating and fuel costs).
- **Inclusion of externalities**: In the case of economic analyses, wherever possible, the relevant externalities should be quantified and monetized. The most important externality in the modern world associated with the power sector is the impact on greenhouse-gas (GHG) emissions: Any project that is financed by the World Bank—in whole or in part, including the provision of partial-risk guarantees (PRGs)—must now present the economic returns with and without consideration of the impact of GHG emissions, using valuations of the global cost of carbon as set out in new World Bank guidelines. This is discussed in detail in Section 2.11.

- **Risk assessment**: The calculated value of ERR or financial internal rate of return (FIRR) is a function of many input assumptions, many of which prove to be difficult to forecast, particularly those related to future prices of thermal generation fuels.

2.2 Difference between economic and financial analyses

The main differences between economic and financial analyses are as follows:

- **Scope**: The financial analysis of a proposed interconnector is focused narrowly on the “immediate project area”—i.e., the area in which construction of the interconnector actually occurs. However, in the economic analysis, the geographic scope may extend far beyond this project area, to include affected consumers and generators that may be far from the interconnector itself. Indeed, to the extent that greenhouse-gas emissions may increase or decrease as a consequence of interconnection, the scope can be global.
- **Numeraire**: The unit of measurement in financial analysis is cash, as reflected in actual market and financial transactions. However, in economic analysis, the unit of measurement is economic cost, which may differ substantially from financial cost—transfer payments such as taxes and import duties do not appear in the table of economic flows at all, and fossil fuels for power generation are valued not at the often-subsidized costs as determined by governments, but by the relevant opportunity costs derived from border costs.
- **Benefits**: In financial analysis, an inflow of cash is a benefit, and an outflow of cash is a cost. Therefore, if imports allow previously unconnected consumers to connect (because of shortages), the benefit to the utility’s financial position is the additional sales revenue. But in economic analysis, the benefit is the consumer’s willingness to pay (WTP), which is determined by the area under the consumer’s demand curve (as explained in Section 2.9).

2.3 Decision criteria

A number of decision criteria have been proposed for CBA:

- ERR (project is economic if ERR > discount rate);
- NPV (project is economic if NPV > 0 at the given discount rate);
- Benefit-cost ratio (BCR) (project is economic if BCR > 1); and
- Payback period (used exclusively in financial analysis).

The first three of these are often taken as equivalent, and particularly so for NPV and ERR. But they are not in fact so.

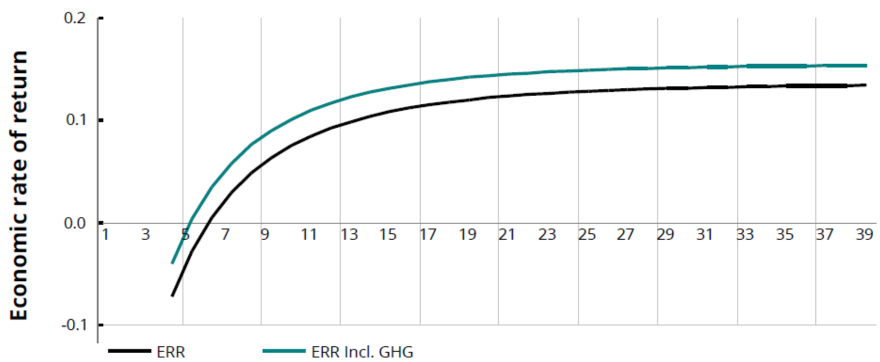
The rate of return is defective as a measure of the relative merit of mutually exclusive projects—a higher rate of return does not necessarily indicate a superior alternative, as measured by the size of the surplus. Moreover, a further presumption of the ERR calculation is that the benefits of the project are re-invested at the internally generated rate of return, yielding further benefits in the next period. But whether these returns can be re-invested at the same rate is often questionable (see Box 2).

An additional issue is that when there is more than one reversal of sign in the net annual flows, the ERR calculation may have multiple solutions.[4] For these reasons, World Bank practice is to use NPV as the main decision criterion. Nevertheless, the (internal) rate of economic return is a widely understood concept and serves as a compact summary measure of economic merit. Consequently the World Bank reports both ERR and NPV, a practice followed in our Template.

ERR should be especially avoided in any ranking exercise; in such cases, the choice should be made on the basis of maximizing the total NPV, given the capital constraint. This rarely provides the same selection of projects as is given by choosing the first ***n*** projects from a list ranked by ERR. BCRs are similarly misleading, as are traditional business indicators such as payback period; both are incorrect indicators of economic profitability.[5]

ERR is typically calculated for the economic life of the outcome under consideration, which in the case of transmission lines may be 40 years or even more. But what is of importance to the risk assessment is how quickly the hurdle rate is achieved—this means that even if a project were abandoned thereafter, it would still have been worthwhile. It is the equivalent of the switching value.[6]
Figure 6 illustrates how the ERR increases gradually over time in a typical project—a project that reduces GHG emissions (as in this example) reaches the hurdle rate more quickly (conversely, a GHG-emissions-increasing project reaches the hurdle rate more slowly).

Figure 6: ERR as a function of economic life



4 Normally there is just one sign reversal—negative flows in the early years reflecting investment, and positive flows once the project is in operation. But some projects may require large additional expenditures during operations that may cause a negative net economic flow in some years.

5 Sqiure, L. and H. van der Tak. 1975. *Economic Analysis of Projects*. Prepared by Johns Hopkins University Press for the World Bank. Washington DC.

6 See Glossary.

Box 2: Decision Criteria

The formulae for NPV and internal rate of return are well known. But care is required when using spreadsheet formulae. The normal presumption (using the EXCEL IRR function) is that the recorded transactions occur at the *end* of each year, and that the calculated value of NPV refers to the beginning of the first year. I, in other words:

$$NPV = \sum_{t=1}^{n} \frac{(B_t - C_t)}{(1+r)^t}$$

where

B_t = Benefits in year t

C_t = Costs in year t

n = Planning horizon

This provides the NPV at the *beginning* of year 1, consistent with the presumption that all *transactions occur at the end of each time period. This is the way most calculations are presented. However, sometimes the NPV is calculated starting in year zero, so:

$$NPV = \sum_{t=0}^{n} \frac{(B_t - C_t)}{(1+r)^t}$$

All other things being equal, the value of NPV calculated in this way will be higher (because the upfront capital investment is not discounted), as shown in this illustrative example in Table B2.1. The NPV of the alternative approach is 10 percent higher than the standard practice.

Table B2.1: Example of Calculating NPV Starting in Year Zero ($US million)

		NPV	Year 0	Year 1	Year 2	Year 3	Year 5
[1]	**Standard practice**						
[2]	Costs	-11.6	-10.0	-1.0	-1.0	-1.0	-1.0
[3]	Benefits	13.6	0.0	5.0	5.0	5.0	5.0
[4]	Net benefits	1.9	-10.0	4.0	4.0	4.0	4.0
[5]	IRR	21.86%					
[6]	**Alternative**						
[7]	Costs	-13.0	-10.0	-1.0	-1.0	-1.0	-1.0
[8]	Benefits	15.2	0.0	5.0	5.0	5.0	5.0
[9]	Net benefits	2.1	-10.0	4.0	4.0	4.0	4.0
[11]	IRR	21.86%					

The main point here is not to argue for one or another approach, but that any deviation from normal practice should be footnoted. In the interest of conservative presentation, the Template follows standard practice.

The Modified IRR

The so-called modified IRR (MIRR) is similar to the IRR, but corrects an important weakness of the IRR, which is that the IRR assumes that all the benefits from the project are re-invested at the internally generated rate of return, yielding further benefits in the next period. So if a project has a high IRR of 30 percent (as would be the case for many transmission projects), it assumes that these benefits would be invested at this same rate. If these are not re-investable at this rate, then the IRR will overstate the true rate of return. The MIRR (which is one of the functions in EXCEL) corrects for this by assuming benefits are re-invested at the opportunity cost of capital.

2.4 Transfer payments

In a financial analysis, CAPEX is assessed at the costs actually incurred, and therefore includes any import duties, value added tax (VAT) and sales tax as may be levied on imported and domestically sourced equipment.

But from society's point of view, import duties and VAT are not economic costs, because they consume no real economic resources, whose allocation for the transmission project would otherwise be available for some other construction project. Such costs simply move money from one pocket to another (in the case of import duties, from the pocket of the power utility importing the equipment, to the pocket of the government). Indeed all taxes, duties, VAT (or in the case of hydro projects, water royalties) are excluded from economic analysis; these are known as "transfer payments."

In a financial analysis, one distinguishes between debt (provided by lending institutions) and equity (provided by internally generated cash, or by shareholders as contributed equity). In the statement of cash flows in a financial analysis, one records equity contributions, loan disbursements by banks, and repayments of principal and interest. But none of these are relevant to economic analysis; what is booked in the table of economic flows is the capital expenditure, stripped of transfer payments that are recorded in the year they are incurred. Who pays for what is not relevant to the aggregate economic returns, although in a regional project, the equitable *distribution* of benefits may be a necessary condition for its successful implementation.

Insurance

Insurance carried by independent power producers (IPPs) is expensive. Its treatment is straightforward in financial analyses—it is always included. But in economic analyses, there are differing views:

- Some argue that it is a transfer payment. The U.S. government states unequivocally that "insurance payments are transfer payments" (*Economic Analysis of Federal Regulations,* U.S. Office of Management and Budget).[7]
- Others argue that insurance is a sharing of the economic cost of real economic loss. Gittinger[8] argues that "an accident that destroys equipment reduces the amount of goods and services available to a society and thus creates a real reduction of national income. To the extent that this loss is carried by all through insurance, the insurance premium is a share of that economic cost."

In World Bank practice, therefore, insurance is included as an economic cost. This will in any event ensure a conservative calculation.

2.5 Transit fees

Transit fees are an excellent example of transfer payments. These are defined in this guidebook as payments made by the trading parties (or an SPV charged with building

7 A small fraction of an insurance premium represents the cost of labor and administration—a real economic cost—but this generally represents a very small part of the total cost.

8 P. Gittinger. 1984. *Economic Analysis of Agricultural Projects,* Economic Development Institute, World Bank.

or operating an interconnection facility) to third parties—which may be other countries through which an interconnection may need pass—or to regions or local governments within one of the trading party countries.

For example, the proposed HVDC project to export power from the Kyrgyz Republic to Pakistan requires a route that crosses Afghanistan, in return for which a transit fee will be paid to Afghanistan. The transit fee can also be paid in kind—Morocco receives such compensation for the Algeria-to-Spain gas-pipeline project.[9] Such transit fees are unrelated to the actual construction costs of the project, and are typically negotiated by the parties involved. In the parlance of economic analysis, this is a form of "benefit sharing," not an economic cost—it constitutes a transfer payment from the beneficiaries of the project (namely the countries involved in the trade) to the third party.

However, in the financial analysis, such transit fees *do* represent costs to the SPV or to governments or utilities that make such payments to the beneficiaries.

2.6 Opportunity cost

The opportunity cost of a good that may be consumed by a proposed project is its value in its next-best alternative use. The most obvious example is the cost of employing previously unemployed labor: The financial cost of that labor is whatever wage is paid. But the economic opportunity cost (to this proposed project) is zero, because society gives up nothing by now employing this otherwise unemployed labor.

Similarly, the *economic* cost of gas is not necessarily what a utility actually pays in cash, which may well be either taxed or subsidized, but its so-called *opportunity* (or *social*) cost—the value of the gas in its best alternative use. For example, if a country that produces gas could get $9/mmBTU by exporting it as LNG, but sets the cost of gas to the power utility at a cost of $4/mmBTU, then the economic and financial costs compare as shown in Table 2.

If exported as LNG, the net gain to the country (the "resource rent") is $2/mmBTU. But if gas is sold to the power company at $4/mmBTU, the net economic benefit is only $0.5/mmBTU. To achieve the same resource rent as in the best alternative, gas for power generation should be priced at $5.5/mmBTU (column [3]); this value should be used in the economic analysis as the economic price of gas for power generation, even though the financial price to the electric utility is only 4$/mmBTU.

9 Seven percent of the volume shipped from Algeria to Spain is taken by Morocco and used for power generation. The price charged to the Moroccan power utility is based on the international price as determined by the Ministry of Energy. The current agreement on the transit fee expires in 2021.

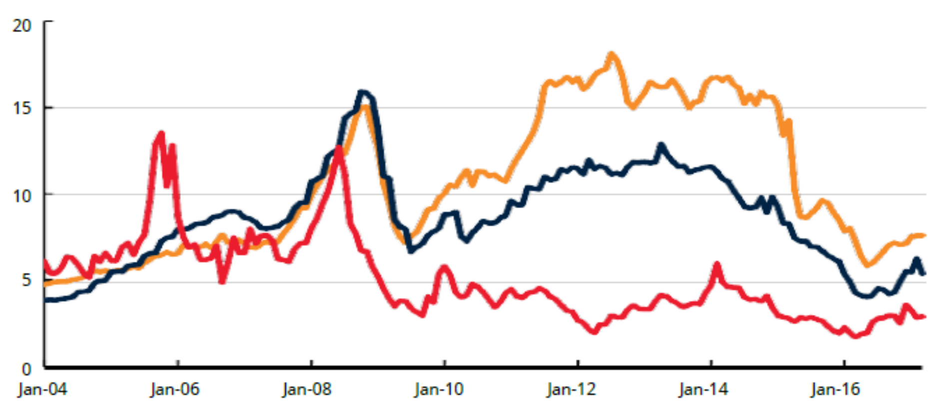
Table 2: Pricing of Gas for Power Generation

	Export	Gas for Power Generation at Subsidized Price	Gas for Power Generation at Economic Price
	[1]	[2]	[3]
Gas at power plant		4.0	5.5
LNG (free on board)	9.00		
Production cost	-3.00	-3.0	-3.0
Liquefaction cost	-3.50		
Transportation from gas field to liquefaction plant	-0.50		
Transportation from gas field to power plant		-0.5	-0.5
Net economic benefit	2.00	0.5	2.0

International Prices

The economic analysis therefore depends greatly on the assumptions made for the future international market prices of thermal fuels. Fossil-fuel prices have become increasingly volatile, as shown in Figure 7 for the case of gas—there was not just the speculative boom in 2008, and its 2009 collapse, and the equally dramatic collapse in 2015 and 2016, but also the prolonged price divergence between Japan, Europe and the United States, which has sharply narrowed of late.

Figure 7: Monthly Gas Prices, $/mmBTU

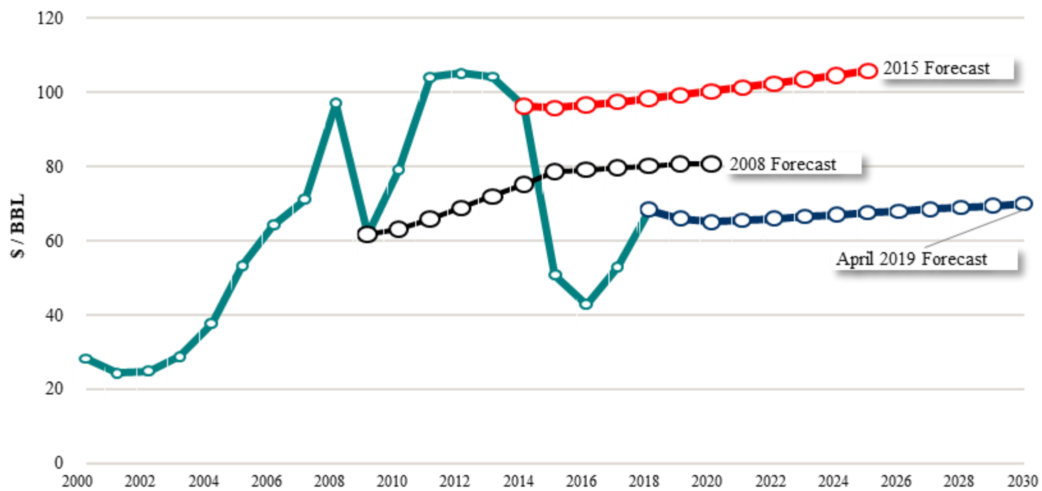


Source: World Bank Commodity Market Forecast, October 2017

Many entities make long-term forecasts for crude oil, coal and natural gas prices, including the World Bank (in its regular commodity-market outlook reports) and the International Energy Agency (IEA) (in its annual World Energy Outlook). In recent years, the IEA forecasts have been issued for several scenarios, depending on assumptions regarding the response of the global community to global climate change.

All such forecasts have high uncertainty, and few forecasts from 2012 to 2014 predicted the dramatic decline in global oil and gas prices in 2015 and 2016. Figure 8 shows the evolution of the World Bank's oil-price forecasts since 2012. Although these have differed sharply in the short term, the 2012 forecast and the latest October 2017 forecast see a similar long-term price of about $75/bbl.

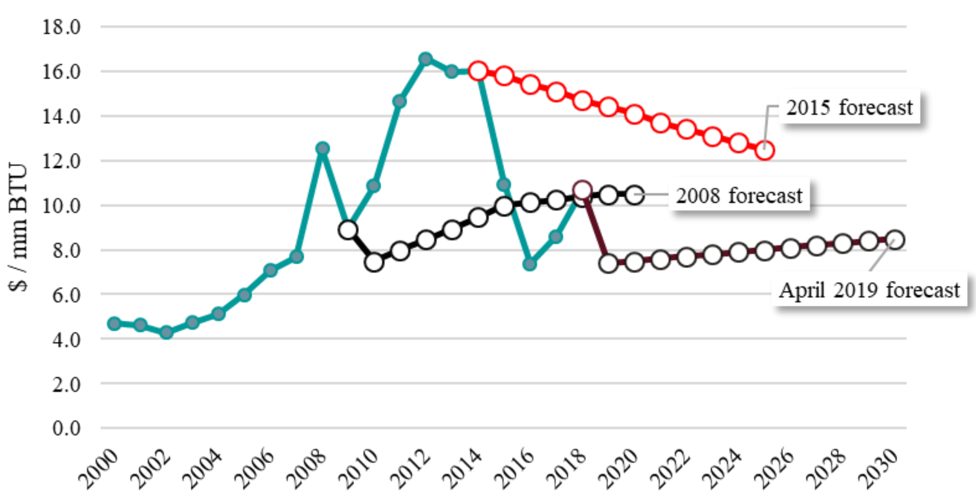
Figure 8: Oil-Price Forecasts of the World Bank[10]



Source: World Bank Commodity Market Outlook

Similar patterns are observed for LNG, gas and coal price forecasts: Figure 9 shows price forecasts for LNG CIF (cost, insurance and freight) Japan (neither the Bank nor IEA issue forecasts for LNG FOB (free on board) Gulf, which would be ~$1/mmBTU lower).

Figure 9: LNG Price Forecasts of the World Bank



There is no easy solution to the problem of price forecasting. The best option is to present the performance of a proposed investment under a set of alternative future scenarios (in the manner of the IEA World Energy Outlook).

10 The World Bank crude-oil price is the average of Brent, Dubai and WTI; it matches reasonably well that of Dubai, and the OPEC reference basket price.

Whether this price volatility matters to the economic and financial returns of a transmission project depends less on the general level of prices than on the *relative* prices of the fuels used and displaced in trade. If efficient gas combined-cycle gas turbines (CCGT) generation in country A displaces inefficient open-cycle generation in country B, increases or decreases in the international gas price may not matter much. But if, for example, natural-gas-generated electricity in Morocco (whether from LNG or imports from Algeria) displaces coal generation at Jorf Lasfar, then what matters is the *relative* price of coal and gas. As shown in Figure 10, the gas-to-coal ratio is no less volatile than the underlying level of prices.

Figure 10: Relative Price of LNG and Coal

Petroleum-Product Prices

Given a forecast for the crude-oil price, the next task is to derive the prices for the petroleum products that are actually used for power generation. Even if only gas is used by the large grid-generation projects, consumers will use diesel to generate electricity.[11]

The relative prices of fuel oil and diesel oil have their own volatility, as shown in Figure 11, which shows the ratio of diesel and fuel-oil prices to Dubai crude. Over the past few years, the diesel-to-Dubai-crude ratio has remained about 1.2, but the fuel-oil-to-Dubai-crude ratio has increased from 0.8 to 0.9. Similar fluctuations are observed for Mediterranean, Rotterdam and Singapore prices.[12]

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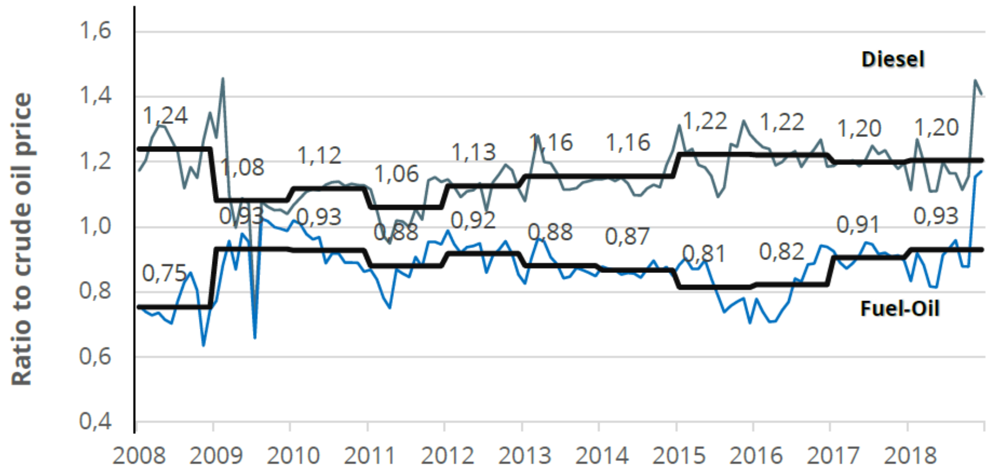
11 As explained in Section 2.9, the cost of self-generation is important to the calculation of the WTP.

12 For a major project, these relationships would likely need re-examination, because they are a function of specific locations and the precise form of fuels used. For example, in the feasibility study for the Saudi-Egypt interconnection (CESI and Tractebel Engineering, *Feasibility Study of Interconnecting the Electrical Networks of the Kingdom of Saudi Arabia and Arab Republic of Egypt*, March 2008), the functional relationships between the OPEC reference basket price, and that of specific crude oils and petroleum products were estimated by linear regression, resulting in the following relationships (albeit without indication of the statistical significance):

- HFO – price of 3.5% sulfur fuel oil = 0.708 x OPEC basket price + 5.055
- Diesel oil price = 1.342 x OPEC basket price – 4.357
- Light Crude Oil price = 0.998 x OPEC basket price – 0.377
- Heavy Crude Oil price = 0.906 x OPEC basket price – 0.931

Figure 11: Ratio of Gulf Diesel and Fuel Prices to Dubai Crude Prices



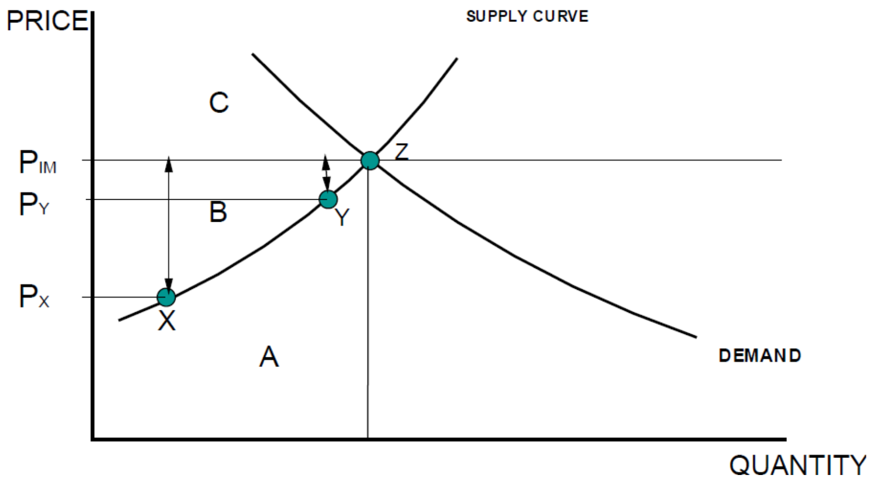
Source: OPEC Monthly Bulletins

2.7 Resource rents, producer surpluses, and production costs

International thermal fuel prices are set by global supply-and-demand balances. However, from the perspective of an individual country endowed with its own thermal fuel resources, the difference between its actual production cost and the world price (adjusted by the relevant transportation and fuel-handling costs, as illustrated in Table 6, and any depletion premium), is the so-called "natural-resource rent."

Figure 12 illustrates the supply curve for natural gas. A supply curve is simply a representation of the levelized production cost of each additional increment of supply. For simplicity this is shown as an upward sloping curve, though in reality this will be a step function defined by the reserves and production of each gas field.

Figure 12: Supply Curve for Natural Gas



The international market price P_{IM} is set by the intersection of the demand and supply curves. A low-cost producer X (e.g., the Islamic Republic of Iran or Qatar) has production costs of P_X, and therefore enjoys a rent of $P_{IM} – P_X$. The higher-cost producer at Y enjoys a much smaller rent of $P_{IM} – P_Y$.

The total cost of production is equal to area A; the total quantity of such rents is represented by area B, which in general is also known as the producer surplus.

2.8 The Discount rate

The choice of discount rate in the calculation of economic returns is critical. In the case of the GCCIA interconnector, whose capital costs were allocated in proportion to the share of CAPEX benefits that follow from the sharing of reserves, the shares would undoubtedly have varied as a function of the discount rate. Obviously agreement was reached on the 7.55-percent discount rate that was used in these calculations, to the mutual satisfaction of all parties.

Nevertheless, over the past few years, the choice of discount rate has become increasingly controversial in connection with climate-change agreements and the estimation of the damage costs of GHG emissions, and the resulting impact on capital-intensive renewable-energy generation projects; many such projects were economic only at very low discount rates. In general, high-voltage transmission-line projects are also very capital intensive, but show good economic and financial returns even at high discount rates.

For some time, in the absence of country-specific studies on the economic opportunity cost of capital (EOCK),[13] or a government directive to use some specific rate, the World Bank (and other international financial institutions, or IFIs) have used 10 to 12 percent as a default. Most countries that run power-sector capacity-expansion models use similar discount rates.

13 See Glossary.

This default has been criticized on three grounds: first, that it discriminates against projects that have long and inter-generational benefits; secondly, that application of a single default value across the huge span of country conditions is an arbitrary simplification (and in any event is a poor proxy for capital rationing); and thirdly, even if one accepted the EOCK basis, that this is much lower today (and in the foreseeable future) than was the case in the 1980s and early 1990s, when this approach first came into widespread use, and detailed calculations were presented.

In response to these concerns, the World Bank has issued new guidance on discount rates grounded in welfare economics,[14] which requires explicit assessment of long-term economic-growth rates, the marginal utility of consumption, and the pure rate of time preference (as stipulated in the Ramsey formula) (see Box 3). Application of this approach leads to discount rates that are twice the real rate of growth of per-capita gross domestic product (GDP). For many countries, this leads to discount rates that are in the five-to-10-percent range, which sometimes leads to lower discount rates than used previously.

