AFGHANISTAN ENERGY STUDY

ENERGY SECURITY TRADE-OFFS UNDER HIGH UNCERTAINTY

Resolving Afghanistan's Power Sector Development Dilemma

Defne Gencer, John Irving, Peter Meier, Richard Spencer, and Chris Wnuk

WORLD BANK GROUP

ESMAP

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Foreword

Afghanistan remains in the bottom 10 percent globally in electricity consumption per capita, and only 34 percent of its population is connected to the grid, among the lowest rates in the world. Both the Afghan government and donors have made power sector development a priority, as demonstrated by initiatives such as the Afghanistan National Development Strategy (ANDS) and the National Energy Supply Program (NESP). Energy is one of Afghanistan's top economic development priorities as electricity is the motor that powers the country's growth.

Afghanistan's power sector faces a planning challenge of enormous complexity embedded in a high degree of uncertainty. Its local generation capacity has remained stagnant (around 340 MW); the rapid growth in consumption has primarily been met by imports (around 80 percent of the total) especially from Uzbekistan, highlighting the significant vulnerability to interruption of its energy supply.

Planning is a fundamental part of addressing the energy stress in Afghanistan and is essential for attracting future investment. An analytical framework is needed to replace sporadic decision making with informed policy choices that will support national efforts to reduce poverty and share prosperity.

This report develops approaches to power sector planning and investment decision making that respond to the uncertainties that Afghanistan faces, while striking a balance between the three main policy imperatives of economic efficiency, energy security, and environmental sustainability. It aims to provide an alternative to the "predict-then-act" approach to planning that will allow for more robust decision making. Instead of identifying the "best" plan to meet a specific forecasted scenario, it poses a different question: given a set of options that can be practicably implemented, which one of these alternatives is the most robust to the main uncertainties?

This study has demonstrated the importance of a functional and high-quality power planning system. We are planning to take the lessons from this report forward.

Mohammad Gul Khulmi
Acting Minister of Energy and Water

Acknowledgments

This paper was prepared by Defne Gencer, John Irving, Peter Meier, Richard Spencer, and Chris Wnuk. It relies on official documentation, background reports, and underlying analysis generated during the course of the analytical and advisory work conducted jointly with the Afghan authorities.

The paper has benefited from information, insights, and feedback provided by individuals and concerned with the work and outside advisors. The authors are grateful for the leadership of Eng. Ghulam Faruq Qazizada, past Deputy Minister for Energy in the Ministry of Energy and Water, and Mr. Razique Samadi, former Chief Executive of Da Afghanistan Breshna Sherkat.

The work could not have been completed without the unstinting support and cooperation of the Afghan working group formed to participate in the activity. They include Musa Arian, Malalai Barikzai, Mohammad Fahim, Yahya Fetree, Mohmmad, Amanullah Ghalib, Humayoon Kohistani, Emal Masud, Mazharuddin, Abdul Jamil Musleh, Ahmad Abdullah Nasrati, Mohammad Nasser, Habib Rahmat, Zia Gul Saljuki, and Mohammad Tahir, from Ministry of Energy and Water; Mohsin Amin and Sayed Khurshid Zaidi from the Interministerial Council on Energy; and Naser Ahmadi, Hazrat Shah Hameedi, Ezzatullah Khaliqi, Mohammad Khalid Khorsand, Nangialai Miakhail, and Abdul Wakil Nasery from Da Afghanistan Breshna Sherkat. Asad Aleem of the Asian Development Bank and Mark Harvey of the UK Department for International Development also contributed to the discussions.

The authors would also like to acknowledge the inputs from the World Bank team which included Afsana Afshar, Abdul Hameed Quraishi, and Parwana Nasiree; the peer reviewers Beatriz Arizu, Kwawu Gaba, Abedalrazq Kahil, and Sameer Shukla.

Last, the financial and technical support by the Energy Sector Management Assistance Program (ESMAP) is gratefully acknowledged. ESMAP—a global knowledge and technical assistance program administered by the World Bank—assists low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth. ESMAP is funded by Australia, Austria, Denmark, the European Commission, Finland, France, Germany, Iceland, Japan, Lithuania, Luxembourg, the Netherlands, Norway, the Rockefeller Foundation, Sweden, Switzerland, the United Kingdom, and the World Bank.

None of those who have been so generous with their help are answerable for any errors, all of which are the responsibility of the authors alone.

Abbreviations and Acronyms

ADB	Asian Development Bank
AEIC	Afghanistan Energy Information Center
AGS	Afghanistan Geological Service
APSMP	Afghanistan Power System Master Plan (2013)
b/b	back-to-back
Bcf	billion cubic feet
BCM	billion cubic meters
BTU	British Thermal Unit
CAPEX	capital expenditure
CAR	Central Asian Republics (Kazakhstan, Kyrgyz Republic, Tajikistan Turkmenistan, and Uzbekistan)
CASA-1000	Central Asia—South Asia Electricity Trade and Transmission Project
CBA	cost-benefit analysis
CCGT	combined cycle gas turbine
CBM	coal bed methane
CIS	Commonwealth of Independent States
CMGC	China Metallurgical Group Corporation
CSP	concentrated solar power
d/c	double circuit
DABS	Da Afghanistan Breshna Sherkat (Afghanistan Power Company)
DC	direct current
EOCK	economic opportunity cost of capital
EPC	engineering procurement and construction
ERR	economic rate of return
ESI	energy security index
FACTS	flexible alternating current transmission system (devices for voltage and system stability control)
FS	feasibility study
GDP	gross domestic product
GHG	greenhouse gas
HH	household
HHV	higher heating value
HVAC	high voltage alternating current
HVDC	high voltage direct current
HVDC b/b	HVDC/HVAC back to back
IAEA	International Atomic Energy Agency
ICE	Inter-ministerial Commission on Energy
IDC	interest during construction
IEA	International Energy Agency

IEG	Independent Evaluation Group (of the World Bank)
IFI	international financial institution
IPP	independent power project
UPS/IPS	Unified Power System (Russia)/Integrated Power System (CIS Republics)
JCC	Japan crude cocktail (see Glossary)
LCC	line commutated converter—conventional method of operating HVDC
LOLP	loss of load probability
LRMC	long run marginal cost (see Glossary)
Mcf	thousand cubic feet
MCM	thousand cubic meters
MEW	Ministry of Energy and Water
mmBTU	million British Thermal Units
MOF	Ministry of Finance
MV	medium voltage
NATO	North Atlantic Treaty Organisation
NCE	Northern Coal Enterprise
NEPS	Northern Electrical Power System—currently operated as three islanded networks
PAP	project-affected person
PPA	power purchase agreement
PTEC	Power Transmission and Connectivity Project (USAID)
RESET	Regional Energy Security and Trade (a program of USAID)
SEPS	Southern Electrical Power System—serving Kandahar and neighboring provinces
SRTP	social rate of time preference (see Glossary)
SVC	social value of carbon
T&D	transmission and distribution
TA	technical assistance
tcf	trillion cubic feet
TUTAP	Turkmenistan, Uzbekistan, Tajikistan, Afghanistan and Pakistan (power trading market)
UAP	Uzbekistan-Afghanistan-Pakistan (HVDC electricity trade project)
USAID	United States Agency for International Development
USGS	United States Geological Survey
VFT	variable frequency transformer
VSC	voltage source converter –HVDC control with reactive power control capability

Currency and Exchange Rate

1 U.S. dollar ($)=68.70 Afghanis (Afs)
Exchange rate effective December 31, 2015
All dollar amounts are U.S. dollars unless otherwise indicated.
All references to tons and million tons per year (mtpy) refer to metric ton (1,000 kg).

Calendar Conversion

Gregorian Year	Solar Year
2008	1386
2009	1387
2010	1388
2011	1389
2012	1390
2013	1391
2014	1392
2015	1393

Executive Summary

The environment in which power sector planning must take place in Afghanistan is especially challenging as a consequence of unusually high levels of uncertainty about potential resources, each with different environmental impacts, compounded by the disadvantages of being a land-locked country and difficult geopolitical circumstances that further complicate energy security. This report explores approaches to address the challenges of power sector planning in Afghanistan.

In the past years, power sector master plans have been prepared for Afghanistan, including one in 1978 and another in 2004. The most recent one was prepared in 2012 with financing from the Asian Development Bank (ADB) and is referred to as the Afghanistan Power Sector Master Plan (APSMP). These planning efforts followed the classical route of least-cost planning based on an approach that requires expert judgement to define the likely future (in terms of load forecasts, international fuel prices, generation costs, and so on) and then use relatively sophisticated planning models to define an optimal expansion plan. The difficulty is that such a plan, prepared based on a planning paradigm sometimes described as "predict-then-act," remains optimal only for the scenario into which it is embedded.

Such plans are based on the assumption that the implementation of their conclusions poses few difficulties. In the unusual circumstances of Afghanistan, assumptions about the ability to finance and implement projects are increasingly coming under question, rendering many of the large projects proposed by the master plans unrealistic in terms of scale, likelihood, and timing of completion, and hence the plans are generally too optimistic. Furthermore, methodologies that rely on the predict-then-act approach do not appear to be grounded in a strategic view about optimum use of resources, embedded in economic reasoning. Hence the traditional approach does not lend itself very well to providing decision makers in Afghanistan helpful information about the robustness of particular strategies.

The questions and issues surrounding decision making and planning in Afghanistan led to the formulation of this Energy Sector Management Assistance Program (ESMAP) funded study on *Energy Security Trade-Offs under High Uncertainty: Resolving Afghanistan's Power Sector Development Dilemma*. The first objective of the study was to develop an approach to power sector planning and investment decision making in Afghanistan that accounts for the high level of uncertainty faced by planners and decision makers, and that strikes a balance between the three main policy imperatives of economic efficiency, energy security, and environmental sustainability. A second objective of the study was to introduce these new approaches to key staff of the relevant entities in the energy sector in Afghanistan, and contribute to their capacity building using a participatory approach, through joint analysis of a set of specific pending planning decisions, and to make recommendations in light of the joint analysis.

The Approach

This report, which is the final output of the study, provides an overview of challenges facing Afghanistan's energy sector, analyzes a select set of key decision problems and future development options, and makes recommendations on the way forward. In its underlying analysis, the report takes a different view about how best to plan the power sector, compared with the more traditional approaches. Rather than try to attempt to forecast the future, then identify the "best" plan to meet that future, the analysis turns the question around, and asks "given a set of options that can be practicably implemented, which one of these alternatives is the most robust to the main uncertainties?" This does not necessarily imply a short-term outlook focused just on the immediate issues: indeed, some of the illustrative problems that are discussed in this report explore what one must do today so that the benefits can be realized *far in the future* (such as the ability to build power generation projects).

This report proposes a set of relatively simple tools, adapted from a field of enquiry known as "decision analysis," to complement the traditional power sector planning methodology. These techniques have been used in the private sector for some time to assist financial portfolio decisions and investment decisions in many sectors, such as oil exploration, where high uncertainty requires a full understanding of risk.

The methodologies developed in this study deal with the often conflicting criteria of least economic cost, energy security, and environmental sustainability. It approaches the issue of discount rates, which have particular relevance for Afghanistan, which must choose between continuing imports (which generally are attractive under high discount rates) and construction of domestic hydropower generation (which generally is more attractive under low discount rates). The study also identifies methodologies that will address both local and global environment impacts of Afghanistan's energy development pathways. It addresses energy security in terms of resilience, risk, and their mitigation.

The Case Studies

Chapter 3 of the report outlines the results from a series of case studies focusing on planning decisions that require urgent attention by the government and are likely to have a significant bearing on the future of Afghanistan's energy sector. These are:

- **Hydropower planning.** Progress toward building new large hydropower projects recommended in the master plans has been slow, perhaps in part because the easiest way to expand supplies has been to increase imports from neighboring countries. Annex 2 of the report applies a *real options* analysis on how to assess the steps in hydropower planning given large uncertainties about Pakistan's willingness to take surplus summer hydropower generation from Afghanistan, geotechnical feasibility of options under consideration, and the difficulties of financing large projects: the decision process is depicted and analyzed in decision-trees.
- **Coal resources.** Notwithstanding several large coal-fired plants appearing in recent master plans, there remains high uncertainty about Afghanistan's coal reserves in terms of their quantity, quality, cost, and the timescale within which they may be available for use. Therefore, master plans that include coal-fired power plant projects are likely to remain speculative. The report describes how a coal resource can be assessed and uncertainty can be reduced, and outlines the key features of a good resource exploration and development program. Annex 3 estimates the economic benefits of a proposed coal exploration program in a *probabilistic scenario analysis*.
- **Natural gas.** The country's first gas-fired power generation project has been delayed, mainly due to the slow progress of well rehabilitation and new exploration and the completion of a new gas pipeline to Mazar-e-Sharif. The gas case study in annex 4 describes how the high uncertainty surrounding the comparison of the development of gas-fired generation versus imported electricity can be clarified using the techniques of *robust decision making*, in which one does not attempt to specify the probability of uncertain future events, but uses statistical techniques to examine patterns and factors of vulnerability of particular choices in a wide range of futures.
- **Transmission development.** The main factor complicating decisions about system development is the high uncertainty about the location of new domestic power projects. The regional problem is lack of synchronization among neighboring power grids and the lack of a grid or distribution code. The case study in annex 5 discusses the main issues in transmission system development.

Findings and Recommendations

Hydropower Development

The analysis in this report shows that the critical uncertainty in moving ahead with the large candidate hydropower projects is *not* the uncertainty of assurances from the government of Pakistan about its willingness to take summer surplus power, which in any event would be conditional on technical feasibility. Rather, it is the uncertainty of the cost of domestic thermal generation alternatives (notably of the Sheberghan gas) and of imported electricity. The Power Purchase Agreement (PPA) that was signed in November 2015 between Afghanistan and Turkmenistan indicates a cost of US¢ 5/kWh, escalated at three percent per year. This is an excellent price for Afghanistan and provides the benchmark cost for domestic hydropower generation at least in the short run, though the quantity available at this price may well not extend to additional imports.

The completed feasibility study for the proposed Bagdhara hydropower project indicates a levelized electricity cost of US¢ 7/kWh. It is important to note that the critical question with respect to Bagdhara is whether adequate geological and geotechnical surveying (with drilling to confirm the depth to bedrock) has been done at the proposed site for technical feasibility to be demonstrated. Moreover, as the feasibility study notes, costs are dependent on the security situation, and there is an unpredictable risk of potential increase of cost and construction time. Uncertainty about capital cost estimates remains high. The analysis shows that decision makers have been better served by waiting for the results of the Bagdhara FS so that its results can be used to recalibrate the APSMP estimates before making any decisions about further hydropower development.

Coal-fired Generation

The use of coal (or coal-bed methane) for power generation is a potentially attractive option for Afghanistan, but until the resources to power these options are verified with some degree of confidence, coal mine and power plant planning is premature. It follows that unless an exploration program is started today, the large future benefits of coal-fired generation (as opposed to imports of baseload power) can never be realized. There are only two options to answer the questions related to coal resource availability: either the private sector explores for and develops the resources it needs, or the public sector funds the exploration and then either develops the resource itself or auctions the proven resource to tender.

The analysis finds that the current mining law is considered too unfavorable by junior mining exploration companies to give them confidence that they would be able to secure financing from international investors to pursue projects in Afghanistan. Similarly, there are likely to be significant challenges associated with options involving the bundling of mineral exploration and power generation projects in a concession to be given to a foreign minerals mining consortium, given the implementation challenges experienced in the copper mining concession in Afghanistan. It follows from this assessment that the only realistic option currently open to the Afghan government is to finance the exploration work itself.

The results of the analysis demonstrate that the expected value of future benefits of a government-financed exploration program far outweighs its upfront costs. Under the most pessimistic outcomes for the cost of coal-generating projects relative to imports, the analysis shows that the expected Net Present Value (NPV) for an exploration program in the known areas of coal resources is $112 million; while under the expected conditions of coal generating costs and imports, the NPV is $369 million. Potential benefits of this magnitude warrant immediate implementation of the proposed Afghan Geological Survey (AGS) program. Indeed, if extended to the presently unexplored areas of the deep coal on the North Afghan Plateau, the NPV rises by $762 million. It also follows that even if the AGS program proved to be two or three times more expensive than estimated here, the economic benefits to Afghanistan remain high.

Gas-fired Generation

Gas-fired generation is a well proven technology with some advantages of modularity over coal and hydropower, especially when using diesel-cycle engines rather than gas turbines. But as with coal, decisions to invest in a gas-fired plant depend on well-characterized and proven reserves of gas.

The results of the analysis show that the decision to proceed with reciprocating engines for use of the Sheberghan gas is robust with respect to the main uncertainties over a very wide range of futures. Even if the cost of Sheberghan gas proves to be double the cost now seen as likely (around $8 rather than $4/mmBTU), the probability that a Sheberghan gas project would deliver negative economic returns is very small. The International Finance Corporation (IFC) of the World Bank Group is considering supporting a 50 MW gas engine project in Mazar-e Sharif. This analysis concludes that the proposed project should be strongly supported since it is of reasonable scale and gas engines are the most robust technology, given the likely operating environment.

Transmission Planning Strategies

Major transmission investment decisions have recently been taken on the basis of recommendations in the APSMP and are currently being implemented. During the next few years, and as conditions are expected to change in the region, the Ministry of Energy and Water (MEW) and Da Afghanistan Breshna Sherkat (DABS) have the opportunity to revisit the priorities for investing in further development of the transmission network. The review process will need to take into account alternative ways of further supporting power transit operations without limiting the ability to meet the competing financial needs for supporting the country's rural electrification program and developing indigenous generation resources.

This could indeed be an appropriate topic for a real options (RO) analysis of transit strategies based on assumptions and decision criteria that take into account (1) the risk of building 500 kV lines that are underutilized because potential transit opportunities fail to materialize; (2) the options for making a return on investment from either 500 kV high voltage alternating current (HVAC) wheeling or high voltage direct current (HVDC) line availability fees or both; (3) the additional investment required to guarantee an equivalent level of reliability and security for the importer or exporter of power; and (4) the future use of dedicated transit facilities at the end of the life of the PPA. Clearly, there is less cost and operational risk to Afghanistan if a dedicated HVDC line is built by its proponents and used for transit operations even though there may be a perceived loss of sovereignty in enabling independent commercial operation.

A key recommendation of this study is that before 2020, when the new transmission projects are expected to be commissioned, there is an urgent need to develop a national grid code, primarily to facilitate negotiations with Afghanistan's neighbors, but also to determine the incremental investments needed to upgrade substations and generation control systems to meet security and reliability standards for the transmission network. The review process necessary to formulate the essential features of a grid code must include a strategy for synchronization between Afghanistan and its neighbors to facilitate the more efficient use of domestic generation. This may include a requirement for new investments in back-to-back HVDC (HVDC b/b) or HVAC interconnections or variable frequency transformer (VFT) facilities, which can transmit electricity between two asynchronous (or synchronous) AC frequency domains.

Any future master plan will need to establish rules for transmission and generation diversity planning to minimize the potential for widespread disruptions and facilitate the development of new hydropower and coal-fired generation that may be associated with large mining operations. There will also need to be a clear policy setting out how Afghanistan proposes to integrate its domestic transmission development (which may be built to achieve a lower standard of reliability) with any new power import, export, or transit proposals that have their own special requirements for security and commercial viability.

Last, a strategy for optimizing the development and eventual interconnection of the large number of small grids is required. They should be made ready to connect and disconnect from the grid operating in both grid-connected or island mode. There needs to be greater consumer engagement to solve power issues locally by enabling the penetration of local renewables in residential, commercial, and industrial customer segments. In this way, distribution can become a transmission system resource, with all its components as part of a cohesive system. This will depend heavily on standardization (physical and data) as could also be established in the grid code.

General Conclusions

The analysis undertaken as part of this study demonstrates the value of a step-by-step planning process in which the option of using particular resources for power generation is evaluated in the framework of an implementation plan, assessing the uncertainties at each step. This is likely to be more useful than developing further large capacity expansion optimization models, which will have limited application in the context of Afghanistan.

The analysis strongly supports the need to prioritize development of IPPs, but at least for the next few years, their scale must be commensurate with realistic assessments of the likely availability of private equity and the suitability of the proposed technology. The proposed 50 MW gas engine-powered IPP at Mazar-e Sharif meets both these requirements, but projects at the 300–600 MW scale and based on Combined Cycle Gas Turbine (CCGT) technology or modern coal technology seem a more distant and unlikely prospect.

This report recommends that MEW initiates a broader national energy plan to look at alternative energy futures to the same level of detail, and based on economic reasoning, as in the APSMP: the main focus of such an exercise being to assess what is the best approach for use of the national fossil fuel and hydro endowment. Indeed, the use of gas to replace diesel in Kabul would also bring significant environmental and public health benefits. A consultant is currently preparing a gas master plan financed by ADB for the Ministry of Mines and Petroleum which may provide an entry point for this higher level plan.

When combined with the difficulties of mobilizing finance for hydropower or thermal generation projects, Afghanistan's need to secure adequate supplies of electricity limit the freedom of choice for development of the power sector. In the short term, there really is no other option but to negotiate large-scale electricity imports from Central Asian Republic (CAR) neighbors, combined with upgrading and rehabilitating existing hydropower projects and increased efforts to develop renewable energy in the rural areas. It is recognized that this has political and security implications for the authorities and underlines the importance of setting up a functional and high-quality planning system.

Essential Components of a Good Planning Framework

A good planning framework would include the following elements:

- The regulatory and legislative basis for conducting planning and for taking investment decisions.
- How different tools (or one particular tool, to be selected from a range) could be used for long-term planning and thereafter for assessing specific investment decisions.
- The responsibilities of each agency involved in the planning, decision making, construction, and operations phases of investments. For the purposes of this review, the focus is necessarily on MEW as the agency responsible for planning and its translation into broader policy making.
- A clear understanding of the capacity, data, and management information systems needed to ensure that planning can be carried out.
- A mechanism by which continuity in planning and decision making is assured, with the implied need for a politically neutral approach that will allow consistency in implementation of the power system plan.

As important as the planning framework is the need to ensure a participatory approach for each step in the planning process. In Afghanistan's case, this may require consulting a broader group of stakeholders than in countries which have not so recently emerged from conflict.

1. Introduction

The power sector in Afghanistan faces a planning challenge of enormous complexity embedded in a high degree of uncertainty. Over the past few years, Afghanistan's local generation capacity has remained stagnant at about 340 MW, and the rapid growth of consumption has been met primarily by imports which are now about 80 percent of total consumption, especially from Uzbekistan, suggesting a high vulnerability to interruption in energy supply. This vulnerability was demonstrated by the loss of power to Kabul in February 2015 and again in January 2016, when first an avalanche and then insurgent action brought down several towers of the 220 kV line that transfers electricity from Uzbekistan to Kabul; for the time that the line was out of commission Kabul had to rely entirely on domestic supplies, leading to significant load shedding. In the past decade, planning capacity has been relatively weak and driven by piecemeal studies. Donor support has lacked clarity in terms of priority investments, although the revitalization of the Inter-ministerial Committee on Energy (ICE) offers the opportunity for significant improvement in the planning process.