An alternative approach is to set the social discount rate at the real interest rate at which countries can actually borrow, as argued by the U.S. Federal Reserve.[15] In fact, this approach reflects the current practice of most European governments, which link the social discount rate to their actual borrowing costs. U.S. government agencies use either the rate based on government borrowing rates, or a higher rate obtained from a social-opportunity-cost-of-capital calculation.

The basis for the five-percent real discount rate used by the World Bank for the Noor CSP project in Morocco was the seven-percent nominal rate for Eurodollar financing in 2013. Table 3 lists data on the recent issuance of dollar-denominated sovereign debt with maturity greater than five years by select developing countries. The rates shown in Table 3, when adjusted by US dollar inflation of about two percent, suggest (real) discount rates in the range of four to six percent.

Table 3: Sovereign Debt Yields

Country	Issue Date	Yield to Maturity	Amount $US million
Kenya	June 2014	6.88%	1,500
Namibia	April 2014	8.63%	1,000
Ivory Coast	July 2014	5.63%	750
Sri Lanka	April 2014	5.13%	500
Pakistan	April 2014	8.25%	1 000
Ecuador	June 2014	7.95%	2,000
Senegal	July 2014	6.25%	500
Honduras	December 2013	8.75%	500
Gabon	December 2013	6.38%	1,500
Bolivia	August 2013	6.25%	500
Nigeria	July 2013	6.63%	500

Source: U.S. Federal Reserve

14 World Bank. 2016. *Discounting Costs and Benefits in Economic Analysis of World Bank Projects*. World Bank OPSPQ Guidance Note, May 9.

15 U.S. Federal Reserve. 2014. *The Social Discount Rate in Developing Countries*. FEDS Notes, October.

Given the different ways of setting discount rates, the recommended procedure for setting the discount rate for interconnection investments is as follows:

- In the first instance, use the rate (or rates) that may be mandated by government policy. Many Ministries of Planning issue guidance on this.
- In the case of regional projects, determine whether consensus can be reached among the beneficiaries (this was indeed achieved in the discussions at the planning stage of the GCCIA).
- Evaluate the historical and forecasted per-capita GDP growth rate, with a view to its application under the World Bank procedure. This will certainly be the basis on which a project financed by the Bank would be appraised, but countries may chose to use their own discount rate for making decisions.
- Assess recent sovereign debt yields.
- Regardless of which rate is chosen for a baseline assessment, run the Template for a range of discount rates in order to establish the robustness of the investment decision to the rate chosen. In most cases, the investment decision for a transmission interconnection will not be sensitive to the discount rate chosen; though as noted in the case of the GCCIA, it will have relevance for agreements on the equitable distribution of benefits.

This pragmatic approach reflects the reality that there is no "correct" discount rate. There remains disagreement among economists about the best approach, but it is unclear that economists are better placed than governments to set the rate. The consensus rate of 7.55 percent set by the GCCIA satisfied the member governments' assessments of what was reasonable and equitable.

Further Reading: Discount Rates

Sustainable Development Practice, *Discounting Costs and Benefits in Economic Analysis of World Bank Projects*, Interim Guidance, 2016.

Zhuang, J., Z. Liang, T. Lin, and F. De Guzman. *Theory and Practice in the Choice of Social Discount Rate for Cost-benefit Analysis: A Survey*, Asian Development Bank, ERD Working paper 94, 2007.

J. Campos, T. Serebrisky, and A. Suárez-Alemán. *Time Goes By: Recent Developments on the Theory and Practice of the Discount Rate*. Infrastructure and Environment Sector Technical Note IDB-TB-862. Inter-American Development Bank, September 2015.

Box 3: World Bank Guidance on Discount Rates

The new World Bank Guidance on the choice of discount rate can be summarised as follows:

- The primary approach to the choice of discount rate should follow the Ramsey formula, in which the discount rate is a function of the long-term average growth rate of per-capita GDP.
- Where a government regulation stipulates some other discount rate, results should also be shown at that rate.
- Whatever the value chosen for the baseline calculations, the economic analysis should present a sensitivity analysis to this assumption.
- The Ramsey formula postulates the social discount rate (*r*) as

$$r = \delta + \gamma g$$

where δ = pure rate of time preference, g is the expected growth rate, and γ is the marginal utility of consumption. The basic assumption is that the marginal value of an additional dollar of net benefits is smaller when the recipients of those benefits are richer. If an economy is growing over time, the recipients of future benefits of a project will be richer, so future benefits are valued less than those that occur in the present, when recipients are less well off.

Application of the formula demands several further assumptions. The first is that the World Bank should not value the welfare of today's individuals more than that of individuals in the future; in other words setting the pure rate of time preference to zero ($\delta = 0$). The second is to rely on the literature to set γ between 1 and 2. Given the Bank's focus on eliminating extreme poverty and boosting the income of the poorest 40 percent of the population, it sets $\gamma = 2$ as being within the range commonly found in the literature. Under these assumptions, the default discount rate equals twice the long-term average growth rate of per-capita GDP.

Clearly the value judgement of the Bank with respect to the valuation of the welfare of today's individuals vs. that of future individuals may not correspond to that of today's government, for which poverty alleviation in the near term dominates policy priorities.

Application to Morocco

Morocco's real GDP growth rates show high volatility, with sharp variations from year to year. Growth was 4.4 percent in 2015, but fell to 1.6 percent in 2016, as a consequence of drought in late 2015. The most recent World Bank Economic Outlook (spring 2016) expects mid-term growth of 2.5 percent in the absence of structural reforms, but also notes that, with full implementation of a comprehensive reform agenda following the autumn 2016 parliamentary elections, economic growth could accelerate and sustainably exceed 3.5 percent over the medium term. The IMF Global Economic Outlook is more optimistic, expecting a rebound to 4.8 percent in 2019, and increasing to 4.9 percent thereafter.

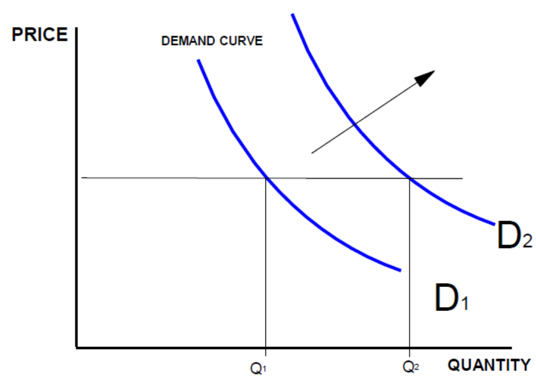
The IMF Global Economic Outlook is more optimistic, expecting a rebound to 4.8 percent in 2019, and increasing to 4.9 of 0.9 percent in 2004 to 1.4 percent in the period of 2012 to 2014. Thus the 10-year average per-capita growth rate has begun to drift down. In the absence of significant improvement in economic performance, a per-capita GDP growth-rate forecast of three percent would seem prudent, leading to a six-percent discount rate under the default assumptions of the new guidelines for the choice of discount rates.

2.9 Willingness to pay

In a financial analysis, the valuation of benefits of additional power sold to consumers is the (retail) tariff. But the *economic* benefit (to society) of additional power delivered by a transmission project is generally greater than the tariff.

To understand why this is so requires first a consideration of the consumer's demand curve for electricity. This describes the quantity of electricity that a consumer demands for a given price: It follows the generally observed rule that the *lower* the price of a good, the *greater* the amount that will be demanded at that price (Figure 13). Note that as income increases, consumers will demand more electricity at any given price—at some tariff level, a rich household (demand curve D_2) will consume much more electricity, e.g., for air-conditioning, than a less well-off household (demand curve D_1).

Figure 13: Demand Curve for Electricity



The first few kWh demanded by consumers is typically for basic lighting and for charging mobile devices (e.g., phones, iPads, music players, radios), for which consumers are prepared to pay prices (for dry cells, kerosene, and battery charging) that are equivalent to 100 times more than they would be prepared to pay for larger quantities of electricity needed for fans and air conditioning.

Table 4 shows the equivalent cost per kWh of electricity from dry cells, which calculate to as much as $890/kWh for AAA cells. Obviously, only very small quantities of electricity will be demanded at such a price.

Table 4: Dry-Cell Battery Costs

	Unit	AAA	AA	C	D
	[1]	[2]	[3]	[4]	[5]
Milliampere hour (1)	mAh	1,250	2,850	8,350	20,500
Watt-hours at nominal 1.5 volts (1)	Watt-hour	1.9	4.3	12.5	30.8
Watt-hours at actual volts (2)	Watt-hour	1.4	3.2	9.4	23.1
Typical U.S. cost	$/battery	1.25	1.00	1.60	1.80
Typical U.S. cost per kWh	$/kWh	890	310	170	80

Notes:
(1) From Energizer battery website (high-quality alkaline batteries)
(2) Actual watt-hours likely in practice, given fall in voltage over time
Source: World Bank (2010)

Household energy surveys reveal that kerosene used for lighting has an equivalent price of as much as $5.0/kWh. A non-electrified household will consume a somewhat larger amount of kerosene for household lighting, but at a price less than that of dry cells.

Some consumers will install their own self-generation units, or benefit from auto-battery charging from an informal provider with a small diesel genset; commercial and industrial consumers may provide their own generators in the absence of the grid. Table 5 shows the cost of self-generation for typical commercial and industrial units.

Table 5: Self-Generation Cost (at 2017 Oil Price)

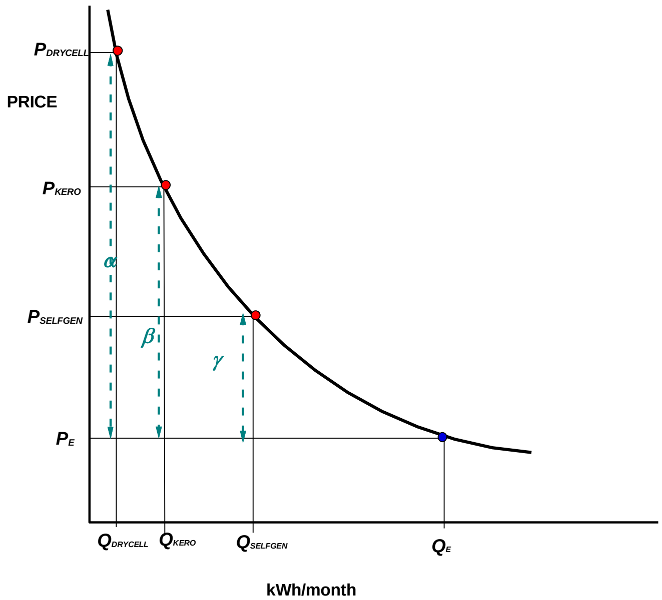
		Commercial	Industrial
		Diesel	Heavy fuel oil (HFO)
Size	kW	5.5	5,000
Capital cost	[$/kW]	888	600
Capital cost	[$1000]	4,884	3,000
Life	[years]	20	20
Discount rate	[ ]	0.08	0.08
CRF	[ ]	0.12	0.12
Annual cost	[$1000]	0.58	360
Running hours	per day	8	16
Running hours	per year	2,920	5,840
Annual energy	MWh/year	16.06	29,200
Capital cost	[$/kWh]	0.036	0.012
Non-fuel O&M	[$/kWh]	0.010	0.005
Fuel cost	[$/liter]	0.82	0.4
Fuel consumption	[liters/kWh]	0.26	0.24
Fuel cost per kWh	[$1,000]	0.2132	0.096
Total cost per kWh	[$1,000]	0.260	0.113

Source: Template {TABLES:Table_42}

The calculations are dependent on the world oil price; shown here is the average world crude-oil price in 2017. If this were to reach $70/bbl over the longer term, the self-generation costs would increase accordingly. In the Template, we assume that the benefit is limited to the avoided variable cost: To include the fixed-cost component of the self-generation cost in the benefit measure would imply that consumers would abandon self-generation entirely. This might be true if the interconnector dramatically decreased the incidence of consumer outages, but for the sake of conservative calculation, such an assumption seems unwarranted.

Figure 14 redraws the demand curve, showing the individual steps in this sequence, where dry cell, kerosene and self-generation consumption have been converted into their equivalent kWh units.

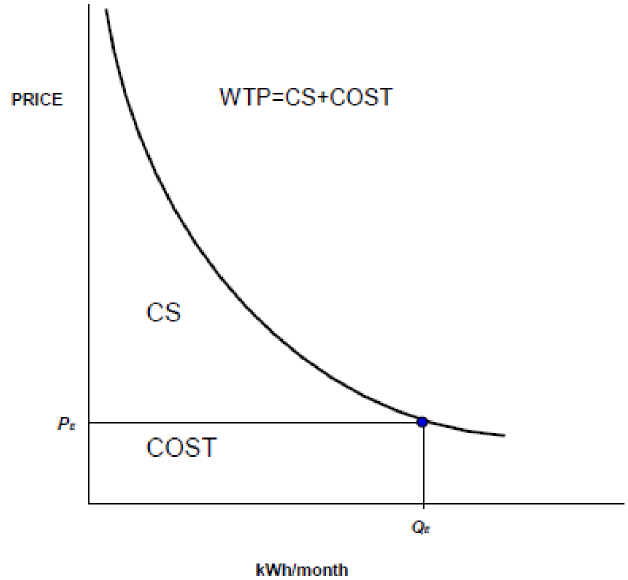
Figure 14: Willingness to Pay



This curve enables us to identify the economic benefit of electricity consumption and grid electrification. Once electrified, the price of electricity (the consumer tariff plus any VAT) is P_E, at which price the consumer consumes Q_E units. For the first $Q_{DRYCELL}$ units, the consumer would be willing to pay $P_{DRYCELL}$, but if electrified, he only pays P_E for that first tranche of consumption. Therefore the consumer gets a net benefit of $\alpha = P_{DRYCELL} - P_E$ for this first tranche of electricity; this is known as the "consumer surplus." Similarly for the kerosene and self-generation tranches, the consumer derives a net benefit of β and γ, respectively.

It follows that the total willingness to pay is the area under the demand curve, and that the total consumer surplus is the difference between WTP and the cost of consumption (given by the area P_E x Q_E) (Figure 15).

Figure 15: Consumer Surplus



While the theory is straightforward, the problem lies in a reliable estimation of the demand curve, complicated by the fact that different categories of consumers each have their own demand curves (because of differences in income, or willingness to pay). A reasonable default assumption, used in the Template, is that WTP is the average of the cost of diesel self-generation and the average retail tariff.

2.10 Shadow pricing of other inputs[16]

A review of current World Bank practice shows that relatively few power-sector project appraisals have shadow-priced domestic (non-traded) inputs and outputs; this is in contrast to ADB practice, where labor inputs are almost always shadow priced.[17] Whether this is really worth doing depends on whether the adjustments are reasonably well grounded (there are few reliable studies of the labor composition of renewable-energy-project construction workforce, and to the best of our knowledge, none for regional electricity-transmission projects), and what proportion of the capital cost is imported equipment. With the exception of hydro (where significant construction labor for civil works is required), for most energy projects—and regional transmission projects in particular—the labor inputs during both construction and operation are relatively small. The Template does not include shadow pricing of labor costs.

A more important issue concerns shadow pricing of foreign exchange. Economic theory holds that if the numeraire is in a foreign currency, domestic costs should be adjusted by the so-called standard correction factor (SCF), which is the ratio of the economic prices of goods in an economy (at their border-price equivalents) to their domestic market prices; its typical default value is 0.9 to 0.95. If the numeraire is in the domestic currency, foreign-exchange costs are adjusted by the shadow exchange rate factor (SERF), which is the reciprocal of the SCF. Without the proper adjustment, the economic returns may be over-estimated.

Whether these adjustments are necessary depends on the particular circumstances of the country in question. In recent World Bank practice, few energy-sector project appraisals have made such adjustments. In the case of the Gulf Cooperation Council (GCC) countries, it is unlikely that shadow pricing of foreign exchange is necessary for appraisal of regional electricity-trade projects. Technical Note 22 of the World Bank (2017) can be consulted for a more detailed discussion.[18]

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16 The best non-technical explanation of shadow pricing is still that in Chapter 12 of R. Turvey and D. Anderson's *Electricity Economics: Essays and Case Studies*, prepared by Johns Hopkins for the World Bank, 1977 ("A Layman's Guide to Shadow Pricing").

17 In all of the ADB projects reviewed, unskilled labor inputs were adjusted by a shadow wage-rate factor of 85 percent, but the source of this adjustment is unclear.

18 Wherein it is recommended that arbitrary default values not be used—if the adjustment is considered important, it should be underpinned by a rigorous calculation (which requires some effort to assemble the necessary macroeconomic data).

2.11 Externalities

The World Bank's 1998 *Handbook on Economic Analysis* defines externalities as: "The difference between the benefits (costs) that accrue to society and the benefits (costs) that accrue to the project entity."

A rigorous definition of an externality in the economics literature is more precise, requiring not merely that society be affected, but also that these effects are *not* conveyed through market price signals.[19]

Externalities can be positive or negative. In the pan-Arab region, the main externalities associated with the power sector relate to emissions of air pollutants and GHGs. A new thermal generation project would doubtless increase GHG emissions. But the most likely result of international electricity trade is for relatively inexpensive power generation to replace more expensive power generation in another country. Most often the incremental inexpensive generation source is also more efficient and uses gas as the thermal fuel, whereas the generation that is displaced is in older and less efficient plants, and may even displace oil or coal, whose air-pollutant emissions may be orders of magnitude greater, thus far outweighing the additional emissions attributable to transmission losses.

Whether the net emissions result of a proposed interconnection project is positive or negative must therefore be based on the specific circumstances. It is generally recognized that in the case of gas generation, the main externality is GHG emissions, because the only local air emission of any consequence is NOx. Gas is the cleanest thermal fuel, and emissions in modern combined-cycle generating plants, per kWh generated, are quite low. In contrast, local air emissions from oil and coal generation are much more damaging (including SOx, particulate matter, and trace metal emissions), and warrant inclusion as a benefit where this generation is displaced by gas generation.

Further Reading: Damage Costs of Local Air Emissions

Lvovsky, K., G. Hughes, D. Maddison, B. Ostrop, and D. Pearce. 2000. *Environmental Costs of Fossil Fuels: A Rapid Assessment Method with Application to Six Cities*. Environment Department Paper 78, World Bank, Washington, DC. Although now some 17 years since publication, still a good introduction to the problems of health damage estimation.

Atkinson, G., and S. Maurato. 2008. *Environmental Cost-benefit Analysis*, Annual Review Environmental Resources, 2008, 33:317-44. An excellent review of environmental valuation methods, and in particular of contingent valuation

Cropper, M., S. Gamkhar, K. Malik, A Limonov, and I. Partridge, 2012. *The Health Effects of Coal Electricity Generation in India*, Resources for the Future.

Cropper, M and S. Khanna, 2014. *How Should the World Bank Estimate Air Pollution Damage.* Resources for the Future.

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[19] Baumol W. and W. Oates. 1988. The *Theory of Environmental Policy.* The classic distinction is given by the example of a labor-intensive factory using coal for power, setting up next to a laundry. Soot that is deposited on clean washing imposes incremental costs on the laundry, and constitutes an externality. But if the price of unskilled labor in the project region increases because the factory offers higher wages, the impact of higher labor costs on the laundry is *not* an externality, because it is conveyed by a market price signal.

Carbon Accounting

All the international financial institutions, and most bilateral financial entities (such as the German KfW, or the British DFID), now require carbon accounting for any power-sector project financed by them. This would certainly apply to any transmission interconnection project in the pan-Arab region. And if financed by the World Bank, there is an additional (and now mandatory) requirement that GHG emissions be valued and included in the CBA presented in the appraisal report.

To include the impact of air emissions in the economic analysis requires several steps. The first is to calculate emissions that depend on three factors:

- The technology used (and in particular, knowledge of its efficiency);
- The characteristics of the fuel; and
- That pollution-control devices are in place.

Absent detailed information about the specific characteristics of fossil fuels, Intergovernmental Panel on Climate Change (IPCC) default values for CO_2 emissions from combustion may be used (see Table 6). Emissions of GHGs per unit of heat energy are lowest for gas.

Table 6: IPCC Defaults: Emissions per Unit of Heat Value in the Fuel

	Kg/TJ	Kg/GJ
Anthracite	98,300	98.3
Bituminous coal	94,600	94.6
Sub-bituminous coal	96,100	96.1
Lignite	101,000	101.0
Diesel	74,100	74.1
Fuel oil	77,400	77.4
Gas	56,100	56.1

Heat values for the IPCC defaults are on a net calorific basis (i.e., LHV). Consequently when calculating emissions per kWh, efficiencies and heat rates should also be specified on an LHV basis. Coal-project LHV efficiencies are typically five percent greater than the HHV efficiency; gas-project LHV efficiencies are typically 10 percent greater than the HHV efficiency.

Based on the default emission factors in Table 6, the IFIs have agreed on a set of harmonized default emission factors per GWh, as shown in Table 7.

Table 7: Default Emission Factors Used by IFIs

	Fuel	Generation Efficiency	Emissions Factor (Ton CO_2/TJ)	Fraction Oxidized in Combustion	Emissions Factor (Ton CO_2/GWh
Sub-critical	Coal	39%	98.3	0.98	889
Super-critical		45%	98.3	0.98	771
Ultra-super-critical		50%	98.3	0.98	694
Integrated gas combined cycle		50%	98.3	0.98	694
Circulated fluidized bed		40%	98.3	0.98	867
Pressurised fluidized bed		41.5%	98.3	0.98	836
Steam turbine	Oil	39%	74.1	0.99	677
Open-cycle gas turbine		39.5%	74.1	0.99	669
Reciprocating engine		45%	74.1	0.99	587
Combined-cycle gas turbine		46%	74.1	0.99	574
Steam turbine	Natural gas	37.5%	56.1	0.995	536
Open-cycle gas turbine		39.5%	56.1	0.995	509
Combined-cycle turbine		60%	56.1	0.995	335

Source: World Bank (2017)

However, it is always better to use actual average efficiencies: for example, in Table 7, the stated efficiency of 60 percent for CCGT is rarely achieved in practice as an annual average. The emission factor (EF) calculates as:[20]

EF = IPCC x HRATE x OX x F

where:
EF = Emission factor in Kg CO2/kWh
IPCC = IPCC default emission factor in Kg CO2/MJ
HRATE = Heat rate in BTU/kWh = 3,412/efficiency
OX = Oxidation factor
F = Conversion factor in MJ/BTU

Because gas is generally priced in $/mmBTU, thermal heat rates are expressed as BTU/kWh.

Social Value of Carbon

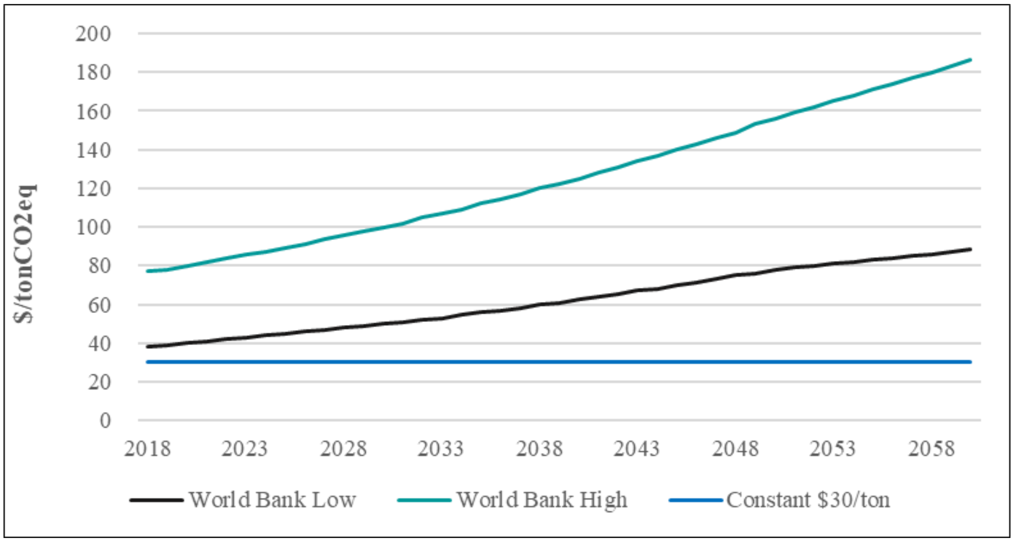
In the case of projects to be financed by the World Bank, the values to be used for GHG emissions are now as shown in Figure 16 and Table 8. The guidelines require that calculations of NPV and ERR be made for three cases:

- No GHG emissions included;
- GHG emissions at their low valuation; and
- GHG emissions at their high valuation.

[20] The Template replicates these calculations based on the actual efficiencies of the technologies in use in the countries participating in a particular trade project, to be found in {TABLES:Table_40}.

Because gas is generally priced in $/mmBTU, thermal heat rates in this guidebook and in the Template are expressed as BTU/kWh.

Figure 16: Recommended Value of Carbon, $/ton[21]



Note: At constant 2017 prices, $ metric ton of CO_2 equivalent
Source: World Bank. 2017. *Shadow price of Carbon in Economic Analysis*. World Bank Guidance Note, Nov 12.

Table 8: World Bank Values for the Social Cost of Carbon

	2018	2019	2020	2021	2022	2023	2024	2025	2029	2030	2040
Low	38	39	40	41	42	43	44	45	49	50	63
High	77	78	80	82	84	86	87	89	98	100	125

Source: Shadow Price of Carbon in Economic Analysis, World Bank, Guidance Note, Nov 12, 2017

For local air emissions, the Template provides a set of default values for damage costs per kWh for each technology, based on the detailed literature review in the World Bank Guidance document on economic analysis of power-sector investment projects (World Bank 2017, Technical Note 25).

Important References: GHG Emissions

Shadow Price of Carbon in Economic Analysis, World Bank, Guidance Note, Nov 12, 2017. This document provides the monetary values to be given to carbon emissions; for renewable-energy projects, these constitute a benefit associated with the avoidance of thermal emissions.

Guidance Note: Greenhouse Gas Accounting for Energy Investment Operations: Transmission & Distribution Projects, Power Generation Projects and Energy Efficiency Projects, Version 2, Sustainable Energy Department, World Bank, January 2015. The approach is now mandatory for all power-sector projects.

[21] The values for GHG emissions shown in Table 8 are included in the Template as {ECON:Table_32}.

2.12 Subsidies and deadweight losses

Subsidies impose significant costs to society. These may well be warranted for social reasons to benefit those in poverty, but subsidies for gas or electricity are in general poorly targeted, meaning that only a small portion of the total subsidy actually reaches the poor. Making direct cash payments to those in need is a better way to provide such subsidies, instead of distorting the price of energy. Moreover, subsidies for energy—whether for fuels used for thermal generation or for electricity—impose an additional cost to society, as explained in Figure 17.

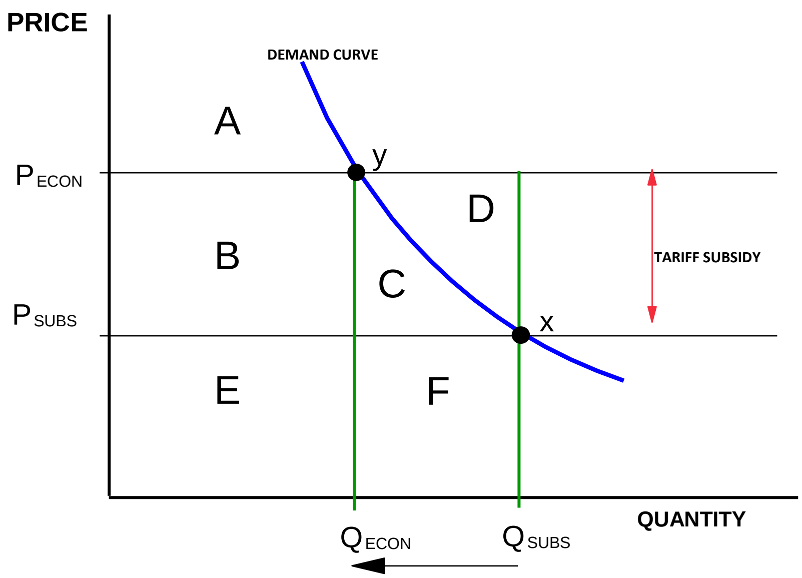


Figure 17: Deadweight Losses

Suppose the subsidized price of gas (or electricity) is P_{SUBS}, at which price the quantity Q_{SUBS} is consumed. At this price, the consumer pays Q_{SUBS} x P_{SUBS}, equivalent to the area E + F. But the cost to society of supplying Q_{SUBS} is the economic price P_{ECON} x Q_{SUBS}, equal to the area B + C + D + E + F; this means that the cost of the subsidy is (P_{ECON} - P_{SUBS}) x Q_{SUBS} (equal to the area B + C + D).

Now suppose the subsidy were removed. At P_{ECON} (the economic price), a smaller quantity Q_{ECON} is consumed. The cost to the consumer is equal to the cost to society. However, the consumer surplus is now only the area A—the consumer has lost (B + C) of his former consumer surplus. But the government's gain is B + C + D, which is greater than the consumer's loss. In other words, by removing the subsidy, society as a whole is better off by the area D. This is called the *deadweight loss* of the subsidy calculation (Table 9).

Table 9: Deadweight Losses

		Consumers	Government (Cost of Supply)	Society
	Subsidized price			
[1]	WTP	A+B+C+E+F		
[2]	Cost	-E-F	-B-C-D-E-F	
[3]	Net benefit (cost)	A+B+C	-B-C-D-E-F	
	Economic price			
[4]	WTP	A+B+E		
[5]	Cost	-B-E	-B-E	
[6]	Net benefit (cost)	A	-B-E	
	Impact of subsidy reduction ([6]-[3])	-B-C	B+C+D	D

Note: Positive value = benefit; negative value = cost

2.13 Economic price of gas

Three methodologies have been proposed for use in the pan-Arab region for the determination of the economic price of gas:

- Derivation based on the U.S. Henry Hub price;
- For gas producers, long-run marginal production costs plus depletion premium; and
- A country-specific approach, assessing the most likely source, adjusted for any transport costs.

Henry Hub Prices

The Henry Hub gas price is increasingly used as an international benchmark, as in:

Henry Hub price + liquefaction + shipping (U.S. to MENA region) + regasification**.**

This results in the total price as shown in column [5] of Table 10. This would result in a significantly higher price than the forecasts for European gas prices: The World Bank forecast for European gas in 2020 is $6/mmBTU (column [6]), compared to $8.58 for LNG based on Henry Hub. Nevertheless, for a country already largely dependent on pipeline gas, there may be an energy-security benefit to an LNG project in the interest of supply diversification.

Table 10: Henry-Hub-Based Benchmark (in $/mmBTU)

	U.S. Henry Hub (1)	Liquefaction	Shipping to MENA Region	Regasification (2)	Total Price	European Gas Price (1)
	[1]	[2]	[3]	[4]	[5]	[6]
2020	3.33	3.5	1.0	0.75	8.58	6.00
2025	3.71	3.5	1.0	0.75	8.96	6.93
2030	4.12	3.5	1.0	0.75	9.37	8.00

Notes:
(1) Based on the Oct 2017 World Bank commodity-price forecasts
(2) Assuming typical floating storage and regasification unit (FSRU) tolling fees and marine infrastructure costs

Box 4: Depletion Premium

The depletion premium is the amount equivalent to the opportunity cost of extracting the resource at some time in the future, above its economic price today, and should be added to the economic cost of production today. If *r* is the discount rate, it is defined as follows:

$$DP_t = \frac{(PS_T - CS_t)(1+r)^t}{(1+r)^T}$$

where

t	=	year,
T	=	year to complete exhaustion
PS_T	=	price of the substitute at the time of complete exhaustion
CS_t	=	price of the domestic resource in year t

The main problem with calculating the value of the premium is the uncertainty about when the resource is exhausted, because the economically exploitable size of a resource is a function of its market value and the cost (and technology) of its extraction. Assessments of reserves can change very rapidly, as illustrated by the dramatic recent developments in gas and oil extraction technology in the United States (fracking).

The necessary assumptions for a sample calculation for a gas field with a remaining time of 15 years to exhaustion, and for which the substitute fuel is taken as LNG, might be as follows

	Units	Value
Remaining resource	BCF	11,250
Extraction rate	BCF/year	750
Time to exhaustion	years	15.0
Present extraction cost	$/mmBTU	4
Substitute fuel		LNG
Substitute price at exhaustion	$/mmBTU	16
Base year		2015
Depletion year (last year of production)		2029

This results in the economic valuation shown below. The economic value increases as the time to exhaustion approaches, ultimately reaching the value of the substitute fuel (LNG).

	Depletion Premium	Economic Value
	$/mmBTU	$/mmBTU
2015	2.19	6.2
2016	2.46	6.5
2017	2.75	6.8
2018	3.08	7.1
2019	3.45	7.4
2020	3.86	7.9
2021	4.33	8.3
2022	4.85	8.8
2023	5.43	9.4
2024	6.08	10.1
2025	6.81	10.8
2026	7.63	11.6
2027	8.54	12.5
2028	9.57	13.6
2029	10.71	14.7
2030	12.00	16.0

LRMC

Many countries in the pan-Arab region have substantial existing gas production, which is likely to be extremely cheap. The costs are already sunk and probably repaid, while the fields are either associated gas or easy, onshore gas. For purposes of trade and electricity analysis, instead of applying an average cost approach, the Bank has proposed to let the pricing depend on a marginal cost approach in these countries. This would imply that, for example in the case of the Islamic Republic of Iran, the pricing would be driven by the cost of developing the South Pars gas field. Long-run marginal cost (LRMC) plus depletion premium is economically rigorous (see Box 4), but for the top eight countries with reserves of more than 100 years at current production rates (see Table 11), the depletion premium is negligible.

The World Bank has analyzed the data for the costs of production of four fields, which can act as good reference prices for long-run marginal production costs in the region—Zohr (offshore; Egypt), Leviathan (offshore; Israel), Tamar (offshore; Israel) and Ain Tsila (onshore; Algeria). These are representative of modern gas discoveries, being either isolated onshore or offshore fields. These fields also have the best cost data (audited corporate presentations with key data were available).

These fields suggest that for a modern field, a breakeven price is between $2.2 and $3.5 per Mcf. A large discovery such as Zohr or Leviathan is likely to be cheaper than future smaller discoveries, but the picture gets complicated as these smaller fields can share costs with the larger ones. The results of this analysis are shown in Table 11.

Table 11: Production Costs for Four Gas Fields

	Reserves	CAPEX	OPEX	Production	Breakeven Price
	Tcf	$billion	$m/year	bcfd	$/Mcf
Zohr	30	12	1.2	2.47	3.25
Tamar	19.3	3.2	0.32	0.9	2.60
Leviathan	21	6	0.6	2.01	2.20
Ain Tsila	2.1	1.5	0.15	0.36	3.50

Source: World Bank (2016)

Country-Specific Approach

Table 12 shows the country-specific approach recommended for use in the regional trade modelling. This requires a forecast of the underlying European and Japanese prices.

Table 12: Country-Specific Approach to Gas Pricing

	Applied Pricing Assumption	Comment
Algeria	EU price minus transportation cost to the EU	LNG and pipeline gas reference price in Algeria determined by reference to EU
Morocco	Algeria + transportation	This price should not deviate too much from the Algerian price and will therefore be driven by the European price.
Tunisia	Algeria + transportation	This price should not deviate too much from the Algerian price and will therefore be driven by the European price.
Libya	EU price minus transportation cost to the EU	LNG and pipeline gas reference price in Libya determined by reference to the EU
Egypt, Arab Rep.	EU price	Egypt's price is the highest in the region. The EU price is chosen as a proxy.
Syrian Arab Republic	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the price should be connected to Egypt's price.
Jordan	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the price should be connected to Egypt's price.
Palestine	Egypt + transportation	Assuming that the Arab Gas Pipeline is operational, the price should be connected to Egypt's price.
Iraq	Marginal production costs	Not connected to the world market and has large reserves. Marginal cost of production drives the cost of gas to the power sector.
Iran, Islamic Rep.	Marginal production costs	Only marginally connected to the world market and has large reserves. Marginal cost of production drives the cost of gas to the power sector. Development of the South Pars field will be the marginal cost.
Qatar	Marginal production costs	Connected to the world market but limited possibilities for additional LNG export. The North Field determines the marginal cost.
Saudi Arabia	Marginal production costs	Not connected to the world market and has large reserves. Marginal cost of production drives the cost of gas to the power sector.
Oman	Qatar + transport	Connected to Qatar via the Dolphin Pipeline.
Yemen, Rep.	Japan CIF price minus shipping	Minor domestic market; most gas is for export. Thus the price must be the LNG price in Japan minus the shipping and transportation costs.
Bahrain	Qatar + transport	Assuming connection to Qatar, close to the cost of developing the ultra-deep offshore fields.
Kuwait	Qatar + transport	Price in Qatar + cost of importing via LNG.
United Arab Emirates	Qatar + transport	Connected to Qatar via the Dolphin Pipeline.

Source: World Bank (2016)

The resulting estimates of gas prices are shown in Table 13.[22]

Table 13: Economic Price of Gas (in $/Mcf)

	2020	2025	2030
Bahrain	3.5	3.5	3.5
Algeria	4.5	5.5	6.5
Egypt, Arab Rep.	5.0	6.0	7.0
Iran, Islamic Rep.	3.0	3.0	3.0
Iraq	3.0	3.0	3.0
Jordan	5.5	6.5	7.5
Kuwait	3.5	3.5	3.5
Lebanon	5.5	6.5	7.5
Libya	4.5	5.5	6.5
Morocco	5.0	6.0	7.0
Saudi Arabia	3.0	3.0	3.0
Oman	3.5	3.5	3.5
Qatar	3.0	3.0	3.0
Syrian Arab Republic	5.5	6.5	7.5
Tunisia	5.0	6.0	7.0
United Arab Emirates	3.5	3.5	3.5
Yemen, Rep.	5.0	6.0	7.0

2.14 Economic analysis at other institutions

This guidebook reflects World Bank practice for economic analysis, and in particular the Guidelines for Economic Analysis of Power Sector Investment Projects. In general, this guidance tends to be more extensive than that of other international financial institutions (such as the ADB), regional lenders (such as the Arab Fund and the EU), or bilateral donors (such as Germany's KfW, the United Kingdom's Department for International Development, and the U.S. Agency for International Development). While all of the above follow the main principles of economic analysis (such as the exclusion of taxes and duties in CAPEX), we note the following differences:

- The World Bank uses NPV as the primary decision criterion (while also presenting ERR for reporting purposes), whereas most others report only the ERR;
- Only the World Bank mandates monetization of GHG emissions and the calculation of NPV (ERR) with and without monetization, using prescribed values for the social value of carbon;
- Only the World Bank requires calculation of switching values rather than just a sensitivity based on fixed deviations (e.g., plus 10 percent for CAPEX, and minus 10 percent for benefits);
- Only the ADB generally applies shadow pricing to labor and foreign-exchange costs (with adjustment factors usually based on rules of thumb), whereas the World Bank (for power projects) uses these adjustments only where country-specific data is easily available;

[22] The economic and financial analysis Template is set up to use any one of these approaches. Table 13 is included in the Template as {TABLES:Table 41}, and the pricing methodology is set up in {ECON:Table22}, which includes the latest World Bank commodity-market forecast for U.S., European and Japanese LNG.

- Only the World Bank mandates a sensitivity analysis to the discount rate, and the use of the Ramsey formula as the default rate; and
- Only the World Bank now mandates a distributional analysis, showing how the economic benefits are shared among the stakeholders (the ADB guidelines for economic analysis do provide extensive discussion about this, but it is rarely applied in its power-sector project appraisals).

ENTSO-E Methodology

A transmission project in the EU requires consideration of the following benefits in a multi-criteria framework:

- B1. Improved security of supply (quantified by changes in expected energy not supplied);
- B2. Socio-economic welfare (SEW) (quantified by the changes in consumer and producer surplus, including the realization of congestion rents and valuation in GHG emissions);
- B3. Renewable-energy integration (measures the reduction of renewable generation curtailment in MWh, and the additional amount of renewable energy generation that is connected by the project);
- B4. Changes in transmission losses (typically measured by system studies with and without the interconnector);
- B5. CO_2 emissions (physical units, with valuation included in B2);[23]
- B6. Technical resilience/system safety (ability to deal with extreme scenarios and contingencies); and
- B7. Robustness/flexibility (the ability to ensure that the needs of the system are met in a future scenario that differs from present projections).

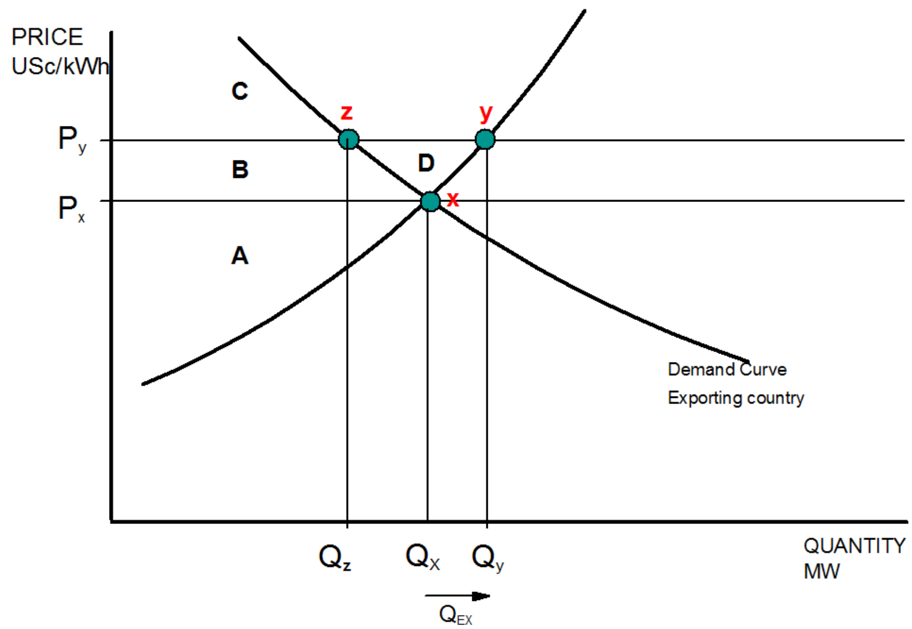
Most of these benefits are to be assessed by performance indicators by which alternatives can be compared; whatever can be monetized is included in B2.

While the obvious benefits of trade (the realization of the congestion rent, which is the quantity traded times the price difference; see Section 5.3) are easily understood, changes in consumer and producer surplus, where prices are set in competitive markets, require more thought—it may not be immediately obvious why prices would rise in the exporting countries when these export to other countries.

Figure 18 explains how exports from a market-based country (or the EU) will affect its prices. Before exports, demand and supply intersect at point $\boldsymbol{x}$: the quantity $\mathbf{Q_x}$ is demanded at the price $\mathbf{P_x}$. With exports of $\mathbf{Q_{EX}}$, the total supplied will increase to $\mathbf{Q_Y}$, at which point the price increases to $\mathbf{P_Y}$. But at this higher price $\mathbf{P_Y}$, the quantity demanded by consumers in the exporting country falls to $\mathbf{Q_z}$

23 The ENTSO-E guidelines simply state that valuation should be at the "long term societal price." ENTSO-E has developed its own scenarios ("visions") for the EU allowance price, whose 2030 values range from €33/ton to €126/ton.

Figure 18: Impact of Exports on Market Prices



In the absence of exports, producers enjoy the producer surplus equal to area A, and consumers experience the consumer surplus equal to the area B + C (Table 14). But in the presence of exports, the *producer* surplus increases from A to A + B + D, while the consumer surplus falls from B + C to C. The net loss of welfare is therefore equal to the area D, though this is of course made up by the benefit of exporting Q_{EX} units at price P_Y.

Table 14: Changes in Consumer and Producer Surplus

	Producers	Consumers	Total benefits
No exports	A	B+C	A+B+C
With exports	A+B+D	C	A+B+C+D
Net impact of exports	B+D	-B	D

Of course the actual values will depend on the elasticity (slopes) of the supply and demand curves. And if the importing country is also market based, the import of electricity will have the opposite effect—in such cases, the *producer* surplus decreases, and the *consumer* surplus decreases.

3 THE ECONOMIC BENEFITS OF ELECTRICITY TRADE

3.1 The Drivers f Power Trade

To understand the nature of the economic benefits of trade, it is useful to enumerate the main underlying drivers of relative power-generation costs across countries:

- Differences in natural-resource endowments;
- Remote access;
- Sharing of reserves;
- Differences in system size;
- Demand and supply diversity; and
- Reliability enhancement.

Differences in Resource Endowments

Neighboring countries often have unequal endowments of natural resources, which result in differences in power-generation costs. For example, Turkmenistan has large resources of low-cost natural gas, whereas neighboring Afghanistan has only small resources of domestic gas of poor quality, and is heavily dependant on imported oil, with average power-generation cost differentials of USc 15 per kWh.[24] This drives the electricity-trade project now underway to bring gas-generated electricity to Afghanistan by a transmission line financed by the ADB.

Similarly, great variations in the gas reserves are observed in the pan-Arab countries, as shown in Table 15.

Remote Access

The vast majority of existing international power-trade arrangements in Africa and Asia is driven by the difficulties of serving remote areas, which may be more easily (and more cost-effectively) supplied by the grid of a neighboring country than by extending the national grid of the country itself. Most often these remote areas are islanded, and synchronized to the grid of the exporting country:

- **Yunnan (China) exports to Vietnam.** Certain areas in the northwestern provinces of Vietnam are connected at 110 kV to the Yunnan grid and islanded.
- **India (Uttar Pradesh and Bihar) exports to Nepal.** The Terai region of Nepal (to the south of the range of mountains between Kathmandu and the Indian border), has long been supplied by the Indian grid.

Such arrangements may well be discontinued as these remote areas become more developed and local loads grow, justifying extension of the national transmission grids to serve them.

24 Gas reserves in Northern Afghanistan are estimated at some 77.4 billion cubic meters (bcm). By contrast, the reserves in Uzbekistan are estimated at 1,900 bcm, and those of Turkmenistan at 8,000 bcm (see: World Bank. 2018. *Energy Security Trade-offs under High Uncertainty: Resolving Afghanistan's Power Sector Development Dilemma).*

Table 15: Gas Reserves and Production in the Pan-Arab Countries

	Reserves	Production	Remaining Years
	Tcf	Tcf/year	Years
Iraq	130	0.2	606
Iran, Islamic Rep.	1201	5.8	209
Yemen, Rep.	17	0.1	168
Qatar	862	5.6	155
Libya	54	0.4	136
Kuwait	63	0.5	132
United Arab Emirates	215	1.7	126
Saudi Arabia	294	2.7	108
Syrian Arab Republic	10	0.2	65
Algeria	159	2.7	58
Egypt, Arab Rep.	77	1.8	43
Oman	25	1.1	24
Tunisia	3	0.1	23
Bahrain	2	0.5	7
Jordan	0	0.1	2
Morocco	0	0.1	1
Lebanon	0	0.1	0

Source: World Bank

Sharing of Reserves

The GCCIA interconnector (see Box 1) is a textbook example of a transmission investment project whose benefits were justified entirely on the basis of the CAPEX savings derived from the sharing of power reserves. The capacity reductions for Phase 1 of the GCCIA interconnector are shown in Table 16; these were derived from running a load-flow model with and without the interconnector under the same loss-of-load probabilities.

Table 16: Capacity-Reduction Benefits for Phase I of the GCCIA (MW)

Country	Load	installed capacity		Cumulative Benefit	Reserve	
		Isolated	Inter-connected		Isolated	Inter-connected
Kuwait	27,017	30,397	29,066	1,331	3,380	2,049
Saudi Arabia	23,210	26,361	24,752	1,609	3,151	1,542
Bahrain	4,989	5,782	5,494	288	795	505
Qatar	4,649	5,427	5,060	367	778	411
Total	59,865	67,967	64,372	3,595	8,102	4,507

Source: T.J. Hammons, "Prospects for Inter-connection in Africa and the Middle East," *Energize*, April 2005, p. 41-45.

Differences in System Size

Where a small country (or one with an as-yet small and weakly developed national grid) adjoins a larger country, it is often cost effective for the small country to import power from a neighbor until such time as the grid of the smaller county grows to a size when it can build larger projects of economic size itself.

A good example is Cambodia, which for the past 15 years relied mainly on imports from Vietnam to serve the major load center of Phnom Penh. The ADB financed a 230-kV transmission line to enable this trade, which is covered by a government-to-government PPA; the main Cambodian grid is therefore synchronized to the Vietnamese grid.

Although this dependence on imports is now falling, as a consequence of the commissioning of Cambodia's first coal project and first large hydro project (the 400-MW Lower Sesan 2), the transmission link will facilitate continued emergency exchanges, and may even offer an opportunity for Cambodian power exports to Vietnam (where the recent cancellation of the Vietnamese nuclear program, and the decision not to build any more new coal projects, will doubtless present a significant opportunity for future integration of the two systems).

Temporal Diversity

Temporal demand or supply diversity occurs when two systems have different patterns of supply and demand at the scale of hours, days, months or seasons. One country may have a *surplus* of power in the summer, while another has a *shortage* of power in the summer—for example, this motivates the proposed CASA-1000 project, which would send surplus summer hydro from the Kyrgyz Republic and Tajikistan to north-western Pakistan, whose summer peaks have been difficult to serve from its own projects.

Figure 19 illustrates the variation of the average marginal costs in high- and low-demand seasons in the countries of the GCC: Figure 20 shows the various interconnections in the World Bank Electricity Panning Model for the pan-Arab region.

Figure 19: Marginal Cost comparisons in the GCC Countries (Seasonal Diversity)

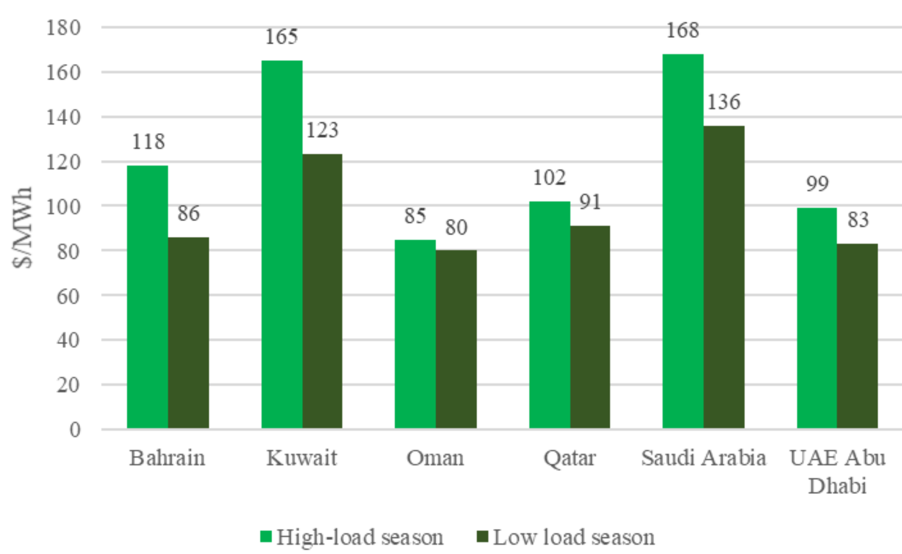
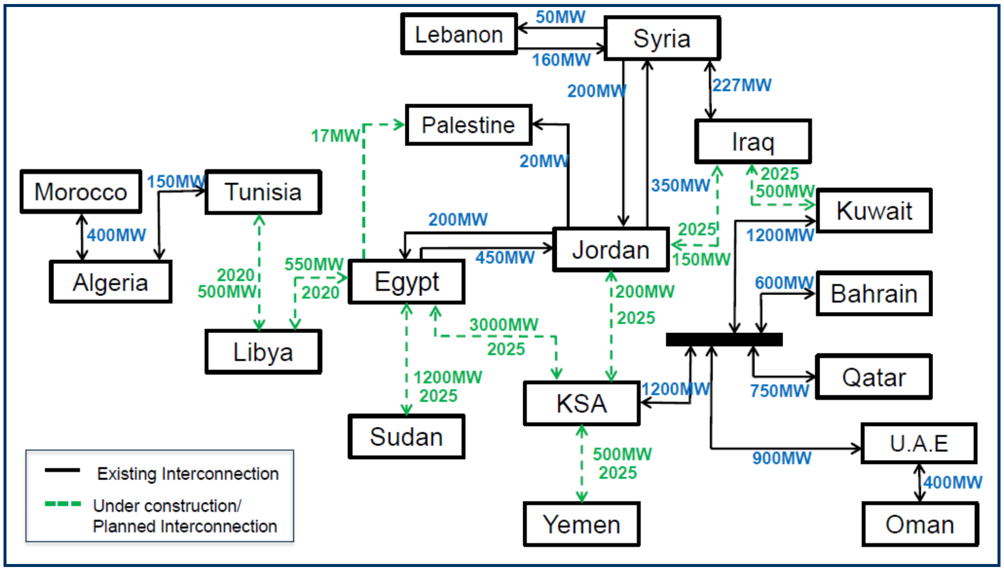


Figure 20: Interconnections in the Pan-Arab Region



An example of seasonal diversity as the rationale for electricity trade is the proposed HVDC link between Ethiopia and Kenya, which would represent the first step in the implementation of an East African Power Pool. This project is important to the economic analysis of power-trade projects because it illustrates how the development of a regional power pool can be started with a single interconnector project whose benefits are easily demonstrated and quantified—in this case, the export of surplus hydro power from Ethiopia to Kenya (see Box 5).