1.1. Power Sector Planning in Afghanistan

In the past decade, two power sector master plans have been prepared for Afghanistan: in 2004 and the more recent APSMP in 2012 which was financed by the ADB.[1] These planning efforts have followed the classical route of least-cost planning based on an approach that requires judgments about the likely future (load forecasts, international fuel prices, generation costs, and so on) and then use relatively sophisticated planning models to define an optimal expansion plan. The difficulty with this approach is that any least-cost plan remains optimal only if the predicted future materializes. Moreover, such plans are based on the assumption that the implementation of their recommendations is straightforward, which in most countries is not unreasonable. But in Afghanistan's unusual circumstances, normal assumptions about the ability to finance and implement projects do not apply: many of the large projects proposed by the master plans are of a scale that is unrealistic, with timelines and financing expectations that are largely too optimistic.

The APSMP, prepared based on a conventional power sector modelling approach, contains much useful information and offers a good analysis of what would be optimal in a less uncertain environment. Nonetheless, the APSMP does not appear to have taken into account a systematic risk assessment of candidate projects, including of technical, implementation, and financing considerations. It therefore relies on what might be characterized as the ideal "least-cost" future.

1. ADB, *Islamic Republic of Afghanistan: Power Sector Master Plan*, Project 43497, May 2013—hereinafter cited as APSMP.

The challenge facing decision makers in Afghanistan's energy sector is how to determine the most robust options now to secure the best possible or least bad outcome in the near or distant future, amid a range of uncertainties. Uncertainty over the extent of Afghanistan's coal resources illustrates this challenge: both master plans propose 300–400 MW-scale coal-fired power plants using Afghanistan's domestic coal resources. Yet to realize the benefits of potential coal use to meet base-load requirements before moving forward with any investment plan, Afghan decision makers must first establish whether in fact there is a resource and, if so, its extent and cost. Questions surrounding the feasibility of large coal-fired plants are further complicated by the peculiar conditions of Afghanistan: in a land-locked county, it cannot simply be assumed that internationally traded coal can be purchased and physically imported for use when it is needed.

Similar problems arise in hydropower planning. The proposed generation expansion plan outlined in APSMP includes several large hydro projects (among others, the 300 MW Kunar B and 789 MW Kunar A, costing $600 million and $2,000 million, respectively).[2] Without the availability of reliable and good quality information on hydrology, site geology, or access to site during development and construction, it is uncertain that such projects can be financed as required by the plan.

There are many questions about the extent to which conventional least-cost planning models can deal with the range of uncertainties faced by Afghanistan, as in many small and post-conflict countries. A case in point is natural gas: Afghanistan may indeed have a high likelihood of being host to natural gas reserves in sufficient quantities for large-scale power generation, but it does not follow that power generation is the best use of that resource. Economic theory demands that domestic resources should be used in the application that has the highest economic value—one of the issues to be evaluated in the forthcoming gas master plan. Kabul is one of the world's most polluted cities, so if gas can be brought to Kabul to displace diesel used for power generation and coal, fuel wood, and waste materials used by some industries and households for their processes, heating, and cooking needs, the local environmental benefits also are large.[3]

Should long gas pipelines be required, there would be further trade-offs related to security. There are important questions of long-term policy into which power sector investment plans should be embedded. The limits of the predict-then-act approach are further illustrated in the 2014 addendum to the APSMP, which presents 23 scenarios, each involving different assumptions about project delays and each costed out, but using the same building blocks of large projects to present a generation expansion plan for each. Such multiplicity of scenarios makes it difficult to derive well-founded recommendations, not least because many of the basic assumptions about load forecasts, international fuel prices, and discount rates are common to all.

2. APSMP, table 6.6.6.1.

3. And far outweigh the GHG emission consequences—which even if Afghanistan were able to build several 1,000 MW of coal projects by 2030, will still leave Afghanistan among the world's smallest emitters of GHG per unit of GDP and per capita.

In the particular circumstances facing Afghanistan, there is need for an alternative approach to planning in the power sector. Afghanistan faces a sector planning problem of high complexity and uncertainty, for which conventional approaches and tools offer little practical help to decision makers in understanding trade-offs and how to deal with uncertainty.

1.2. Objectives and Scope of this Study

This study was framed in the recognition of the government's need for developing a modern decision framework for sector planning. It recognizes the large uncertainties, and potentially conflicting objectives of economic efficiency, energy security, and environmental sustainability. The limitations of traditional planning approaches and the need to address the various questions and issues surrounding decision making and planning in Afghanistan led to the formulation of this study. Its first objective is to develop an approach to power sector planning and investment decision making in Afghanistan that accounts for the high level of uncertainty faced by planners and decision makers and that strikes a balance between the three main policy imperatives of economic efficiency, energy security, and environmental sustainability. The second objective is to introduce these new approaches to key staff at the relevant entities in Afghanistan by a joint analysis of a set of specific pending planning decisions and to make recommendations in light of the joint analysis.

The focus of this study was to develop an alternative analytical framework for tackling key decision making and planning problems in Afghanistan's power sector. It then aimed to apply this framework to concrete problems that require immediate decisions, working closely with key staff of the MEW and DABS, the national power utility. To achieve the objectives, a study team comprising World Bank staff and consultants with complementary expertise in transmission planning, fuel supply options, generation planning, and energy economics was formed. As part of the study, two workshops were held bringing together the larger study group. The first workshop, held in December 2014, discussed the proposed framework and methodology, and identified the real-life decisions facing the ministry and utility. The second workshop was held in May 2015, with representatives from MEW, DABS, and ICE working jointly to apply the approaches developed for decision making under uncertainty to the selected decision problems. This report, which is the final output of the broader study, provides an overview of challenges facing Afghanistan's energy sector, analyzes a select set of key decision problems and future development options, and makes recommendations on the way forward. In its underlying analyses, the report takes a different view about how best to plan the power sector compared with the more traditional approaches.

Rather than try to attempt to forecast the future, then identify the "best" plan to meet that future, the analysis turns the question around, and asks "given a set of options that can be practicably implemented, which one of these alternatives is the most robust to the main uncertainties?" Instead of adopting the traditional "forecast-then-act" approach to planning (i.e., act on the basis of the set of assumptions seen as most likely to identify the least-cost strategy), this study explores an approach in which risk and return are explicitly considered. This report proposes a set of relatively simple tools, adapted from a field of enquiry known as "decision analysis" or "decision making under uncertainty," to complement the traditional power sector planning methodology.[4] These techniques have been used in the private sector for some time to assist financial portfolio and investment decisions in sectors where high uncertainty requires a full understanding of risk and where some of the uncertainties can be resolved by additional research, exploration, or data gathering. The classic application of this approach is in the oil and gas industry, where developers are faced with the question of how much additional expenditure is justified on surveys and seismic studies before drilling a well. In power sector planning, the analogous problem is encountered in the geothermal sector: how much so-called 3G (geology, geochemistry, and geophysics) is warranted before exploration drilling commences for a given geothermal work area. Such problems lead to the concept of the so-called expected value of perfect information and to the concept of real options (the value of waiting until uncertainties are resolved)—both concepts are illustrated in the case studies in this report.

The decision making under uncertainty approach requires explicit consideration of risk preferences of the decision maker and of an understanding of the consequences of making decisions based on assumptions that subsequently prove to have been in error. The use of an approach based on decision making under uncertainty does not necessarily imply an emphasis on the short term, focused just on the immediate issues: indeed, some of the illustrative problems that are discussed in this report explore what one must do today so that the expected benefits can be realized in the future.

The primary audience of this report is decision makers in the key Afghan agencies in the sector, especially the Ministry of Finance (MOF), MEW, ICE, and DABS. This report is structured to focus on the needs of the primary audience, with a shorter main report targeting decision makers, accompanied by technical annexes covering the detailed technical discussions, case studies, and analyses that can be useful for other audiences, including energy sector practitioners in Afghanistan and other countries facing similar challenges.

4. The classic works include H. Raiffa, *Decision Analysis: Introductory Lectures on Choices under Uncertainty*, Addison-Wesley, 1968 and A. K. Dixit and R. Pindyck, *Investment Under Uncertainty*, Princeton University Press, 1994.

Organization of the report. The main part of the report is organized as follows: section 1 introduces the study and its objectives; section 2 summarizes the sector challenges and outlines the methodology; section 3 applies the proposed approach to analyze a series of urgent problems facing Afghanistan today and section 4 discusses the main findings, recommendations, and next steps, primarily for the benefit of decision makers in Afghanistan. The technical annexes, targeted to energy sector practitioners, delve deeper into the key components of the study, starting with the methodology, followed by detailed case studies on urgent problems facing Afghanistan's energy sector, and additional information that may be useful for technical specialists.

2. Afghanistan's Power Sector development Dilemma

This section describes the essential problems related to Afghanistan's power sector development and the unusually high levels of uncertainty that make decision making so difficult. The government of Afghanistan is faced with having to make decisions about the future of the energy sector in a way that balances the sometimes competing objectives of economic efficiency, energy security, and environmental sustainability. This is true for decision makers in most countries. There are many answers to the question of what to do next, but the difficulty has been that the sequence of the recommended projects in proposed plans has few links to the likelihood that these projects can actually be implemented given the many uncertainties. This chapter discusses how the government's objectives are framed in the current state of the Afghan energy sector and elaborates on the approach it has adopted.

2.1. Institutional Setting in the Electricity Sector

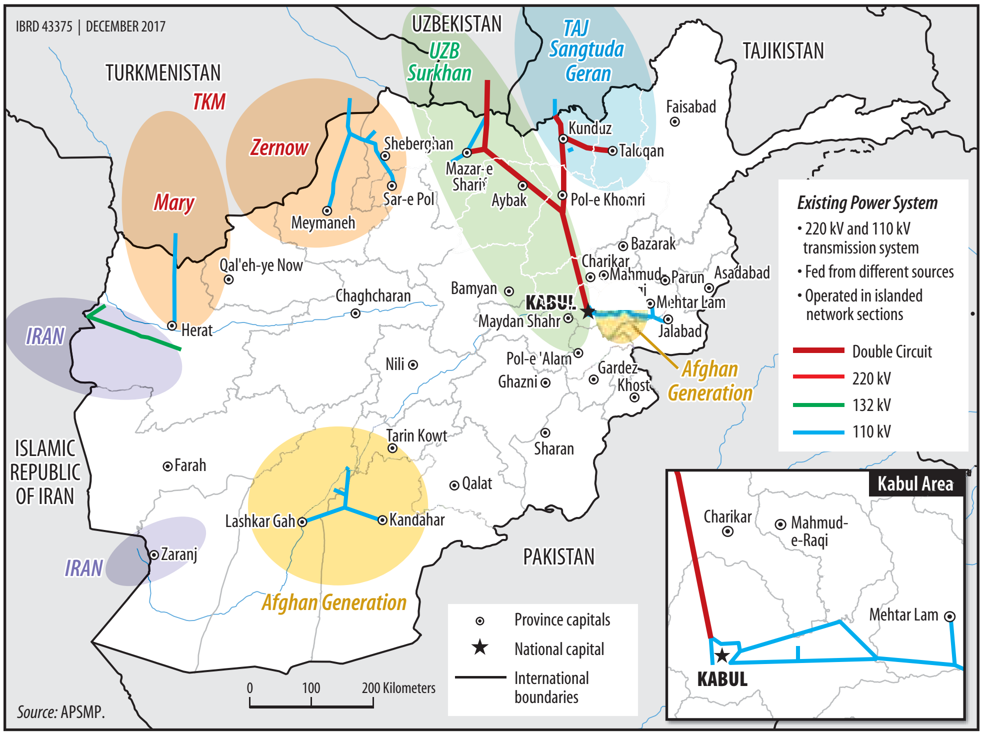
Primary authority and responsibility for the electricity sector resides with MEW. In May 2008, the government of Afghanistan corporatized MEW's National Electricity Service Department *Da Afghanistan Breshna Mossasa* (DABM), and it became an independent state-owned utility *Da Afghanistan Breshna Sherkat* (DABS). This vertically integrated utility is responsible for electricity operations in the entire country: its shares are owned by the MOF (45 percent), MEW (35 percent), the Ministry of Economy (10 percent), and the Ministry of Urban Development (10 percent). MEW is responsible for power sector planning, while DABS is responsible for operations.

In August 2014, the government announced plans to create an Energy Master Planning Secretariat (EMP-s) in MEW. Its principal purpose was to be responsible for updating the APSMP, for preparation of consolidated budgets for submission to MOF, and for reporting implementation progress to the Ministry of Economy. This entity is expected to become operational in the near future.

ICE has served as an important coordinating body. It meets every few months, and issues detailed minutes that summarize the status of planning and project implementation.[5]

5. This body also has a website that provides much useful information (https://sites.google.com/site/iceafghanistan). Efforts to reinstate the Afghanistan Energy Information Center (AEIC), previously funded by USAID, are now underway.

Figure 2.1. The Grid Systems of Afghanistan



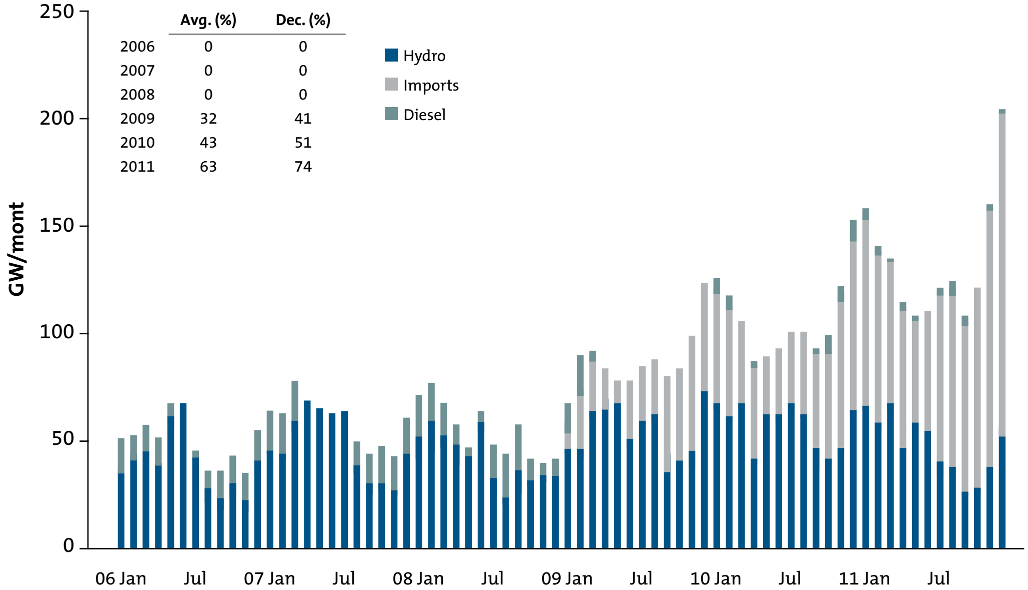
Source: APSMP.

2.2. Power Supply and Demand Over the Past Decade

There is no single Afghan power system. It presently consists of four distinct service areas along with numerous small isolated systems that may take some time to interconnect (figure 2.1). Each is connected in some way to a source of generation, mostly imported, to which part or all of the corresponding Afghan system is then synchronized, creating a series of "islands." Of the four main geographically separate power networks in Afghanistan, the North East Power System (NEPS) is the largest. The NEPS currently supplies part of Kabul city over long 220 kV links from Tajikistan and, separately, Uzbekistan. Other parts of Kabul are supplied from various local hydro and diesel generators which are currently not allowed to be synchronized with the NEPS (for reasons explained below). Under a USAID sponsored project it is expected that by 2018, NEPS will be interconnected with the Kandahar-based South East Power System (SEPS).

Over the past few years, the rapid growth of Afghanistan's electricity consumption has depended on imports. It has been possible primarily due to the rapid growth of supply from the CARs, and from Uzbekistan in particular. In 2011, almost 80 percent of the country's total supply was imported from Uzbekistan. In the past decade, only one new generation project has been built—a 105 MW diesel project in Kabul, which has been little used due to diesel fuel shortages and high operating costs.

Figure 2.2. Monthly Energy Supply to the Kabul Region



Source: Authors' analysis based on DABS data.

The distinguishing feature of energy demand in Afghanistan is the sharp winter peak. As shown in figure 2.2, December–January consumption is between 150–180 percent of the summer consumption. The figure also shows the change in generation mix: with the start of significant imports in early 2009, diesels have rarely been used, and by 2011, 74 percent of the Kabul demand was derived from imports brought from the North across the Salang Pass transmission line.

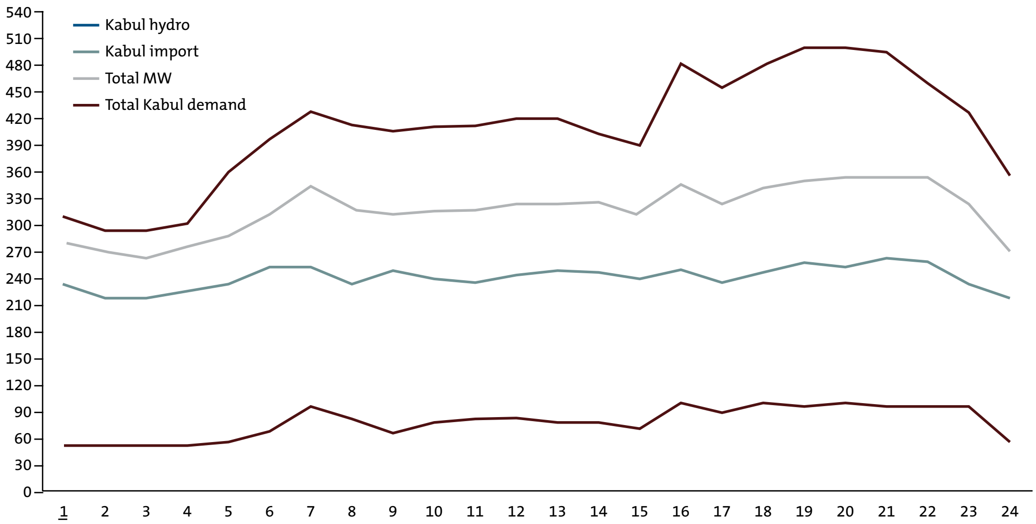
With demand far in excess of supply, loads are severely curtailed. Figure 2.3 shows the average hourly demand for February 2015: of the estimated total peak demand of 497 MW (at 20:00), just 350 MW can be met, of which 252 MW derives from imports.

No less severe is the power situation in SEPS that supplies Kandahar and Helmand provinces. In November 2014, it was reported that 93 factories in Kandahar were inoperative due to power shortages[6] One of the cornerstones of economic development in the region is the new industrial park development at Shurandam—where over 100 small factories had started up in the last few years, with access to reliable electricity produced by NATO military-run generators powered by fuel procured and donated by USAID.[7] The sustainability of this development—a key element of the NATO counter-insurgency strategy—

6. Minutes of the ICE meeting, November 2014.

7. K Oscarsson. 2012. Energy-Development-Security Nexus in Afghanistan, *Journal of Energy Security*, November 2012.

Figure 2.3. Hourly Load Curve for February 2015



Source: DABS presentation to the ICE meeting, February 2015.

is unclear once donor funds expire, and if more sustainable sources of power are delayed. Without reliable grid supply, the only other source is diesel self-generation at costs that are prohibitive (even at the lower oil prices of early 2016) and which would directly challenge the fragile economic development of the region. It is precisely this urgency to provide greater electricity access (throughout Afghanistan) that has driven NEPS/DABS electricity supply to its extraordinary dependence on electricity imports from Afghanistan's northern neighbors and the need to bring on additional supplies once the SEPS/NEPS connection is complete.

In Afghanistan, energy security and supply diversification have, for the time being, been subordinated to the requirements of low-cost supply expansion. Nevertheless, it is understood that over-reliance on a single source entails significant risk, not merely due to potential impacts in the event of interruption (be it from security or natural causes), but also the loss of negotiating leverage on prices for new IPP generation projects. The ease with which imports have been rapidly expanded also appears to have reduced the incentives to properly examine other generation alternatives. Notwithstanding the recommendations of the 2004 NorConsult Master Plan to undertake feasibility studies for large hydropower projects, only a single FS to international standards, for the Bagdhara project, has been completed. In the 2012 APSMP, this project appears for construction only after the two projects on the Kunar River for which detailed FS have yet to be prepared.

2.3. Trade with Neighboring Countries

Afghanistan is landlocked, surrounded by energy rich neighbors to the west and north and an energy-hungry Pakistan to the east. Given its geographical position and fragility, it has looked to its neighbors for electricity supply. Its historic role as a conduit between central and south Asia lends itself to the concept of Afghanistan as an energy transit country between CARs and Pakistan.

Central Asian Republics

Although attractive, importing power from the CARs incurs significant costs. It is important to recognize that the neighboring Tajik, Turkmen, and Uzbek power systems operate asynchronously with one another and with Afghanistan (although the Turkmen system is synchronized with that of Iran). Hence, importing power from these different countries obliges Afghanistan to operate several separate power systems, each synchronized with its neighboring supplier or with its own domestic supply (which is itself not synchronized). While this has helped Afghanistan grow its electricity consumption over the last five years, asynchronous supplies limit opportunities to interconnect to improve security of supplies and expand the power network in a rational way. Afghanistan's contract with Uzbekistan expressly forbids DABS from synchronizing domestic generation plants with the Uzbek system. On the other hand, the contract with Turkmenistan stipulates that the high voltage (HV) transmission facilities in Afghanistan must have "identical technical characteristics with those of Turkmenistan…" Other smaller load centers adjacent to the Uzbekistan-Kabul transmission lines are similarly constrained to use their own diesel or smaller generation without access to the cheaper Uzbek power.

If Afghanistan is to avoid wasteful and costly duplication, further investment in transmission cannot avoid the synchronization issue. In the first instance, it is essential that Afghanistan adopt the relevant elements of a grid code acceptable to the CARs to enable DABS to synchronize its in-country generation with the imported power systems.

Pakistan

Pakistan presently suffers from persistent power shortages. These occur especially during the summer, when electricity demand is at its peak. This acute shortage is the driving force for the various proposals for electricity trade in the region and the CASA-1000 project in particular.