A good example of hourly diversity is shown in Figure 21, which shows the forecasted 2030 load curves of Saudi Arabia (Western Operating Area) and the Republic of Yemen by hour and season, as presented in a study of a potential interconnection between them.[25]

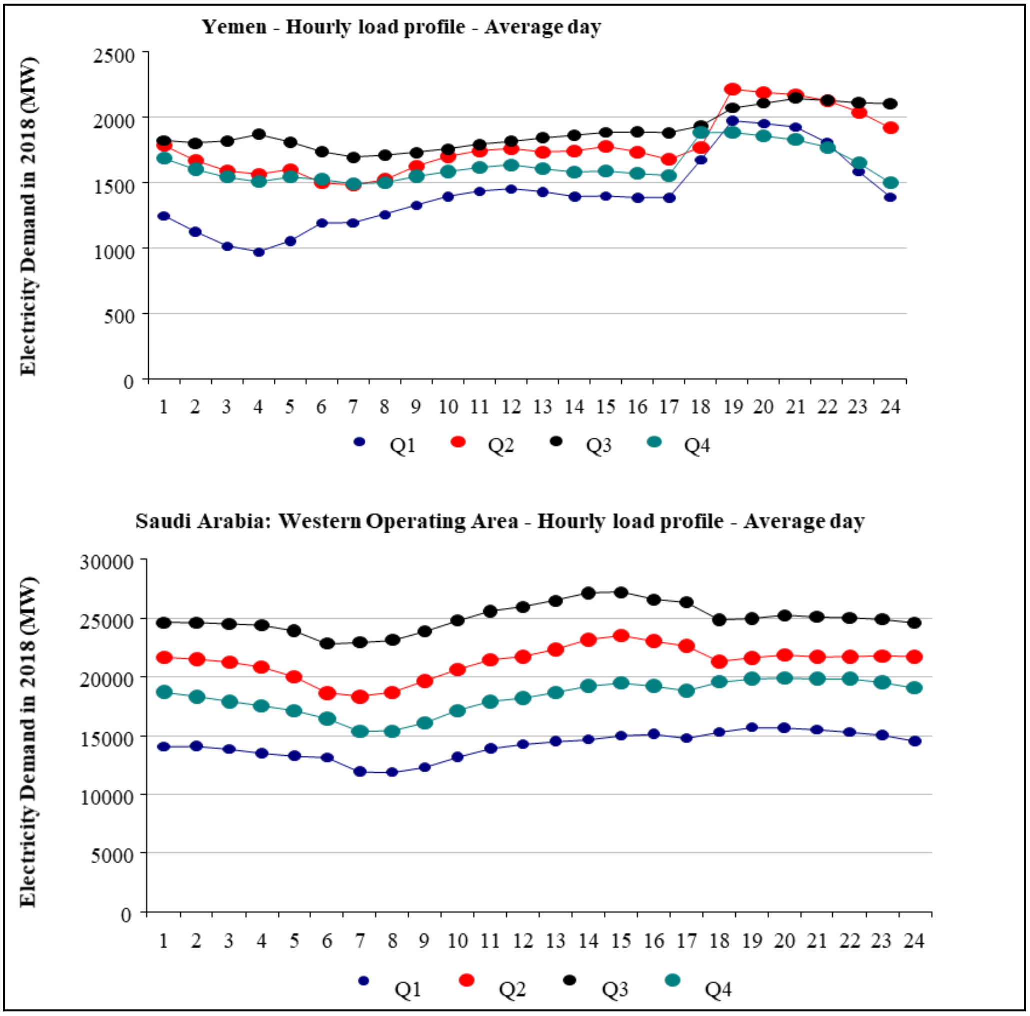
When comparing the load curves of Saudi Arabia and the Republic of Yemen, it is evident that:

- The seasonal variation in Saudi Arabia—about 12,000 MW difference between summer and winter—is very large compared to the seasonal variation of the Republic of Yemen (around 1,000 MW), and indeed of the total demand in the Republic of Yemen (2,200 MW).
- The peak summer demand in Saudi Arabia is in the early afternoon (as air-conditioning loads peak), but in the Republic of Yemen (in all seasons), the peak is between 18:00 and 23:00.
- With the Saudi system peaking mid-day, there is spare capacity to generate in the evening to meet the Republic of Yemen’s evening peak. Given the strong seasonal variation in Saudi Arabia, this holds for all seasons.[26]

[25] The demand forecasts for the Republic of Yemen were prepared in 2012, prior to the Republic of Yemen conflict, and are no longer valid: Grid demand has collapsed, with high uncertainty as to how long it will take for pre-conflict economic activity, and grid demand growth, to be restored.

[26] Under the assumption that Saudi Arabia has adequate interconnection capacity between the southern operating area (which would be the connection point to a Yemen interconnection) and the other operating regions.

Figure 21: Hourly and Seasonal Diversity: Saudi Arabia and the Republic of Yemen



Source: World Bank

Joint Development

Joint international project development is illustrated by the Manatali and Felou hydro projects in West Africa, where the output of hydro projects located in one country is shared between three countries. The Felou hydro project is located in Senegal, but the output is shared by three countries (Senegal, Mali and Mauritania), through agreements facilitated by the Senegal River Basin Development Organization (OMVS), which owns and operates the 225-kV transmission network.[27]

[27] That links Dakar (Senegal), Nouakchott (Mauritania) and Bamako (Mali). OMVS is the regional Senegal River Basin Development Organization (Organisation pour la Mise en Valeur du Fleuve Sénégal).

OMVS decided that in the case of the Felou project, costs would be shared equally, regardless of the distribution of benefits, which were estimated as follows: Mali—45 percent; Mauritania—30 percent; and Senegal—25 percent.[28]

The GCCIA could also be classified as such a joint development project, because it was collaboratively developed by several countries, with an agreed-upon share of costs and benefits assigned to each.

Enclave Projects

Enclave projects are sometimes cited as examples of trade, but these do not really constitute trade as that term is generally used. These are again most often hydro projects connected to large grids that just happen to be located across a national border.

The 290-MW Xekamen 1 hydro project in Laos is a good example. It was built, owned and operated by the Vietnam Laos Joint Stock Company Limited. All of its output is delivered to, and synchronized with, the EVN grid in Vietnam. A share of that power is considered owned by Laos, but that equivalent amount of power is returned back to Laos across other transmission lines that connect the two countries.

The Nam Theun 2 and Xayaburi hydro projects, also in Laos, but connected to the Thai grid, are similar projects. Although there have been long-standing discussions to synchronize the power grids of these countries, progress has been slow; however, eventually these transmission systems may well become part of the regional grid. In most such projects, the division of net economic benefits is most unequal, with only a small share of benefits accruing to the host country.

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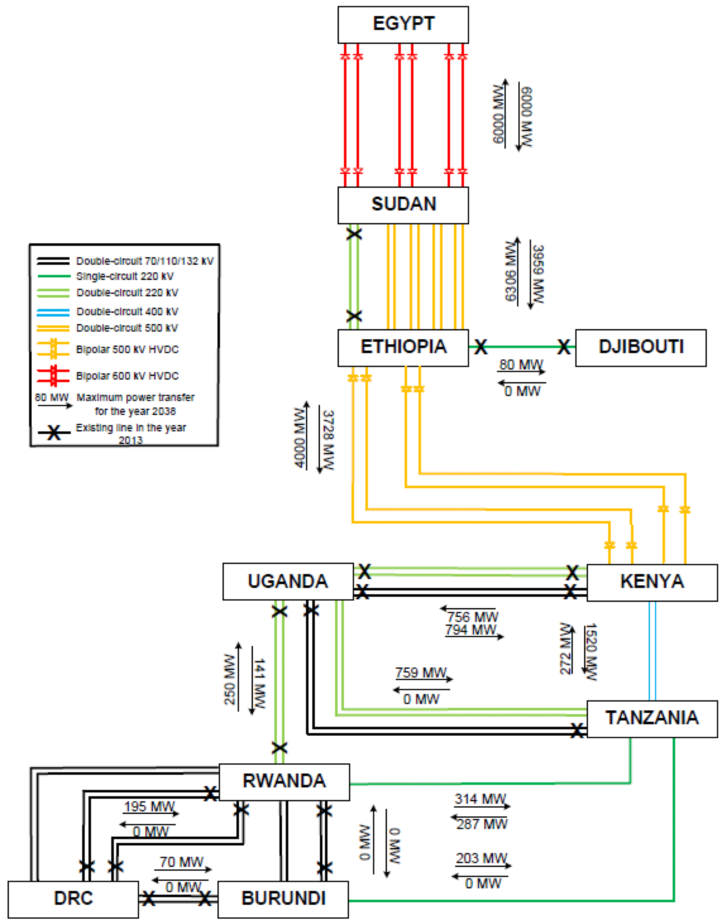
[28] Such favorable conditions to facilitate agreements are not always present: For example, larger hydro projects in Nepal, designed for export to India, were frustrated for decades because the parties were unable to agree on equitable distribution of benefits.

Box 5: The Eastern Electricity Highway Project

The proposed investment is a 1,045-km, bipolar, 500-kV HVDC overhead transmission line, with a 2,000-MW transfer capacity in both directions, and converter substations at either end. Ethiopia and Kenya would each bear the costs of the portion of HVDC line that falls within each country, and a converter station on each side. Some additional grid-reinforcement investments are required on the Kenyan side to ensure reliable operation.



The economic analysis is based on detailed modelling studies that identify this interconnection as part of a least-cost regional power-systems configuration. For the CBA presented in the Project Appraisal Document it was assumed that the line would be used only for bilateral trade from Ethiopia to Kenya, including 400 MW of firm capacity, as agreed in a PPA, and up to an additional 600 MW over the lifetime of the project. The main incremental benefit that accrues to the importing country is the avoided cost of coal and geothermal power (estimated at $0.12/kWh), so with an agreed-upon PPA cost of $0.07/kWh, the net benefit to Kenya is $0.05/kWh, with a 21.1-percent overall ERR. As noted in the appraisal summary, what governs the distribution of benefits is the export price—the higher this price, the greater the share that accrues to Ethiopia.

The pan-Arab economic and financial analysis Template allows precisely such a sensitivity analysis to study the distribution of net economic benefits between the parties.

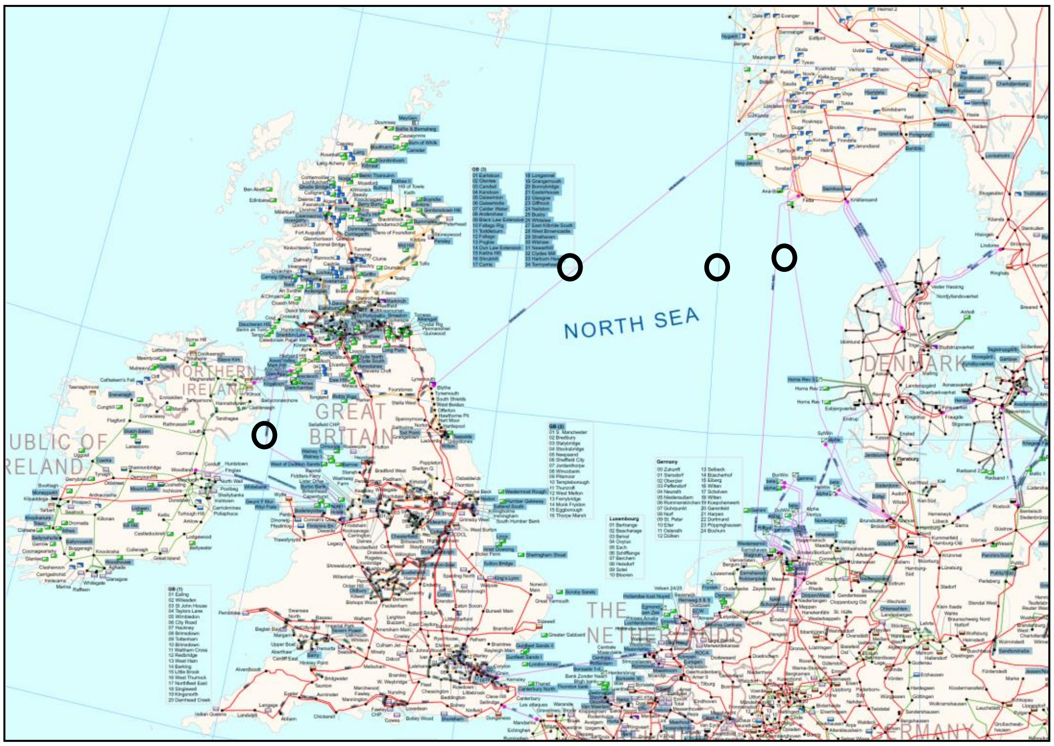
Source: Project Appraisal Document, *Eastern Electricity Highway Project*, Report 69252-AFR, June 2012. ($243 million to Ethiopia and $441 million to Kenya).

The Nam Theun 2 and Xayaburi hydro projects, also in Laos, but connected to the Thai grid, are similar projects. Although there have been long-standing discussions to synchronize the power grids of these countries, progress has been slow; however, eventually these transmission systems may well become part of the regional grid. In most such projects, the division of net economic benefits is most unequal, with only a small share of benefits accruing to the host country.

Renewables

In some regions of the world, but notably in Europe, interconnectors between countries have enabled the additional penetration of renewables, due to the unequal endowment of renewable energy. The high penetration of wind generation in northwestern Germany and Denmark has been enabled by the close connection with Norway's hydro resources. Similarly, the interconnection between Hunterston in Scotland and Frodsham in England was motivated primarily by the large number of wind farms (and superior wind regime) in Scotland) (Figure 22).

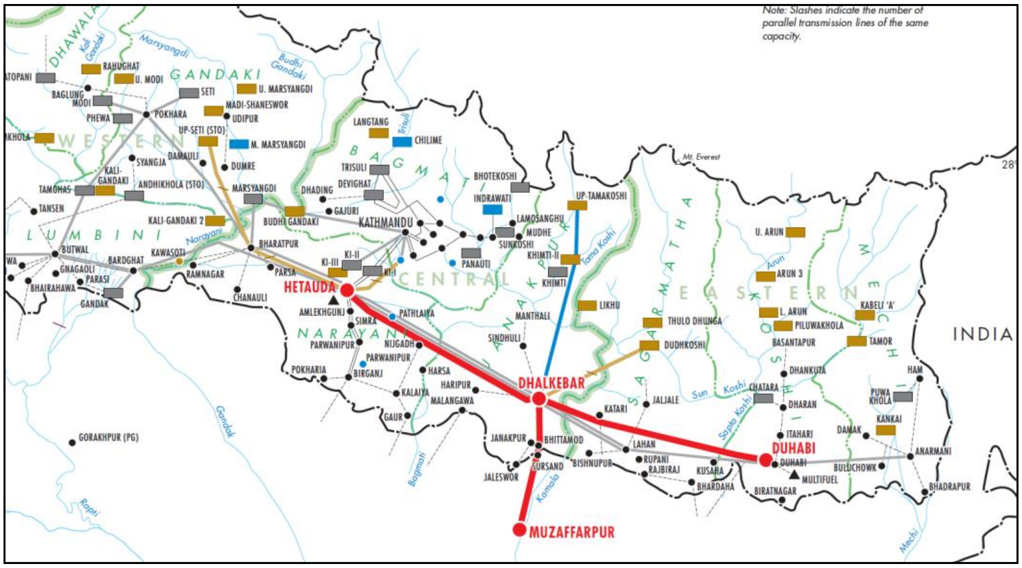
Figure 22: Interconnections in Northwestern Europe



Source: ENTSO-E

The World Bank-financed India-Nepal power-transmission project is an example of a transmission project designed to facilitate the export of Nepal's hydro electricity (as well as the import of thermal energy from India) (Figure 23).

Figure 23: India-Nepal Power-Transmission Project



Source: World Bank, *Nepal India Power Transmission and Trade Project*, Project Appraisal Document Report 59893-NP, May 2011.

The principles elaborated in the guidance—which in the case of the pan-Arab region apply in the first instance to trade in thermally generated energy—are independent of the generation technologies involved. In Section 5.2, we discuss the implications of the proposed pricing rule for electricity trade in the region in the case of renewable-energy technologies that have near-zero marginal variable production costs.

Transmission projects designed primarily to evacuate energy from power-generation projects—whether renewable or not—cannot be appraised as self-standing projects; they have no economic rate of return in isolation of generation. Rather, the incremental transmission costs should be included in the CAPEX of the generation projects and assessed as a single project (and compared to the next-best generation alternative that also includes its incremental transmission costs).

3.2 The benefits of transmission projects

The methodology for technical, economic and financial analysis of a proposed transmission line that connects two countries is no different from the methodology one would use to analyze a connection between two regions or two load centers within a single country. These benefits are listed in Table 17.

From a purely technical point of view, it does not matter whether a transmission line crosses a provincial or international border. There is no better example than the development of the power system in the five Central Asian republics during the days of the Soviet Union[29]—the transmission system of the five fully synchronized systems was developed without regard to national boundaries, with a regional dispatch center in Tashkent. Only once the republics became independent countries did the problems of

29 Uzbekistan, Kazakhstan, the Kyrgyz Republic, Turkmenistan, and Tajikistan.

power exchanges between countries become apparent, the immediate difficulty being that each country now had its own (weak and non-tradable) currency, and in the absence of an acceptable and available common currency, power trade was possible only through barter arrangements.[30]

Table 17: The Benefits of Transmission Projects

Benefit	Examples	Nature of Benefit
Reliability improvement	Interconnect two load centers	Avoids the cost of outages to consumers, or avoids CAPEX for reserve margin requirements that would bring the same improvement of reliability
Loss reduction in a supply-constrained system	Add transformer capacity to an overloaded substation	kWh saved become available for sale to consumers
Loss reduction in an unconstrained supply system	Replace an overloaded 115-kV line with a 230-kV line	kWh saved reduce the amount of generation required to meet demand
Evacuation of additional power	Project to connect a new generating plant	Additional power made available to consumers
OPEX reduction	SMART grid project to automate substations	Lowers the cost of power transmission (eventually passed onto the consumer)
CAPEX reduction by sharing of reserves	Lower financial CAPEX cost	Lower investment requirements at economic prices (excluding import duties and taxes)
Generation substitution	Importing country imports at lower financial cost than domestic generation	Lower generation costs

Table 17 illustrates the general technical nature of benefits of transmission projects. However, the main challenge for economic and financial analysis is how these benefits are to be quantified and monetized. The principles that apply to this quantification and monetization are again of a universal nature, and do not depend on the extent to which a transmission line crosses a border. Of course, connecting two unsynchronized national systems imposes additional costs (say for a back-to-back synchronous connection), but the nature of the benefits is unchanged.

3.3 Differences between economic and financial analysis

Financial analysis is generally well understood. Costs and benefits are stated simply at their cash, market and transaction values, at nominal cost. Economic analysis, by contrast, is often not understood. The numeraire is not cash costs and benefits, but *economic* costs and benefits, which may be quite different from the financial costs. As

30 Subsequently Uzbekistan withdrew from joint operation, and Turkmenistan and Tajikistan are now isolated from the Central Asian Unified Energy System.

shown in Table 18, the quantification of economic benefits relies on some concepts that may be unfamiliar to most engineers—such as willingness to pay—and are explained in the sections that follow.

Table 18: Benefit Valuation in Economic and Financial Analysis

Benefit	Financial Analysis (Perspective of the Power Utility)	Economic Analysis (Perspective of Society)
Reliability improvement	Additional sales to consumers (at the consumer tariff) (1)	Avoided economic cost of supply interruptions to consumers (typically valued at the "value of lost load" (VoLL)
Loss reduction in a supply-constrained system	kWh saved can now be sold to consumers at the consumer tariff	kWh saved, valued at willingness to pay (WTP)
Loss reduction in an unconstrained supply system	Depends on the methodology of transmission pricing	Avoided cost of generation, valued at economic price
Evacuation of additional power	Additional sales at the relevant tariff	kWh supplied to consumers, valued at WTP
OPEX reduction	Depends on the methodology of transmission pricing (2)	Reduction in cost of transmission benefits consumers by lowering their cost of electricity
CAPEX reduction by sharing of reserves	Lower financial CAPEX cost	Lower CAPEX at economic prices (excluding import duties and taxes)
Generation substitution	Importing country imports at lower financial cost than domestic generation	Generation differentials valued at economic prices

Notes:

(1) Assuming a vertically integrated state-owned utility. If the transmission system is owned by an unbundled transmission company (TRANSCO), the financial benefit to the TRANSCO depends on the transmission pricing methodology.

(2) If the remuneration to the TRANSCO is based solely on GWh delivered (as is the case, for example, in Vietnam), there is no financial benefit to it. Whether OPEX reductions result in a financial benefit depends on how it is regulated (in some regulatory regimes, the benefits of efficiency improvements are shared between the utility and consumers).

3.4 Capacity benefits

Explanation

The benefits of lower generation are of two types: the avoidance of variable costs, and the avoidance of capacity costs. The avoided variable costs—most of which are fuel costs—should be valued at the economic cost of fuel; this means the cost at international prices, adjusted for any transportation cost, and excluding any taxes and import duties. The benefit is transparent, and the calculation is straightforward.

Whether or not there occurs a capacity benefit depends on the magnitude and certainty of the increased power. If country A signs a 20-year PPA to supply country B with 500 MW of power, then country B would not need to build its own 500-MW project, and it would be reasonable to claim a benefit for avoided capacity. However, country A would certainly incur a capacity *cost* to build a 500-MW generation plant dedicated to exports.

Whether in fact country B would completely avoid building 500 MW of its own capacity given imports of this magnitude would depend on the perception of the reliability of the imports. This would be an issue to be explored in the economic and financial analysis, to determine the extent to which the trade is dependent on the avoided capacity costs in the importing country. Certainly in the case of occasional trades between A and B across an existing interconnection, that does not assure either party of firm power, one cannot reasonably claim a capacity benefit.

One must be careful not to double count. The calculation of capacity credits from the sharing of reserves depends on a comparison of the capacity expansion plans with and without the interconnection at the same level of reliability, so if one claims this capacity credit, one cannot also claim a benefit from reliability improvement.

Calculation

A reliable calculation can only be made by a formal capacity-expansion planning model, in which the model is run for two cases, with and without the proposed interconnector, in both cases using the same level of reliability (for example, for the same loss of load probability). If the interconnector defers or eliminates some projects, the present value of the CAPEX between the two cases constitutes the capacity benefit that can be claimed. This was the methodology used in the establishment of the GCCIA (see above, Section 3.1.3 and Table 15)).

How the total capacity credit benefit is shared is a separate question, and cannot be answered by the economic analysis, because the equitable apportionment of costs and benefits is a matter for negotiation between the parties.

3.5. Improved reliability

Explanation

In theory, the benefit of an interconnection that improves reliability can be seen as the avoided cost of the incremental capacity in the importing country that would avoid the outage in the absence of imports; indeed, this is the basis of the rationale for the GCCIA. However, in practice, a utility may often be unwilling to add expensive capacity to insure against forced outages or unexpected demand peaks, especially where retail tariffs do not cover the true cost of supply.

For the financial analysis, the revenue impact of emergency power exchanges on the power utility is small and limited to the additional sales revenue enabled by the imports.

However, for the economic analysis, the cost to consumers of unscheduled outages may well be a multiple of the tariff. A small shop faced with a one-hour outage may lose evening sales that are many multiples of the cost of electricity; for major industries, disruption of manufacturing processes may similarly impose high costs.

Calculation

Quantifying the benefits of improved reliability is the most difficult of all of the valuation problems in regional electricity trade. The problem is that there are few reliable studies of the costs of such outages based on credible data, so in practice, most estimates of the VoLL are quite arbitrary, and vary from $0.5/kWh to as much as $3/kWh. Box 6 lists some of the issues in estimating VoLL and the cost of unserved energy (CoUE).

A recent World Bank report on the application of smart-grid technology to the transmission system in Vietnam[31] proposes $3.00/kWh as the VoLL, a value it justifies on the basis of U.S. and European practice. Another World Bank source has reviewed VoLL estimates across a range of countries, and finds values in the range of $0.3 to $1.2 per kWh. A detailed study of the macroeconomic impacts of a 10-day blackout in Georgia estimated the VoLL at $0.56/kWh.[32]

The difficulty is that, the more reliable the system, the greater will be the VoLL when an outage does occur. In the presence of endemic power cuts, consumers will protect themselves with self-generation units, whose costs are in the range of USc 20 to USc 30 per kWh (depending on the oil price). Poor residential households can rarely afford such generators, but use in commercial, hotel and industrial sectors is widespread. As the system becomes more reliable, and endemic power cuts become more rare, fewer self-generation units are maintained, so when power cuts do occur, their impact is much greater.

The methodology of calculation is straightforward. Table 19 illustrates a typical calculation for Vietnam, a country with good n-1 transmission system reliability. The reductions are typically just a few hours per year; inclusion of the reliability benefits associated with a regional energy trade will likely be small, even at typical VoLL in the range of $0.5 to $1.00 per kWh.

Table 19: Impact of Smart-Grid Transmission System Investment on Reliability

Reliability Metric	Units	No project	With project
500Kv			
Failure times/year	Number of occurrences	0.8	0.2
Duration/incident	Hours	8	3
Failure hours/year	Hours/year	6.4	0.6
220Kv			
Failure times/year	Number of occurrences	1.6	0.2
Duration/incident	Hours	16.0	3
Failure hours/year	Hours/year	25.6	0.6

Source: World Bank. 2014. *Project Appraisal Document for a $500 million Loan to Vietnam for a Transmission Efficiency Project*. Report PAD766 (July 14): Table 3, page 62.

The Template allows inclusion of the reliability benefit in the economic analysis, using a VoLL multiplier of 10 times the average consumer tariff as the default. It requires an

31 World Bank. 2016. *Smart Grid to Enhance Power Transmission in Vietnam* (July).

32 World Bank. 2017. *Power Sector Investment Projects: Guidelines for Economic Analysis* (May).

estimate of the fraction of total GWh traded that reduces outage in the importing country.

Box 6: Issues in the Determination of VoLL and CoUE

- In developed countries with highly reliable systems, few users will have their own backup systems, so blackouts, when they occur, may entail high costs for industrial and commercial users, and great inconvenience for domestic consumers. Estimates of CoUE in excess of $1/kWh are generally from the Organisation for Economic Co-operation and Development (OECD) countries.
- Even in developed countries, some of the estimates of CoUE are of doubtful credibility. For example, a study for the U.K. regulator OFGEN[33] claimed domestic customers' VoLL in the range of $9.7 to $16.50 per kWh (based on a one-hour outage, at different times of day and in different seasons), using a "stated preference choice experiment in terms of willingness to accept (WTA) a payment for an outage." When repeated as a WTP to avoid an outage, the estimates are an order of magnitude lower, at $1.5 to $2.3 per kWh. Methodology is everything. [34]
- Even where methodological rigor is present, different methodologies will yield considerable variation (as in the case of the TERI studies in India, which compared three different methods of estimating the CoUE for industries and agriculture.
- In systems with poor reliability, typical of some developing countries, when shortages will be regular and prolonged, a large number of industrial and commercial consumers will have their own backup supplies. A study of Sri Lanka (which experienced endemic shortages from the mid 1990s to 2010, when the first coal project was built) showed that 92 percent of the sampled industries had backup facilities. Their CoUE can be approximated by the cost of self-generation (with fixed costs allocated across the period of generation, based on the assumed number of hours of operation per year).
- Many countries that use system planning models simply use some default value (typically $0.5 to $0.75 per kWh) as the CoUE, with no clear rationale provided.
- The CoUE will depend on whether interruptions are planned or unplanned. In systems of endemic shortages, load-shedding operations can be announced in advance, whereas emergency load shedding to maintain system stability, or outages attributed to faults, are obviously unplanned. A study of Sri Lanka determined that the CoUE for planned interruptions was $0.66/kWh, increasing to $1.06/kWh for unplanned outages.[35]
- CoUE estimates for calculations in reliability-improvement projects (say in the typical transmission and distribution project) will be higher than the CoUE used for WTP calculations in systems of endemic power shortages (because the running hours are much smaller in the former case).
- Use of the ratio of GDP to electricity consumption is not a particularly good proxy for CoUE, because it bears little relationship to demand and energy usage at the margin, and

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33 London Economics. 2013. *The Value of Lost Load for Electricity in Great Britain*. Report to OFGEM (July).

34 The question for WTA was: "How much would you be willing to accept in compensation for a one-hour outage?" For WTP it was: "How much are you willing to pay to *avoid* an outage?"

35 D.P. Colambage, et al. 2016. *Assessment of the Cost of Unserved Energy for Sri Lanka Industries*. IEEE, ICEEOT Conference.

does not isolate the contribution of energy consumption to GDP from the contribution of numerous other inputs that produce the GDP.[36] In any event, such aggregates may be distorted by a few highly electricity-intensive industries that account for disproportionate shares of total electricity consumption.

- There are few detailed studies of the economic cost of prolonged outages. One such exception is a study in Georgia, which estimated the cost of a 10-day blackout in 2013 at $14 million, equivalent to $0.56/kWh, as the basis for its quantification of the value of reliability improvement.

3.6 Imported Power

In the first instance, imported power will be considered by the load dispatcher of the importing country on the basis of its variable cost, and inserted into the merit order accordingly. In general, one may assume that it will simply displace the most expensive domestic generation, so the calculation of the benefit to the importing country is straightforward. The impact on the consumer is indirect, assuming that the cost savings are indeed passed through into the retail tariffs.

However, it is also possible that imports will serve previously unserved customers, who may not be served in the absence of imports because of insufficient domestic generation capacity.[37] In this case, there is a difference between the resulting economic and financial benefits.

The financial impact on the utility is the additional revenue from the sale , always assuming the retail tariff is higher that the cost of imports (adjusted for distribution losses). The financial impact on the consumer will depend on the extent to which previously unserved consumers generate their own power—their financial benefit will be the avoided cost of (diesel) self-generation.

The economic benefit to previously unserved consumers will be their WTP, which in most cases will be higher than the cost of diesel self-generation. Even where many unserved consumers cannot afford diesel self-generation (or can afford only very few kWh at that cost), *at the margin*, the additional power will be taken up by those consumers most willing to pay—these will be commercial and industrial consumers, who are most likely to have diesel self-generation.

36 Nevertheless, the South African Department of Energy claims this method to be “internationally accepted as a minimum value for CoUE.”

37 It may also be the case that where the incremental financial revenue at a subsidized tariff does not cover the variable financial cost of peak generation, the utility has a strong incentive not to generate, even though it may well have the *ability* to generate. Afghanistan is the classic example: The 100-MW Tarakil diesel project built in Kabul in 2005 with USAID funding has rarely been used, because the cost of diesel fuel is prohibitively expensive, and far exceeds the retail tariff—every kWh supplied therefore increases the financial losses, making for a powerful incentive for the utility to impose curtailments. Meeting this unserved demand awaits the arrival of gas-generated imports from Turkmenistan.

3.7 Loss reduction

The benefits of loss reduction will depend on whether the system is constrained or unconstrained. If the system is unconstrained—that is, a system that during normal operation can meet the demand—the reduction of losses will result in lower generation necessary to meet the same demand. On the other hand, if loss reduction occurs in a constrained system, the kWh saved can be sold to previously curtailed customers. The benefits to consumers should be valued at their WTP.

In other words, there need to be no separate estimates of "loss reductions," because these follow from the changes in generation and consumption. The key is simply to prepare a detailed energy balance.[38]

3.8 Energy security

Experience with regional power markets around the world suggests that concerns with domestic security of supply often limit participation in regional electricity trade. However, there is often a lack of an economic framework for thinking about what is a reasonable domestic energy-security premium. Just such an example confronts Morocco, which is faced with a choice of importing more gas (or electricity) from Algeria, or building its own LNG terminal to import from the broader international LNG market. Importing Algerian gas (the present agreement) expires soon, but importing more gas has been rejected on national energy-security grounds. The implied lifetime energy-security premium runs (in NPV terms) to several hundred million dollars.

Certainly, it is true that importing large blocks of electricity (not just sharing reserves, or opportunistic trades) locks countries into a long-term embrace, so the benefits have to be overwhelming to justify the risk. This is exemplified by the proposed Turkmenistan-to-Afghanistan interconnector, where the economic benefits are indeed overwhelming, because the gas-generated imports substitute for prohibitively expensive diesel generation in the Kabul load center. This is true even though the long transmission line through the remote Salang pass is quite exposed to Taliban attacks (as occurred in January 2016), resulting in significant power cuts in Kabul.

In any event, even in the absence of energy trade, how does a country decide what is the appropriate level of generation reserve, and what is the safe level of supply diversity? Indeed, in the case of transmission, achieving n-1 or even n-2 reliability involves significant additional costs. But few countries have provided a clear trade-off analysis between cost and additional reliability. Indeed, there is no reason why, in principle, an interconnector built to import electricity from some other country might not improve supply diversity, if the remaining generation is dependent upon imported fuel supply from other countries.

Economic analysis cannot provide the answer to what is the optimal level of supply security. However, economic analysis can inform the trade-offs that decision-makers must accept among options with different net benefits and energy-security risks.

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38 The construction of such an energy balance is described in Section 6.2 of the User Manual.

4 ECONOMIC RETURNS

4.1 The table of economic flows

The table of economic flows records:

- The costs of the interconnection, CAPEX and OPEX, and
- The incremental economic costs of additional (exported) energy in each country, minus the economic costs:
- Capacity benefits (in both countries, as arise from the sharing of reserves, which was the main benefit quantified in the economic analysis of the GCCIA);
- Reliability benefits (in the importing country);
- Avoided generation cost (in the importing country); and
- Incremental consumption (in the importing country, if imported energy reduces previously unserved energy),

from which result the net economic flows (row [41]) in Exhibit 1. Note the format of presentation, consistent with good spreadsheet practice: years in columns, and flows in rows.[39]

One must be careful not to double count. The calculation of capacity credits from the sharing of reserves depends on a comparison of the capacity expansion plans with and without the interconnection at the *same* level of reliability, so if one claims this capacity credit, one cannot also claim a benefit from reliability improvement.

Note that nowhere in this table of economic flows is there any mention of the price of power as may be negotiated between countries and reflected in a PPA. This is because the PPA price is neither an economic cost to the buyer, nor an economic benefit to the seller—rather it is a transfer price that simply moves money from one pocket (country) to another pocket (country). It is nevertheless a key part of the financial assessment. Pricing is taken up in the next section.

Similarly, nowhere in this table is there a mention of any transit fee that may be paid to a third country for the right of the interconnector to traverse its sovereign territory. Again this is a transfer payment (from the trading parties to the third country) that neither consumes nor generates an economic resource. But it too is important for the financial analysis, because the feasibility of the interconnection may depend on it.

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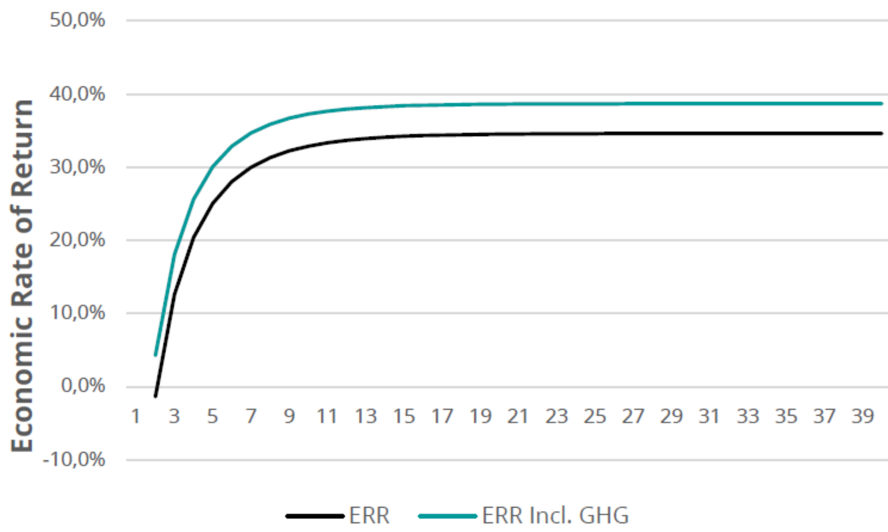
39 This is the universal convention in financial modeling, but for reasons unknown, one still finds the presentation of economic returns in a format in which the rows are years, and the columns the transactions. Such a format does not meet international best practice.

Exhibit 1: The Table of Economic Flows

30	Table of economic flows			1	Eygpt-Jordan 400kV 2nd circuit				TYPE 1 template: utilities		
					2018	2019	2020	2021	2022	2023	2024
				NPV	-3	-2	-1	0	1	2	3
[1]	**COSTS**										
[2]	Transmission & interconnection CAPEX		[$USm]	***-49,5***	-0,3	-24,0	-22,7	-14,4			
[3]	Less VAT & import duty on CAPEX		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[4]	Transmission & interconnection OPEX		[$USm]	***-10,5***	0,0	0,0	0,0	0,0	-1,0	-1,0	-1,0
[5]	***Incremental generation for export***										
[6]	**Egypt**	CCCT	[$US/kWh]		0,043	0,044	0,044	0,045	0,046	0,047	0,048
[7]	Generation		[GWh]						354	354	354
[8]	Cost		[$USm]	***-179,6***	0,0	0,0	0,0	0,0	-16,3	-16,6	-17,0
[9]	Incremental generation CAPEX		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[10]	**Jordan**	CCCT	[$US/kWh]		0,043	0,047	0,047	0,047	0,048	0,048	0,048
[11]	Generation		[GWh]						0	0	0
[12]	Cost		[$USm]	***0,0***	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[13]	Incremental generation CAPEX		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[14]	Total cost		[$USm]	***-239,6***	-0,3	-24,0	-22,7	-14,4	-17,3	-17,6	-18,0
[15]	**BENEFITS**										
[16]	***Capacity benefit from sharing of reserves***										
[17]	Egypt		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[18]	Jordan		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[19]	***Avoided capacity benefit importing country***										
[20]	Egypt		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[21]	Jordan		[$USm]	***0,0***	0,0	0,0	0,0	0,0			
[22]	***Reliability benefits***										
[23]	**Egypt**										
[24]	Value of lost load (VOLL)	0	[$US/kWh]		0,0	0,0	0,0	0,0	0,00	0,00	0,00
[25]	Energy outages reduced	0,000	[GWh]		0	0	0	0	0,00	0,00	0,00
[26]	Reliability benefit		[$USm]	***0,0***	0	0	0	0	0,00	0,00	0,00
[27]	**Jordan**										
[28]	Value of lost load (VOLL)	0	[$US/kWh]		0	0	0	0	0,00	0,00	0,00
[29]	Energy outages reduced	0,005	[GWh]		0	0	0	0	0,8	0,8	0,8
[30]	Reliability benefit		[$USm]	***0,0***	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[31]	***Avoided generation cost***										
[32]	**Egypt**	GT	[$US/kWh]		0,056	0,057	0,058	0,060	0,061	0,062	0,063
[33]	Generation		[GWh]		0	0	0	0	0	0	0
[34]	Avoided generation benefit		[$USm]	***0,0***	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[35]	**Jordan**	DHFO	[$US/kWh]		0,067	0,070	0,071	0,072	0,073	0,074	0,075
[36]	Generation		[GWh]		0	0	0	0	170	170	170
[37]	Avoided generation benefit		[$USm]	***128,3***	0,0	0,0	0,0	0,0	12,4	12,6	12,8
[38]	***Incremental consumption***										
[39]	**Egypt**		[GWh]		0	0	0	0	0	0	0
[40]	WTP	41	[$US/kWh]						0,212	0,215	0,218
[41]	Consumer benefit		[$USm]	***0,0***	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[42]	**Jordan**		[GWh]		0	0	0	0	158	158	158
[43]	WTP	38	[$US/kWh]						0,216	0,221	0,225
[44]	Consumer benefit		[$USm]	***376,2***	0,0	0,0	0,0	0,0	34,2	34,9	35,6
[45]	Total benefits		[$USm]	***504,5***	0,0	0,0	0,0	0,0	46,6	47,5	48,3
[46]	**Net economic flows**		**[$USm]**	***264,9***	**-0,3**	**-24,0**	**-22,7**	**-14,4**	**29,3**	**29,8**	**30,4**
[47]	ERR (before environmental benefits)		[ ]	***34,6%***							
[48]	**Environmental benefits**										
[49]	Avoided local health damage, net		[$USm]	***5,9***	0,0	0,0	0,0	0,0	0,3	0,3	0,3
[50]	Adjusted economic flows		[$USm]	***270,8***	-0,3	-24,0	-22,7	-14,4	29,6	30,2	30,7
[51]	ERR		[ ]	***34,9%***							
[52]	Avoided GHG emission damages World Bank Low		[$USm]	***63,1***	0,0	0,0	0,0	0,0	4,3	4,5	4,7
[53]	Economic flows including GHG emission benefits [Table 28]		[$USm]	***333,9***	-0,3	-24,0	-22,7	-14,4	34,0	34,7	35,4
[54]	ERR including environmental benefits		[ ]	***38,7%***						4,2%	
[55]	*Memo items*										
[56]	Deflator		[ ]		1,00	1,0	1,0	1,1	1,1	1,1	1,1
[57]	Economic flows [at constant prices]		[$USm]	***191,7***	-0,35	-23,6	-21,8	-13,6	27,5	27,4	27,4
[58]	ERR		[ ]	***32,4%***							
[59]	Economic flows incl.global benefits		[$USm]	***237,0***	-0,3	-23,6	-21,8	-13,6	31,5	31,6	31,6
[60]	ERR including environmental benefits		[ ]	***36,1%***							

Figure 24: ERR as a Function of Actual Project Life



4.2 Externalities

It is important that such calculations are presented transparently, which is best done as shown in Exhibit 2. The total local environmental externalities are shown in this exhibit as a benefit (row [49]), under the presumption that local air emissions decrease due to the most likely substitution of more efficient thermal generation for less efficient thermal generation, and that this benefit offsets the additional generation (derived from the more efficient projects) that follows from additional transmission losses.

Exhibit 2: Externalities

31 Externalities				1	Eygpt-Jordan 400kV 2nd circuit				TYPE 1 template: utilities		
					2018	2019	2020	2021	2022	2023	2024
	Technology	Values		NPV	-3	-2	-1	0	1	2	3
[1] **Global externalities [at constant prices]**											
[2] ***Incremental generation for export***											
[3] **Egypt**			[GWh]		0,00	0,00	0,00	0,00	353,54	353,54	353,54
[4] GHG emissions factor	CCCT	0,39	[kg/kWh]								
[5] Increased GHG emissions			[million tons]		0,00	0,00	0,00	0,00	0,14	0,14	0,14
[6] **Jordan**			[GWh]								
[7] GHG emissions factor	CCCT	0,39	[kg/kWh]								
[8] Increased GHG emissions			[million tons]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[9] ***Avoided generation***											
[10] **Egypt**			[GWh]								
[11] GHG emissions factor	GT	0,51	[kg/kWh]								
[12] Decreased GHG emissions			[million tons]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[13] **Jordan**			[GWh]		0,00	0,00	0,00	0,00	169,79	169,79	169,79
[14] GHG emissions	DHFO	0,75	[kg/kWh]								
[15] Decreased GHG emissions			[million tons]		0,00	0,00	0,00	0,00	-0,13	-0,13	-0,13
[16] ***Avoided self-generation***											
[17] **Egypt**			[GWh]								
[18] GHG emissions	DSG	0,83	[kg/kWh]								
[19] Decreases in GHG emissions			[million tons]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[20] **Jordan**			[GWh]		0,00	0,00	0,00	0,00	126,32	126,32	126,32
[21] GHG emissions	**DSG**	0,83	[kg/kWh]								
[22] Decreases in GHG emissions			[million tons]		0,00	0,00	0,00	0,00	-0,10	-0,10	-0,10
[23] Total change in GHG emissions			[million tons]		0,00	0,00	0,00	0,00	-0,10	-0,10	-0,10
[24] Social value of carbon	**World Bank Low**		[$/ton]		38,00	39,00	40,00	41,00	42,00	43,00	44,00
[25] Global GHG emissions benefit			***[$USm]***	45,3	0,00	0,00	0,00	0,00	4,02	4,12	4,21
[26] **Local air emission damage costs [at constant prices]**											
[27] ***Incremental generation for export***											
[28] **Egypt**			[GWh]		0,00	0,00	0,00	0,00	353,54	353,54	353,54
[29] Health damage cost	CCCT	0,10	[USc/kWh]								
[30] Escalated by per capita gdpgrowth		0,04	[USc/kWh]		0,10	0,10	0,11	0,11	0,12	0,12	0,13
[31] Damage cost			[$USm]	*-0,6*	0,00	0,00	0,00	0,00	-0,04	-0,04	-0,04
[32] **Jordan**			[GWh]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[33] Health damage cost	CCCT	0,10	[USc/kWh]								
[34] Escalated by per capita gdpgrowth		0,04	[USc/kWh]		0,10	0,10	0,11	0,11	0,12	0,12	0,13
[35] Damage cost			[$USm]	*0,0*	0,00	0,00	0,00	0,00	0,00	0,00	0,00
[36] ***Avoided generation***											
[37] **Egypt**			[GWh]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[38] Health damage cost	GT	0,12	[USc/kWh]								
[39] Escalated by per capita gdpgrowth			[USc/kWh]		0,12	0,12	0,12	0,12	0,12	0,12	0,12
[40] Damage cost			[$USm]	*0,0*	0,00	0,00	0,00	0,00	0,00	0,00	0,00
[41] **Jordan**			[GWh]		0,00	0,00	0,00	0,00	126,32	126,32	126,32
[42] Health damage cost	DHFO	0,20	[USc/kWh]								
[42] Escalated by per capita gdpgrowth		0,04	[USc/kWh]		0,20	0,21	0,22	0,22	0,23	0,24	0,25
[43] Avoided damage cost			[$USm]	*0,4*	0,00	0,00	0,00	0,00	0,03	0,03	0,03
[44] ***Avoided self-generation***											
[44] **Egypt**			[GWh]		0,00	0,00	0,00	0,00	0,00	0,00	0,00
[45] Health damage cost	DSG	2,00	[USc/kWh]								
[45] Escalated by per capita gdpgrowth		0,00	[USc/kWh]		2,00	2,00	2,00	2,00	2,00	2,00	2,00
[46] Avoided damage cost			[$USm]	*0,0*	0,00	0,00	0,00	0,00	0,00	0,00	0,00
[47] **Jordan**			[GWh]		0,00	0,00	0,00	0,00	126,32	126,32	126,32
[47] Health damage cost	DSG	2,00	[USc/kWh]								
[48] Escalated by per capita gdpgrowth		0,04	[USc/kWh]		2,00	2,08	2,16	2,25	2,34	2,43	2,53
[48] Avoided damage cost			[$USm]	*4,2*	0,00	0,00	0,00	0,00	0,30	0,31	0,32
[49] **Total avoided damage cost [benefit]**			***[$USm]***	4,1	0,00	0,00	0,00	0,00	0,28	0,30	0,31

5 PRICING AND SUBSIDIES

How traded electricity should be priced is not straightforward. The principles that apply depend on the nature of the trade. What may be suitable for an opportunistic trade may not necessarily be so where investment for an additional interconnector must be made. Moreover, what may be financially convenient and acceptable to both parties in an opportunistic trade may not necessarily be optimal from the perspectives of both governments, particularly when utility prices are distorted by subsidies on fuel prices or on tariffs.

The main point is that PPA prices determine how the economic and financial benefits are shared. Neither economic nor financial analysis can provide the definitive answer to what should be the optimal price for traded electricity. Even where prices are determined in open competitive markets (which is the economist's preferred mechanism on grounds of economic theory), as many countries with such market mechanisms have discovered, these can be manipulated to the detriment of consumers. This is particularly true of electricity markets, which are quite different to most traded commodities, because of issues with long lead time for investment, the difficulty (and still-high cost) of storage, and the complexities associated with ensuring adequacy of generation capacity. And although not a major problem in most pan-Arab countries, in countries where a significant portion of electricity is generated in multi-purpose hydro projects, hydro production is often subordinated to irrigation and flood-control objectives. Moreover, the most obvious market failure is that generation prices have rarely internalized externality costs, to the great detriment of renewable-energy generation.

5.1 Proposed pricing for the Pan-Arab region

The Proposed Pricing Rule

The report on pricing cross-border electricity trades[40] proposes that marginal production costs be calculated for different periods of the day and year, based on international fuel prices. Transactions would be based on a sharing of costs and benefits (cost in selling country + value in buying country, divided by 2). In emergencies, the price would be cost plus a fixed mark-up of, for example, 15 percent. The proposal also permits exchanges in kind, so if one country exported power during one period, the receiving country would return an equivalent amount of power, based on the value of the power in the different periods (see Box 7). All transactions would be based on the marginal production costs of the regional market facilitator.

All prices in this scheme would be based on the relevant economic netback costs (i.e., based on international prices, adjusted as illustrated in Table 2): In the vocabulary of economic analysis, the costs represent the incremental variable generation costs of the exporter, and the benefits are the avoided variable costs of the importer, both at economic prices.

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40 World Bank. 2017. *Pricing Cross-border Electricity in PAEM Transition Phase: Possible Regional Solutions to Scale up Electricity Trade* (November).

This procedure for equitable sharing of benefits is based on successful international precedents, but the difficulty is that the certainty of short-term marginal costs is inversely proportional to time—at time steps of hours and days, these can be readily calculated, and at the scale of weeks and months, or even seasons, reasonable estimates can be made. However, a PPA necessary to underpin a major investment project requires estimates over time periods that correspond to debt-service obligations, which could be many years, even for typical shorter-term commercial loans.

Box 7: Proposal for Power-Trade Pricing

Example 1: Normal Trade

- The regional market facilitator's published marginal production costs in Saudi Arabia for the upcoming summer period are $168/MWh in Saudi Arabia and $118/MWh in Bahrain.
- Saudi Arabia and Bahrain agree to enter into a bilateral contract for sale by Bahrain to Saudi Arabia of 100 MW during each hour of each day, in the period June 1 to August 31 (total of 92 days and 220,800 MWh).
- Saudi Arabia would pay Bahrain $143/MWh ((168 + 118)/2), or $343,200/day, or $31.57 million for the contract period (220,800 * 143).
- Bahrain would make a profit of $5.52 million, and Saudi Arabia would realize a savings of $5.52 million.

Example 2: Exchange-in-Kind

- The regional market facilitator's published marginal production costs for the GCC region are $123/MWh in high-load periods and $100/MWh in low-load periods.
- Saudi Arabia and Bahrain agree to enter into a bilateral exchange-in-kind contract. Bahrain agrees to deliver to Saudi Arabia 100 MW in each hour of each day (2,000 MWh/day) during the period June 1 to August 31 (total of 92 days and 220,800 MWh). Saudi Arabia agrees to deliver an exchange-in-kind to Bahrain during the period November 1 to January 31 (total of 92 days).
- The value of the energy delivered by Bahrain in the sub-regional market during the high-load period is $27.6 million. The value of the same amount of energy in the sub-regional market during the low-load period is $22.08 million. Therefore, Saudi Arabia would return to Bahrain 276,000 MWh during the period of November 1 to January 31 (or 3,000 MWh/day on average).

Example 3: Emergency transfer

- The regional market facilitator's published marginal production costs in Saudi Arabia for the upcoming summer period are $168/MWh in Saudi Arabia and $118/MWh in Bahrain.
- Bahrain experiences an emergency situation on its power system, owing to the sudden loss of a major generation facility.
- Bahrain estimates it will need emergency assistance of 200 MW for 10 hours to avoid involuntary load cuts.
- Bahrain contacts Saudi Arabia for emergency assistance, which Saudi Arabia agrees to provide. Saudi Arabia and Bahrain enter into a bilateral contract for 200 MW continuous for 10 hours between 8 a.m. and 6 p.m., for a total of 2,000 MWh.
- Saudi Arabia agrees to deliver to Bahrain 2,000 MWh at a mark-up of 15 percent over its high-load marginal production cost published by the regional market facilitator, or $193.2/MWh (168 * 1.15).
- At the conclusion of the contract, Bahrain pays Saudi Arabia $386,400.

Renewable Energy

In principle, there is no reason why the proposed pricing rule could not apply to opportunistic trade in blocks of renewable energy. The only difference is one of degree: Renewable energy has essentially zero marginal variable cost, and in the case of most photovoltaic production in the Gulf countries, is little affected by variable cloud cover, hence is much more predictable in its timing and magnitude than in many other regions of the world. With zero marginal cost in the exporting country, the recommended price would simply be 50 percent of the avoided economic cost of thermal generation in the importing country. However, it is not obvious why a country would wish to export energy of zero marginal cost, unless it has so overbuilt its variable renewable-energy capacity that no further domestic thermal capacity can be ramped down.

Indeed, in the absence of binding requirements to achieve particular levels of renewable-energy generation, a transmission interconnector investment project being enabled solely for the import of renewable energy seems unlikely. Most countries have only aspirational renewable-energy targets under the Paris climate-change accords, with provisos that these are dependent upon concessional finance. If country A has more expensive renewable energy than country B, then imports from B to A to meet A's *binding* targets would be justified, as illustrated in the examples provided in Section 3.1.8.

Many interconnectors have been built to evacuate large hydro-power from one country to another (such as the NT2 and Xayaburi projects in the Lao People's Democratic Republic evacuated to Thailand), but this is for dispatchable peaking power, unrelated to renewable-energy targets.

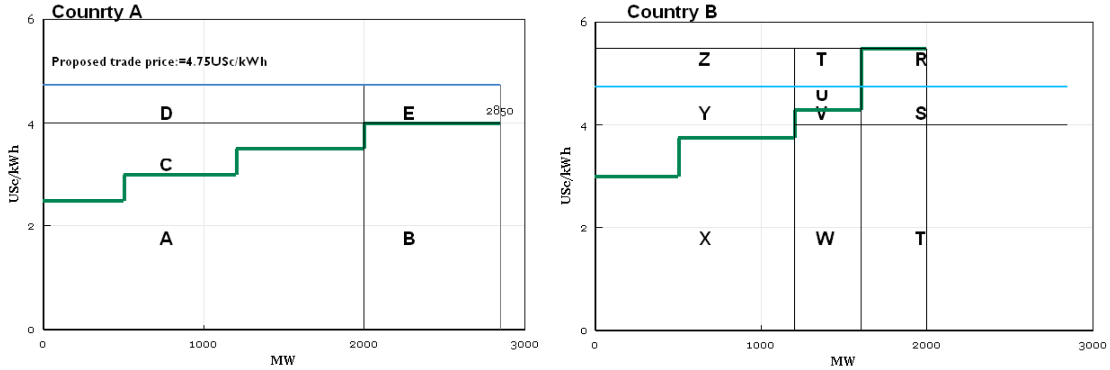
Ambitious proposals have been made for large-scale renewable-energy exports from the pan-Arab region to Europe, which would necessarily require large transmission investment. But such projects would be so large that no generalized pricing rule would apply; it would instead be negotiated on a project-by-project basis.