Pakistan's power shortages affect Afghanistan's hydropower planning considerations. Looking forward, the extent to which Pakistan's shortages will persist in the medium to long term is a fundamental question for Afghanistan. It is widely assumed that were Afghanistan to build its own new large hydropower projects, Pakistan would be a potential buyer for their expected summer surplus. Pakistan is now redoubling its efforts to build its own large hydropower projects: the 1,320 MW Tarbela 4 extension is now under construction, and a further 1,320 MW for Tarbela 5 is under consideration. The much larger 4,350 MW Dasu hydropower project is also nearing construction start, with financing in place for the 2,160 MW Phase I project nearing close and preliminary work now underway. Moreover, gas sector reforms are underway in Pakistan, which, if successful, may result in more gas being available for power generation, which would also alleviate power shortages if implemented. The extent of *summer* power shortages in Pakistan ten years from now, and Pakistan's willingness to pay for importing summer power from new regional interconnection projects, is therefore unclear.[8]

Pakistan's need to import for gas-based electricity is also uncertain. Pakistan might be a willing buyer of gas-based electricity imported from Turkmenistan, as envisaged under regional power trade projects involving Afghanistan as a transit country. That must be balanced against Pakistan's intention to build its own CCGT projects based on imported LNG. Power imports from Turkmenistan would be attractive to Pakistan only if the price of gas-fired generation in Turkmenistan is sufficiently low to offset the cost of transmission plus the cost of any transit fee charged by Afghanistan. So that will depend mainly on the size of the difference between the LNG price in the Asia Pacific market (LNG would most likely to imported from Qatar, although Pakistan is also reportedly exploring other suppliers), and the market price of gas in Turkmenistan (driven by competition between potential gas suppliers to China, including Turkmenistan and Russia). In the past, that differential has been large but it may narrow in the future if the global efforts to decouple LNG prices from oil prices succeed and the current surplus persists.

Gas transit opportunities may compete with electricity transit. Moreover, Pakistan is actively exploring imports of pipeline gas from Iran, while also pursuing the Turkmenistan Afghanistan Pakistan India (TAPI) gas pipeline project. In the latter case, Afghanistan stands to receive substantial transit revenues as well as gas for its own use. More revenue from transit—implying Pakistan and India are importing more gas—may mean less opportunity to sell summer surplus hydro to Pakistan.

2.4. Power Sector Development Vision

Past national power plans (and the recent APSMP) have been ambitious. In 2011, it was anticipated that by 2014/2015, the construction of a 400 MW coal project would be underway, including the additional transmission infrastructure in place to evacuate the power; that the connection between SEPS and NEPS would be complete, that major hydro projects would be underway on the Kunar River following transboundary agreements for hydropower development; and that the Sheberghan gas project would be underway (table 2.1 and figure 2.4). Their projected costs far exceeded the level of likely financing available, with the consequence that they raised expectations among some stakeholders while also making prioritization difficult.

8. It is also possible that ten years hence the CASA-1000 facilities could be used to export power from Pakistan to support Afghanistan or Tajikistan during their winter shortages.

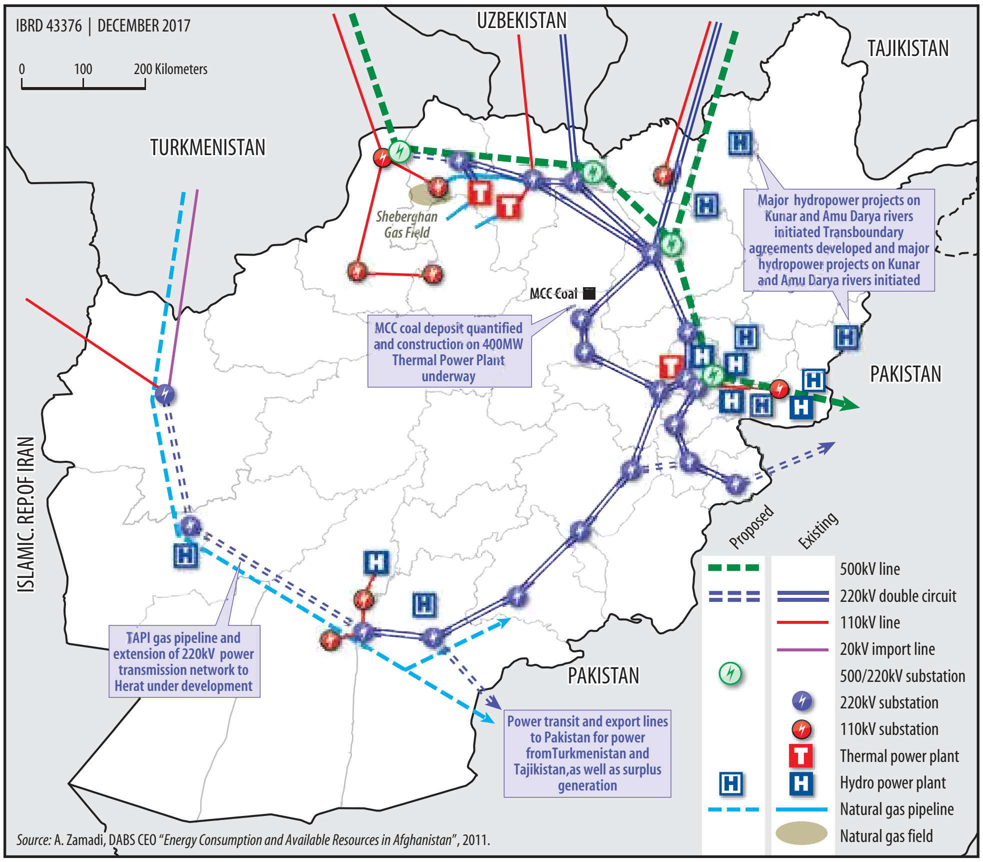
Table 2.1. The "Robust" Generation Capacity Expansion Plan 2016–32

Year	Size (MW)	Project
2016	150	NEPS_SEPS connection
2017	150	Sheberghan gas
2018	50	Sheberghan gas
	300	TKM UZB import
2019		
2020	700	TKM UZB import
2021	50	Sheberghan gas
2022	100	Sheberghan gas
2023	150	NEPS_SEPS connection
2023	50	Sheberghan gas
2024	300	Kunar B (Hydro)
2025		
2026	789	Kunar A (Hydro)
2027	400	Bamyan Coal
2028		Kajaki addition(Hydro)
2029	800	Bamyan Coal
		Olambagh (Hydro)
2030		
2031		
2032	210	Bagdhara (Hydro)

Source: APSMP, p.10–75.

Preparation of master plans can increase risks. The risk is that the master plan simply becomes the entry point for a proposed project which does not ensure that there is either financing or the need to build it. It misses the purpose of there being a living document to guide the development of the sector. This is a problem that is not unique to Afghanistan, and most countries make efforts to avoid this by instituting a set master planning cycle, perhaps in line with a broader economic planning model such as a five-year economic development plan. Other countries provide annual updates. The risk of not doing so is that a rolling master plan that evolves simply gets bigger, and it becomes impossible to remove projects from the plan once they are in because vested interests continue to support their inclusion. The general guiding principle should be that power sector master plans, as any other plan, must be realistic and achievable.

Figure 2.4. Vision 2014/2015 As Seen in 2011



Source: A. Zamadi, DABS CEO "Energy Consumption and Available Resources in Afghanistan," 2011.

Many investments have been delayed. The NEPS-SEPS connection—supported by USAID—is now expected to be completed only in 2018, although it is unclear how synchronization issues would be dealt with. The coal-fired power plant project is stalled—the China Metallurgical Group Corporation (CMGC) coal resource assessment was significantly delayed by security problems in the region, and the status of the mining concession is also unclear. Little progress has been made on the Sheberghan gas power generation project. However, some progress on the 500 kV ADB-financed transmission lines has been achieved, with the 500 kV line (initially to be operated at 220 kV) in the North about to start construction.[9]

9. According to the ICE meeting of February 2015, construction contracts for the first phase were to be awarded in the 2Q 2015.

2.5. Energy Security Concerns and Decision Making in the Sector

Dimensions of Energy Security in the Afghan Context

Expansion of electricity supply has come at the expense of increasing import dependence. In Afghanistan, the expansion of electricity supply over the past 7–8 years has relied almost exclusively on imports from its northern and western neighbors, at average costs of less than 6 US¢/kWh. This has come at the potential geopolitical risk concomitant with dependence on its neighbors and particularly on Uzbekistan, which provides the bulk of imports for NEPS and the Kabul region. It also depends on the physical security of the single 220 kV transmission corridor that brings power to the Kabul region. Even though an energy security policy may not have been explicitly formulated by the government, the way in which the trade-off has been made in practice makes clear that the risks stemming from the sector's vulnerability to changes in geopolitical circumstances or damage to the Salang Pass transmission corridor are not considered severe when assessed against the alternative of constraining consumption to the available domestic supply. It is well recognized that access to affordable grid-connected electricity is central to economic development, which is acknowledged to be the only route to a long-term sustainable future. Section A1.3 in annex 1 provides further details on the most predominant energy security concerns that were discussed during the course of this study. A broader discussion of the different descriptions and interpretations of implications of energy security is also available in annex 1.

Physical security is an increasing source of uncertainty. The prevailing perceptions of the security issues facing Afghanistan reflect the view as seen by Afghan officials involved in the day-to-day operation of the power system and faced with short-term priorities. These can be summarized as: the imperative of ensuring supply to consumers, the lack of domestic refinery capacity, dependence on electricity imports, the harsh weather in Afghanistan, local opposition, and insurgent activity.

There is a disconnect between the perceptions of energy security among Afghan officials and potential investors and equipment suppliers overseas.[10] Unfortunately, it is the perception of parties outside Afghanistan—particularly potential investors—that pose the most significant obstacle to developing the generation options for the long term. In addition to the problems faced by the Chinese mining consortium in assessing the coal resource,

10. There is no doubt that physical security concerns may easily become misused as a convenient cover for the mismanagement of foreign contractors. The SIGAR report on the Tarakhil project asserted that delays and cost overruns were largely a consequence of ambiguities in the statement of work, delays in subcontract awards, subcontractor performance problems, lack of onsite quality assurance, lack of timely approvals, and poor communication between USAID and the contractors. The only Afghanistan-specific issue was delays associated with land ownership (also noted by the World Bank Enterprise Survey as one of the main constraints to private investment). See SIGAR, *Special Report: Contract Delays and Cost Overruns for the Kabul Power Plant and Sustainability Remains a Key Challenge*. January 2010.

other recent examples include: difficulties of consulting companies working on hydropower FS that require extensive on-the-ground investigations and limited interest in bidding to supply and install equipment that require specialized and skilled staff presence in country.

Decision Making Implications of Energy Security

Private investment is limited by poor security and political instability. As noted in the World Bank's 2014 Business Enterprise Survey of Afghanistan,[11] after political instability (25 percent), corruption (16 percent), access to land (14 percent), and finance (12 percent), lack of electricity is cited by 10 percent of businesses as the main obstacle to private investment.[12] These assessments severely constrain the freedom of choice for power-sector investment in Afghanistan and has led to significant distortions, particularly over-investment in transmission and under-investment in generation.

Costs and feasibility are affected by uncertainty. Detailed feasibility studies show that generation project construction costs, as an example, for a CCGT in Northern Afghanistan, could be 60 percent greater than a comparable unit in Pakistan (attributable to "substantial logistics and security costs").[13] Similarly, the cost estimate for extra security for the construction of the CASA-1000 transmission line was increased by $60 million in the latest FS update.[14] Therefore, in the absence of a sustained improvement in the overall security environment, the feasibility of any large project being built as an IPP will be highly uncertain and will involve significant risks and costs.

Energy security concerns need to be addressed pragmatically during decision making. If a decision maker is to compare two alternative investments or two alternative generation plans and ask which contributes more to energy security, then the first question is how the security dimension of each would be quantified in practice. The usual expedient is textual discussions (often on the presumption that the argument is self-evident and needs no further explanation), but these inevitably descend into vague assertions for which there may or may not be much basis and which contribute few meaningful insights. The case studies in the annexes of this report show practical ways of quantifying the security dimension.

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11. World Bank, Business Enterprise Survey: *Afghanistan Country Profile*, 2014.
12. The World Bank also ranks Afghanistan 183rd overall in its annual *Doing Business 2015* review of business regulations for domestic companies in 189 economies. While Afghanistan ranks high in starting a business, it is nearly last in dealing with construction permits, getting electricity, registering property, trading across borders, and enforcing contracts.
13. AEAI, *Gas/Power Related Infrastructure Assessment*, Sheberghan Gas Field Development Project, Report to USAID, April 2011 (see table 3, Capital Costs).
14. World Bank, *Project Appraisal Document*, *CASA-1000, Economic Analysis Annex*, March 2014.

A quantitative approach to energy security first requires a decision about whether it should be treated as an economic externality or as a separate attribute. If the former, it needs to be quantified, monetized, and included in the table of economic flows (or NPV) calculations. To be treated as a separate attribute, it needs to reflect an objective separate to that of maximizing economic returns. An analogy may be drawn to the treatment of greenhouse gas (GHG) emissions reductions: one can either monetize the global social value of carbon and include the resulting flows in the calculation of economic returns or, recognizing the inherent difficulties of estimating such damage costs, calculate the (undiscounted) lifetime carbon emissions and then focus on the trade-offs between the two.

In the case of Afghanistan, narrowly defined dimensions of energy security are subordinate to the overall public security environment—which plays a major role in determining the costs of infrastructure investment (and power sector capital costs in particular), and even the ability to finance and implement any large capital investment. Common sense dictates that the physical security aspects are built into the economic costs of the project (and indeed may influence the choice of one project over another—Bagdhara over Kunar for example). But the energy security implications do not so easily lend themselves to this quantification in an individual project and can only be done by comparing some measure of system security (for example loss of load probability—LOLP) with two different projects and seeing which one gives the "more secure" result.

2.6. Environmental and Social Concerns and Decision Making

To some extent, environmental and social concerns are already being taken into account in energy sector decision making. The 2012 APSMP notes that:

> The general considerations and preliminary social screening of the selected projects … reveal that the social impacts of energy infrastructure projects are mainly related to land use, land acquisition and resettlement issues … as well as to Environment, Health and Safety impacts that will arise during the construction and operation phases of the projects that are the subject of the Environmental Impact Assessment and Environmental Management Plans.

For example, as noted in annex 1, consideration of social impact issues have already shaped the design of the Bagdhara hydro project, whose reservoir design was adjusted to avoid large-scale resettlement issues. Other preliminary studies of potential hydro projects suggest that the application of international safeguards policies should not pose insuperable difficulties.

Greenhouse Gas Emissions

The avoidance of greenhouse gas (GHG) emissions is unlikely to be a primary concern for policy makers: Afghanistan's GHG emissions are among the lowest in the world, both in absolute and per capita terms (table 2.2). Afghanistan ranks at the bottom of the list, with emissions of less than 0.1 tons/capita. It can be stated with confidence that Afghanistan's GHG emissions will remain negligible even if by 2030, several thousand MW of coal base load capacity were in operation.[15]

Table 2.2. International Comparisons, CO_2 Emissions Per Capita (2008)

	Tons CO_2/Capita
United States	18.38
Germany	9.79
United Kingdom	8.32
Austria	8.31
South Africa	6.93
China	4.92
Global average	4.39
Vietnam	1.19
Sri Lanka	0.61
Afghanistan (1991)	0.20
Afghanistan (2020)[a]	0.18
Afghanistan (1998)	0.03

a. Assuming an additional 1000 MW of coal generation, see text below

Quantifying the GHG emissions of alternative power sector options is straightforward (and described in the World Bank's 2015 guidelines for carbon accounting).[16] It is also likely that the strict guidelines that apply to the World Bank's financing of coal projects could almost certainly be met, given the need for thermal power to improve energy security, reduce power shortages, and increased access. The main consideration would turn on whether gas is available in sufficient quantity as a viable alternative to coal.

The World Bank has now also issued guidelines for the valuation of carbon emissions, so calculation of economic returns with and without inclusion of carbon emissions is also straightforward.[17] If the baseline carbon values ($30/ton CO_2 in 2015, increasing to $50/ton by 2030) were applied to the valuation of coal and its alternatives—it would add 2.7 US¢/kWh to a coal project, but only 1 US¢/kWh to a gas CCGT. The summary of the cost benefit analysis in table 2.3 shows the impact of adding the damage cost of GHGs at the baseline level recommended by the World Bank.[18] More detailed calculations are in annex 1.

These are illustrative calculations and this paper does not argue that Afghanistan should make urgent power-sector decisions based purely on the avoidance of GHG emission damage costs. Indeed, these simple calculations are made much more difficult when the various uncertainties in assumptions are taken into account. However, the calculations

15. There is much uncertainty about population size. The World Development Indicator (WDI) database gives the 2010 population as 34.4 million—which value is used in this report unless stated to the contrary.
16. World Bank Sustainable Energy Department, Guidance Note: GHG Accounting for Energy Investment Operations, Version 2, January 2015.
17. World Bank, *Criteria for Screening Coal Projects under the Strategic Framework for Development and Climate Change*, 2010.
18. *Social Value of Carbon in Project Appraisal*, Guidance Note to World Bank Group Staff, September 2014.

Table 2.3. Cost Benefit Analysis of Illustrative Options With and Without GHG Damage Costs Included, 10 Percent Discount Rate

	Without GHG Damage Costs		With GHG Damage Costs	
	NPV ($m)	LCOE (¢/kWh)	NPV ($m)	LCOE (¢/kWh)
Imports	908	8.0	1,226	9.8
Domestic Gas	1,013	8.1	1,246	10.0
Renewables	1,235	9.9	1,235	9.9

do show the importance of the discount rate assumption, and the main principle involved, namely that the relevant externalities and damage costs be monetized and included in the table of costs and benefits.

Table 2.4. Estimated Ambient Levels of Particulates, µg/m³

Inversion Layer Height	$PM_{2.5}$	PM_{10}
Kabul, 500 meters[a]	39.5	396
Kabul, 250 meters[a]	79.0	792
EPA standard[a]	15.0	
Mazar-e-Sharif[b]	68.0	334
Kabul[b]	86.0	260
Beijing[b]	56.0	121

Sources:
a. A Sediqi, Preliminary Assessment of Air Quality in Kabul.
b. World Health Organization, Ambient (outdoor) Air Pollution in Cities Database 2014.

Local Air Quality

Kabul has recorded levels of ambient air pollutants greater even than Beijing and Lahore. Located at a high altitude, ringed by mountains, and subject to frequent atmospheric inversions, concentrations of $PM_{2.5}$, SOx and NOx are multiples of generally accepted safe levels (table 2.4). According to the Ministry of Health, some 3,000 deaths per year in Kabul are attributable to the toxic air quality: in a sample of 200 hospital patients, 80 percent had elevated levels of lead (indicative of leaded gasoline). Indeed, so serious are the perceptions of poor air quality that the U.S. Defense Department has been petitioned to include exposure to Kabul's toxic air quality conditions in military service personal histories.[19]

The direct contributions of DABS thermal generation to these air quality levels is minimal. Major sources of pollution include motor vehicles (many of which are old and poorly maintained), brick kilns, and open burning of tires and waste material. Coal (of unknown quality) is widely used as a residential fuel, including in small district heating systems for new residential developments. The Tarakhil diesel plant and other generators owned by DABS are used infrequently.

Self-generation of electricity is likely a large contributor to local air pollution. As grid power delivered to Kabul has increased in recent years, the use of diesel self-generation will have declined (other things equal), but with renewed economic and industrial growth, power shortages remain widespread, and estimates of the current self-generation capacity in

19. Letter from U.S. Senator Wyden to the U.S. Secretary of Defense Leon Panetta, 2012 www.wyden.senate.gov/download/kabul-air-quality-letter.

Table 2.5. Cost of Social and Environmental Mitigation Plans

Project	MW	Total Project Cost ($USm)	$/kW	EMP ($USm)	SMP ($USm)	Total ($USm)	As percent of Total Cost (%)	Resettled Housholds	Affected Housholds	SMP Cost Per Houshold ($)
Chunek	390	558	1,431	5.0	11.9	16.9	3.0	323	323	36,904
Dab	450	884	1,964	4.4	17.7	22.1	2.5	480	480	36,854
Surtaq	410	660	1,610	5.0	11.6	16.6	2.5	300	300	38,600
Lar Sultan	390	1,030	2,641	4.0	13.1	17.1	1.7	325	325	40,369
Sagi	300	611	2,037	1.3	6.5	7.8	1.3	210	349	30,857
Kunar_A	789	1,600	2,028			36.4	2.3	1,234	2,844	29,498

Source: 2009 Pre-feasibility studies; 2009 FS for Shal (Kunar).

commercial and industrial enterprises is between 25–100 MW. In addition, in the residential sector, many households have two-stroke gasoline generators. The strong winter peak demand for electricity is largely attributable to the widespread use of electric bar-heaters. Much residential heating and cooking is from burning wood, coal, and waste—though LPG has begun to replace it for cooking. Greater availability of grid-electricity can only be beneficial from the point of view of reducing emissions from heating and cooking, though it is likely to exacerbate difficulties of meeting peak demand.[20]

Social Impacts

Social impacts are not expected to be a major source of uncertainty in planning. Major generation and transmission projects, as well as domestic resource exploitation (coal, gas, oil, hydro), may affect the well-being, land use, and livelihoods of project-affected persons (PAPs). There is little reliable information about the number of PAPs likely to be displaced by the large hydropower projects: the prefeasibility study of five smaller Kunar River projects showed the number of displaced households in the few hundreds (table 2.5), with the cost of social mitigation plans between $6.5 and $18 million. It is estimated that for Kunar A, if 1,234 households are to be resettled, the total costs of the EMP and SMP would be at about $36.4 million. The detailed feasibility study for Bagdhara suggests that by restricting the reservoir level to 1,375 meters above sea level (masl), no resettlement is needed for the dam, and the transmission line would require the resettlement of ten households. It would therefore seem possible that by careful design and good management, uncertainties in planning related to social impacts can be minimized.

20. It is well understood that the damage costs of diesel self-generators, located in densely populated urban areas, with uncontrolled emissions emitted at or near ground level, have damage costs per kg of pollutant, are 1–2 orders of magnitude greater than from modern utility-scale generators fitted with high stacks, located in remote areas, and fitted with state-of-the-art pollution controls (see for example Lvovsky et al. 1990). This would likely hold true for Afghanistan as well: any large coal generation project would be far away from the major urban population centers near the coal mine from which the coal is to be obtained. For details, see World Bank, *Economic Analysis of Power Sector Projects: Guidance Note*. Technical annex B5, June 2015).

The costs of social and environmental management and mitigation plans, and of other related safeguards policies, are readily monetized and included in the table of economic flows—though given the limited information at hand, such estimates are again subject to high uncertainty. Based on the information in table 2.2, the incremental costs in the case of hydropower projects may be taken as 3 percent.