5.2 Exporting subsidies

Consider the supply curve for power generation in Country A, shown in Figure 25. The domestic demand in A is 2,000 MW, which intersects the (green) supply curve at USc 4/kWh, which is the marginal price. There are no subsidies, so the supply curve reflects economic prices**.** The net benefit is the producer surplus (area C), which calculates to $97.2 million. The average cost of production is USc 31/kWh. At this price, there is an additional 850 MW of unused capacity that could potentially be exported. However, exporting at the marginal price has little attraction, because the incremental benefit equals the incremental cost.

The supply curve of country B lies substantially above that of country A, and the average cost is USc 4.02/kWh. The marginal cost (the last step in the supply curve) is USc 5.5/kWh. It follows that the proposed trading price is the average of 4.0 and 5.5 = USc 4.75/kWh, shown as the blue line in this figure. Total costs in B in the absence of trade are $578 million.

Figure 25: Supply and Demand Curves, Without Trade[41]



Country A

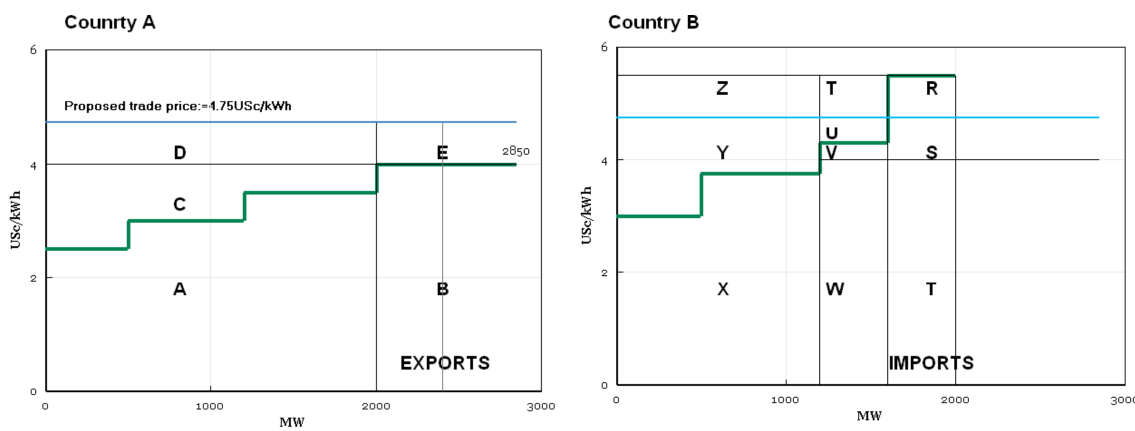
Demand	MW	2000
LF		0.6
Energy	GWh	10.5
Production cost	[$USm]	323.2
Producer surplus	[$USm]	97.2
total	[$USm]	420.5
average cost	[USc/kW	3.1
Potential exports	MW	850

Country B

Demand	MW	2000	
LF		0.6	
Energy	GWh	10.5	
Production cost	[$USm]	422.8	X+W+T+V+R+S
Producer surplus	[$USm]	155.3	T+U+Y+Z
total	[$USm]	578.2	
average cost	[$USc/kW	4.02	

Clearly, if B can import from A, costs will decrease. If the demand slab from 1,600 MW to 2,000 MW can be met by imports at USc 4.75/kWh, then in Figure 26, the net gain from exports is equal to area E, which is also equal to $15.8 million—a consequence of the pricing formula that shares costs and benefits equally.

Figure 26: Supply and Demand Curves, with 400 MW Traded from A to B



Country A

Demand	MW	2000	
LF		0.6	
Energy	TWh	10.5	
Production cost	[$USm]	323.2	A
Producer surplus	[$USm]	97.2	C
total	[$USm]	420.5	
average cost	[USc/kWh]	3.1	
Potential exports	MW	850	
Actual exports	MW	400	
	[TWh]	2.1	
Export revenue	[$USm]	99.9	E+B
Export costs	[$USm]	84.1	B
Net gain	[$USm]	15.8	E

Country B

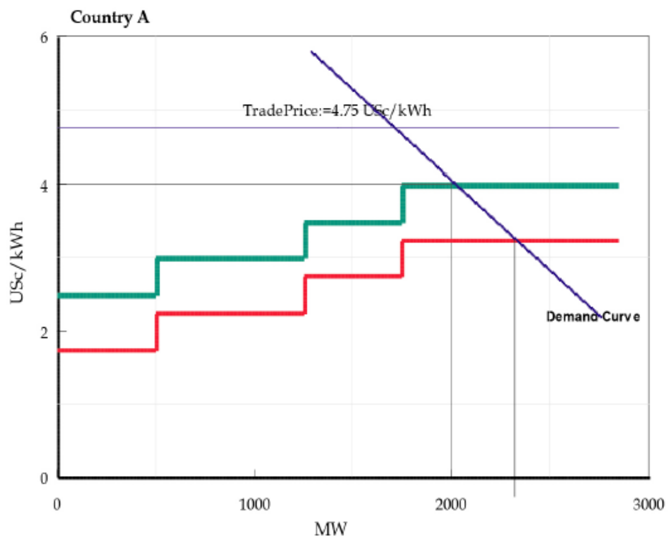
Demand	MW	2000	
LF		0.6	
Energy	TWh	10.5	
Production cost	[$USm]	422.8	X+W+T+V+R+S
Producer surplus	[$USm]	155.3	T+U+Y+Z
total	[$USm]	578.2	
average cost	[$USc/kV	4.0	
Net gain	[$USm]	15.8	R

41 See Section 2.7 for a definition of producer (and consumer) surplus. In Figure 12, the producer surplus is defined as area B.

The main obstacle to this scheme is that in some countries, gas prices for generators are highly subsidized, and dispatch decisions are made on the basis of marginal financial costs (i.e., the costs actually experienced by the utility), rather than the *economic* costs as may be determined by an outside party (such as a regional market facilitator). Therefore the question is the extent to which the proposed scheme can be implemented in the presence of subsidies.

In Figure 27 we assume that Country A subsidises gas (or electricity or both). The impact of the subsidy is to lower the supply curve, so the intersection with the demand curve occurs at a higher level of generation.

Figure 27: Impact of Subsidy on Demand



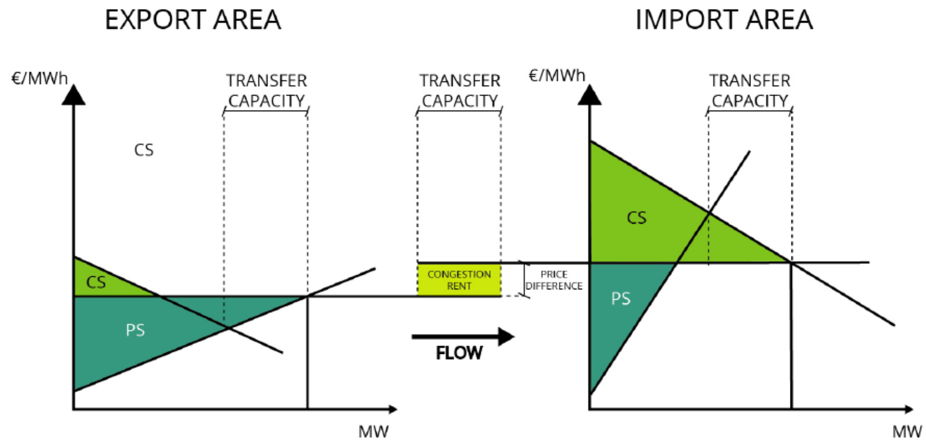
The first consequence of such a subsidy is a deadweight loss to society (for reasons explained above). At this price, the demand increases from 2,000 MW to 2,300 MW. Because the total available capacity in country A in this illustrative example is 2,750 MW, there would still be the ability to export 400 MW to country B, but one can see that, depending on the extent of the subsidy, the export potential in the potentially exporting but subsidized country may well be constrained.

Now if trade must occur at the USc 4.75/kWh price that is deemed to be the agreed-upon economic price, and if the spare capacity in A were in fact available, the trade will still occur. The revenue to the exporting utility would be unchanged. In Section 9, we discuss how the extent of subsidies can be calculated in practice, and how, if prices are not based on economic costs, subsidies can be exported.

5.3 Congestion rents

In European CBA practice for transmission interconnections between two market-based systems, the term *congestion rent* is used. This is defined as the MW value of the interconnection transfer multiplied by its marginal social value, calculated as the difference in economic price between the two markets (as illustrated in Figure 28).

Figure 28: Congestion Rents



Note: CS = consumer surplus; PS = producer surplus
Source: CESI. 2016. *Economic Analysis Complement for Tunisia-Italy Interconnection*, Report to the World Bank.

In the economic analysis required for an interconnection to the EU, these congestion rents are generally assumed to be shared equally—this is consistent with the pricing mechanism proposed by the World Bank, as discussed in Section 5.2.

5.4 Pricing for investment projects

The pan-Arab trade pricing proposal has no precedents in international practice—we know of no PPA in which the tariff schedule makes reference to marginal economic costs estimated by a third party. Importing and exporting countries typically agree on a tariff based on what is seen to be reasonable, equitable and profitable to both parties.

This is especially the case for projects for which there is no wheeling fee paid to a third party as the mechanism to recover CAPEX, because each country builds the transmission lines to its border crossing point. When a new interconnector is constructed, the investment made by each party may be quite unequal, so the traded price needs to reflect an equitable recovery of the investment costs of each party.

A further difficulty that is the difference in certainty of costs. That portion of the revenue requirements of each party accounted for by the interconnector CAPEX will be reasonably well known at the time of PPA signature (limited mainly by the generally relatively small uncertainty of price contingencies during construction), whereas the future variable cost (whether financial or economic) of generation is subject to much greater uncertainty.

One possibility is that the purchase price is structured as a two-part tariff: a capacity payment that reflects the incremental CAPEX expenditure of the two parties (incremental generation and transmission to the border for the exporting country; additional transmission from the border to the load center for the importing country), and an energy charge that is tied (in the case of the pan-Arab region) to the international gas price (for which a number of published markers would exist), or which would be determined by the same entity that determines the marginal economic prices in the present pan-Arab pricing proposal.

In the illustrations of the previous section, we see that the proposed pricing formula works well in cases in which opportunistic trades are possible by virtue of unused capacity. Any investment costs in the existing interconnections are sunk, and so play no role in determining the transaction price.

But now suppose the 400 MW of exports from A to B required an additional investment to cover the incremental generation plant needed for dedicated exports of 400 MW, as well as the costs of an additional interconnector, which, for the sake of argument, we may suppose totals USc 3/kWh (levelized over 20 years). This results in an additional $63 million, which exceeds the benefits of the energy trade. In this case, if country A has to incur capital costs, and both countries incur the cost of an additional interconnector, this investment would be uneconomical.

That changes if country B would also have to build an additional generating plant in order to meet its (future) demand. In that case, if the incremental CAPEX is limited to the transmission interconnector, then the incremental CAPEX is limited to USc 1/kWh, or $21 million. This would be subtracted from the previously calculated net benefit of $31.8 million, for a net benefit of $10.8 million; thus the investment would be economical.

In the Template, the calculations are based on net present values—instead of just sharing the variable costs and benefits of generation, we also take into account the various capacity consequences (as explained in Section 3.4, and in the User Manual), which because of timing issues are best calculated as net present values rather than levelized costs. Although this is not a simple calculation, and although the NPV calculations are inevitably affected by the choice of discount rate, the experience of the GCCIA shows that using NPVs as a basis (in that case derived from a complex generation-expansion planning model) is practical as well as rigorous.[42]

In short, for opportunistic electricity trades using existing interconnectors and generating plants, the proposed pricing formula provides a robust and equitable basis for setting prices. However, for investment projects setting transaction prices on the basis of equitable sharing of costs and benefits, NPVs are the recommended approach. Section 6.9 of the User Manual explains how the calculations for the transaction price are set up in the Template.

5.5 Wheeling fees

For projects involving an SPV, a wheeling fee would need to be paid to the SPV for it to recover the capital costs of constructing the interconnector, to cover OPEX, and to provide a return on equity. Its calculation is straightforward, and the Template has been designed to provide two approaches: The first is to fix a tariff and calculate the FIRR; the second is to calculate the tariff given some target FIRR. In practice, if the project is

[42] Indeed, even if one were to express fixed costs as levelized costs denominated in USc/kWh, one would still need to choose a discount rate.

to be competitively bid, most likely the bidders would bid for a wheeling-fee price (and the actual FIRR would not necessarily be known).

One also needs to decide in what proportion the trading parties share the wheeling fee. The starting point should again be an equal sharing of the costs, as for the price of traded power; however, the Template also allows this to be set by the user. Similar considerations also apply to the allocation of the technical losses in the interconnection facility: What is exported *into* the interconnector will not be the same as what is imported *from* the interconnector.

But in the case, for example, of the Egypt-to-Jordan interconnection, which involves a submarine cable between the substations in Egypt and Jordan, how the losses are shared requires more explicit treatment (and must be fixed, in advance, in the PPA). An obvious proposal is that the quantity traded be fixed at the average of the input and output meters (which is the default provision in the Template).

Box 8: Examples of Wheeling-Charge Structures

Transmission Line for Power Evacuation From the 400-MW Lower Sesan 2 Hydro Project, Cambodia
This 2 x 230 kV transmission line was built by an SPV that is a wholly owned subsidiary of the Malaysian company Pestech, under a 25-year build-own-operate-transfer (BOOT) project with the Cambodian state-owned power utility Electricite de Cambodge. The wheeling charge is structured as a fixed payment of $12.2 million for the first three years, followed by a payment of $18.2 million for the remaining 22 years.

Wheeling Charges Under Open-Access Provisions in Maharashtra (India)
Wheeling fee for long-term access is denominated as Rs/kW/month (Rs 239.88/kW in fiscal year 2017-2018 ($3.67/kW), increasing to Rs 242.08/kW/month in fiscal year 2019-2020 ($3.71/kW)). A transfer of 100 MW throughout the year therefore incurs a wheeling charge of ~$4.4 million.

Short-term transfers and renewable energy are charged per kWh, at a rate of Rs 0.32/kWh in fiscal year 2017-2018, increasing to Rs 0.34/kWh in fiscal year 2018-2019 (USc 0.49/kWh).

6 PRINCIPLES OF FINANCIAL ANALYSIS

6.1 Financing Projects

Financing projects has many dimensions about which decisions have to be made. Many potential projects have large economic benefits, but their realization is dependent upon the ability to create a financial structure that enables capital mobilization and is sustainable over the lifetime of a transmission project.

The proposal for an interconnection between Saudi Arabia and the Republic of Yemen is an excellent example: The technical challenges are modest, and the economic benefits are very large, but its realization depends primarily on the extent to which the risks can be sufficiently mitigated (or willingly assumed) by potential parties to the project.

- **A viable technical design—**In the case of transmission projects, this is rarely a major issue (the main issue being the extent to which new technologies, such as multi-terminal HVDC, are commercial).
- **The institutional and legal basis—**What entity will design, build, own and operate a proposed interconnection project, and with what legal underpinning?
- **The capital structure—**Those who contribute to the debt and equity of a project are its financial stakeholders. The capital structure also affects the financial cost of a project—a project financed entirely with private equity and commercial debt will cost more than a utility project financed with concessional finance from IFIs.
- **Risk allocation and mitigation—**The most important point is that many (but by no means all) risk-mitigation measures to protect one stakeholder invariably impose a cost on another—insurance is never free, and stakeholders who assume higher risk will require higher returns. Risks should be allocated to the parties that are best placed to manage them.

Institutional and Legal Basis

Section 1.2 has already described the distinction between projects implemented by utilities (with each country building the interconnection to the border-crossing point) and projects implemented by an SPV operating across borders (such as the GCCIA). But even SPVs can take a multitude of different forms, and there are many ways for utilities to implement projects.

The single most important issue in financial project design is the degree of recourse lenders have against the project owner. For example, a utility may choose to implement a project under various models:

- No ring-fencing of accounts; the project is just one of many that fall under the jurisdiction of its transmission department;
- Creation of an internal business unit, with better transparency for financial management; and
- Creation of an SPV, either as a wholly owned or partially owned subsidiary, which ring-fences accounts and offers the best transparency.

However, even if organized as a subsidiary, this does not provide a shield against a failure to meet debt-service obligations—lenders will require recourse to the balance sheet of the parent company, or in the case of IFI lending to a state-owned utility, will require a sovereign guarantee from the government.

In a so-called "project finance" (or "non-recourse") financing, lenders have no recourse to the balance sheets of owners. Although formal definitions of project finance vary, the essential point is that the repayment of the loan is limited to the assets of the project and its revenue stream. In such a case, the creditworthiness of the buyer (or the entity that pays the wheeling fee necessary to meet the revenue requirements) will largely determine the feasibility of such a financing. There are few examples of purely private transmission projects in developing countries, and those that as do exist benefit from a government guarantee (such as the Cambodia project; see Box 8).

Capital Structure

The two extremes are easily formulated (Figure 29). A purely private project has only private equity, and only commercial debt. This may come in several tranches, and may involve syndication. The tranches of debt may have different levels of security. What is sometimes termed "senior debt" has the highest degree of security, meaning that in any project liquidation, these debtors must be fully paid out before all other claimants. Next would be "junior" (or "mezzanine") debt, whose holders in turn must be fully paid out before equity holders.[43] Senior debt has the lowest risk, and therefore commands the lowest interest rate; equity has the highest risk, and therefore requires the highest return. Note that the capital structures shown here are purely illustrative; the allocated percentages may vary considerably from case to case.

The traditional utility financing model has equity provided by the utility itself (through net internal cash generation); it is also sometimes augmented by direct equity contributions from a government. Creditworthy utilities may in turn raise funds for capital investment through bond issues and/or commercial borrowing. Typically in the case of regional transmission projects, the debt has been provided by IFIs such as the World Bank, secured through sovereign guarantees.

However, for two reasons the traditional utility-finance model has come under pressure. The first is limited headroom for sovereign guarantees, with ministries of finance increasingly reluctant to provide these to state-owned utilities. Second, the supply of concessionary finance is coming under pressure, as the resources of the IFIs are being shifted to other sectors.

This has led to the increasing use of private-public-partnerships (PPPs). As suggested by Figure 29, their capital structures may be quite complicated. The equity participation may include the private-sector arm of the IFIs (in the case of the World Bank group, the International Finance Corporation [IFC]), outright grants, or direct infusions of

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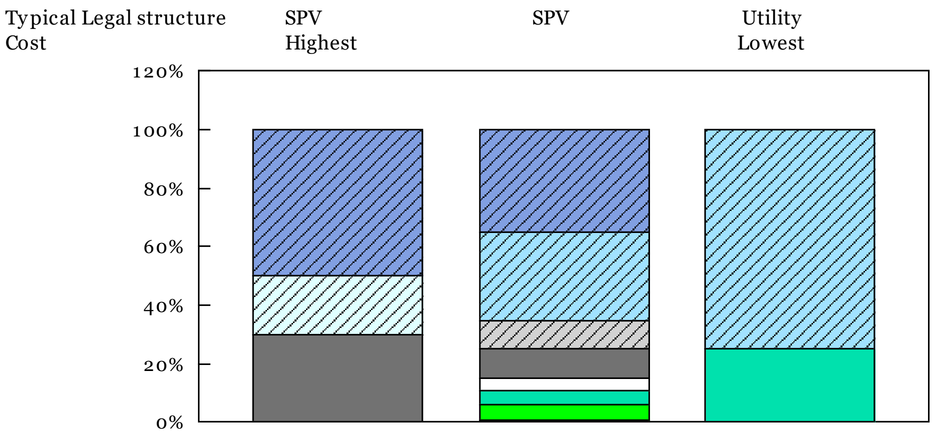
43 So called "quasi-equity" (sometimes called a revenue-participation agreement) is another intermediate form of financing that stands between equity and debt. Quasi-equity financing involves tailor-made repayment terms, with a typical duration of two to eight years. Commonly, no principal repayment is required for the first year or two. Options can also include balloon payments (repaying the entire loan at the end of the term) and cash-flow sweeps (partial repayments when extra funds are available).

equity from governments. On the debt side, lenders may include commercial lenders, bilateral lenders and entities such as the Arab Fund, as well as one or more IFIs. Commercial debt may also be secured by partial risk guarantees (PRGs) provided by the World Bank Group.

Figure 29: Illustrative Capital Structures



	Private	PPP	Traditional utility
Grants		1%	
Govt Equity		5%	
Utility equity		5%	25%
IFI Equity		4%	
Private equity	30%	10%	
Junior debt	20%		
Bilateral debt		10%	
IFI debt		30%	75%
Commercial	50%	35%	

This has led to the increasing use of private-public-partnerships (PPPs). As suggested by Figure 29, their capital structures may be quite complicated. The equity participation may include the private-sector arm of the IFIs (in the case of the World Bank group, the International Finance Corporation [IFC]), outright grants, or direct infusions of equity from governments. On the debt side, lenders may include commercial lenders, bilateral lenders and entities such as the Arab Fund, as well as one or more IFIs. Commercial debt may also be secured by partial risk guarantees (PRGs) provided by the World Bank Group.

There are several advantages to PPPs compared to wholly private projects. First, the participation of the IFIs, even if only in the provision of PRGs, provides additional comfort to lenders, allowing commercial debt to be offered at a lower interest rate and over longer tenors.[44] In some cases, commercial debt cannot be mobilized at all if IFI guarantees are not in place. Second, the participation of IFIs provides additional comfort to equity holders through diversification of risk and the technical and financial know-how that IFIs bring to the table.

44 The reduction in interest rate on the commercial debt will be greater than the "service charge" of the typical PRG.

Box 9: Institutional Arrangements and Capital Structure for the Nepal-India Transmission Project

The project has two main components: a 400-kV line between Muzaffapur in India and Dhalkebar in Nepal, with each county responsible for financing the line in its territory; and, entirely in Nepal, a line from Hetauda via Dhalkebar to Duhabi (as the first phase of a 400-kV east-west backbone in Nepal).(see Figure 22)

The main-cross-border line between India and Nepal will be constructed and owned by two SPVs, one in each country, with equity composition as follows:

- The Indian portion of the project would be owned by an SPV called Crossborder Power Transmission Company Private Limited (CPTC). This is a joint venture comprising POWERGRID (26 percent); Sutlej Jal Vidyut Nigam Ltd (SJVNL) (26 percent); and Infrastructure Leasing and Finance Services (IL&FS) (48 percent). A 10-percent share for NEA (with a concomitant reduction in IL&FS' shareholding) is under consideration.
- The SPV to own the Nepal portion of the cross-border transmission line is called Power Transmission Company Nepal Limited (PTCN) and is also a joint venture. The current shareholders are NEA (50 percent); and IL&FS (50 percent). POWERGRID has received its board's authorization to take up to 26-percent equity in PTCN (with a concomitant reduction in IL&FS' shareholding).

The financing plan, as presented in the World Bank appraisal report (Table B9.1); assumes that the main transmission line is based on an equity-to-debt ratio of 30:70. The debt is seen to be a mix of commercial borrowing, lines of credit from the government of India, and the World Bank Group's International Development Association (IDA).

Table B9.1: Financing Plan

Financing Plan	Muzaffarpur-Sursand line (India Portion of D-M line)	Dhalkebar-Bhittamod line (Nepal Portion of D-M line)	Hetauda-Dhalkebar-Duhabi line	Total
Equity Financing				
IL&FS	3.74	0.62	0.00	4.36
POWERGRID	2.56	1.62	0.00	4.18
NEA	0.98	3.98	29.75	34.71
Sutlej Jal Vidyut Nigam Ltd (SJVNL)	2.56	0.00	0.00	2.56
Others-Nepal FIs / Banks	0.00	0.00	0.00	0.00
Total Equity Financing	**9.85**	**6.21**	**29.75**	**45.81**
Debt Financing				
Commercial Borrowing	22.98	1.30	0.00	24.27
Line of Credit from Government of India	0.00	13.20	0.00	13.20
Proposed IDA Credit	0.00	0.00	99.00	99.00
On-Going Power Development Project			20.00	20.00
Total Debt Financing	**22.98**	**14.50**	**119.00**	**156.47**
Total Financing	**32.82**	**20.71**	**148.75**	**202.28**

The potential downside from the perspective of private equity is the need to comply with IFI safeguard policies, which may be seen as onerous (and time-consuming).[45]

In some countries, the ability to structure SPVs with more than one category of shareholders may be limited. In others the returns required by government- or state-owned utilities to be lower than those of private equity (in order to keep financing costs as low as possible in the interest of consumers).[46]

The financing plan for a PPP involving several countries can be complex. For example, the India-Nepal transmission project involves two SPVs, one for each country (see Box 9), with a mix of private and public equity.

6.2 Project vs. equity returns

Traditional World Bank practice has been for the economic analysis to be accompanied by a so-called "project" financial analysis, with the calculation of a "project FIRR." Taxes and duties and other transfer payments excluded in the economic costs are added back in, and the resulting financial return compared to the weighted average cost of capital (WACC). If the FIRR is greater than WACC, a project is deemed financially feasible. Both the FIRR and the WACC were calculated at constant prices.

This may have been useful when almost all power-sector projects were in the hands of a vertically integrated, state-owned utility, and where, in effect, financing was on the balance sheet of this entity, and for which a utility-wide WACC calculation was relevant. It has also been argued that this avoids setting out the details of financing, which may not be fully known at the time of project appraisal. Thus much of the emphasis in financial analysis of power-sector projects was (and still is) on the financial condition of the *borrower*; in reality, the project FIRR at constant prices commanded little attention.

This approach has diminishing relevance today. Many power-sector projects are implemented as PPPs, whose financing is essentially on a project-finance basis, and whose financial acceptability to private investors is based on actual expected and nominal cash flows. The financial structure of such projects is integral to the SPVs that

45 The cost of compliance with the World Bank's safeguards policies in the India-Nepal transmission line is $15million, with the following policies being triggered:

Safeguard Policies Triggered by the Project	Yes	No
Environmental Assessment (OP/BP 4.01)	X	
Natural Habitats (OP/BP 4.04)	X	
Pest Management (OP 4.09)		X
Physical Cultural Resources (OP/BP 4.11)	X	
Involuntary Resettlement (OP/BP 4.12)	X	
Indigenous Peoples (OP/BP 4.10)	X	
Forests (OP/BP 4.36)	X	
Safety of Dams (OP/BP 4.37)		X
Projects in Disputed Areas (OP/BP 7.60)*		X
Projects on International Waterways (OP/BP 7.50)		X

46 This is not a practice encouraged by the World Bank or by economists—when utilities invest in subsidiaries, they should be required to earn a sufficient return to enable them to establish their own creditworthiness (bond rating) and improve their self-financing ratios.

are created to develop and implement projects. In any event, the WACC calculation does not take into account loan tenors, which are central to the determination of cash flows, and to the debt service cover ratio (DSCR). The present version of the Template provides for calculation of the equity return on any SPV proposed to finance an interconnection for power trade.

6.3 Nominal vs. constant prices

The traditional calculation of "project financial return" of past World Bank and ADB practice is presented at constant prices, the rationale being to exclude the impacts of inflation. However, as soon as the actual financial structure of an SPV is considered, because debt-service payments are expressed in nominal terms, conversion of these to constant prices also requires assumptions about inflation, so one might as well use nominal prices throughout, with explicit assumptions about domestic and U.S.-dollar inflation (which is how a private-sector entity assesses a project anyway). Moreover, foreign-exchange risks can only be properly assessed under explicit assumptions about local currency-exchange rates.

For these reasons, the financial analysis is presented in nominal terms, with explicit assumptions for currency-exchange rates.

6.4 Taxes

Three main types of taxes require consideration:

- Corporate income tax (CIT),
- Import duty on imported equipment, and
- Value added tax (VAT).

The main issue is the extent to which taxes are recoverable, and can be excluded from the financial analysis of the SPV. (As noted above, all taxes are excluded from the economic analysis.)

CIT presents no difficulties—it is not recoverable, and therefore constitutes an incremental financial cost. In the Template, one selects the corporate income-tax rate, if any, that may be levied on the SPV in {SPV:Table 10}. Similarly, import duties, if levied, are not recoverable, and should therefore be included in the CAPEX recorded in the financial analysis.

Past treatment of VAT in financial analysis is often inconsistent. VAT is a recoverable tax—that is to say, whatever VAT an SPV pays on *inputs*, is recoverable from the VAT charged, collected, and remitted to government on its *outputs*. Therefore, VAT paid on domestic equipment for a proposed project is *not* an incremental cost, because it can be deducted from the VAT paid on the output[47], and, in principle, does not need to be included in the financial analysis.

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47 Indeed many authorities state categorically that financial analysis should *exclude* VAT. For example, the EU guide on cost-benefit analysis (European Commission, *Guide to Cost-Benefit Analysis of Investment Projects*, December 2014) states: "The analysis should be carried out net

Nevertheless, even if recoverable, VAT is part of the total investment outlay that has to be paid for and needs to be funded; the additional (capitalized) interest during construction (IDC) that is payable on such VAT is *not* recoverable. Therefore, in the table of incremental cash flows, VAT transactions should be given separate line items. A conservative approach would be to assume a one-year lag between VAT on the domestic component of investment inputs, and its recovery from VAT levied on the SPV's transactions.

6.5 Contingencies

We recommend that the World Bank (and ADB) practice of distinguishing between *physical* and *price* contingencies be followed. Contingencies need to be differentiated between so-called "physical contingencies"— which reflect uncertainties in unit quantities of goods, or uncertainties in unit costs—and "price contingencies," which reflect uncertainties attributable to inflation. Financial costs include both; economic costs (if stated at constant prices) include only *physical* contingencies.

6.6 Power-Purchase Agreements

A major project to enable international power trade requires a PPA to be bankable. Some key provisions of such agreements need to be simulated by the Template, so that they can be tested during PPA negotiations.

Delivery Point

The delivery point is not necessarily the same as the metering point(s). Most often, the delivery point is defined as the location where the transmission assets intersect the international boundary. Each party will meter electricity at the substations at either end of the line. The quantity invoiced therefore needs to be defined on the basis of some formula for the allocation of transmission losses between the parties.

Quantities and Price

A typical PPA (typically in an article that sets out the obligations of the parties) will specify some annual target GWh to be transferred (which may change over time), with an upper bound on MW. This volume may vary within some defined range, with volumes above and below this range being subject to a different price. Some of the details on daily limits and the share of energy to be delivered during peak hours are important for the PPA, but are unlikely to affect the calculations of the economic and financial analysis, whose time step is normally annual.

Loss Allocation

It does not necessarily follow that transmission losses in the interconnector should be shared equally. Indeed one common arrangement is that the quantity of losses is calculated as the difference between the meter readings at the exporting and importing substations, and that these would then be allocated on the basis of the distance between

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of VAT, both on purchase (cost) and sales (revenues), if this is recoverable by the project promoter. [Only] when VAT is not recoverable, it must be included."

the delivery point and the two meters at each end, subject to other adjustments if the technical characteristics of the line on either side of the border differ[48] (see Box 10 for an example).

Box 10: Key Provisions of the Turkmenistan-Afghanistan PPA

This agreement, signed in 2015, governs the export of 300 MW of gas-generated power in Turkmenistan to Afghanistan, across a 500-kV transmission line that connects the Atamurat substation in Turkmenistan to the Andkhoi substation in Afghanistan (financed by the ADB). The parties to the PPA are the respective state-owned power companies—Turkmenenergo and Da Afghanistan Breshna Sherkat —and endorsed by the respective Ministries of Energy.

Delivery Point

This is defined as the physical location where the transmission assets intersect the international boundary between Afghanistan and Turkmenistan. The metering points are the two substations (Atamurat and Andkhoi).

Quantity

The agreed-upon energy volume, calculated at the delivery point, was 899 GWh in 2018, increasing to 1,515 GWh by 2027. Annual energy delivered that is greater than 120 percent of the contracted quantity, or less than 80 percent of the contracted quantity, is defined as "unscheduled energy" and subject to a premium or discount payment, unless the unscheduled energy results from a force majeure or curtailment event. The demand shall not exceed 300 MW.[49] The premium to be paid for such unscheduled energy is not stated in the PPA.

Price

The base price is USc 5/kWh as of the year of signature (2015), increasing by three percent per year (USc 5.56/kWh in the first year of operation, 2018), increasing to USc 7.13/kWh in 2027.

Losses

The signed PPA is vague about the allocation of losses, stating only that it shall be allocated on the basis of the "resistance and line length upon completion of construction." The draft proposed that losses to each party should be based on the share of the line length between the delivery point and the respective substations.

The invoiced amount will be the reading at the Turkmenistan substation minus the looses allocated to Turkmenenergo. Because the distance from Atamurat and the delivery point is 300 km, and that from the delivery point to Andkhoi is 50 km, the proposed share of losses assigned to Turkmenistan was 300 / 350 = 85.7 percent. Evidently the parties agreed to settle this once the line had been built, and the final lengths and conductor characteristics were known.

Penalties for Failure to Meet the Agreed-Upon Commercial Operations Date

If either party fails to meet the stipulated commercial operations date (COD), it shall pay $8,000 per day for up to three months to the other party. This is related to the timely completion of the transmission line itself, which is not discussed in the PPA.

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48 For example, differences in the grid codes, and minimum conductor requirements, were an issue in the design of the interconnection between the Xekamen 1 hydro project in the Lao People's Democratic Republic and the 500-kV Pleiku substation in Vietnam.

49 The load factor of the line therefore calculates to 34 percent in 2018, increasing to 58 percent in 2027.

Box 11: Partial Risk Guarantees

World Bank guarantees catalyze private financial flows to developing countries by mitigating critical government performance risks that the private financiers are reluctant to assume. Guarantees cover private debt against a government's (or government entity's) failure to meet specific obligations to a private or public project.

PRG basic facts: PRGs cover private lenders, or investors through shareholder loans, against the risk of a government (or government-owned entity) failing to perform its contractual obligations with respect to a private project. World Bank PRGs are available for all countries eligible for International Bank for Reconstruction and Development (IBRD) loans. PRGs can be used for any commercial debt instruments (loans, bonds) provided by any private institution, including debt provided by sponsors in the form of shareholder loans. PRGs can cover both foreign-currency and local-currency debt.

Coverage: PRGs typically cover some part of the total outstanding principal and accrued interest of a debt tranche. The typical leverage is about 1.6, meaning that a debt of $160 million would need to be covered by a $100-million guarantee, and can cover extended maturities necessary to make the project financially viable.

Fees: Currently the following fees are payable by private project sponsors (or the project company) to the World Bank:

- *Front-End Fee*: A one-time fee of 0.25 percent on the amount of the guarantee;
- *Initiation Fee*: A one-time fee of 0.15 percent on the amount of the guarantee, or a minimum of $100,000;
- *Processing Fee*: A one-time fee of up to 0.5 percent on the amount of the guarantee; and
- *Guarantee Fee*: A fee of 0.3 percent per annum on the disbursed and outstanding guarantee amount.

Impact on commercial debt terms: Typically commercial lenders will provide longer tenors (two to three years longer than normal) and lower interest rates (one to two percent lower) on loans guaranteed by a PRG.

Treatment in the model: Front-end fee, initiation fee and processing fees (as defined above) are aggregated and treated as a single "front-end fee," assumed payable at financial closure, and expressed as a percentage. As the principal is paid down, the annual guarantee fee decreases. The PRG calculations, if any, are provided in the Template at the bottom of {SPV:Table 16}: it is assumed that the loan that is guaranteed is loan #2.

Source: http://siteresources.worldbank.org/INTGUARANTEES/Resources/IBRD_PRG.pdf

In the case of opportunistic trades in an established power pool such as the GCCIA, trades are agreed on the basis of a given amount, adjusted on an agreed loss rate, subject to real-time adjustment to be reconciled in the next settlement period. So if country A wishes to buy 100 MW from country B, the trade volume (by the seller) is set at 100 + X (where X is the estimated loss rate set by GCCIA), and payment of (100 + X) P is made (where P is the agreed-upon transaction price). Any post-trade reconciliation, once the actual real-time monitored X is known, will be made in the next (weekly) settlement period.

At first glance, this might suggest that losses are assumed by the buyer, who pays for 100 + X. However, because GCCIA does not (yet) set trading prices, the agreed-upon price is whatever the parties to the trade consider equitable, without a formal allocation of losses. In other words, only if the marginal generation prices are *imposed* on buyer and seller under an agreed-upon regional pricing mechanism, is a formal calculation of losses and their allocation required.

7 FINANCIAL ASSESSMENT

7.1 Overview

The financial assessment of a proposed transmission line to facilitate electricity trade has two main components:

- Analysis of the financial flows of the power companies (and governments) that participate in the trade, and
- Analysis of the financial flows involving any SPV that is created to own, build and operate the transmission interconnection.

The financial analysis is dominated by several important assumptions:

- The **transaction price**, which is the remuneration paid by the importing party to the exporting party. This has been discussed in Section 5.3. In the case of investment projects, this price will be set out in the PPA, typically codified in a schedule to the PPA. The PPA also defines any formulae for indexing, and how deviations from agreed amounts to are settled.
- Where an SPV has been created to implement the interconnector, there is a **wheeling fee**. This fee is the mechanism by which the SPV secures sufficient revenue to meet its obligations to build and operate the interconnector (the so-called revenue requirements), which include debt service, OPEX, and some agreed-upon equity return to the partiers that contribute to the equity of the SPV.
- Where an interconnector crosses the territory of a third (or subsequent) country, a **transit fee** is paid to the third country for the privilege of crossing its territory. As noted in Section 1.4, this is in addition to the actual costs of construction (or any payments for the relocation and resettlement of project-affected persons) of the interconnector in the territory of that third country.

7.2 Financial Assessment

The financial assessment examines the cash flows experienced by each stakeholder, and is likely to include the following:

- The power utilities in importing and exporting countries;
- Consumers of electricity;
- Governments (which collect taxes and provide subsidies);
- Transit countries;
- Any SPVs established by the trading parties (see Section 7.3);
- Banks (commercial, bilateral donors and/or IFIs, as the case may be);
- Providers of guarantees; and
- Private investors.

The necessary information can be assembled in many different formats. In the economic and financial analysis Template, the information is organized in two main sections, one for each country involved in the investment project. Exhibit 3 shows a typical country tabulation of financial costs. This table is generated by the Template for general use; for any particular proposal, different rows may have zero values. In this example, an SPV is used to build and operate the interconnection, so the CAPEX and OPEX of the interconnection are recovered by the wheeling fee to the SPV (whose revenue requirements would be assessed in the SPV financial model), rather than shown under "interconnection investment."[50]

Exhibit 3: Financial Assessment (SPV Builds Interconnector)

24	Financial Assessment, Country A				Egypt	1	Eygpt-Jordan 400kV 2nd circuit				TYPE 1 template: utilities	
					2018	2019	2020	2021	2022	2023	2024	2025
				NPV	-3	-2	-1	0	1	2	3	4
[1]	**COST**											
[2]	***Incremental generation cost (for exports)***											
[3]	Generation cost		[USc/kWh]		3,28	3,28	3,28	3,28	3,28	3,28	3,28	3,28
[4]	Generation		[GWh]						354	354	354	354
[5]	Generation cost		[$USm]	*101,7*	0	0	0	0	11,6	11,6	11,6	11,6
[6]	Incremental generation capex		[$USm]	*0,0*	0	0	0	0				
[7]	***Interconnection cost [wheeling fee][if type 2]***		[$USm]	*0,0*	0	0	0	0	0,0	0,0	0,0	0,0
[8]	Egypt share	0,00	[$USm]	*0,0*	0	0	0	0	0,0	0,0	0,0	0,0
[9]	***Direct inter-connection investment to border [if type 1]***											
[10]	Capex		[$USm]	*43,8*	0,0	22,5	19,9	11,9				
[11]	Loan disbursements		[$USm]	*-35,1*	0,0	-18,0	-15,9	-9,5				
[12]	Equity		[$USm]	*-8,8*	0,0	-4,5	-4,0	-2,4				
[13]	Repayment of principal		[$USm]	*13,6*	0,0	0,0	0,0	0,0	1,7	1,7	1,7	1,7
[14]	Interest		[$USm]	*11,1*	0,0	0,4	1,0	1,5	1,7	1,6	1,6	1,5
[15]	Commitment fee (if not capitalised)		[$USm]	*0,1*	0,0	0,1	0,0	0,0				
[16]	Opex		[$USm]	*8,3*	0,0	0,0	0,0	0,0	0,8	0,8	0,8	0,8
[17]	**Total direct transmission investment**		**[$USm]**	*33,2*	**0,0**	**0,4**	**1,1**	**1,6**	**4,2**	**4,2**	**4,1**	**4,0**
[18]	***Avoided utility generation costs***											
[19]	Ppa price imports		[USc/kWh]						0,0	0,0	0,0	0,0
[20]	Nominal volume imported at s/s	**Aqaba**	[GWh]						0,0	0,0	0,0	0,0
[21]	Egypt share of losses	**0,6**	[GWh]						0,0	0,0	0,0	0,0
[22]	Gwh		[GWh]						0,0	0,0	0,0	0,0
[23]	**Net cost of imports**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[24]	**Total costs**		**[$USm]**	*135*	**0**	**0**	**1**	**2**	**15,8**	**15,8**	**15,7**	**15,6**
[25]	**BENEFITS**											
[26]	***Exports***											
[27]	Export price escalation	1,000	[ ]						1,000	1,000	1,000	1,000
[28]	Ppa price exports	1,00	[USc/kWh]						6,06	6,06	6,06	6,06
[29]	Nominal volume sold at s/s	Taba	[GWh]						350	350	350	350
[30]	Egypt share of losses	**0,6**	[GWh]						-4,2	-4,2	-4,2	-4,2
[31]	Net sales (at notional delivery point)		[GWh]						345,8	345,8	345,8	345,8
[32]	**Net export revenue**		**[$USm]**	*183,7*	**0,0**	**0,0**	**0,0**	**0,0**	**21,0**	**21,0**	**21,0**	**21,0**
[33]	***Avoided utility generation costs***											
[34]	Avoided generation cost		[USc/kWh]						4,32	4,32	4,32	4,32
[35]	Avoided generation		[GWh]						0,0	0,0	0,0	0,0
[36]	**Avoided generation cost**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[37]	***Consumer sales***											
[38]	Sold to consumers		[GWh]						0,0	0,0	0,0	0,0
[39]	Retail tariff	42	[USc/kWh]						8,7	8,8	9,0	9,2
[40]	**Revenue from consumer sales**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[41]	***Avoided capital costs***											
[42]	Avoided capacity, sharing of reserves		[$USm]	0,0	0,0	0,0	0,0	0,0				
[43]	Avoided generation capex		[$USm]	0,0	0,0	0,0	0,0	0,0				
[44]	**Total avoided capacity costs**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[45]	**Total benefit**		**[$USm]**	*184*	**0**	**0**	**0**	**0**	**21,0**	**21,0**	**21,0**	**21,0**
[46]	**Net financial benefit (to utility)**		**[$USm]**	*49*	**0**	**0**	**-1**	**-2**	**5,1**	**5,2**	**5,3**	**5,3**
[47]	**CONSUMERS**											
[48]	Avoided self-gen		[GWh]						0,0	0,0	0,0	0,0
[49]	Retail diesel selfgen cost	11,0	[USc/kWh]						23,3	23,6	23,8	24,0
[50]	Avoided diesel costs (=benefit)		[$USm]	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[51]	Purchases at retail tariff		[$USm]	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[52]	**Net financial benefit to consumers**		**[USm]**	*0*	**0**	**0**	**0**	**0**	**0,0**	**0,0**	**0,0**	**0,0**

50 In the Template, the implementation model that entrusts construction and operation to an SPV is called a Type 2 project. In cases where the interconnector is built by each country utility (to its respective border), the Template refers to a Type 1 project (see Exhibit 4).

Exhibit 4 shows the assessment where there is no SPV and no wheeling fee; instead, each utility builds its portion of the interconnector to the border. Thus the associated financing transactions are shown in rows [10]-[16].

Exhibit 4: Financial Assessment (Utilities Build the Interconnector)

24	Financial Assessment, Country A				Egypt	1	Eygpt-Jordan 400kV 2nd circuit				TYPE 1 template: utilities	
					2018	2019	2020	2021	2022	2023	2024	2025
				NPV	-3	-2	-1	0	1	2	3	4
[1]	**COST**											
[2]	***Incremental generation cost (for exports)***											
[3]	Generation cost		[USc/kWh]		3,28	3,28	3,28	3,28	3,28	3,28	3,28	3,28
[4]	Generation		[GWh]						354	354	354	354
[5]	Generation cost		[$USm]	*101,7*	0	0	0	0	11,6	11,6	11,6	11,6
[6]	Incremental generation capex		[$USm]	*0,0*	0	0	0	0				
[7]	***Interconnection cost [wheeling fee][if type 2]***		[$USm]	*0,0*	0	0	0	0	0,0	0,0	0,0	0,0
[8]	Egypt share	0,00	[$USm]	*0,0*	0	0	0	0	0,0	0,0	0,0	0,0
[9]	***Direct inter-connection investment to border [if type 1]***											
[10]	Capex		[$USm]	*43,8*	0,0	22,5	19,9	11,9				
[11]	Loan disbursements		[$USm]	*-35,1*	0,0	-18,0	-15,9	-9,5				
[12]	Equity		[$USm]	*-8,8*	0,0	-4,5	-4,0	-2,4				
[13]	Repayment of principal		[$USm]	*13,6*	0,0	0,0	0,0	0,0	1,7	1,7	1,7	1,7
[14]	Interest		[$USm]	*11,1*	0,0	0,4	1,0	1,5	1,7	1,6	1,6	1,5
[15]	Commitment fee (if not capitalised)		[$USm]	*0,1*	0,0	0,1	0,0	0,0				
[16]	Opex		[$USm]	*8,3*	0,0	0,0	0,0	0,0	0,8	0,8	0,8	0,8
[17]	**Total direct transmission investment**		**[$USm]**	*33,2*	**0,0**	**0,4**	**1,1**	**1,6**	**4,2**	**4,2**	**4,1**	**4,0**
[18]	***Avoided utility generation costs***											
[19]	Ppa price imports		[USc/kWh]						0,0	0,0	0,0	0,0
[20]	Nominal volume imported at s/s	**Aqaba**	[GWh]						0,0	0,0	0,0	0,0
[21]	Egypt share of losses	**0,6**	[GWh]						0,0	0,0	0,0	0,0
[22]	Gwh		[GWh]						0,0	0,0	0,0	0,0
[23]	**Net cost of imports**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[24]	**Total costs**		**[$USm]**	*135*	**0**	**0**	**1**	**2**	**15,8**	**15,8**	**15,7**	**15,6**
[25]	**Benefits**											
[26]	***Exports***											
[27]	Export price escalation	1,000	[ ]						1,000	1,000	1,000	1,000
[28]	Ppa price exports	1,00	[USc/kWh]						6,06	6,06	6,06	6,06
[29]	Nominal volume sold at s/s	Taba	[GWh]						350	350	350	350
[30]	Egypt share of losses	**0,6**	[GWh]						-4,2	-4,2	-4,2	-4,2
[31]	Net sales (at notional delivery point)		[GWh]						345,8	345,8	345,8	345,8
[32]	**Net export revenue**		**[$USm]**	*183,7*	**0,0**	**0,0**	**0,0**	**0,0**	**21,0**	**21,0**	**21,0**	**21,0**
[33]	***Avoided utility generation costs***											
[34]	Avoided generation cost		[USc/kWh]						4,32	4,32	4,32	4,32
[35]	Avoided generation		[GWh]						0,0	0,0	0,0	0,0
[36]	**Avoided generation cost**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[37]	***Consumer sales***											
[38]	Sold to consumers		[GWh]						0,0	0,0	0,0	0,0
[39]	Retail tariff	42	[USc/kWh]						8,7	8,8	9,0	9,2
[40]	**Revenue from consumer sales**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[41]	***Avoided capital costs***											
[42]	Avoided capacity, sharing of reserves		[$USm]	0,0	0,0	0,0	0,0	0,0				
[43]	Avoided generation capex		[$USm]	0,0	0,0	0,0	0,0	0,0				
[44]	**Total avoided capacity costs**		**[$USm]**	*0,0*	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**	**0,0**
[45]	**Total benefit**		**[$USm]**	*184*	**0**	**0**	**0**	**0**	**21,0**	**21,0**	**21,0**	**21,0**
[46]	**Net financial benefit (to utility)**		**[$USm]**	*49*	**0**	**0**	**-1**	**-2**	**5,1**	**5,2**	**5,3**	**5,3**
[47]	**Consumers**											
[48]	Avoided self-gen		[GWh]						0,0	0,0	0,0	0,0
[49]	Retail diesel selfgen cost	11,0	[USc/kWh]						23,3	23,6	23,8	24,0
[50]	Avoided diesel costs (=benefit)		[$USm]	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[51]	Purchases at retail tariff		[$USm]	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
[52]	**Net financial benefit to consumers**		**[USm]**	*0*	**0**	**0**	**0**	**0**	**0,0**	**0,0**	**0,0**	**0,0**

Source: Template {ECON:Table 24}

7.3 Analysis of an SPV

Where the implementation of an investment project to facilitate trade is entrusted to an SPV, the main task is to ensure financial sustainability of that entity. An SPV can be financed in many different ways, and indeed can operate in many different ways.

For example, the GCCIA is an SPV that raised 100 percent of the necessary capital investment from the participating countries (with a distribution of shares as noted in Box 1); because the investment was fully financed by equity, the GCCIA has no debt-service obligations. However, in such a case, how these contributions to the CAPEX of the SPV are financed is the subject of the financial assessment, as discussed in Section 7.2.

In the more general case, where an SPV is created by the participating countries (with or without additional private equity), the task of the financial analysis is to determine the size of the wheeling fee, based on an analysis of the SPV's revenue requirements. The fee has to be sufficient to recover debt, to provide a return on equity, to ensure adequate cash flow to fund lender requirements (debt-service reserve account), and to meet ongoing operating costs.

This revenue-requirements approach applies regardless of the actual financing structure—whether loans are provided by IFIs or private banks; whether equity capital is provided by state-owned utilities or by private sources; or whether there is limited or non-recourse financing.

The Template adopts the classical format and nomenclature of utility financial analysis, consisting of the three main tables that correspond to the usual financial statements:

- Income statement (sometimes referred to as the profit/loss statement);
- Sources and uses of funds (which records the cash flows); and
- Balance sheet.

These are augmented by a series of supporting tables, including:

- Tariff-revenue calculations;
- Debt-service calculations;
- Debt-service reserve account; and
- Shareholder funds (which provides the calculation of the return on shareholder’s equity).

In some countries, the accounting standards may require a different form of cash-flow reporting. For example, in some countries, the cash flows need to be reported under three different headings (cash flow from operating activities, cash flow from investing activities, and cash flows from financing activities). But this is merely a rearrangement of the rows of the table of sources and uses of funds in the Template.

The complete set of financial analysis tables is described in the User Manual, Section 5.

8 DISTRIBUTIONAL ANALYSIS

The reconciliation of economic and financial flows is at the heart of the distributional analysis. This answers the question of how the economic costs and benefits are distributed among the stakeholders.

8.1 Methodology

Exhibit 5 illustrates the tabular format that best displays this analysis. All the entries in this table represent NPVs, denominated in millions of dollars. The columns represent the stakeholders; the rows represent individual transactions. For each stakeholder, a positive entry represents a revenue, and a negative entry a cost.

Exhibit 5: The Format for Distributional Analysis

Distribution of financial costs $USm as NPV at 8% discount rate				2 TYPE 2 template: SPV							
	Egypt			Jordan							
	Utility	Consumers	Govt	Utility	consumers	Govt	SPV	Private	transit fees	Banks	Total
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Country A: Egypt											
Wheeling fees to SPV	-31.5						31.5				0.0
Interconnection costs:OPEX	0.0										0.0
Interconnection costs:CAPEX	0.0										0.0
financing transactions	0.0		0.0							0.0	0.0
Exports											
Generating cost for exports	-101.7										-101.7
Benefits of Exports	183.7										183.7
Imports											
Benefits:Avoided generation	0.0										0.0
Benefits:Additional sales	0.0	0.0									0.0
Benefits:Avoided self generation cost		0.0									0.0
Cost of Imports	0.0										0.0
Country B: Jordan											
Wheeling fees to SPV				-31.5			31.5				0.0
Interconnection costs: OPEX				0.0							0.0
Interconnection costs:CAPEX				0.0							0.0
financing transactions				0.0		0.0				0.0	0.0
Exports											
Generating cost for exports				0.0							0.0
Benefits of Exports				0.0							0.0
Imports											
Benefits:Avoided generation				113.8							113.8
Benefits:Additional sales				169.3	-169.3						0.0
Benefits:Avoided self generation cost					287.6						287.6
Cost of Imports				-183.7							-183.7
Transit country/Benefit sharing							0.0		0.0	0.0	0.0
SPV											
CAPEX			0.0			0.0	-49.5				-49.5
OPEX							-10.5				-10.5
Loan disbursements							40.5			-40.5	0.0
Principal repayments							-19.4			19.4	0.0
Interest							-9.7			9.7	0.0
corporate income tax			0.0			0.0	0.0				0.0
equity contributions			-3.0			-3.0	10.1	-4.0			0.0
dividend distribution			7.0			7.0	-23.3	9.3			0.0
misc.adjustments							-1.3			1.3	0.0
total	**50.5**	**0.0**	**3.9**	**67.9**	**118.3**	**3.9**	**0.0**	**5.3**	**0.0**	**-10.1**	**239.8**

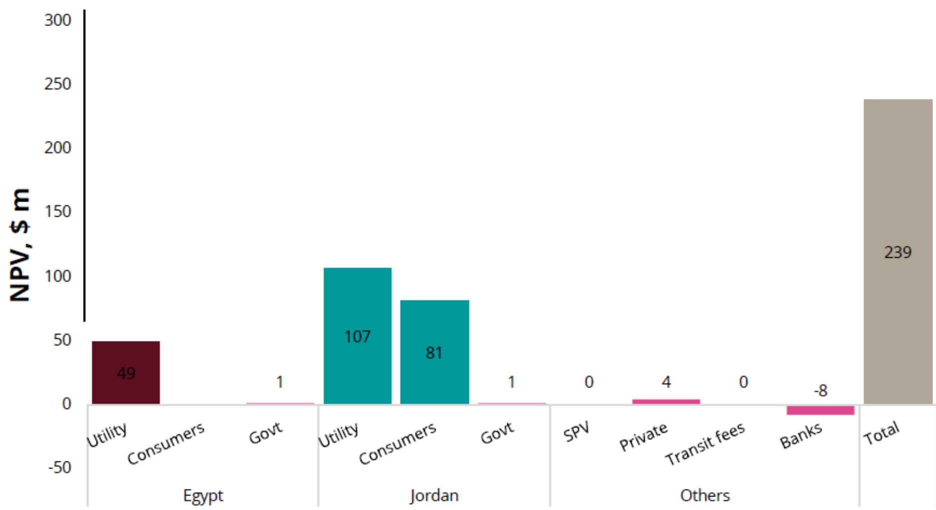
Source: Template {ECON}Table 26

The export revenue that accrues to Egypt (+$183.7 million as an NPV; row[8]) is offset by an equivalent negative entry that is the cost of imports to Jordan (row[26]).