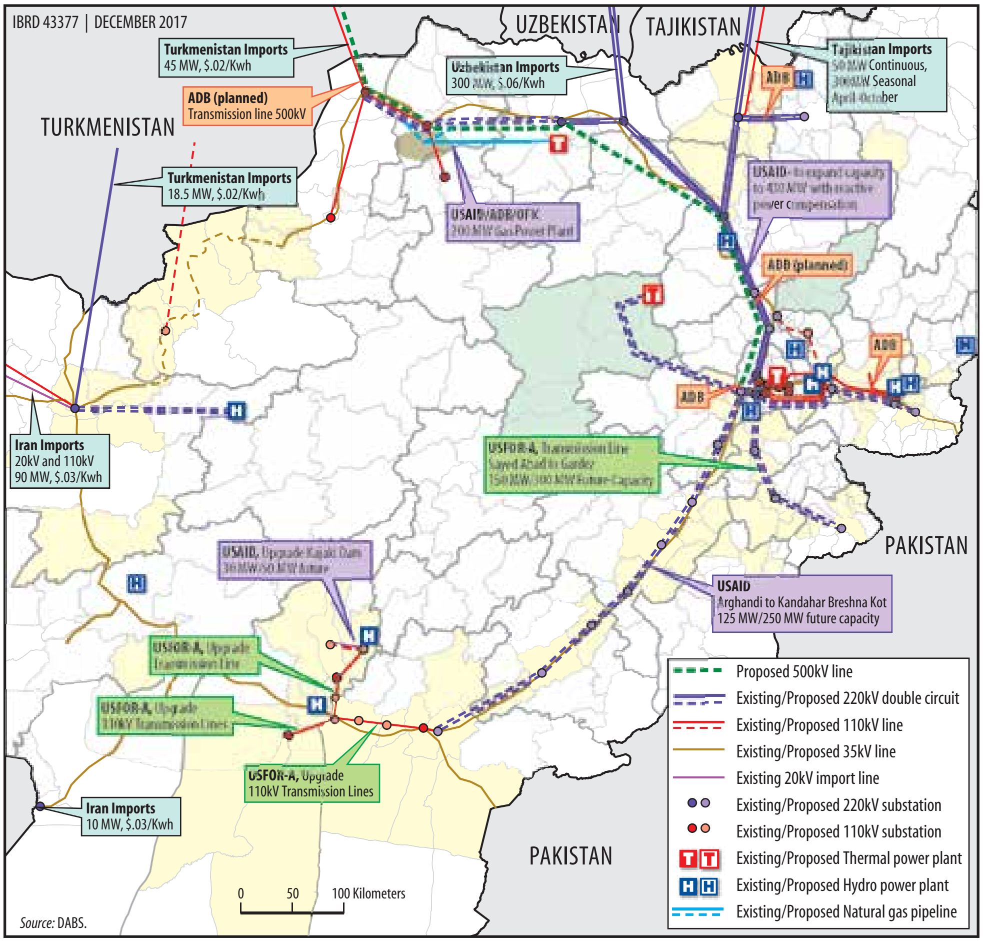
2.7. Dimensions of Uncertainty In Decision Making in Afghanistan

A wide range of uncertainties impact the extent to which different energy sector objectives can be achieved. The additional high degree of uncertainty makes Afghanistan's task much more complex than that facing most countries which must balance economic efficiency, energy security, and environmental sustainability since the uncertainties may compromise the extent to which these objectives can be achieved or even traded off one another. Uncertainties include the following: [21]

- ***Import dependency.*** For the past 10 years, Afghanistan's main source of new supply has been imports, to the point that 80 percent of the 2014 NEPS consumption came from its neighbors, exposing Afghanistan to the risks of supply disruption and supply contraction if the previously available surpluses decline due to increasing domestic needs of Afghanistan's neighbors. Figure 2.5, drawn from 2012, shows continued expectation of dependence on imports in the short term, based on investment plans for import lines. To date, these supplies have been relatively secure, but the extent to which this stability will persist is unclear.
- ***Geopolitical considerations.*** Afghanistan is faced with a challenging geopolitical situation. Being landlocked, it is entirely dependent on the goodwill of its neighbors for much of its energy supply, not just for electricity imports, but also for oil imports. The challenges in cooperation among the CAR countries is expected to continue to frustrate plans to implement the APSMP concept of development of a TUTAP power market. In January 2012, Iran closed its border with Afghanistan for oil trade, causing significant disruption. The evolution of bilateral relations with Pakistan and India are even more uncertain given that the relationship between India and Pakistan is itself uncertain. If the lifting of sanctions on Iran improves the general geopolitical climate in the region, there may well be benefits to Afghanistan—though this too is subject to much uncertainty.
- ***Gas resource uncertainty.*** How much gas there may be in the Sheberghan fields is subject to great uncertainty: recent studies show that, based on current information, the variation between the high and low estimates of the maximum rate of resource extraction span an order of magnitude. The difficulty is that

21. These issues are all discussed in more detail in the relevant case studies (annexes 2, 3, 4, and 5) and their summaries in section 3.

Figure 2.5. Short-term Investment Plans 2012

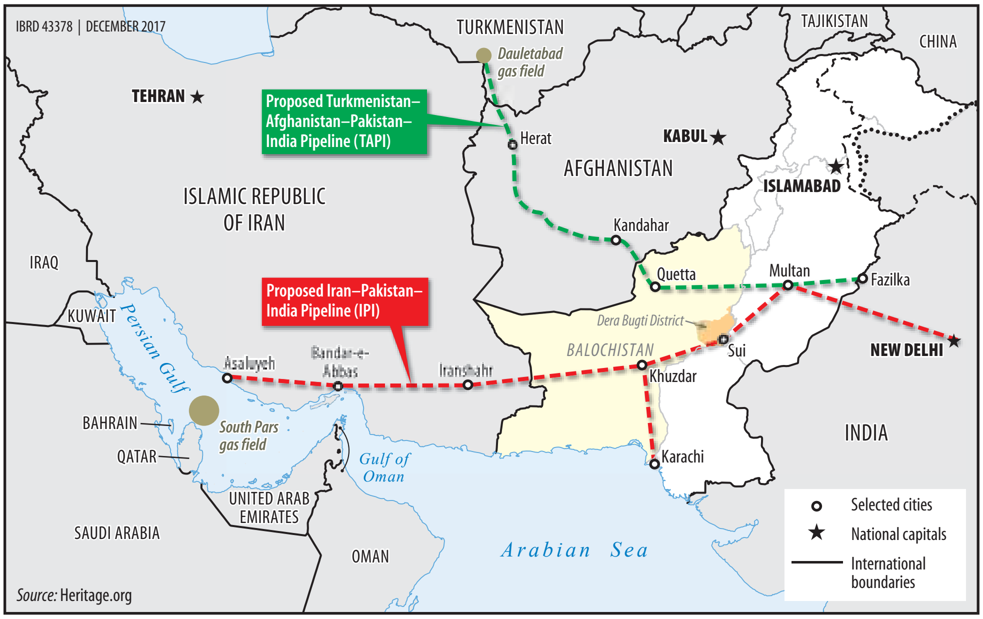


Source: DABS.

some decisions about the gas distribution infrastructure (capacity and routing of pipelines) must be made in the absence of good information about the ultimately available reserves, leading to high risks of both over- and under- capacity in gas transmission (and hence rendering the investments economically inefficient), and the location and size of gas-fired power plants.

- ***Coal resource uncertainty.*** Coal mining in Afghanistan has a long history, and there is extensive small-scale mining to supply local needs. But whether there is adequate resource to support a large, utility-scale coal-fired power project is uncertain: most of the resource information dates to the Soviet era, and both quantity and quality of the coal reserves are uncertain. A Chinese mining consortium investigated the coal resource with a view to building such a project

Figure 2.6. Gas Pipeline Proposals



to provide power to meet its own mining requirements and supply the rest to DABS: however, this reportedly ran into security-related difficulties, so it remains unclear what conclusions were drawn from that investigation, if any. It is understood that even if the mining concession survives, the willingness to include a large power station now seems quite unlikely, making the development of such a power plant dependent on IPPs.

- ***TAPI.*** The gas supply uncertainty is further complicated by the possibility of the Turkmenistan-Afghanistan-Pakistan-India gas pipeline (TAPI), which might allow any Afghanistan share of gas to be used for a gas-fired power generation project in the Kandahar (SEPS) region, but also by the increasing possibility of a competing Iran-Pakistan (IP) pipeline becoming operational, as shown in in figure 2.6.
- ***Hydrological uncertainty.*** Much of the hydro-meteorological network was damaged or destroyed during the conflicts, and record-keeping at some existing hydro-meteorological stations has only recently improved. With the only reliable data going back to the 1980s, the extent to which precipitation and flow regimes have changed over the past decades remains unclear.
- ***Climate change uncertainty.*** Some of the major hydro projects are on the Kunar River, which rises in the Himalayas. The impacts of climate change on hydro projects have already begun to be observed in some other countries in the region (such as Nepal). Reliable methods of estimating the impacts of climate change on the inflow hydrology of hydropower projects are still under development.

- ***Hydropower project development uncertainty.*** The first two new hydropower projects recommended by the APSMP are on the Kunar River, which rises, and subsequently returns, to Pakistan. Although in 2013 the government of Pakistan and the government of Afghanistan signed an agreement to jointly study the cascade development of this river basin,[22] the realization of such projects is subject to high uncertainty given the high sensitivity to riparian issues in the region and the history of international water agreements (and disputes) in South Asia.
- ***Geological and geotechnical uncertainty.*** In the case of the Kunar hydropower projects, the 2009 feasibility study of Kunar A (Shal) did not conduct the necessary onsite geological and geotechnical investigations for security reasons. However, the proposed approach, namely that the EPC contractor would conduct detailed geological and geotechnical studies *after* project tendering, is highly unrealistic. International experience suggests that either no serious contractor would be willing to assume the risks for an ill-defined project based on incomplete data or the bids would be inflated to cover the contractor's geological risks—in either case, inevitably resulting in disputes. No international financing institution (IFI) would be likely to have any interest in financing such a project. In short, for a large hydropower project to be bankable requires that the FS include, among others, detailed geological and geotechnical investigations.
- ***Export potential to/from Pakistan.*** Pakistan presently has severe power shortages, particularly in summer—and this makes Pakistan an important potential buyer, particularly of surplus summer hydro. Development of the many hydropower projects on the Kunar River will depend on Pakistan's willingness to take the substantial summer surplus power that these projects will produce. But Pakistan has its own large hydro projects under development (such as the 2,800 MW Tarbela extensions and the 4,300 MW Dasu project), and current policy reforms are expected to eventually lead to making more gas available for power generation, which may well alleviate the worst of the summer shortages.
- ***Regional hydro surplus uncertainty.*** CASA-1000 would be the first major investment to enable regional electricity trade, with the goal of exporting the existing summer hydro surplus in Tajikistan and Kyrgyzstan to Pakistan (and to Afghanistan). Additional hydro projects are being discussed in these countries, which may prolong the time period during which a summer hydro surplus persists, but the timetable for such projects is highly uncertain. If there are no further projects in these countries, then there is an opportunity for Afghanistan to build its own hydro project, which will also have summer surplus that could be exported over the CASA-1000 project.
- ***Energy trade uncertainty.*** Several energy trade proposals in the region are pending. How many and when these may be realized is not just a question of geo-political feasibility, but sheer scale of investment and financing difficulties. Each

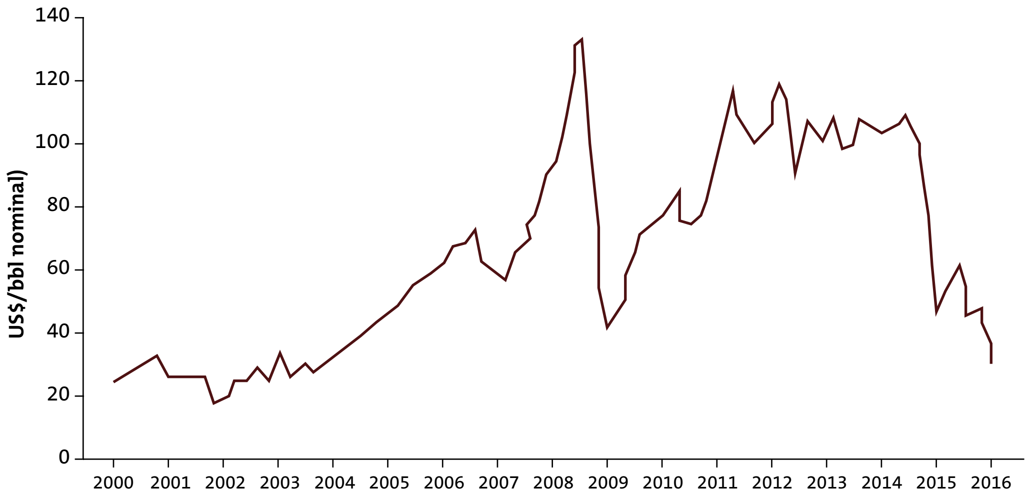
22. The governments have requested the assistance of the World Bank to study the cascade development of the Kunar: preliminary technical work is now underway.

may have a low probability of ultimate realization in any given year, but bring potentially very large economic benefits to Afghanistan if they were to proceed. A domestic railway system is also under discussion, the realization of which would have significant impacts on petroleum product and coal trade.[23] A further uncertainty is introduced in considering whether to trade electricity or fuels, the balance of which is dependent on relative costs of each; recent volatile fuel prices have served to underline this.

- ***Stranded asset risk and synchronization uncertainty.*** Whether the Afghanistan power system can be synchronized with that of one or more of its neighbors depends not just on Afghanistan's bilateral relations with these neighbors, but also relations among these neighbors among themselves; the restoration of Soviet-era synchronization of the Central Asian Republics may be decades distant. This has great consequences for transmission planning in Afghanistan, with potential risks of stranded assets (back-to-back interconnections of asynchronous systems, as proposed by the APSMP) if resynchronization were to occur. In the short term, the question is whether and when Afghanistan's domestic generators can be synchronized with one of the sources of imports (particularly Uzbekistan), which would avoid the tedious and inflexible operation of the NEPS as two or three separate systems. This has been discussed for some years, but the timing of any agreement is uncertain.
- ***IPP uncertainty.*** Several proposals are under consideration for developing power generation projects as IPPs, including coal-fired power generation at large copper and iron ore mining concessions, and for the development of the Sheberghan gas generation project. The bankability of IPPs in Afghanistan in the short- to medium-term will depend on how major risks are managed, including creditworthiness of the buyer (DABS), the security situation, and general perceptions of country risk.
- ***Oil price uncertainty.*** The world oil price is the main determinant, not just of other internationally traded fuels such as LNG in the Asia Pacific market where the price has historically been linked to the crude oil price (through the Japan Crude Cocktail, JCC), but more directly to the price of diesel for self-generation, whose differential to the grid-electricity price drives much of the consumer demand. The economic benefit of renewable energy as a substitute for diesel self-generation is directly linked to this differential: at $100/bbl solar PV for off-grid application is economic, but not at $50/bbl. At the time of writing (March 2016), the oil price (Brent) stands at around $35/bbl and has recently dipped below $30/bbl (see figure 2.7). The short-to-medium term outlook is highly uncertain: some analysts expect prices to be as low as $30/bbl for some time—on the other hand, escalation and spillover effects of the conflicts in Iraq, Yemen, and Syria could also see a sharp increase in price.

23. ADB, 2010. *Afghanistan: Railway Development Study*, Project Number ADB TA 7259–AFG.

Figure 2.7. Brent Crude Oil (ICE)



Source: NASDAQ, April 3, 2015; average of Brent, WTI and Dubai.

- ***Gas price uncertainty.*** The extent to which Pakistan would be a potential buyer of gas-based power generation depends on its price. Is it cost effective to import CCGT gas-power from Turkmenistan compared with CCGT in Pakistan using imported LNG? Both could exploit scale economies and build CCGTs at 800 MW scale (not possible in Afghanistan at Sheberghan), so the question becomes whether the price difference between the cost of imported LNG in Pakistan and the gas price in the CARs is large enough to pay for the HVDC transmission line from Turkmenistan to Pakistan plus the Afghanistan transit fee? Whatever may be the result of such a calculation, it is certainly subject to high uncertainty since it depends on: (1) the extent to which LNG prices in the Asia Pacific market will become decoupled from the oil price; (2) the *level* of LNG prices (spot prices have gone from $16/mmBTU to $7/mmBTU in the past year); and (3) China's willingness-to-pay for Turkmenistan gas and Gazprom pricing policy that largely determine gas prices in the CAR region (which have generally been much lower than LNG gas prices in the Asia Pacific region)—all of which are uncertain.

2.8. Consequences of Uncertainties for Power Planning

These uncertainties pose great difficulties for conventional power planning. The difficulties that are well illustrated by reference to the APSMP, which sets out the schedule of new generation projects shown in table 2.1.

Each project in the existing expansion plan is subject to uncertainty. This capacity expansion plan was derived in the conventional way, starting with a demand forecast, and alternative sources of supply then selected to meet that demand under the least-cost criterion. While this is certainly a reasonable approach in various contexts, the achievability of this plan in practice, given the current circumstances in Afghanistan, can be questioned. Every one of the projects included in the capacity expansion plan in table 2.3 is subject to one or more of the uncertainties noted above. Despite all its strengths, APSMP is not accompanied by a formal risk analysis that assesses the uncertainty in its key assumptions or the relative riskiness of one plant's realization compared with another's. The APSMP does acknowledge that "further study is required" for many of the options it proposes. To be able to make the urgent decisions that are required to be made now, Afghan decision makers may see value in adopting a practical perspective for assessing implications of uncertainties on the efficiency and realisms of the options facing them.

Interdependence of projects adds to uncertainties. The treatment of the NEPS/SEPS interconnection as generation expansion illustrates how the interdependency of separate projects can also create uncertainty. Presently, the SEPS power supply is based on diesel sets in Kandahar and hydro at the Kajaki hydro project. APSMP argues that the potential for extension of hydropower in SEPS is limited to the potential along the Helmand River, and generation from imported diesel is not economically justifiable. USAID is funding an interconnection, some 490 km along the Kabul-Kandahar road: the construction of the $814 million project began in 2012 and is now scheduled for completion in 2018.[24] There are sound political reasons to connect the two systems given that the economic development of Helmand is seen as a high priority to promote political stability. APSMP expected that the "major hydropower resources in the Northeast of Afghanistan" would enable additional supply to be delivered to SEPS through the NEPS/SEPS interconnection, but these are not likely to be available until the mid-2020s. More recently, the expectation is that the additional supplies available from expanded imports from Turkmenistan would be available as additional supply. The viability of the NEPS/SEPS interconnection is dependent on otherwise independent projects that are themselves subject to uncertainties.

24. http://www.usaid.gov/news-information/fact-sheets/power-transmission-expansion-and-connectivity-ptec-project-0.

A review of the capacity expansion plan reveals a range of practical problems for implementation:

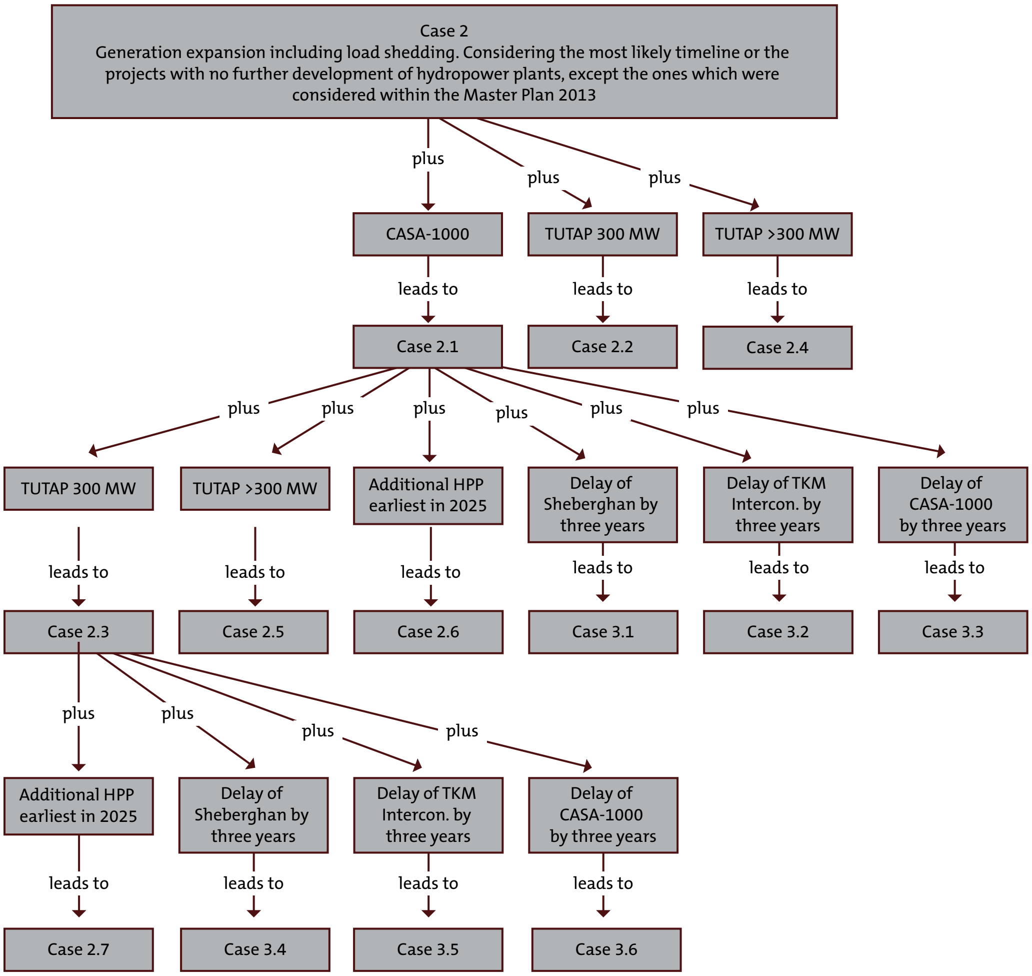
- ***Capital mobilization.*** To what extent does capital mobilization constrain both new domestic generation projects and the long-term development of the transmission grid? Under what circumstances can public sector financing be supplemented by private investment?
- ***Development of domestic resources.*** There has been little progress on further exploration of the Sheberghan gas field. Without a confirmation of the additional resources, which necessarily means drilling, there can be little progress for a gas supply agreement, one of the essential prerequisites for mobilizing an IPP for implementation. The coal resource is even less confirmed (as discussed in detail in annex 3).
- ***The readiness of the new hydro projects.*** In the 2014 addendum to the APSMP, the Kunar B project is advanced to start construction in 2018. As noted above, given that work on a detailed FS has yet to commence, construction starting before 2020 seems very unlikely: even if a FS and all its environmental studies could be completed in three years, it will take at least another year before financial closure can be reached, so 2020 appears to be the very earliest for construction to start. If financial closure depends on agreements with Pakistan on benefit sharing and a signed PPA for the export of the expected summer surplus, even 2020 may be optimistic.

Uncertainties of timing cannot be dealt with easily by the use of scenarios. This is illustrated by the addendum that was prepared in 2014.[25] The 2014 addendum deals with various uncertainties by adding a large set of additional scenarios, four of which involve no load shedding and 17 of which involve various degrees of load shedding and delays in project implementation (figure 2.8). In its "no load shedding" baseline, Sheberghan is delayed to 2020, but Kunar B is accelerated to 2022 (from 2024) and Kunar A to 2023 (from 2026). This timing is questionable: with a five-year construction period, construction would need to begin for Kunar A in 2017 and Kunar B in 2018. Given that neither project yet has a bankable FS (which will take at least two years) and that arranging for finance will take at least a year, it would appear that this schedule cannot be achieved. Using scenarios as the basis for testing robustness itself introduces further uncertainty.

Nor can scenarios deal with resource uncertainties, international energy prices, and synchronization options. These demonstrate the limits of the "predict-then-act" approach. The results of these 23 separate scenarios are difficult to interpret precisely because every one of them is subject to a range of uncertainties that are not considered. Conversely, if all the uncertainties were included as separate scenarios, there would need to be several

25. Although the APSMP was completed in February 2014, an APSMP addendum was issued in October 2014. This appears to have modified the TUTAP concept as originally designed by opting for using duplicate asynchronous supplies for domestic use from Turkmenistan and Uzbekistan for the medium term, recognizing the role of the CASA-1000 project and pushing back further export links to Pakistan to the outer years of the plan.

Figure 2.8. Scenario Design in the APSMP Addendum



Source: APSMP 2014 Addendum

hundred, and that in turn would further confuse their interpretation. Moreover, at the end of such an analytical process, what gets built ends up being driven by the availability of funds and the priorities of the donors whose priorities are often set by the imperatives of their lending and disbursement plans as much as by any specific master plan. In short, completely new approaches are required as illustrated in the case studies discussed in the next chapter and in the annexes.

3. Case Studies

This section summarizes the case studies, each dealing with specific problems that require immediate attention by the government. Section 3.1 deals with planning for hydro projects (with details in annex 2); section 3.2 with the potential use of coal for power generation (details in annex 3); section 3.3 deals with decisions about developing domestic gas resources (details in annex 4); and section 3.4 describes how transmission planning decisions are hampered by unresolved issues peculiar to Afghanistan being bordered by large asynchronous power systems (details in annex 5).

3.1. Planning for Hydro Projects

Progress in planning for new hydropower projects has been slow. Notwithstanding successive recommendations that new large hydropower projects be built, progress toward implementation of these projects has been slow, perhaps in part because the easiest way to expand supplies has been to increase imports from neighboring countries. By way of example, the many hydro projects in the Kunar River Basin have appeared in all of the various power sector master plans, but assumptions made about the size and technical feasibility are subject to very high uncertainty. In the APSMP Kunar B is recommended for development before all other hydropower projects with an entry into service of 2024, based on studies that cannot be considered to be complete treatments. On the other hand, the Bagdhara hydropower plant has a more comprehensive FS completed in 2015 but is expected to enter service in 2032.

A key question is whether to proceed with a cascade development study for Kunar. The funding decision for the $5–10 million required for the Kunar River cascade development study and subsequent detailed feasibility studies is especially relevant, because the latest study of the Kunar hydro projects recommends that the riparian issues with Pakistan "be clarified before work on the FS for cascade development is started"—which could be in 1 year, 5 years, 10 years, or indeed never. At the same time, it is pointed out that a FS without confirmation of the geological and geotechnical conditions—which means drilling at site—is likely to be of limited value and hence not the best use of resources.

The problem of how to proceed on hydro projects is a classic example of a real option.[26] The specific question to be asked here is whether one should commission a FS for one of the Kunar River projects now, or delay and reconsider one year later, given the present uncertainties about: (1) whether and when agreement can be reached with Pakistan on

26. A real option is the right, but not the obligation, to invest in a future project of unknown benefit at a known cost today. A real option implies at least two time steps: a decision to be made today—whether to take the option—followed by a decision to be made tomorrow—whether to make the investment. There are many good texts. T. Copeland and V. Antikarov, *Real Options: A Practitioner's Guide*, Texere, New York, 2001 is one of them.

joint development of the Kunar River; (2) the ultimate capital cost of the hydro project; (3) whether summer surplus hydro of the project can in fact be exported either through the CASA-1000 project, which may have spare capacity depending on the rate of decline of the summer surplus in Tajikistan and Kyrgyzstan, or through a new transmission corridor along the Kunar River; and (4) what would be the cost of energy from the next best alternative (either imports or generation at a Sheberghan CCGT).

The real options analysis is depicted in a decision tree. The details of its structure and calculations are described in annex 2, which presents the case study. Important here is simply the idea that the problem is captured as a series of decision nodes (that require actions—such as a funding decision for a FS and whether to abandon, delay, or proceed with construction) and chance nodes (that characterize the uncertainties faced). The options available at each decision node are assessed on the basis of maximizing NPV (or minimizing the present value of costs to meet a given level of demand). There is also the assumption that learning takes place over time that will help inform the decision making.

The case study concludes that the critical uncertainty in moving ahead with the large candidate hydropower projects is the cost of domestic thermal generation alternatives and of imported electricity. It is *not* the uncertainty of assurances from the government of Pakistan about its willingness to take summer surplus power which in any event would be conditional on subsequent technical feasibility. The Power Purchase Agreement (PPA) that was signed in November 2015 between Afghanistan and Turkmenistan indicates a cost of 5 US¢/kWh, escalated at three percent per year. This is an excellent price for Afghanistan, and provides the benchmark cost for domestic hydropower generation at least in the short run, although the quantity of year round thermal power available at this price may well not extend to additional imports.

The Bagdhara FS indicates that a recalibration of the APSMP estimates is needed. Bagdhara is the hydropower project with the most recent FS completed to international standards in 2015. The FS recommends a plant size of 226.5 MW with an estimated capital cost of $562 million ($2,481/kW) and average annual generation of 857 GWh. The FS cautions that "depending on the security situation there is an unpredictable risk of potential increase of cost and construction time." Uncertainty about previous capital cost estimates is thus high and serves to underline the need to recalibrate the APSMP estimates before making any further decisions about hydropower development. The analysis shows that decision makers have been better served by waiting for the results of the Bagdhara FS so that its results can be used to recalibrate the APSMP estimates before making any decisions about further hydropower development.

3.2. Planning for Coal for Power Generation

Notwithstanding several large coal-fired plants appearing in every recent master plan, there remains high uncertainty about Afghanistan's coal reserves. Their quantity, quality, cost, and the timescale within which they may be available for use are not well known. Unless a comprehensive exploration program is started today, the large future benefits of coal-fired generation (as opposed to imports of base load power) can never be realized, nor can the cost be fully understood. The main question is the potential economic benefits of such an exploration program; a subsidiary question is who should undertake such a program.

The case study presented in annex 3 aims to establish whether the costs of a near-term exploration program be justified by a demonstration of the future economic benefits. To deal with the wide ranges of uncertainty that characterize the extent of benefits, the technique of probabilistic scenario analysis is used to evaluate the many layers of uncertainty and the different probabilities that may apply at each level: an exploration program may be unsuccessful in finding any coal at all (or insufficient even for a small 100 MW project)—or it may find enough for several 1,000 MW—but with such benefits appearing only some 5–6 years after the resource is proven because of the time required to develop a large mine and build the power plant. Even if enough coal is found, whether it is economic to exploit the resource depends on the cost of coal-based power generation relative to the next best alternative for base load power, likely to be imports of gas fired electricity from Turkmenistan or possibly gas delivered to Afghanistan by one of the regional pipeline projects such as TAPI.

The quantitative analysis requires two steps. First, one evaluates the cost of generation from coal (assuming enough was found), which is subject to uncertainties in capital costs and the cost of fuel, and compares it with the cost of imported base-load power, which is subject to the uncertainty of the PPA price and the cost of incremental transmission connection. The results are summarized in table 3.1: the NPV of coal generation ranges from $309 to $463 million; that of imports from $565 to $788 million. The nine entries in the bold face type represent the net benefits under the different combinations of conditions for domestic coal generation and imports. For example, for unfavorable (highest cost) coal and favorable (lowest cost) imports the net benefit of coal is $565 million minus $463 million=$102 million.

With th***e potential future benefits of coal in hand, one then assesses these benefits against the costs of the exploration program.*** The calculation has to take into account that the costs of the exploration program are required today, whereas the benefits will only be realized in the future: even if the exploration program is successful there will be a time lag between the demonstration of the resource and the earliest date that coal can be produced. In this analysis the following assumptions are made:

- Funds for the Afghanistan Geological Survey (AGS) program committed: 2016
- AGS exploration program begins: 2017
- A potential resource identified: 2019
- Financial closure of the project: 2021
- Construction time: Three years, hence, commercial operation date (COD): 2024.

The NPVs must now be brought back to a single base year. The benefits shown in table 3.2 are to the beginning of 2024, and must be brought back to the NPV in 2016, at which point they can be compared with the outlay required in 2016 for the proposed AGS exploration program. It is also the case that the exploration program has potentially many outcomes: there may be no coal at all (of sufficient size for a 100 MW project)—but there may also be enough coal for 1,000 MW or more.

Table 3.1. Net Benefits—$, millions (as NPV, 10 percent discount rate)

		Imports		
		Favorable 7.5 USc/kWh	Expected 8.5 USc/kWh	Unfavorable $9.5USc/kWh
	Import NPV>	565	676	788
	coal NPV			
Favorable[a]	309	255	367	479
Expected[b]	384	180	292	404
Unfavorable[c]	463	102	214	326

a. Coal cost $50/ton, capital cost 1,600 $/kW.
b. Coal cost $60/ton, capital cost 1,920 $/kW.
c. Coal cost $70/ton, capital cost 2,240 $/ton.

Table 3.2. NPV of the Exploration Program in Known Coal Fields

	NPV	Prob. (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
			Exploration			PS	Financial Closure	Construction			COD 1st Project		COD 2nd Project		COD 3rd Project		COD 4th Project		COD 5th Project
[1] AGS exploration program 1	-24.8	100	-7.5	-15	-7.5														
[2] Outcomes:																			
[3] Unsuccessful, no coal	0.0	5																	
[4] 100 MW	10.8	25									102								
[5] 400 MW	75.0	50									102		305						
[6] 700 MW	35.7	15									102		305		305				
[7] 1,000 MW	9.3	3									102		305		305		305		
[8] 1,300 MW	6.2	2									102		305		305		305		305
[9] Total NPV	112.2	100																	

The calculations necessary to assess the NPV of the AGS exploration program in the existing coal areas are shown in table 3.2. In row 1, the estimated costs of the program appear: these costs are (relatively) certain. Rows 3–8 assign a probability distribution for the prospects of various levels of coal resource being discovered. Row 3 shows that the probability that the exploration program is wholly unsuccessful is 5 percent—it contributes nothing to the expected NPV. Row 4 shows the probability of finding just enough coal for a single 100 MW project as 25 percent: but its benefits realized only in 2024—which under the most pessimistic circumstances yields a net benefit of just $102 million (in 2024).[27] When this is discounted back to 2016, and multiplied by the 25 percent probability, the contribution to NPV is $10.8 million.

The chance of finding enough coal for 400 MW is 50 percent. It is assumed that the first project would still be 100 MW, but that two years thereafter a 300 MW project is built (recognizing the difficulties of financing large projects). Therefore, the net benefit will be 3 x 102=$305 million (another conservative assumption since scale economies would reduce the capital costs per kW assumed in the calculations for table 3.2). This calculation is repeated for the other exploration outcomes, from which the total expected NPV, including the upfront costs of the AGS program, is $112 million. Under less pessimistic assumptions (for example, expected value for both coal imports and coal generation costs, the $292 million entry in table 3.2), the NPV of the AGS exploration program is $365 million.

The robustness of the AGS program NPV can be tested by calculation of the switching value for the probability of no coal being found. This calculates to 83 percent for the most unfavorable benefit of coal generation (i.e., under a favorable cost of future imports and unfavorable cost of the coal project). In other words, the probability of finding only enough coal for 100 MW project would have to be 17 percent or less for the exploration program to have negative returns. In light of what is already known about the current extent of coal mining in Afghanistan, this is considered highly unlikely. Annex 3 also presents similar calculations for a second stage of the exploration program, which should convert the deep coal resource of the North Afghan platform: for this second stage, the NPV under the most pessimistic circumstances is $249 million.

Having first decided on the primary question of whether to proceed with an exploration program, the choice of who should undertake it is simple. Either the private sector explores for and develops the resources it needs or the public sector funds the exploration and then either develops the resource itself or auctions the proven resource to tender. The case study shows that the current mining law is seen as so unfavorable by junior mining exploration companies that there is limited confidence that such companies would be able to secure financing from international investors to pursue projects in Afghanistan. Similarly, there are likely to be significant challenges associated with options involving the bundling of mineral exploration and power generation projects in concessions to be

27. That is, corresponding to the entry in table 3.2 for unfavorable coal, favorable imports.

given to a foreign minerals mining consortium, given the implementation challenges experienced in the copper mining concession in Afghanistan. It follows that the only realistic option currently open to the Afghan government is to finance the exploration work itself.

The case study shows that the potential benefits of this magnitude warrant immediate implementation of the proposed AGS program. It also finds that even if the AGS program proved to be two to three times more expensive than estimated, the economic benefits to Afghanistan remain very high indeed.

3.3. Planning Domestic Thermal Generation Using Gas

Thermal generation in the Afghan power system is needed to meet the winter peak. System peak demand occurs during the winter months, when hydro flows are at their lowest. Thermal power plants are also not prone to variations in output due to variations in hydrology and are thus well-positioned to support Afghanistan's growing demand. Hence, both coal and gas generation feature prominently in the APSMP scenarios. A gas CCGT at Sheberghan appears at 400 MW scale in most of the APSMP addendum scenarios with commercial operations date (COD) of 2020, and coal generation appears in the original APSMP at 400 MW at Aynak, and another 800 MW at Haji Gak[28], both at $1,700/kW (albeit with the qualification that: "It is unknown if the necessary coal reserves exist in Afghanistan"). In the APSMP addendum there appears just a single 400 MW coal project at Bamyan.

Exploitation of the gas reserves has attracted the most attention. In addition to studies on gas use for generation, uses other than for power generation have been examined, including exports and a gas pipeline to Kabul where gas would displace diesel fuel. While a gas project at Sheberghan has been considered for many years, decisions have been delayed as a result of continuing uncertainty over the actual size of the resource, the appropriate technology to be applied if gas were to be used on a large scale for electricity generation, and the ability to finance a project as an IPP. Most recently, there has been a proposal for a 50 MW gas engine IPP project in Mazar, to be supplied by the newly refurbished gas pipeline from the Sheberghan gas field.

The Mazar IPP has been much delayed, mainly due to the slow progress of well rehabilitation and new exploration and the completion of a new gas pipeline to Mazar-e-Sharif. The case study in annex 4 describes how the high uncertainty surrounding the comparison of the development of gas-fired generation versus imported electricity can be clarified using the techniques of robust decision making, in which one does not attempt to specify the probability of uncertain future events but uses statistical techniques to examine patterns and factors of vulnerability of particular choices in a wide range of futures.

28. APSMP, table 6.1.2–5.

The Basic Question: Gas Generation Versus Imports

High costs of generation investment in Afghanistan. In the absence of energy security constraints and geopolitical considerations, the question of whether Afghanistan should use its gas resources for power generation are easily answered. A gas-fired power project in Afghanistan will have higher costs because of:

- ***Scale economies.*** Even a relatively large 200–400 MW CCGT in Sheberghan will have higher investment costs per kW than an 850 MW scale project in Turkmenistan. The smaller project will also have a lower heat rate.
- ***Security-related construction premia.*** As noted, costs for the Sheberghan project are estimated to be 60 percent higher than international levels.
- ***Gas quality.*** The gas in Sheberghan is sour and of lower quality than in Turkmenistan, which will incur an additional cost for gas treatment.
- ***Gas field development costs.*** Gas field development will be more costly than in the CARs: One study estimates a premium of 60 percent just to account for the more mountainous terrain (rather than flat, smooth steppe), the lack of supply equipment and materials, and the inability to provide much of the necessary specialized personnel. Moreover, this premium does not account for any demining or security expenses which might be necessary for an upstream project in Afghanistan.

Offsetting avoided transmission costs. On the other hand, a project in Afghanistan will have lower costs because the distance from the generation point in Turkmenistan to Sheberghan is several 100 km. This involves transmission losses and the cost of the transmission line itself, which are avoided if the power plant is built at Sheberghan.

An important question concerns how the resource rent would be shared between Afghanistan and Turkmenistan. Imports of gas-based electricity will be based on the market price of gas in Turkmenistan (set largely by China's willingness to pay), not on the actual production cost of gas (for example, as defined by the long run marginal cost (LRMC) of gas extraction). If the market price of gas is, for example, \$8/mmBTU, but the LRMC is only \$1/mmBTU, then the resource rent that accrues to the government of Turkmenistan (or to the production entity involved) is \$7/mmBTU. So even if the LRMC in Afghanistan is triple that of Turkmenistan, generation in Afghanistan brings a resource rent of \$5/mmBTU. Of course, that rent would also be available if the gas were used to supply Kabul to displace diesel oil and petroleum-based LPG: while that would entail a significant additional gas transmission cost, the value of gas is highest where it displaces oil. The low LRMCs in the CARs are a result of the large size of their gas fields and production volumes: these are not achievable in Afghanistan even under the most optimistic scenario of gas resources. At the same time, this explains the interest of Turkmenistan of selling gas-based electricity to Afghanistan: it thereby locks in for the long term a significant resource rent.

Table 3.3. Plausible Ranges of Uncertainty

Uncertainty		Minimum	Maximum
Imported electricity price	USc/kWh	4.0	12.00
Capital cost multiplier (Afghanistan premium)	[ ]	1.0	2.00
Self Gen cost (function of world oil price and diesel imports)	USc/kWh	0.2	0.35
Sheberghan Gas price (delivered)	$/mmBTU	3.0	11.00
Demand uncertainty	annual load factor	0.9	0.65
Import security proxy	days/year	5.0	80.00
Gas field security proxy	days/year	5.0	80.00
Transmission security proxy (Salang pass)	days/year	5.0	80.00

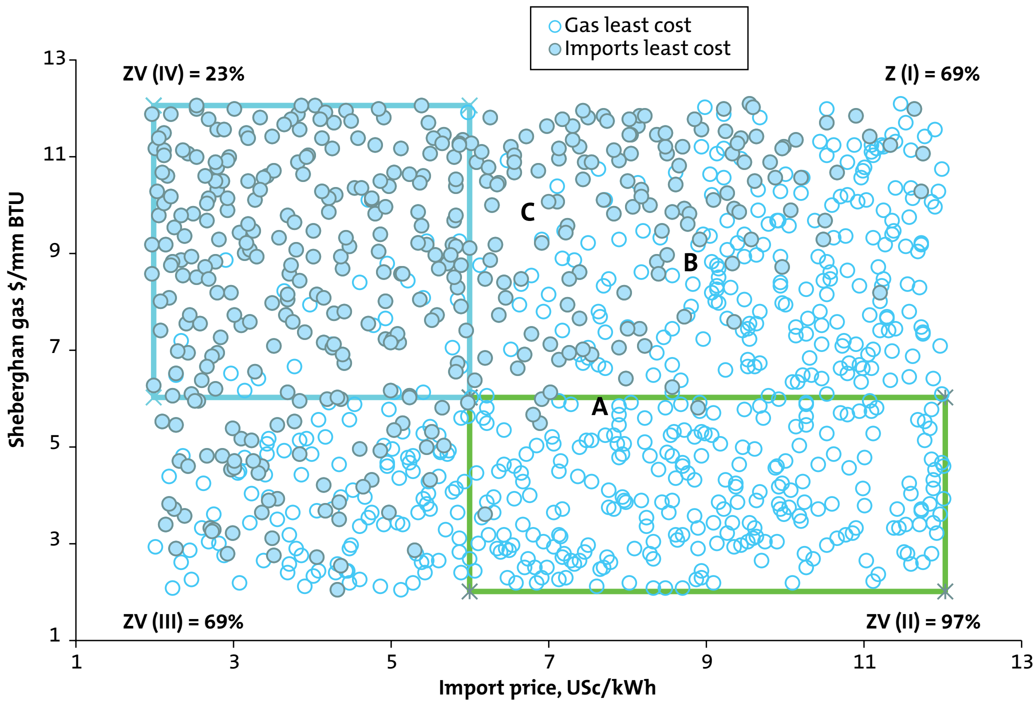
In any comparison of the costs of domestic gas generation against imports, there are numerous assumptions on which depends the choice of one option over the other. Conventional techniques of sensitivity analysis have limited power when many input assumptions may simultaneously vary. It is easy to show the sensitivity of the result to, for example, capital costs of gas engines or to a specific size of the gas resource, but when all the main variables are uncertain, this gets difficult. Monte Carlo simulation—a much used tool of risk assessment—is a partial answer. Here, a probability distribution is assigned to each variable, and the economic analysis calculated several hundred (or thousand) times at each iteration, using input values drawn from these distributions and then presenting the result as a probability distribution of the present value of the comparison (see figure A4.4 for examples). But the main difficulty here is that defining probability distributions for some of the variables may be very difficult—defining a probability distribution for, as an example, the future CAR market price for gas is almost impossible (as well illustrated by the 2014–15 collapse of international energy prices).

Testing Robustness of the Gas Investment Decision

Avoiding decisions based on "predict-then-act." The essential question for "predict-then-act" decisions is how to make the best estimate of the future, and then chose the least-cost option. A better approach is to ask: "given the difficulties of predicting the future, which option is more robust to these uncertainties?" This implies looking at the performance of each option in all plausible futures (which may well run into the tens of thousands, each reflecting different combinations of individual input assumptions), and then examining the vulnerability of a particular option to identified risks. The trick is to do this without necessarily needing to say anything about the probability of an input assumption being at a particular value. Table 3.3 shows the plausible ranges of uncertainty set for the analysis of the gas generation decision.

Figure 3.1 shows a plot of a 1,000 plausible futures. The dark (blue) dots are the combination of gas price ($/mmBTU) and import price (US¢/kWh) for which imports are the preferred option; the light (green) circles represent those for which the gas generation is the

Figure 3.1. Scenario Discovery



preferred option. The robustness of the decision (i.e., the proportion of cases in which the right decision is made) in quadrant II is very high: if the import price is greater than 6 cents/kWh and the gas price less than $6/mmBTU, then whatever the combination of ***all*** other uncertainties (security outages for gas supply and transmission corridors, capital cost escalations, world oil prices, capacity utilization, demand uncertainty, and heat rate), there is a 97 percent chance of Sheberghan power generation being the correct decision. The "Z(j)" shown in this figure is the percentage of cases in each quadrant (j) in which Sheberghan gas is the preferred option. The points marked A, B and C reflects the judgment of individuals as to what are the "most likely" set of future conditions.

The results of figure 3.1 suggest that if indeed import prices were above 6 USc/kWh, a decision to proceed with Sheberghan gas would be low risk. At the time this analysis was developed in early 2015, there was still considerable uncertainty about the price of imports from Turkmenistan since the PPA was still under negotiation—and the negotiations for renewal of the Uzbekistan PPA were expected at 8–8.5 US¢/kWh. Moreover, there remains continuing uncertainty about the production cost of Sheberghan gas—the only way of resolving that uncertainty is to proceed with the necessary further gas field development: the gas master plan for Afghanistan has yet to be completed—which should provide guidance on what the gas production costs will likely be and whether that gas should be used to displace diesel use in Kabul or for power generation. If the delivered gas price is below $6/mmBTU, then there is a very low probability of a negative rate of return. LRMC estimates of the gas cost (see annex 4, table A4.5) suggest costs of around $3/mmBTU, so there remains a margin of error of 100 percent before the $6/mmBTU threshold is breached.