In this presentation, the net impact on the SPV is always zero, because it is assumed that any surplus is distributed to the shareholders, who are the beneficiaries of the dividend payouts. Rows [5], [18], and [31] to [33] represent the impact of debt finance. In this example, we assume that it is the SPV that raises the finance, so the loan transactions for both Egypt and Jordan are shown as zero in the SPV transactions (rows [31] to [33]).

The column totals in such a table (Exhibit 5, row [38]) represent the net impact on each stakeholder, conveniently displayed as shown in Figure 30.

Figure 30: Stakeholder Impacts[51]



The reason why the net impact on the banks is negative ($8.1 million) is explained as follows: If a bank lends money at an interest rate less than the discount rate, there is a net transfer from the bank to the lender when the flows are summarised as an NPV at that discount rate. This is to be expected: It is precisely the purpose of concessionary finance from the IFIs (or indeed from concessionary finance provided by a donor country) to buy down the cost of capital. In this case, we assume IFI finance to the SPV at four percent, below the discount rate used in the NPV calculations, hence the negative net impact on the banks.

8.2 Impact of subsidies

Subsidies on electricity, or on the fuel used for thermal generation, can impede international electricity trade because of the fear of "exporting subsidies." Suppose, for example, that Egypt subsidizes gas for power generation, so that from the utilities' perspective, an export could be profitably offered to Jordan at any price that is above its cost of subsidized generation.

51 In the Template, this chart is provided in {ECON:Table 26}.

However, from the point of view of the country, this would be a poor proposition, because if the true economic cost of gas for power generation is higher than the subsidized price, then in effect Jordan benefits from the subsidies provided to the Egyptian utility. In effect, the subsidy would be “exported,” and the fear of this impedes trade. The magnitude of the problem is easily demonstrated by the methodology described above.

Consider, for example, Exhibit 6—a purely illustrative example, in which Egypt is assumed to export electricity to Jordan, using subsidized gas for power generation in a CCGT. In Jordan, the imports displace expensive diesel generation, using heavy fuel oil (assumed for purposes of illustration also to be subsidized).

Exhibit 6: Exporting Subsidy (Illustrative Example)

Distribution of economic costs and benefits	$USm as NPV at 8% discount rate			Eygpt-Jordan 400kV 2nd circuit					TYPE 2 template: SPV				
	Egypt			Jordan							WORLD		
	Utility	Consumers	Govt	Utility	Consumers	Govt	SPV	Private	Transit fees	Banks	Total Econ Benefit	GHG benefit	Total
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
[1] **Incremental costs**													
[2] Interconnection CAPEX	0.0		0.0	0.0		0.0	**-49.5**				-49.5		-49.5
[3] Interconnection OPEX	0.0			-10.5			-10.5				-21.0		-21.0
[4] incremental generation CAPEX	0.0			0.0							0.0		0.0
[5] SPV remuneration	-31.5			-31.5			63.1				0.0		0.0
[6] SPV corporate income tax			0.0			0.0	0.0				0.0		0.0
[7] SPV equity			-3.0			-3.0	10.1	-4.0			0.0		0.0
[8] SPV dividends			7.0			7.0	-23.3	9.3			0.0		0.0
[9] SPV banking transactions							10.1			-10.1	0.0		0.0
[10] power trade from Egypt to Jordan	183.7			-183.7							0.0		0.0
[11] incremental generation in Egypt	-101.7		-78.0								**-179.6**		-179.6
[12] power trade from Jordan to Egypt	0.0			0.0							0.0		0.0
[13] incremental generation in Jordan				0.0		0.0					**0.0**		0.0
[14] Retail sales and purchases	0.0	0.0		169.3	-169.3						0.0		0.0
[15] **incremental benefits: Egypt**													
[16] avoided generation	0.0		0.0								**0.0**		0.0
[17] consumer benefits		0.0									0.0		0.0
[18] **incremental benefits: Jordan**													
[19] avoided generation				113.8		14.5					**128.3**		128.3
[20] consumer benefits					376.2						376.2		376.2
[21] **reliability benefits**		0.0			0.0						0.0		0.0
[22] **Capacity benefits**													
[23] avoided generation CAPEX	0.0			0.0							0.0		0.0
[24] shared reserves benefit	0.0			0.0							0.0		0.0
[25] benefit sharing/transit fees							0.0		0.0		0.0		0.0
[26] Local health damages		-0.9			6.8						5.9		5.9
[27] GHG emission benefits											0.0	63.1	63.1
[28] **total**	**50.5**	**-0.9**	**-74.0**	**57.4**	**213.7**	**18.5**	**0.0**	**5.3**	**0.0**	**-10.1**	**260.3**	**63.1**	**323.5**

In this exhibit, the subsidy in the exporting country (Egypt) becomes apparent in row [11]. The cost of the incremental generation, at the subsidized price paid by the Egyptian utility, is $101.7 million (as NPV). But the economic price of the gas used—based on the higher opportunity cost (see Section 2.6) —is $179.6 million. The difference is the value of the subsidy ($78 million). This represents the cost to the government of Egypt of exporting electricity to Jordan at the subsidized price—a benefit that is captured in Jordan (by increasing the benefits to Jordan’s consumers).

At the same time (under the assumptions of this illustration), there is a gain to the government of Jordan, because it now *avoids* the subsidy. In row [19], there is a benefit to the Jordanian utility of $113.8 million, which is the cost of fuel at its subsidized price. But the gain to the country is the higher economic cost of the unsubsidized fuel, or $128.3 million. Hence there is an additional benefit to the government of Jordan of $14.5 million in *avoided* subsidy.

9 RISK ASSESSMENT

9.1 Risks and their mitigation

Table 20 lists some of the risks that may be encountered in a major transmission-line project built to facilitate trade. Although the list is long, the risks of transmission projects are in general lower than the risks for many other types of energy-sector projects (such as the geo-technical and hydrology risks of hydro projects, or the many environmental risks associated with coal projects).

In column [3]. we assess the ability to quantify and model the various risks in the financial (and economic) analysis. One may observe that the impact of many of these risks is not so much the transaction cost of mitigation (such as the appointment of independent engineers to review), as the delay in achieving the planned date of commercial operation (plus the impact of any additional costs needed to fix an identified problem). Delays are often coupled with construction-cost overruns, the combined impact of which is to reduce the economic and financial returns. How these various risks are handled in the spreadsheet Template for economic and financial analysis are described in detail in the Template User Manual. Robustness of returns to delays in operation is one of the most important considerations in a risk assessment.

Table 20: Risks of Transmission Interconnection Projects and Their Mitigation

Risks	Possible mitigation	Ability to quantify and include in financial models
Financial Risks		
• Exchange rates	FOREX hedging; transactions denominated in FOREX (e.g., as in the GCCIA)	Good; easy to model
• FOREX interest rates	Interest-rate swaps	Good; easy to model
• Commercial-lender risk appetite	Loan syndication; participation of IFIs; IFI PRGs; sovereign guarantees	PRGs easy to model
• Equity-provider risk exposure	Participation of IFIs; sovereign guarantees; IFI PRGs	PRGs easy to model
• Lender security (inability to meet debt-service obligations)	Debt-service reserve account	Good: easy to model; DSCR is widely used as an indictor of lender security.
Country Risk		
• Events that would trigger political force majeure in a PPA (notably resumption of conflict in an importing country, or changes of policy in either Saudi Arabia or the importing country)	Generally outside the control of project decision-makers; in the case of private financing, mitigated by buyout provisions and guarantees from the Multilateral Investment Guarantee Agency (MIGA) of the World Bank Group.	Not directly quantifiable, except by showing how the FIRR and ERR increase over time (how many years of operation are required to achieve the hurdle rates)
• Corruption risk	International competitive bidding (ICB) under proper oversight	Difficult to quantify, other than any concomitant risk of project delays in the event of legal proceedings
• Dispute-resolution risk	Generally recognized international-arbitration provisions	Difficult to quantify and monetize
• Importing country	Demonstrate that interconnection	Modelled by excluding

Risks	Possible mitigation	Ability to quantify and include in financial models
geopolitical-risk perceptions	may bring benefits even if the corresponding capacity-expansion plan is not adjusted, and that in some cases, an additional interconnection may increase supply diversity.	capacity credits
• Transit country risk (delays in transit fee negotiations and access & security provisions)	Early involvement of transit country; commitment to benefit-sharing provisions	Benefit-sharing easy to model
• Non-political force majeure (earthquakes, floods, extreme weather)	Adequate technical review of final design[52]	Not quantifiable; costs of independent review are trivial
• Technical Risks		
• Technical design and tender-document shortcomings	Appointment of an independent engineer; review of detailed feasibility study by independent party (e.g., IFI)	Transaction cost of review is trivial, but failure of early identification may lead to significant delays
• Technology risks (notably for ultra-high-voltage lines and advanced back-to-back BtB) connections.	Independent review by expert specialists	Evaluate alternative technical options, avoiding advanced technologies to show trade-off between cost and risk
International Risks		
• International fossil-fuel price uncertainty	Fuel-price hedging; supply diversification in importing country	Straightforward to model in principle, but fuel price hedging practical only over short time horizons; not really relevant for transmission-line projects (though may affect the outcome of the proposed pricing mechanism)
• Future international agreements on fossil-fuel use (or carbon taxes)	Incremental generation of the exporter to use best-available technology to minimize CO_2 emissions per kWh delivered	Impact of CO_2 tax easily modelled; valuation of carbon mainly an issue for the *economic* analysis
Construction Risk		
• Equipment, procurement and construction (EPC) failure, non-performance	Performance bonds; penalties for late COD	Danger of delay and additional costs; impact of delayed COD easily modelled
• Equipment-supplier non-performance (e.g., for BtB equipment)	Liquidated damages; adequate commissioning protocols	
Security Risks		
• Attacks on the interconnector, or on related facilities (including incremental generation)	Rapid security plan for rapid repair of interconnector; adequate spares inventory; locate high-tech BtB facilities in Saudi Arabia rather than importing country	Best modelled in a scenario model, in which revenues fall out for given lengths of time (in the case of transmission projects, likely to be far higher than the costs of repair)
Environmental and Social Risks		
• Lack of buy-in from affected stakeholders	Adequate public consultation; benefit sharing	Benefit-sharing outlays easy to model; material impacts if environmental and social problems delay project

52 In the case of hydro projects assured by independent dam-safety committee review. For electricity interconnection projects in the Arab region, independent review of any BtB or submarine sections may be considered.

Risks	Possible mitigation	Ability to quantify and include in financial models
		completion
• Social risks (resettlement without proper consultation and adequate compensation; poor land-acquisition procedures)	Adherence to good safeguard practice (resettlement action plans, stakeholder engagement plans)	Incremental costs of safeguards can be estimated and compared to often much-greater impact on economic and financial returns due to delay
• Environmental risks (including construction in environmentally sensitive areas)	Need to follow good construction practices, with covenants to ensure adequate supervision and adherence to site-specific environmental-management plans	Incremental costs of safeguards can be estimated and compared to often much-greater impact on economic and financial returns due to delay
Commercial Risks		
• Non-performance of (importing country) buyer (failure to take, failure to pay)	Take or pay provisions; payment escrow account	Easy to model (cost defined by PPA, revenue defined by actual transactions)
• Non-performance or failure of an SPV	Payment escrow; buyback provisions	Payment escrow and impact on cash management easy to model
• Related facilities of exporter (incremental generation, transmission to the interconnection) not ready in time	Liquidated damages; government guarantees of wheeling fee to SPV; back-to-back agreements between parties (see text example in the India-Nepal transmission line)	Resulting delay easy to model

9.2 Customised measures

Although many risk mitigation measures are relatively straightforward and widely used (such as debt-service escrow accounts, interest-rate swaps, and performance bonds), others require customised measures.

For example, in the Nepal-India project, to mitigate the risks that NEA (Nepal's state owned utility) would face in paying the transmission service charge for the cross-border transmission line, NEA is planning to enter into back-to-back transmission-service agreements with expected users of the cross-border line (and the associated internal lines). The users would be mainly IPPs that are developing generation projects to export power to India. The active IPP developers in Nepal and NEA have entered into a memorandum of understanding (MoU) whereby the IPPs have indicated their willingness to pay the transmission service fee (essentially the capacity charge) to NEA, from the time the line is commissioned. Moreover, NEA has also begun discussions with industrial consumers to enter into back-to-back power-sales agreements for the internal sale of power to be imported from India. These back-to-back sales agreements would pass the obligations of NEA on to the industrial consumers.

World Bank project-appraisal reports require the presentation of an operational-risk assessment framework (ORAF), as illustrated in Table 21 for the India-Nepal transmission project.

Table 21: World Bank Operational-Risk Assessment Framework: India-Nepal Transmission Project

ORAF Risk Levels	Risk Rating	Risk description	Proposed mitigation measures
Stakeholder risks	MI	(i) No support from new governments and opposition by one or more of the political parties in Nepal (could affect timely provision of counterpart funds) (ii) A complication in the political relations between India and Nepal with the new Government. India is a stakeholder in the project and political developments/ reactions in India could impact the project (iii) Withdrawal of one or more of the sponsors – IL&FS and/or NEA Local opposition based on a perceived inadequacy in benefits-sharing and access to electricity.	(i) Design and implement a communications strategy aimed at creating an enabling environment for the Project and at conveying the benefits of the project as they apply to all stakeholder groups. The strategy will include: (a) ongoing consultations with all stakeholder groups to understand their concerns; (b) targeted communication initiatives to address these concerns; (c) providing easy access to information about project; (d) effective grievance redress mechanisms. (ii) Maintaining momentum on preparatory actions including the signing of the requisite project agreements and reaching financial close.
Implementing Agency risks	MI	Capacity at NEA is low in project management, FM, and procurement The possibility of fraud and corruption exists The protracted decision-making process could delay implementation	(i) The capacity development plan put in place and the extensive oversight built into the project design (ii) The routine nature of the transmission investment and the existence of a robust competitive market for such ICB
Design Risk	MI	The complex project design – comprising NEA and two SPVs for the Dhalkebar-Muzaffarpur project, multiple sources of financing, and multiple agreements to create the policy, regulatory and legal framework presents implementation risks.	The regulatory and legal framework to be incorporated in a set of agreements is fully developed and is being negotiated. Nepal and NEA are experienced in dealing with commercial and legal agreements for power purchase from IPPs and even import of power on a small scale. Capacity development interventions have been built into theProject and in the ongoing Power Development Project.
Safeguard risks	MI	Risks of inadequate assessment or improper handling of Safeguards aspects could delay project preparation and approval; and during implementation could negatively impact the local area and the affected population. Policies triggered include Environmental Assessment policy (OP 4.01), Policy on Involuntary Resettlement (OP4.12), Forests (OP 4.36), Indigenous Peoples (OP 4.12), Natural Habitats (OP 4.04), and Physical and Cultural Resources (OP	(i) Applicable elements from the Nepal Peace Filter will be examined for incorporating into the social safeguards. (ii) Bank support to NEA's ESSD is strengthened by engagement in the ongoing Power Development Project. (iii) The Lenders' Engineer will monitor the implementation of Safeguards mitigation plans. Sustained communications

ORAF Risk Levels	Risk Rating	Risk description	Proposed mitigation measures
		4.11). ILO 169 creates greater local demands for control over resources.	initiatives will be undertaken to inform the affected stakeholder groups about the possible impacts of the project and the mitigation measures taken to address these impacts. (iv) Careful attention to social aspects of project preparation including benefits-sharing.
Program and donor risk	MI	Commitment for the regional program could wane due to changes in government in Nepal or to suspicions around a "fair deal" in the cross-border power trade.	Intensive engagement by the Bank team will continue during implementation. Closely monitoring the evolving political economy of the project and calibrating responses in terms of implementation plans and stakeholder outreach
Delivery Quantity risk(contract management, Sustainabilty and M&E risks)	ML	Risks of inadequate coordination of construction schedules could result in the infrastructure not being ready to evacuate power from India and face NEA with "take or pay" penalties. (The D-M Line and at least one line (either Hetauda Dhalkebar or Dhalkebar-Duhabi) of the H-D-D line have to be essentially completed at the same time) Weak project management and M&E capacity.	i) The advice and assistance provided by the hired consultants/advisors/supervising engineers will help to minimize this risk. (ii) The capacity building plans will address capacity constraints.

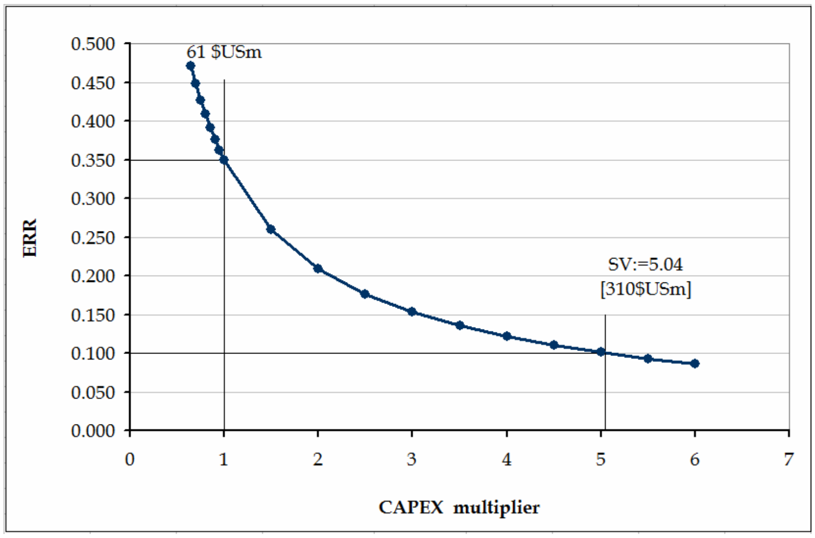
9.3 Quantitative risk assessment

The difficulty with a standard switching-values analysis—of the type shown in Figure 31 - which demonstrates the sensitivity of ERR to a single-input assumption (in this case CAPEX, with a switching value (SV) of 5.04 (i.e., 504% of the baseline value)—is that it assumes that all other input variables remain unchanged.

This is rarely achieved in practice, because in reality, all of the main input assumptions are likely to have uncertainty associated with them. The way around this problem is so-called Monte Carlo simulation, in which the calculation of ERR and FIRR are done hundreds or thousands of times, at each iteration drawing values from the probability distributions of the individual data assumption. This results in a probability distribution of economic rate of return (ERR) and FIRR, from which one may derive the probability of a project not reaching the hurdle rate—equal to the area under the probability-density function to the left of the hurdle rate. In the example of Figure 32 this computes to 21.6 percent.[53]

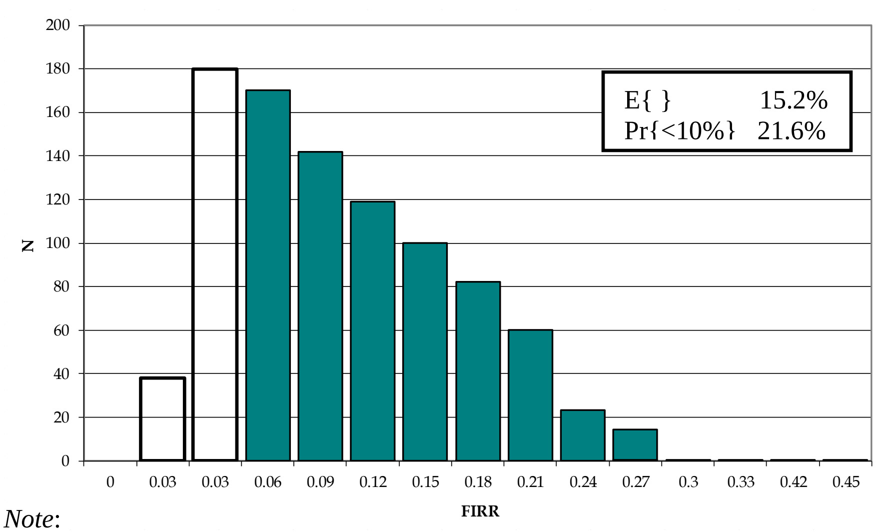
[53] See User Manual, Section 3.13, on how such an analysis is generated in the Template.

Figure 31: Switching-Value Analysis, ERR vs. CAPEX



Even with this approach, there may be difficulty in specifying probability distributions, particularly for exogenous uncertainties such as the future world oil price. However, from the perspective of making the most conservative assumptions about uncertainty, the best approach is to assume uniform probability distribution within some plausible bounds of uncertainty. For the CAPEX of a transmission interconnection consisting of conventional HVAC, plausible bounds might be from minus 15 percent of the baseline (which is usually that judged most likely by the electrical engineers designing the line, including the [physical] contingency allowance) to plus 50 percent of the baseline. Just such plausible bounds were used to prepare Figure 32.

Figure 32: Probability Distribution of FIRR



Note:
E{ }=expected value of FIRR
Pr{<10%}=probability of the FIRR falling below the 10% hurdle rate

Basis point (bp)	A term used in banking and finance to describe small variations in interest rates, whereby 100 basis points = one percent (therefore 40 basis points = 0.4 percent, etc.).
Border price—free on board (FOB) or cost, insurance and freight (CIF)	The value of a traded good at a country's border—FOB for exports or CIF for imports.
Commitment fee	The fee levied by lenders on undisbursed funds.
Debt-service reserve account (DSRA)	An account required to be set up as a condition of borrowing from commercial banks, which covers some months of debt-service payments. This must typically be fully funded before dividends are paid to shareholders. In some cases, some part of the funding must be done upfront at the time of financial closure.
Economic opportunity cost of capital (EOCK)	The weighted average of the demand price of capital (the consumption rate of interest) and the supply price of capital (investment rate of interest).
Higher heating value (HHV)	Also known as gross calorific value, the HHV of a fuel is the amount of heat released by a specified quantity (initially at 25°C) once it is combusted and the products have returned to a temperature of 25°C. HHV includes the latent heat of the vaporization of water in the combustion products. It is mainly used in the United States. Henry Hub gas prices are based on HHV. See also LHV.
International Standards Organization (ISO) conditions	The nameplate capacity of a thermal-generating project under the conditions defined by the ISO (i.e., at sea level and 15ºC).
Japan Crude Cocktail (JCC)	The average monthly CIF price of all crude oil imported into Japan. Used as a basis for liquid natural gas (LNG) contracts in the Asia-Pacific market.
Lower heating value **(**LHV)	Also known as net calorific value, the LHV of a fuel is defined as the amount of heat released by combusting a specified quantity (initially at 25°C) and returning the temperature of the combustion products to 150°C. This assumes that the latent heat of vaporization of water in the reaction products is *not* recovered (in contrast to HHV). The LHV is generally used in Europe. The difference between LHV and HHV is greatest for natural gas (LHV = 47.1 MJ/kg, whereas HHV = 52.2 MJ/kg, or about 10 percent higher), smallest for solid fuels (e.g., for a typical coal, LHV = 22.7 MJ/kg, whereas HHV = 23.9, or about five percent higher). Russian gas prices are based on LHV. Intergovernmental Panel on Climate Change (IPCC) default values for greenhouse-gas (GHG) emission calculations are based on LHV.

London interbank offered rate (LIBOR)	The interest rate that London banks charge each other. Different rates apply to different currencies and terms (overnight, 30 days, six months, etc.). The rates are published daily by the British Banking Association (www.bba.org.uk), based on a survey of a panel of banks. LIBOR rates are widely used as the reference for variable-interest commercial loans (e.g., "six-month LIBOR+2%").
Opportunity cost	The benefit lost from not using a good or resource for its best alternative use. Opportunity costs measured at economic prices should be used in economic analyses as the measure of benefits.
Physical contingencies	Contingencies included in project financing for unanticipated variations in the bill of quantities (e.g., for a greater length of a transmission line than estimated). They are considered to be part of the economic cost.
Postage-stamp rate	A transmission charge that does not vary according to distance from the source of the power supply, so-called because postage stamps for letters are typically sold at a fixed price, regardless of destination within the same country.
Price contingencies	Contingencies included in project financing for cost increases attributable to inflation. These are not considered to be part of the economic cost (where economic returns are calculated at constant prices).
Pure rate of time preference (ρ)	Considered to consist of two components: individuals' impatience or myopia (though this component is ignored in many studies because of the difficulty of measuring it), and the risk of death (or as argued by Nicholas Stern, the risk of the extinction of the human race).
Ramsey formula	According to the noted British economist Frank Ramsey, the social rate of time preference (SRTP) is the sum of two terms: a utility discount rate reflecting the *pure* time preference (ρ) plus the product of the elasticity of the marginal utility of consumption (γ) and the annual growth rate of per-capita real consumption (g); thus SRTP = $\rho+\gamma g$.
Shadow exchange rate factor (SERF)	The inverse of the standard conversion factor (SCF). The shadow exchange rate is often greater than the official exchange rate, indicating that domestic consumers place a higher value on foreign exchange than is given by the official exchange rate.
Social rate of time preference (SRTP)	The rate at which society is willing to postpone a unit of current consumption in exchange for more future consumption. The use of the SRTP as the social discount rate is based on the argument that public projects displace current consumption, and streams of costs and benefits to be discounted are essentially streams of consumption goods either postponed or gained. There are two general methods in use for its empirical estimation: (1) the after-tax return on government bonds (or other low-risk marketable securities), and (2) the Ramsey formula.
Special purpose vehicle (SPV)	An entity (corporation or limited partnership), which is sometimes a subsidiary of one or more other corporations, and is established for some limited and specific purpose (such as building, owning and operating a transmission facility), with a legal and financial

	status separate from that of its shareholders.
Standard conversion factor (SCF)	The ratio of the economic price of goods in an economy (at their border-price equivalents) to their domestic market price. It represents the extent to which economic prices, in general, are lower than the domestic market values.
Switching value	In a sensitivity analysis, the value of an input data assumption that brings the economic rate of return (ERR) to the hurdle rate (equivalent to bringing the net present value [NPV] to zero).
Transit fee	Payments made to third parties, particularly countries, in compensation for allowing an interconnection to pass across the territory of that third party. For example, Afghanistan will collect a transit fee for the HVDC line that will export surplus hydropower from the Kyrgyz Republic and Tajikistan to Pakistan. Similarly, Morocco is paid a transit fee for the Algeria-to-Spain gas pipeline. Transit fees are sometimes paid in kind rather than as monetary payments.
Wheeling fee	Payments made to the entity owning and operating the interconnection facility, to recover its costs and generate a return on equity.

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