In early November 2015, the long-awaited PPA between DABS and the Turkmenenergo of Turkmenistan was signed at a price of 5 US¢/kWh. The PPA covers imports of electricity from Turkmenistan from January 1, 2018 to December 31, 2027. The price of 5 US¢/kWh is for 2015, rising by 3 percent per year (i.e., 7.13 USc/kWh in 2027), with agreed volumes of 899 GWh in 2018, increasing to 1,516 GWh in 2027. By comparison, the estimated energy from the Bagdhara hydro project is 968 GWh, and total energy imports in 2014 were 3,814 GWh (of which 1,426 GWh were from Uzbekistan and 1,103 GWh from Tajikistan). A 50 MW gas engine project at Sheberghan would produce 300 GWh at a 0.7 load factor, representing only a small fraction of imports.

This is a low price that is clearly to Afghanistan's advantage. At first glance, it makes the development of the gas engine project at Sheberghan less pressing. However, the probability that a Sheberghan gas project would deliver negative economic returns is small. The International Finance Corporation (IFC) of the World Bank Group is considering supporting a 50 MW gas engine project in Mazar-e Sharif. This analysis concludes that the proposed project should be still be supported since it is of reasonable scale and gas engines are the most robust technology given the likely operating environment. Moreover, if this relatively modest-sized project cannot be done as an IPP, then the prospects for other IPP development (including hydro projects) would be even less likely to attract private sector interest. Efforts to confirm the size and cost of the gas resource also remains a policy priority even with the next tranche of imports becoming available at low cost.

3.4. Transmission Planning

The case study in annex 5 discusses the main issues in transmission system development. The analysis finds that a grid/distribution code is urgently needed in Afghanistan to address issues in connecting the mostly renewables-based mini-grids. It also underlines the difficulties in the operation of the system stemming from Uzbekistan's resistance to Afghanistan synchronizing its own generation projects to the Uzbek grid, resulting in the segregation of the Kabul supply network, with one part connected to the Uzbek grid, one part to the Tajik system when it is operating, and a third to DABS's own system.

Major transmission investment decisions have recently been taken on the basis of recommendations in the APSMP and are currently being implemented. During the next few years and as conditions are expected to change in the region, MEW and DABS have the opportunity to revisit the priorities for investing in further development of the transmission network on the same basis. The review process will need to take into account alternative ways of further supporting power transit operations without limiting the ability to meet the competing financial needs of supporting the country's rural electrification program and developing domestic generation resources.

This could be an appropriate subject for a real options analysis of transit strategies. The analysis would be based on assumptions and decision criteria that take into account: (1) the risk of building 500 kV lines that are underutilized because potential transit opportunities fail to materialize; (2) the options for making a return on investment from 500 kV HVAC wheeling, HVDC line availability fees, or both; (3) the additional investment required to guarantee an acceptable level of reliability and security for the importer or exporter of power; and (4) the future use of dedicated transit facilities at the end of the life of the PPA. Clearly there is less cost and operational risk to Afghanistan if a dedicated HVDC line is built by its proponents and used for transit operations, even though there may be a perceived lack of sovereignty in enabling a commercial operation to operate independently.

A key recommendation of this study is to develop a national grid code before 2020. It will be needed when the new transmission projects are expected to be commissioned, primarily to facilitate negotiations with Afghanistan's neighbors, but also to determine the incremental investments needed to upgrade substations and generation control systems to meet security and reliability standards for the transmission network. The review process necessary to formulate the essential features of a grid code must include a strategy for synchronization between Afghanistan and its neighbors to facilitate the more efficient use of domestic generation. This may include a requirement for new investments in back-to-back HVDC interconnections or variable frequency transformer (VFT) facilities, which can transmit electricity between two asynchronous (or synchronous) AC frequency domains.

Any future master plan will need to establish rules for transmission and generation diversity planning. They are needed to minimize the potential for widespread disruptions and facilitate the development of new hydropower and coal-fired generation that may be associated with large mining operations. There will also need to be a policy clarifying how Afghanistan proposes to integrate its domestic transmission development (which may be built to achieve a lower standard of reliability compared with those involved in imports, exports or transit flows) with any new power transit proposals that have their own special requirements for security and commercial viability.

A strategy for optimizing the development and eventual interconnection of the large number of small, isolated grids is required. They should be made ready to connect and disconnect from the grid operating in both grid-connected or island mode. There needs to be greater consumer engagement to solve power issues locally by enabling the penetration of local renewables to supply residential, commercial, and industrial customers. In this way, distribution can become a transmission system resource, with all its components as part of a cohesive system. This will require high dependency on standardization (physical and data) as could also be established in the grid code.

4. Conclusions and Recommendations

4.1. Decision Making Under Uncertainty

The Afghanistan power sector faces unusually high levels of uncertainty, as discussed in the preceding sections. Nevertheless, there are a range of relatively simple analytical tools—whose applications are illustrated in this report—that are available to inform decisions in such circumstances. These have long been used in the private sector and can give confidence to the decision maker by providing useful information about the robustness of the decision to uncertain futures.

4.2. The Limits of "Predict-then-act" Planning

The addendum to the APSMP pushes to the limit the traditional "predict-then-act" approach. In response to criticisms that the original APSMP paid insufficient attention to many uncertainties, 23 alternative scenarios are presented. Rearranging the same set of generation projects and imports under a range of uncertain assumptions about international fuel prices, capital costs, Afghanistan-specific cost premia, and discount rates has merit. But in the absence of an explicit framework for consideration of the probabilities involved, this does not really assist the decision maker: it can even increase uncertainty and indecision in the face of so many options from which to choose "the best."

Project size and technology cannot be chosen independent of country circumstances. Undoubtedly, large projects offer scale economies over smaller projects, but if such projects stretch implementation or financing capacity beyond their limits, their inclusion in any of the scenarios is not going to be very useful for the decision maker. The same applies to the technology variants considered: it is undoubtedly true that CCGT offers higher efficiencies over open-cycle combustion turbines or gas engines, and hence the lowest cost per kWh. But CCGT plants are highly complex, require significant water supplies, and present substantial challenges compared with gas engines and open-cycle machines, which can be installed, operated, and secured much more easily, and for which the Afghanistan construction cost premium will be lower than CCGTs. Gas engine generating capacity can be built in small increments that can be much more easily financed: their cost per kWh may well be higher than that of a CCGT, but if CCGTs cannot be financed in reality, again, their inclusion in scenarios for the short to medium term will be of limited value to the decision maker and could in fact be a distraction.

4.3. Energy Rather than Power Sector Planning

The analysis demonstrates the importance of energy sector planning. Both coal and natural gas have uses other than power generation, and economic theory holds that resources should be used where the highest value can be extracted from them. Power sector planning exercises (including the APSMP) seek to address investment planning by careful quantitative analysis and economic reasoning. But "national energy plans" risk being statements of aspirational goals, with little quantitative analysis to support them. One cannot meaningfully plan the optimal utilization of national resources without credible resource assessment: the presence of large coal projects in a power sector master plan does not therefore make much sense in the absence of a verified resource.

Should the gas resources prove to be at the upper end of the resource estimates, then the highest value use of the gas is to replace diesel. To be sure, there are security implications of a long pipeline from Sheberghan to Kabul. For example, in Pakistan, gas pipelines are regular targets of terrorist attacks, but as equally well shown by Pakistan's experience, gas pipelines can be repaired relatively quickly. The value added from replacing diesel imports appears to be worth the risk and difficulty of operating a gas pipeline.

The report recommends that MEW initiates a broader national energy plan that looks at alternative energy futures at the same level of detail. Based on economic reasoning, as in the APSMP, the main focus of such an exercise should be to assess the best utilization of the national fossil and water resources. Indeed, the use of gas to replace diesel in Kabul would also bring significant environmental and public health benefits. The Ministry of Petroleum and Natural Resources is currently preparing a gas master plan financed by ADB with consultant support, but for it to bring real added value, it must be closely coordinated with MEW's plans.

When combined with the difficulties of mobilizing finance for thermal or hydro generation projects, Afghanistan's energy security concerns limit the freedom of choice for development of the power sector. In the short term, there really is no other choice but to negotiate large-scale electricity imports from CAR neighbors, combined with upgrading and rehabilitating existing hydro projects, and to increase efforts to develop renewable energy in the rural areas. It is recognized that this has political and security implications for the authorities and underlines the importance of setting up a functional and high-quality planning system that is an essential precursor to moving away from the current state of affairs.

4.4. Hydropower Planning

The risks identified in the FS for Bagdhara would not appear to change the conclusion that the magnitude of the investment required prevents its early implementation. The probabilities noted in the decision-trees of annex 2 suggest that this or any other large hydro project is simply too risky. Given the high uncertainties of the security situation, the emphasis for developing Afghanistan's domestic resources should continue to be in smaller projects commensurate with the risk appetite of potential investors.

For other hydropower projects, the range of uncertainty about earlier capital cost estimates remains high. The Bagdhara FS results could be used to recalibrate the APSMP estimates of table 2.3 before making any further decisions about new hydropower development. Without confirmed technical feasibility, the likelihood of finding a reputable international EPC contractor or a PPA being bankable are remote. The prospects for hydropower development, most of the output from which is provided in summer using a private-public partnership approach, are further diminished for a PPA of this magnitude with DABS because revenues will be relatively low.

4.5. Coal for Power Generation

The results of the analysis demonstrate that the expected value of future benefits far outweigh the upfront costs of any coal exploration program. The use of coal or coal-bed methane for power generation are attractive options for Afghanistan, but the resources must be found and developed. A coal exploration program has high potential rewards. Under the pessimistic outcomes for the cost of coal-generating projects relative to imports, the expected NPV for an exploration program in the known areas of coal resources is $112 million; under expected conditions of coal-generating costs and imports, the NPV is $369 million. If extended to the presently unexplored areas of the deep coal North Afghan Plateau, the NPV rises by $762 million.

Potential benefits of this magnitude warrant immediate implementation of an exploration program. The analysis suggests that a publicly-financed coal exploration program conducted by AGS is the most attractive in the short term, given that the legal and regulatory conditions are not attractive to private sector mining exploration companies. It also follows from the analysis that even if the AGS program proved to be two to three times more expensive than estimated, the benefits remain very high indeed. Nor would adding the potential GHG damage costs, which cannot be estimated until the quantity and quality of the coal resource is likely to render the exploration program substantially less attractive. The analysis presented also demonstrates the value of a step-by-step planning process, in which the option of using coal for power generation is assessed in the framework of an implementation plan that assesses the uncertainties at each step. This is likely to be far more helpful in the long run than running large-capacity expansion optimization models.

4.6. Gas Power Generation Planning

Domestic generation costs are likely to be higher than their equivalent imports. Imports of electricity that is produced using gas-fired generation are likely to benefit from scale economies, lower construction costs because of avoided security costs, and lower cost gas. These lower costs of imported electricity based on gas-fired generation are unlikely to be offset by the lower cost of domestic gas fired generation within Afghanistan. In the short to medium term, Afghanistan is likely to remain a significant importer of gas-fired electricity. The tariff for imports from Turkmenistan, due to start in January 2018, is 5 US¢/kWh, and the initial agreed volume of 899 GWh/year is significant and similar to the level of imports from Uzbekistan (1,426 GWh in 2014) and Tajikistan (1,103 GWh in 2014).

Notwithstanding the low price of power imports, development of domestic gas generation capacity is economic. Despite this, a power generation project relying on domestic gas from Sheberghan remains attractive, and the probability that it will deliver negative economic returns is small. This report concludes that the proposed 50 MW gas engine plant at Mazar-e-Sharif should be supported as an IPP, and recommends against attempts to scale up the project or use more sophisticated CCGT technology in this first step. The plant would produce around 300 GWh/year and would thus be only a small fraction of imports.

4.7. Transmission Planning Strategies

The main factors complicating decisions about system development are the high uncertainty about the location of new domestic power projects, synchronization among neighboring power grids, and the lack of a grid or distribution code. Hence, the report recommends that before 2020, when new transmission projects are expected to be commissioned, there is a need to develop a national grid code. The planning process must include a strategy for synchronization between Afghanistan and its neighbors to facilitate the more efficient use of domestic generation. The requirement for new investments in HVDC b/b or VFT facilities to provide interconnections was identified in the APSMP; a strategy could refine this program to reduce the investment required and the risk of creating stranded assets. In addition, before future master plans are prepared, MEW and DABS will need to establish rules for transmission and generation diversity. Last, a strategy for optimizing the development and eventual interconnection of the large number of small grids is required.

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Annex 1.
Methodological Considerations

This annex discusses methodologies and how one deals with the often conflicting criteria of least economic cost, environmental sustainability, and energy security. Energy security is the most difficult of these three, because it encompasses so many different concepts and therefore commands most of the attention here.

A1.1. Economic Efficiency

Economic efficiency has three main dimensions: producing goods at the lowest cost is only one of them:

- ***Productive efficiency.*** Electricity or a fossil fuel should be produced at the least economic cost. If prices are too high because of monopolistic behavior or price collusion, even inefficient firms can continue to make money and stay in business. Productive efficiency can be promoted through competition, open access, and price regulation.
- ***Allocative efficiency.*** Prices should reflect underlying economic costs so that electricity (or a fossil fuel) is allocated to its highest value use. If prices are too low, consumers may consume more for nonessential purposes, or waste energy purchased for essential purposes. If shortages arise because prices are too low, then some of those willing to pay a high price may be unable to obtain any, while some of those who do not value the resource highly may waste it.
- ***Dynamic efficiency.*** Firms should introduce innovation and improvement in the market as new technologies become available.

Allocative efficiency for electricity, gas, and coal in Afghanistan is poor. The retail gas price is around $14 per thousand cubic meter (MCM), far below market prices in central Asia of around $200/MCM.[29] Retail electricity prices have increased of late but are still generally below the economic (and financial) cost of supply. Productive efficiency is also poor: while there are no reliable data on transmission and distribution (T&D) losses, the general consensus is that there is considerable scope for improvement. Several hydro-generating plants are in urgent need of rehabilitation.

29. See box A4.1 for details of conversion factors and calorific values for fossil fuels.

In World Bank practice, power system planning is generally conducted at economic prices—so capacity expansion planning models are run with domestically produced fossil fuels priced at import parity prices and to the exclusion of transfer payments (taxes, import duties, value added tax). But that is not universally true: often these models are run by utilities using their financial prices, which may include significant taxes and subsidies. The APSMP is based on economic costs, though there is little discussion about fossil fuel prices and how gas prices in CARs or Pakistan might be affected by changes in international oil and LNG markets. Pakistan's willingness-to-pay for surplus summer hydro (whether from the CARs via CASA-1000, or from possible exports of Afghanistan's' future large hydro) is very much a question of the cost gas-fired CCGT in Afghanistan—which sets the upper bound for peaking hydro prices.[30]

Nevertheless, the measurement and quantification of the economic efficiency objective poses relatively few problems: the methodology of cost-benefit analysis (CBA) is long established, and its application to power sector planning and investment problems is relatively straightforward.

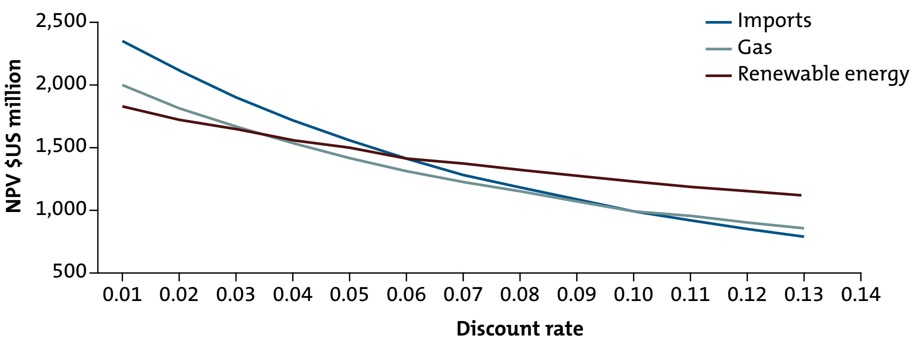
The Discount Rate

The main issue to be resolved is the choice of the discount rate: just how to define the government's economic opportunity cost of capital given Afghanistan's unique fiscal and economic circumstances? All IFI energy sector infrastructure activities in Afghanistan over the past years have been in the form of grants. But although the actual financial cost of capital is zero, this does not mean capital is unconstrained: in practice, the supply of capital from the donors and IFIs is a function of their (limited) willingness to mobilize grant funds. Funding of T&D appears to be possible without much controversy, but funding for generation projects will be much more difficult. Afghanistan is already eligible for IDA financing, but only as grants—it will get around $400 million in IDA-17 (fiscal 2015–18).

The choice of discount rate is one of the critical assumptions for CBA. In the past few years, there has been increasing discussion within the World Bank about the extent to which the normal discount rate used in the past (10–12 percent) is still an appropriate measure given that the cost of capital has greatly fallen. For example, for the Concentrated Solar Power (CSP) project in Morocco, a 5 percent (real) discount rate was used, on grounds that the actual economic opportunity cost of capital (EOCK), as reflected in the latest government Euro and $ bond issues, was 7 percent (nominal).[31] It is widely argued that high discount rates discriminate against projects whose benefits arise mainly in the long term (and so discriminate against investments directed at long-term climate change). But that is true even when projects of relatively short life are considered. Others argue that the EOCK is in any event not the appropriate measure of the social discount

30. We return to this problem in annex 4.
31. World Bank, 2014. *Project Appraisal Document, Morocco Concentrated Solar Power Project*.

Figure A1.1. NPV as a Function of Discount Rate



rate and argue for application of the (so-called) Ramsey Formula, which links the discount rate to long-term consumption growth based on the social rate of time preference (SRTP), which generally yields discount rates in the 2–8 percent range.[32]

As an illustration of the practical importance of the choice of discount rate, consider the problem now faced by Afghanistan: should the country continue to rely mainly on imported electricity from its CAR neighbors, or should it build its own CCGT based on Sheberghan gas or develop its own smaller scale renewable energy projects. The comparison is made on the basis of a 300 MW of additional load imported at an annual load factor of 0.7. Comparing like with like means that to produce the same amount of energy as the gas and import options with a 35 percent annual capacity factor one must build 600 MW of wind.[33]

The NPV calculations at the traditional 10 percent discount rate are shown in table A1.1: the results show that the NPV of the cost of imports is $998 million compared with $1,013 million for gas and $1,235 million for renewable energy. Imports are the least-cost option (though not by much).

But if the discount rate changes, then the conclusions also change. Figure A1.1 shows the NPV for each option as a function of the discount rate. Imports are only the least-cost option for discount rates above 9 percent; from 4 to 9 percent the indicated choice is gas, and below 4 percent the indicated choice is renewable energy. In short, the lower the discount rate, the more attractive is the renewable energy option.

32. see, e.g., H. Lopez, *The Social Discount rate: Estimates for Nine Latin American Countries*, Policy Research Working Paper 4639, World Bank; and Zhuang, J., Z. Liang, Tun 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.

33. For the moment, the analysis ignores any capacity penalties associated with intermittent renewables.

Table A1.1. NPV Calculations, 10 Percent Discount Rate

			NPV	2015	2016	2017	2018	2019	2020	2021	2022
[1] A. Imports											
[2] # of 50 MW units	6										
[3]	300	MW									
[4] Capacity factor	0.7	[ ]									
[5] GWh in Kabul		[GWh]				1,839.6	1,839.6	1,839.6	1,839.6	1,839.6	1,839.6
[6] Import price		[$/kWh]				0.08	0.08	0.08	0.08	0.08	0.08
[7] Import cost		**[$USm]**	**998**			**147.2**	**147.2**	**147.2**	**147.2**	**147.2**	**147.2**
[8] Levelized cost		[USc/kWh]	8.0								
[9] B. Gas											
[10] # of 50 MW units	6										
[11] Total installed cap.	300	[MW]									
[12] Energy		[GWh]	12,469			1,840	1,840	1,840	1,840	1,840	1,840
[13] Capital cost	850	[$/kW]									
[14] Afghanistan premium	1.5	[ ]									
[15] Investment cost		[$USm]		191.25	191.25						
[16] Gas cost		[$/mmBTU]				8.0	8.0	8.0	8.0	8.0	8.0
[17] Heat rate	6,828	BTU/kWh									
[18] Fuel cost		[$USm]				100.5	100.5	100.5	100.5	100.5	100.5
[19] Total cost		**[$USm]**	**1,013**	**191.25**	**191.25**	**100.5**	**100.5**	**100.5**	**100.5**	**100.5**	**100.5**
[20] Levelized cost		[USc/kWh]	8.1								
[21] C. Renewable energy											
[22] Units installed	12										
[23] Total installed cap.	600	[MW]									
[24] Capacity factor	0.35										
[25]		[GWh]	12,469			1,839.6	1,839.6	1,839.6	1,839.6	1,839.6	1,839.6
[26] Capital cost	1,500	[$/kW]									
[27] Afghanistan premium	1.25	[ ]									
[28] Investment cost		[$USm]			1,125.0						
[29] O&M cost	0.04	[$USm]				45.0	45.0	45.0	45.0	45.0	45.0
[30] Total cost		**[$USm]**	**1,235**	**0.0**	**1,125.0**	**45.0**	**45.0**	**45.0**	**45.0**	**45.0**	**45.0**
[31] Levelized cost		[USc/kWh]	9.9								

Note: Calculations are for an assumption 20 year life: for sake of legibility the snapshot shown here is just for the first few years.

A1.2. Environmental Sustainability

These comparisons do not take into account the negative externalities of fossil-based generation. In most countries, the objective of environmental sustainability in power sector development is dominated by the need to address two main sets of externalities: at the global level, the avoidance of GHG emissions; and at the local level, the impacts of local air and water emissions on environmental quality and human health, particularly those arising through the emission of particulates (this report mainly refers to particulates of ten microns or less, or PM_{10}), oxides of sulfur (SOx) and oxides of nitrogen (NOx).

The conventional (classical) view of natural resource economics is that the best way to achieve environmentally sensitive decision making is to ensure that environmental externalities are valued in economic terms and included in the table of economic flows rather than lowering discount rates.[34] The main concern of this analysis is therefore to ensure that the full costs of environmental externalities are incorporated into the analysis to allow proper comparison of options.

GHG Emissions

Imports are based on gas generation in the CARs, and therefore also generate GHG emissions. How do the results change if these externalities are taken into account? The recent Bank guidance on valuation of carbon is an important step in this direction: these guidelines suggest the values shown in table A1.2.

Table A1.2. Social Value of Carbon (SVC) (in 2014 $)

	2015	2020	2030	2040	2050
Low	15	20	30	40	50
Base	30	35	50	65	80
High	50	60	90	120	150

Source: Social Value of Carbon in Project Appraisal, Guidance Note to World Bank Group Staff, September 2014.

In table A1.3, the analysis adds (in the case of imports in rows 9–14) a calculation of the GHG emission damage costs using the baseline values in table A1.2.[35] Now at the 10 percent discount rate, the cost of the renewable energy option ($1,235 million) is only marginally above the import option ($1,126), and below the gas option ($1,246 million). Indeed, at all discount rates below 10 percent, renewable energy is the least-cost option when the GHG emission damage costs are taken into account.

Figure A1.2 shows the same comparison as figure A1.1, but now with NPVs calculated to reflect the GHG emission damage costs. One observes that the renewable energy is the least-cost option for all discount rates less than 11 percent; above 11 percent the least-cost option is imports.

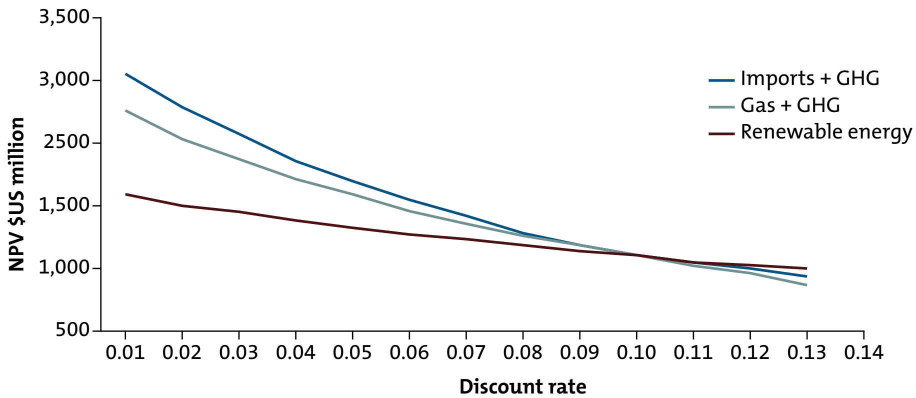
34. Section 14.5 of Pearce and Turner (1990) discusses alternatives to reducing discount rates to reflect environmental concerns. Markandya and Pearce (1991) make the same point ("the effects of carbon emissions should therefore be captured in the social cost of carbon, not in the discount rate").

35. The values shown in table 3.2 have updated to 2015 prices, and interpolated for the annual values shown in row [9].

Table A1.3. NPV Calculations Including GHG Damage Costs (10 Percent Discount Rate)

			NPV	2015	2016	2017	2018	2019	2020	2021	2022
[1] A. Imports											
[2] # of 50 MW units	6										
[3]	300	MW									
[4] Capacity factor	0.7	[ ]									
[5] GWh in Kabul		[GWh]				1839.6	1839.6	1839.6	1839.6	1839.6	1839.6
[6] Import price		[$/kWh]				0.08	0.08	0.08	0.08	0.08	0.08
[7] Import cost		[$USm]	998			147.2	147.2	147.2	147.2	147.2	147.2
[8] Levelized cost		[USc/kWh]	8.0								
[9] GHG emission factor	0.45	kg/kWh									
[10] GHG emissions		[1,000 t]				828	828	828	828	828	828
[11] Environmental damage cost		[\$/tonCO_2]				32.6	33.7	34.7	35.7	37.2	38.8
[12] Damage costs		[$USm]				27.0	27.9	28.7	29.6	30.8	32.1
[13] Adjusted costs		**[$USm]**	**1226**			**174.2**	**175.0**	**175.9**	**176.7**	**178.0**	**179.3**
[14] Levelized cost		[USc/kWh]	9.8								
[15] B. Gas											
[16] # of 50 MW units	6										
[17] Total installed capacity	300										
[18] Energy		[GWh]	12,469			1,840	1,840	1,840	1,840	1,840	1,840
[19] Capital cost	850	[$/kW]									
[20] Afghanistan premium	1.5	[ ]									
[21] Investment cost		[$USm]		191.25	191.25						
[22] Gas cost		[$/mmBTU]				8.0	8.0	8.0	8.0	8.0	8.0
[23] Heat rate	6828	BTU/kWh									
[24] Fuel cost		[$USm]				100.5	100.5	100.5	100.5	100.5	100.5
[25] Total cost		[$USm]	1013	191.25	191.25	100.5	100.5	100.5	100.5	100.5	100.5
[26] Levelized cost		[USc/kWh]	8.1								
[27] GHG emission factor	0.46	kg/kWh				846	846	846	846	846	846
[28] Damage costs		[$USm]				27.6	28.5	29.3	30.2	31.5	32.8
[29] Adjusted costs		**[$USm]**	**1246**	**191.3**	**191.3**	**128.1**	**129.0**	**129.8**	**130.7**	**132.0**	**133.3**
[30] Levelized cost			10.0								
[31] C. Renewable energy											
[32] Units installed	12										
[33] Total installed capacity	600										
[34] Capacity factor	0.35										
[35]		[GWh]	12,469			1,839.6	1,839.6	1,839.6	1,839.6	1,839.6	1,839.6
[36] Capital cost	1,500	[$/kW]									
[37] Afghanistan premium	1.25	[ ]									
[38] Investment cost		[$USm]			1,125.0						
[39] O&M cost	0.04	[$USm]				45.0	45.0	45.0	45.0	45.0	45.0
[40] Total cost		**[$USm]**	**1,235**	**0.0**	**1,125.0**	**45.0**	**45.0**	**45.0**	**45.0**	**45.0**	**45.0**
[41] Levelized cost		[USc/kWh]	9.9								

Figure A1.2. Comparison of NPVs as a Function of Discount Rate When GHG Damage Costs Are Included



These are illustrative calculations and as noted below, this paper does not argue that Afghanistan should make urgent power sector decisions based on the avoidance of GHG emission damage costs. Indeed, these simple calculations are made much more difficult when the various uncertainties in assumptions are taken into account. However, the calculations do show the importance of the discount rate assumption and the main principle involved, namely that the relevant externalities and damage costs be monetized and included in the table of costs and benefits.

The avoidance of GHG emissions commands little primacy for government policymakers (or indeed of the global community) in making policy choices: Afghanistan's GHG emissions are among the lowest in the world, both in absolute and in per capita terms (table A1.4). Afghanistan ranks at the bottom of the list with emissions less than 0.1 tons/capita, together with four of the poorest African countries.[36] It can be stated with confidence that Afghanistan's GHG emissions will remain negligible, even if by 2030 several thousand MW of coal base load capacity were in operation.

The overriding priority of the international community for Afghanistan is poverty alleviation, social stability and justice, and continued economic development following the departure of

Table A1.4. International Comparisons, CO_2 Emissions Per Capita (2008)

	Tons CO_2/Capita
United States	18.38
Germany	9.79
United Kingdom	8.32
Austria	8.31
South Africa	6.93
China	4.92
Global average	4.39
Vietnam	1.19
Sri Lanka	0.61
Afghanistan (1991)	0.20
Afghanistan (2020)[a]	0.18
Afghanistan (1998)	0.03

a. Assuming an additional 1000 MW of coal generation, see text below

36. Mali, Chad, Burundi and the Democratic Republic of Congo.

NATO Forces. In any event, quantifying the GHG emissions of alternative power sector options is straightforward (and described in the 2015 guidelines for carbon accounting). It is also likely that the strict guidelines that apply to the World Bank's financing of coal projects could almost certainly be met, given the need for thermal power to improve energy security, reduce power shortages, and increase access. The main consideration would turn on whether gas is available in sufficient quantity as a viable alternative to coal.

The World Bank has now also issued guidelines for the valuation of carbon emissions, so calculation of economic returns with and without inclusion of carbon emissions is also straightforward.[37] If the baseline carbon values ($30/ton CO_2 in 2015, increasing to $50/ton by 2030) were applied to the valuation of coal and its alternatives—it would add 2.7 US¢/kWh to a coal project, but only 1 US¢/kWh to a gas CCGT.

Local Air Quality

Kabul is one of the world's most polluted cities, with recorded levels of ambient air pollutants greater than Beijing and Lahore. Located at a high altitude, ringed by mountains, and subject to frequent inversions, concentrations of $PM_{2.5}$, SOx, and NOx are multiples of generally accepted safe levels (table A1.5). According to the Ministry of Health, some 3,000 deaths per year in Kabul are attributable to the toxic air quality conditions: in a sample of 200 hospital patients, 80 percent had elevated levels of lead (indicative of leaded gasoline). Indeed, so serious are the perceptions of poor air quality that the U.S. Defense Department has been petitioned to include exposure to Kabul's toxic air quality conditions in military service personnel histories.[38]

Table A1.5. Estimated Ambient Levels of Particulates, µg/m³

Inversion Layer Height	$PM_{2.5}$	PM_{10}
Kabul, 500 meters[a]	39.5	396
Kabul, 250 meters[a]	79.0	792
EPA standard[a]	15.0	
Mazar-e-Sharif[b]	68.0	334
Kabul[b]	86.0	260
Beijing[b]	56.0	121

Sources:
a. A Sediqi, Preliminary Assessment of Air Quality in Kabul.
b. World Health Organization, Ambient (outdoor) Air Pollution in Cities Database 2014.

The direct contributions of DABS thermal generation to these air quality levels is minimal since the Tarakhil diesel is used infrequently. Major sources of pollution include motor vehicles (many of which are old and poorly maintained), brick kilns, and open burning of tires and waste material. Coal of unknown and probably variable quality is widely used as a residential fuel, including in small district heating systems for new residential developments.

As grid power delivered to Kabul has increased in recent years, the use of diesel self-generation will have declined (other things being equal) but with renewed economic and industrial growth, power shortages remain widespread, and estimates of the current

37. World Bank, *Criteria for Screening Coal Projects under the Strategic Framework for Development and Climate Change*, 2010.
38. Letter from U.S. Senator Wyden to the U.S. Secretary of Defence Leon Panetta, 2012 www.wyden.senate.gov/download/kabul-air-quality-letter.

Table A1.6. Cost of Social and Environmental Mitigation Plans

Project	MW	Total Project Cost ($USm)	$/kW	EMP ($USm)	SMP ($USm)	Total ($USm)	As Percent of Total Cost (%)	Resettled Housholds	Affected Housholds	SMP Cost Per Houshold ($)
Chunek	390	558	1,431	5.0	11.9	16.9	3.0	323	323	36,904
Dab	450	884	1,964	4.4	17.7	22.1	2.5	480	480	36,854
Surtaq	410	660	1,610	5.0	11.6	16.6	2.5	300	300	38,600
Lar Sultan	390	1,030	2,641	4.0	13.1	17.1	1.7	325	325	40,369
Sagi	300	611	2,037	1.3	6.5	7.8	1.3	210	349	30,857
Kunar_A	789	1,600	2,028			36.4	2.3	1,234	2,844	29,498

Source: 2009 Pre-feasibility studies; 2009 FS for Shal (Kunar).

self-generation capacity in commercial and industrial enterprises is between 25–100 MW. In the residential sector, many households have 2-stroke gasoline generators. The strong winter peak demand for electricity is largely attributable to the widespread use of electric bar-heaters. Given that much residential heating and cooking is from burning wood, coal and waste, greater availability of grid-electricity can only be beneficial—though LPG has begun to replace fuel wood and coal for cooking.[39]

As shown in the calculations of the case studies, inclusion of the damage costs of both local and GHG emissions have little impact on the calculation and comparison of economic returns, especially when the avoided damage costs associated with the reduction of self-generation and indoor air pollution are also included.

Social Impacts

Major generation and transmission projects, as well as domestic resource exploitation (coal, gas, oil, hydro), may affect the well-being, land use, and livelihoods of project-affected persons (PAPs).[40] There is little reliable information about the number of PAPs likely to be displaced by the large hydro projects: the prefeasibility study of five smaller Kunar River projects showed the number of displaced households in the few hundreds (table A1.6), with the cost of social mitigation plans of $6.5 to $18 million. That for Kunar A is 1,234 households to be resettled, with total costs of the EMP and SMP at $36.4 million.

39. It is well understood that the damage costs of diesel self generators, located in densely populated urban areas, with uncontrolled emissions emitted at or near ground level, have damage costs per kg of pollutant, are 1–2 orders of magnitude greater than from modern utility scale generators fitted with high stacks, located in remote areas, and fitted with state-of-the-art pollution controls. (see, e.g., Lvovsky et al. 1990). This would likely hold true for Afghanistan as well: any large coal generation project would be far way from the major urban population centres. For details, see World Bank, *Economic Analysis of Power Sector Projects: Guidance Note*. Technical annex B5, June 2015).

40. The 2012 Afghanistan Power Sector Master Plan notes as follows:

> The general considerations and preliminary social screening of the selected projects … reveal that the social impacts of energy infrastructure projects are mainly related to land use, land acquisition and resettlement issues … as well as to Environment, Health and Safety impacts that will arise during the construction and operation phases of the projects that are the subject of the Environmental Impact Assessment and Environmental Management Plans.

The original feasibility study for Bagdhara indicated that some 20,000 people would be displaced if the full supply level for the reservoir was set at 1,460 masl. The updated feasibility study prepared in 2015 adjusts the full supply level to 1,375 masl, in which it is stated that no people would be affected by the reservoir.

The costs of social and environmental management and mitigation plans and of other related safeguards policies are readily monetized and included in the table of economic flows—though given the limited information at hand, such estimates are again subject to high uncertainty. Based on the information in table A1.4, the incremental costs in the case of hydro projects may be taken as 3 percent.

A1.3. Energy Security

Energy security is one of the main uncertainties in small and fragile countries, but is also an aspect of energy and power system planning that has been much discussed, most often in connection with high cost renewable energy projects: when economic returns in a conventional CBA fail to reach hurdle rates, might not the energy security benefits provide additional justification, even if not monetized? Yet as noted by many, “energy security” has rarely been clearly defined, which makes it hard to measure and therefore difficult to balance against other policy objectives. Indeed, discussion of energy security requires much caution and skepticism.[41]

Most governments assert that energy security is a concern, and energy security is a frequent topic of political debate. Indeed, governments, international institutions and the international financial institutions (IFIs) define energy security in many different ways: each has its own definition according to the risks and threats it perceives. Some definitions are so broad as to become very difficult to relate to practical decision making, much less to construct meaningful indicators. For example, IEA’s definition of energy security is the uninterrupted physical availability at a price that is affordable while respecting environmental concerns (IEA, 2001) encompasses not just “security,” but includes many of the other objectives of energy policy: how to quantify so grand a concept is attempted only by the very brave.[42]

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41. As noted by the eminent MIT economist Paul Joskow (2008), “There is one thing that has not changed since the early 1970s. If you cannot think of a reasoned rationale for some policy based on standard economic reasoning, then argue that the policy is necessary to promote “energy security.” No less scathing is the U.S. Chamber of Commerce (that publishes an annual Index of U.S. Energy Security Risk), “thrown around ad nauseam by politicians, the media, and scholars alike, any advancement in securing our energy sector has been overshadowed by an inability to determine what is meant by this vague, but important objective—begging the question, how can we protect something we have failed to define?” (U.S. Chamber of Commerce, Institute for 21st Century Energy, Index of U.S. Energy Security Risk, 2011).

42. The U.K. government has a similarly encompassing definition: “Consumers should have access to the energy services they need (physical security) at prices that avoid excessive volatility (price security), and delivered alongside achievement of our legally binding targets on carbon emissions and renewable energy” (U.K. Secretary of State for Energy and Climate Change, Energy Security Strategy, Report to Parliament, November 2012).

Taylor and Van Doren (2008) note the differences between the perception of energy security among economists and that among (American) "foreign policy elites." The principal focus of the former is macroeconomic impact of fossil fuel price volatility; the focus of the latter is geopolitical extortion. They point out that on closer inspection, most of the fears about geopolitical extortion are groundless, pointing to the failure of oil embargoes to physically interrupt oil supplies to particular target countries: for example in the 1972/73 Arab oil embargo, instead of buying oil from Arab members of OPEC, the U.S. simply bought from non-Arab sources (and the customers displaced by the U.S. bought from the Arab OPEC members). Of course prices increased sharply, but quantities were unaffected: U.S. oil imports increased from 1.7 mbd in 1971 to 3.2 mbd in 1973. They similarly dismiss other related foreign policy concerns about energy security.[43]

Definitions of Energy Security

There are wide differences in how governments perceive their energy security: sometimes these are stated explicitly, in other cases they are evident from actions. What constitutes energy security (or insecurity) is determined by the perceptions of government, examples of which include:

- ***The U.K. government in 1912.*** Arguably the first example of an expressly announced energy security policy, Winston Churchill famously noted that "We must become the owners or at any rate the controllers at the source of at least a proportion of the oil which we require."[44]
- ***The government of Saudi Arabia in 2012.*** The commitment to large scale development of CSP reflects not just its excellent solar regime and opportunity to become a global leader in a new industry, but the need to hedge the vulnerability of the Saudi oil infrastructure and its oil exports to blockade of the Straits of Hormuz.[45]
- ***The government of Nepal in the 1990s.*** The goal of energy sufficiency was articulated on grounds of its rich hydro resource and that Nepal's energy policy should build hydro projects and export the hydro surplus to India rather than rely on electricity imports from India whose Eastern provinces at the time had a surplus of coal-fired capacity suitable for export as base-load. While electricity self-sufficiency was largely attained, the result of the reluctance to see energy trade as a two-way opportunity resulted in no progress in exporting hydro power and

43. For example, that in order to ensure the uninterrupted flow of oil, the U.S. must maintain friendly relations with oil producers (such as with Iran) or that money from oil imports finds its way to fund terrorist organizations. The authors argue that neither concern has any evidence to support it.
44. History records the emergence of energy security as a major policy problem for the U.K. government in the conversion of the British Royal Navy from coal to oil first proposed in 1882. This was finally realized in 1912 with the construction of the first oil-powered battleship. In the language of cost-benefit analysis, the military benefits of oil as a naval fuel (no smoke, 30 minutes to reach full power, not 3–4 hours, a third of the engine weight, and a quarter of the fuel weight for equal horsepower, 12 hours instead of 5 days to refuel) far exceeded the incremental cost of oil and the cost of securing the supply. The problem was that while Britain had coal, it had no oil, which needed to be secured from the Middle East—a fact that shaped (and held hostage) British foreign policy for the next 50 years.
45. The Saudi Electricity Company 550 MW Duba 1 project, an integrated solar combined cycle project, is the first CSP project in a program that has set a target of 41 GW of solar power by 2032 (CSP 25 GW, PV 16 GW).

endemic power shortages, particularly because an almost all-hydro system was exposed to increasing hydrology risk.[46]

- ***The United States in 2011.*** The March 2011 speech of President Obama articulated America's energy security problem as freedom from oil imports:

> "…there are no quick fixes. We will keep on being a victim to shifts in the oil market until we get serious about a long-term policy for secure, affordable energy… The United States of America cannot afford to bet our long-term prosperity and security on a resource that will eventually run out… So today, I'm setting a new goal: one that is reasonable, achievable, and necessary. When I was elected to this office, America imported 11 million barrels of oil a day. By a little more than a decade from now, we will have cut that by one-third."[47]

In fact, by 2013, U.S. oil imports had already fallen by half—albeit less as a consequence of new federal government policies as much as by the private sector-led fracking technology revolution.

Lessons from the Energy Security Literature

Since the 1973 OPEC oil embargo, a growing literature has grappled with the question of how to define and quantify energy security concerns. In the economics literature, the emphasis of energy security discussions—particularly since the mid-1970s—is on the macroeconomic impacts of oil price shocks. Bohi, Toman, and Walls (1996) summarize much of the early work and define *energy insecurity* as the *loss of welfare that may occur as a result of a change in the price or availability of energy*; Tang et al. (2010) examine the impact of oil price shocks on the chinese economy; and Ebrahim et al. (2014)[48] assess the macroeconomic consequences of oil price volatility—all typical examples of a still-growing literature. Much of this work is focused on the asymmetries of oil price shocks (the costs of sharp oil price rises—including inflation and recession—are not matched by the benefits of any subsequent price falls): it is the price and consequent macroeconomic impacts, rather than curtailments in physical supply that is the main concern. This is complemented by a substantial World Bank literature that deals with strategies to mitigate the impacts of oil price shocks in developing countries (both importers and exporters).[49]

Translating price volatility impacts into a risk premium that could be built into CBA is difficult, and rarely attempted. A recent study for Latin America by the Inter-American

46. See e.g., World Bank, *Nepal Hydropower Exports*, 1999.
47. http://www.nationaljournal.com/energy/obama-s-energy-security-speech-there-are-no-quick-fixes-20110330.
48. This paper from Oxford University includes an excellent literature review of the various impacts of oil price volatility (industrial production, employment, inflation and monetary policy, unemployment, stagflation).
49. See, e.g., Spatafora and Warner (1996); Bacon and Kojima (2006); Timilsina (2013).

Development Bank[50] suggests the risk premium to be very small, (0.01 US¢/kWh), an order of magnitude lower than, for example, the damage costs from local air pollution of thermal generation. Another recent study to develop an avoided cost renewable energy tariff for Indonesian geothermal projects[51] estimates the volatility premium at 0.07 US¢/kWh (estimated as the cost to the ministry of finance of short-term financing of unexpected increased subsidy to PLN as a result of volatility induced forecasting errors of coal prices.

Another strand of the relevant literature is to cast renewable energy as a hedge against fossil fuel price volatility, as first proposed by Auerbuch (2000). He argued that the role of renewable energy projects in a portfolio of generating projects was akin to the role of essentially risk-free treasuries in a financial portfolio. The application of mean-variance portfolio theory is useful, but one must be careful not to overstate the case: wind projects in particular have high annual variability due to wind speed variations—though because this risk is uncorrelated with the factors that drive fossil fuel price variability, it can still serve as a hedge.

The general theme of renewable energy as a hedge against fossil price uncertainty has been taken up by Bolinger and Wiser (2005) at the U.S. Lawrence Berkeley National Laboratory. This argues that—at least in the U.S. where futures markets for natural gas are well developed—renewable energy can be a cost-effective hedge when compared with futures hedging. However, sophisticated oil-price hedging strategies for small developing countries are to be recommended only with great caution (Sri Lanka's recent attempts to do so were an unmitigated disaster, with losses in the hundreds of millions of dollars).[52]

This survey points to a number of important lessons for Afghanistan:

- The general conclusions about the ineffectiveness of embargoes and physical interruptions, or the threat of interruption, ***do not apply to landlocked countries***. Afghanistan's experience with Iran, Nepal's experience with India, and even Switzerland's experience in World War II,[53] all show that landlocked countries are indeed exposed to this category of energy security concern.

50. W. Vergara et al., *Societal Benefits from Renewable Energy in Latin America and the Caribbean*, *IDB Technical Note*, January 2014.
51. World Bank and ADB, *Unlocking Indonesia's Geothermal Potential*, October 2014.
52. Both the ENRON and Ceylon Petroleum Company fiascos are well described at http://www.risk.net/energy-risk/feature/2323248/the-10-biggest-energy-risk-management-disasters-of-the-past-20-years.
53. Switzerland experienced the most extreme case of energy security related geopolitical extortion: During World War II, Switzerland was almost entirely dependent on imported coal for winter space heating, which enabled Nazi Germany to force Switzerland to export machinery and hi-tech goods to Germany in exchange for coal, in contravention of international laws on neutrality (Wylie, 2003). But such *successful* examples of extortion are rare.

- Even during the height of the cold war, the Soviet Union did not disrupt gas supply to Europe (that has other gas import options), but Russian threats to cut off pipeline gas supply to the Ukraine and Georgia have been more successful.
- Definitions of energy security vary from country to country. These need to be clearly established in consultation with the government at the outset of a planning study (or project appraisal).
- One should distinguish between the resilience of the power system and the risks associated with specific projects. System resilience is primarily about diversity (the more diverse the sources of supply, the less is the impact of a given shock) and about energy efficiency and energy intensity (if energy is used efficiently, again, the less is the impact of an external shock). Efficient pricing is an important dimension of this: the fewer and lower the subsidies, the better.
- Security should be treated as a separate attribute—and a quantitative indicator selected to quantify it. In most cases, there will likely be a trade-off between economic efficiency and the energy security attribute.
- The relevant security attribute will be a function of the level of planning involved. For example, the Herfindahl index as a measure of generation supply diversity may be appropriate for a generation planning study. But for a project selection appraisal, the various project-specific risks should be enumerated and costed on the basis of outages (unserved energy) and repair costs.

Energy Security in Afghanistan

The definition of energy security concerns was taken up at the May 2015 workshop. In order of importance, these were defined by the participants as follows:

- ***People need power.*** As the first priority, unanimously accepted by all of the government and utility officials present. Access to reliable low-cost electricity is viewed as fundamental to economic and social development, which in turn are the best guarantors for a reduction in insurgency.
- ***Weather.*** In the seven years since the construction of the 220 kV transmission line across the Salang Pass, and large-scale imports of electricity from northern neighbors, one of the two major disruptions has been due to inclement winter weather: in late February 2015, avalanches destroyed several towers, resulting in a six-week disruption to Kabul's power supply.
- ***Lack of refinery capacity.*** This makes Afghanistan vulnerable to border closures, given that diesel fuel is imported by tanker truck. In January 2011, Iran closed the border to diesel trucks for the officially given reason of discouraging smuggling. This demonstrated how vulnerable Afghanistan's diesel supplies were,in the event of any disruption of trade at the border, regardless of the reason—commercial or political.[54]

54. Given the withdrawal of NATO forces, the workshop participants did not see a repetition of such an embargo as an important threat for the future.

- ***Dependence on electricity imports.*** The lack of import alternatives in the short term leads to the impression of a weak bargaining position for Afghanistan when negotiating the price of electricity imports from Uzbekistan to supply the NEPS system and Kabul. However, while the price has certainly increased over the past few years, the price now being requested by Uzbekistan for firm power over the next year (around 8 US¢/kWh) is not unreasonable given current market conditions for gas in the CARs (see case study in annex 3).
- ***Local opposition.*** The main disruption to transmission infrastructure construction and right-of-way clearance has been local opposition "Locals see the line, but they see no benefit and get no power." The use of local contractors during construction is a partial solution to this problem, and appendix 1 to annex 5 presents some technical solutions to delivering small amounts of power along a major transmission line.[55] As in many other developing countries, as soon as a project is announced (and particularly those funded by IFIs known to insist on generous compensation packages), it has been reported that "land grabbers" appear as potential beneficiaries, claiming to be eligible for the compensation package expected to be on offer.
- ***Insurgent action.*** Attacks on small-scale energy infrastructure are rare, and so far no small off-grid renewable energy facility in rural areas has been targeted. There have been many reported security problems where foreigners have been concerned (the Chinese mining consortium experienced problems during its investigations of coal resources)[56] or where the presence of NATO forces have attracted insurgents (such as at the Kajaki hydro project). Separate insurgent attacks in Baghlan province in early 2016 led to Kabul's supply from northern imports being disrupted for the first time.

These perceptions of the security issues facing Afghanistan reflect the view as seen by officials of the government of Afghanistan involved in the day-to-day operation of the power system and faced with short-term priorities. Unfortunately, it is the perception of parties *outside* Afghanistan, particularly among potential investors, that pose the most significant obstacle to developing the generation options over the long term. In addition to the problems faced by the Chinese Mining consortium (noted above), other recent examples include:

- The reluctance of the Indian consulting company preparing the FS for the Kunar A hydro project to conduct the necessary geological and geotechnical studies on grounds of insurgent activity, resulting in a FS that is of little practical value since it cannot confirm technical feasibility.
- The refusal of potential suppliers of converter stations for the HVDC CASA-1000 project to bid for the proposed Kabul converter station (they have also refused to

55. Using the so-called Shield Wire System (used in several developing countries). See appendix 1 to annex 5.
56. The government's response of sending 400 troops to the Hagi Gak concession area was deemed insufficient by the CMGC, who discontinued survey work on grounds of poor security (though it has also been argued that this withdrawal may have been related to renegotiation of the concession arrangements).

bid for the converter station in Peshawar, which may lead to the relocation of the Pakistan end of the HVDC line closer to the main load centers).

- According to the U.S. Special Inspector General for Afghanistan Reconstruction (SIGAR), turbine parts for the Kajaki hydro projects have been onsite since 2008 but uninstalled due to "security threats."[57]

In other words, there is a disconnect between the perceptions of the energy security as perceived by those Afghanistan officials intimately involved in the day-to-day planning and operation of the power system—who are accustomed to the realities of daily life in Afghanistan—and the perceptions of potential investors and equipment suppliers overseas.[58] These assessments severely constrain the freedom of choice for power sector investment in Afghanistan and have led to significant distortions, particularly to over-investment in transmission and under-investment in generation.

Risk, Risk Mitigation, and Resilience in Afghanistan

Energy insecurity can be described as a basket of applicable risks—different countries will have different perceptions of the relevant risks in their baskets, which are typically one or more of the risks listed in table A1.7. Risk mitigation refers to actions focused on the mitigation of specific risks—hedging of oil prices (mitigating against price volatility) and increasing fuel supply stocks at fossil power plants (mitigating against the risk of physical supply disruption). The important point is that all such mitigation actions come at a cost and that these costs can be compared with the expected value of the cost of the risk. The cost of a one-month disruption to coal supply for example caused by an accident that disrupts coal trains can be calculated as the cost of lost generation plus the cost of restoring the supply.

Resilience and metrics for its quantification capture the degree to which the power sector is robust with respect to exogenous uncertainties. This is an attribute of the *system* and not of the riskiness of a particular project. Accordingly, the extent of resilience will be determined by sectoral policies, and particularly those that improve the efficiency of the sector: industrial energy efficiency that improves the energy/GDP intensity or T&D loss reduction—both improve the resilience to exogenous risks no less than the introduction of renewable energy to diversify the supply mix. Many definitions of energy resilience have been proposed:

57. The reports of the Special Inspector General for Afghanistan reconstruction (SIGAR) to the U.S. Congress reveal the extent to which U.S. contractors have encountered problems in various power sector projects. The extent to which claims of "security problems" is used as cover for other implementation and management problems is unclear, but reports of this kind shape the perceptions of potential overseas investors about security risks (see, e.g. SIGAR, *Quarterly Report to the United States Congress*, April 2015).

58. There is no doubt that "Security" seems to be a convenient cover for the mismanagement of foreign contractors. The SIGAR report on the Tarakhil project showed that the delays and cost overruns were largely a consequence of ambiguities in the statement of work, delays in subcontract awards, subcontractor performance problems, lack of onsite quality assurance, lack of timely approvals, and poor communication between USAID and the contractors. The only Afghanistan-specific issue was delays associated with land ownership issues (also noted by the World Bank Enterprise Survey as one of the main constraints to private investment). See SIGAR, *Special Report: Contract delays and Cost Overruns for the Kabul Power Plant and Sustainability Remains a Key Challenge*. January 2010.

Table A1.7. The Risk Dimensions of Energy Security

	Physical Security	Price Security
Short term	■ Technical failures (forced outages at generators) ■ Natural resource variability (hydrology and wind speed variations) ■ Natural force majeure (typhoons, extreme drought) ■ Political force majeure (strikes, terrorist attacks) ■ Supply chain disruptions ■ Cyber attacks ■ Government embargoes	■ Price volatility ■ Commodity price bubbles
Long term	■ Resource depletion ■ Climate change	■ Price fixing by cartels ■ Changing patterns of global demand

Source: Winzer (2011), Parkinson (2013)

- Simple measures such as the fraction of oil demand met by imports in oil supply (much used in the U.S.).
- More sophisticated numerical indicators of diversity of supply (under the presumption that greater diversity implies better energy security), such as the Herfindahl index (and its derivatives, discussed further below).
- Energy (electricity) consumption per unit of GDP—the more energy intensive the economy, the greater the impact of supply disruption or price volatility.

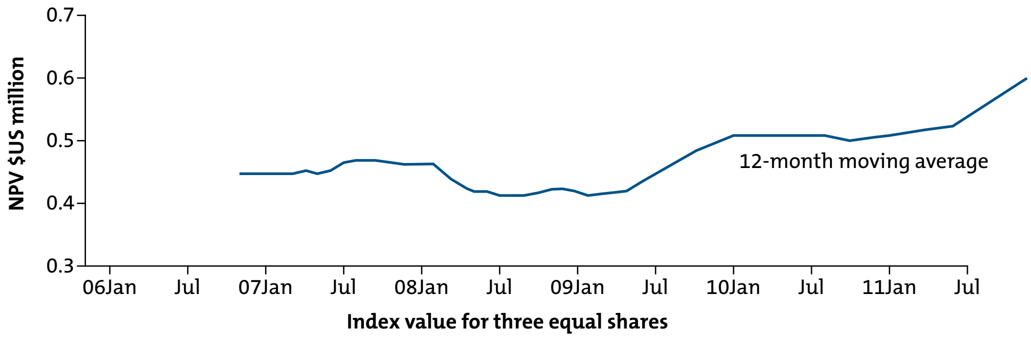
The most common indicator of supply diversity (or generation mix diversity in the case of the power sector) is the Herfindahl Index, a dimensionless measure used originally to assess the degree of concentration and competition of firms in industrial sectors. The index ***H*** is calculated simply as the sum of squares of the market or generation mix shares s_i for each of the n shares as follows:

$$H = \sum_{n} S_i^2$$

The *lower* the value of ***H,*** the *greater* the diversity of fuels. In estimating diversification of supply by this approach, if there were only one fuel, the index would be 1; if there were ten fuels, each taking the same share, the index would be 0.1. The shares are best expressed as installed *capacity* shares rather than energy shares. Obviously, introducing new renewable energy forms into a power system will increase such diversity, but as noted above, it is not always true that greater supply diversity significantly improves the main security risks of power supply to the consumer.[59]

59. When one looks at diversity of supply, the value of a 100 MW thermal project normally run at 70–90 percent is much greater than the value of a 100 MW wind project that has a 15 percent annual capacity factor. The thermal project can be run at 90 percent (if there is enough fuel in its tanks), but the total average capacity factor of the wind project cannot be increased (and in any event may not be available at the system peak). So it is not installed capacity that is the relevant metric but the maximum dependable capacity that should be used.

Figure A1.3. Supply Diversity Index: Afghanistan



The case of energy efficiency improvements is instructive: all other things equal, T&D loss reduction or energy efficiency projects will reduce the need for supply but leave its mix (and hence its H-index) largely unchanged—howeve, the resilience of the economy (for example, measured as kWh per unit of GDP) will surely improve.[60]

Figure A1.3 compares the Herfindahl index for the NEPS supply, with a notional index value of 0.333 for three equal shares. With the growing dominance of electricity imports, and the more or less complete phasing out of diesel generation in Kabul, the index value has increased from 0.45 in 2007 to 0.6 by the end of 2011—the supply has become *less* diverse.

60. The International Energy Agency (Blythe and Levebre, 2007) modified this simple diversity measure by weighting the shares by the relative political risk (ri) associated with each source, the "energy security index" energy security index (ESI) defined as

$$ESI = \sum_{n} r_i s_i^2$$

where zero geo-political risk would reflected by r=1, and maximum oil import risk (e.g., oil that must pass through the Straits of Hormuz), by r=10. Studies of a similar genre include Wintzer (2011) who assesses European vulnerability to Russian gas imports; and Grubb et al (2006) who assess energy security and carbon reduction for the U.K.. In an IMF working paper, Cohen et al. (2011) use a similar index based on the risk assessments of the Political Risk Services Group and reported in the International Country Risk Guide (PSRG,2014). (Afghanistan is not among the 145 countries monitored by PRSG).

Annex 2: Case Study—Hydropower Project Development

A2.1. Background

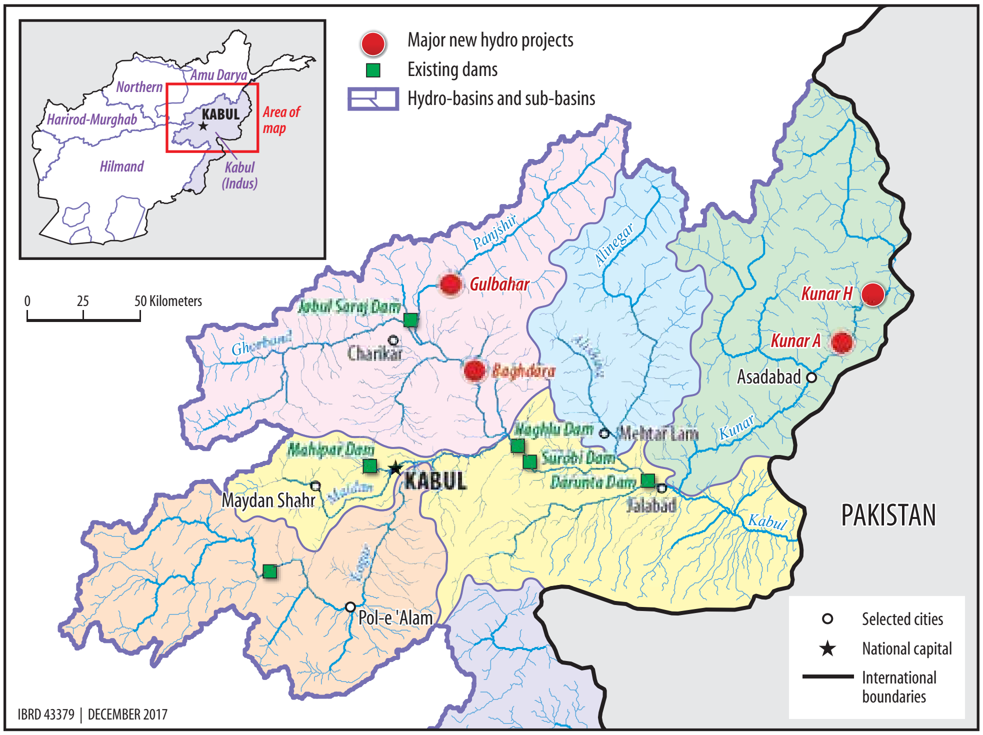
There is little question that Afghanistan is endowed with significant hydro resources.[61] But as with all energy resources, the question is not one of their existence but one of economic feasiblilty. Successive master plans have recommended that new hydro projects be developed, but progress toward their realization has been slow.

This section examines the question of how and when to proceed with the development of new large hydro projects in Afghanistan that have been recommended for implementation by plans going back more than 30 years. The locations of existing and candidate projects in the east of the country where much of the potential lies are shown in figure A2.1. Decisions about hydro have been repeatedly delayed perhaps because of the ease with which imports have grown—the high capital cost of hydro has also discouraged the preparation of modern feasibility studies.

The distinguishing feature of hydro projects is their site-specific dependence, which requires a favorable combination of topography, hydrology, and geology, and the fact that this requires expensive feasibility study to establish. For Afghanistan, there is the additional problem of matching hydro output to strong seasonal load dependence—peak demand is in winter (December–January), but peak inflows are in summer (figure A2.2). This same problem is common to Afghanistan's northern neighbors, Tajikistan and Kyrgyzstan, which also have hydro surpluses in summer, and is one of the reasons why summer surplus hydro from these countries has been available to Afghanistan at low cost. This is in contrast to Pakistan, which faces summer power shortages and which is therefore the driver for the CASA-1000 project that will deliver summer surplus power from the hydro surplus countries in Central Asia to Northeastern Pakistan by HVDC transmission across Afghanistan.

61. Afghanistan is also reputed to have significant wind resources especially in the southwestern part of the country (near Herat and Farah). It is possible these could be developed more quickly than hydro but very little information is currently available about wind characteristics: see: http://www.red-mew.gov.af/ren-sources-publication/wind/potential-map-wind/.

Figure A2.1. Existing and Planned Hydro Projects in the Kabul/Kunar River Basins

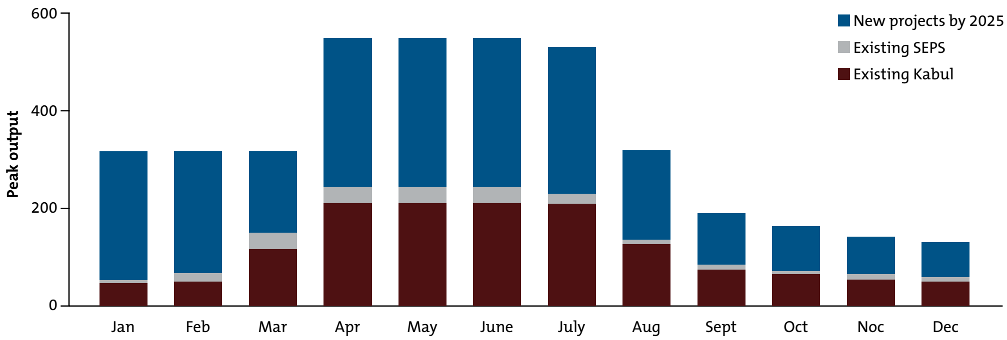


Note: Red circles=major new hydro projects; green circles=existing dams.

Previous studies have identified a list of potential hydropower sites totaling some 23,000 MW. APSMP identifies several hydropower projects for development to enter service in the period to 2032, as shown in table A2.1. At the start of this study, there were no feasibility studies to international standards for any of the projects identified in the APSMP, and most studies were dated.

Since then, the FS for Bagdhara hydropower project has been completed, which with the benefit of some additional geotechnical exploration concluded that the project was "technically feasible under consideration of the prevailing hydrological, topographic, geological, infrastructure, environmental and social conditions." Of particular note is the conclusion that a lower full reservoir level of 1,375 masl would avoid resettlement from the inundation of fertile Bagram/Gulbahar Plain. The recommended installed capacity is 226.5 MW rather than the previous estimate of 210 MW shown in table B.1. Energy generation is 876 GWh, slightly lower than the previous estimate of 968 GWh because the new design also contemplates drinking water supply to Kabul. Total EPC cost (at constant 2014/2015 prices) is $562 million, slightly lower than the $600 million of the 2012 APSMP. A six-year construction period is envisaged with civil works beginning in 2017 and completed in 2022. The report cautions that "depending on the security situation there is an unpredictable risk of potential increase of cost and construction time."

Figure A2.2. The Seasonality of Hydro Production (SEPS+NEPS, 2025)



Source: APSMP.

Table A2.1. The Hydropower Projects in the "Robust" Generation Capacity Expansion Plan Recommended by the APSMP

Project	MW	$USm	$/kW	GWh	LF	LCOE USc/kWh
Bagdhara	**210.0**	**600**	**2,857**	**968**	**0.53**	**9.30**
Surobi 2	180.0	700	3,889	891	0.57	11.78
Kunar A (Shal)	789.0	2,000	2,535	4,772	0.69	6.29
Kajaki addition	100.0	300	3,000	493	0.56	9.13
Kukcha	445.0	1,400	3,146	2,238	0.57	9.38
Gulbahar (Panshir)	120.0	500	4,167	594	0.57	12.63
Capar	116.0	450	3,879	574	0.56	11.76
Kama	45.0	180	4,000	223	0.57	12.11
Kunar B	**300.0**	**600**	**2,000**	**1,485**	**0.57**	**6.06**
Kajaki extension	18.5	90	4,865	91	0.56	14.84
Olambagh	90.0	400	4,444	444	0.56	13.51
Kilagai	60.0	250	4,167	297	0.57	12.63
Salma	40.0	200	5,000	197	0.56	15.23
Upper Amu	1,000.0	2,500	2,500	4,955	0.57	7.57
Dashtijum	4,000.0	8,000	2,000	19,819	0.57	6.05

Source: APSMP.

Box A2.1. Real Options

A real option is the right, but not the obligation, to invest in a future project of unknown benefit at a known cost today. Just like buying a plot of land gives one the right (but not obligation) to erect a building in the future, a real option implies at least two time steps—a decision to be made today, followed by a decision to be made tomorrow.

The value of a real option is

=Expected Net Present Value (calculated in the usual way)
+ Value of options created
- Value of options destroyed

Thus, an investment today that has positive net benefits but fails to create new options may be less desirable than an investment with fewer (or even no) benefits today but that results in increased or better options in the future. So, there may be a value in implementing a project that does not provide any benefit today but makes it possible to implement another project at a later point in time.

There are several necessary conditions for the real option value approach to be relevant: uncertainty, learning, and flexibility—which one can illustrate in the case of a hydro project for which the commissioning of a detailed feasibility study (FS) is an example:

Uncertainty. Without which there is no need to consider the possibility of deferring an investment decision: the future is known and the best decision under certainty can be made now. But one does not start dam construction until the various geotechnical uncertainties have been resolved.

Learning. That is, the state of information regarding uncertainty must change over time. The FS represents that learning. If it is unlikely that uncertainties will be resolved over time, then one might as well make a decision today.[a]

Flexibility. If the FS shows that the hydro project will be uneconomical (or technically infeasible), one must be prepared not to proceed.

a. Even with the benefits of a FS, however, not all geotechnical problems can be resolved—there are several examples of dam axes being changed once construction started and foundation and geological fault conditions verified. Similarly, notwithstanding that commercial lenders often insist they take no tunneling risk (which means that the costs of unexpected geological conditions must be covered by equity), depending on terrain, it may be judged uneconomical to confirm by drilling at the FS stage the actual rock conditions deep underground. A FS can never eliminate all uncertainty.

Given the magnitude of the financing needed, and the work that remains to be done to put it in place and undertake contracting, perhaps the APSMP commissioning date is more realistic.

The problem of how to proceed on hydro projects is a classic example of a real option, which is described in more detail in box A2.1.[62] The specific question to be asked is whether one should commission a FS for one of the Kunar River projects now or delay and reconsider one year later, given the present uncertainties about: (1) whether and when agreement can be reached with Pakistan on joint development of the Kunar River; (2) the ultimate capital cost of the hydro project; (3) whether summer surplus hydro of the project can in fact be exported (either through the CASA-1000 project, which may have spare capacity depending on the rate of decline of the summer surplus in Tajikistan and KYR, or through a new transmission corridor along the Kunar River); and (4) what would be the cost of energy from the next-best alternative (either imports or generation at a Sheberghan CCGT).

The funding decision for the $5–10 million required for the Kunar River cascade development study and subsequent detailed feasibility studies is especially relevant because the latest study of the Kunar hydro projects recommends that the riparian issues with Pakistan "be clarified before work on the FS for cascade development is started"—which could be in 1 year, 5 years, 10 years, or indeed never. At the same time, it is pointed out that a FS without confirmation of the geological and geotechnical conditions—which means drilling at site—is likely to be of limited value and, hence, not the best use of resources.

A2.2. The Economics of Hydropower

The hydro project candidates listed at table A2.1 are assumed to provide the best information available on them, although the reliability of some of the assumptions and calculations are at least open to question. For example, it seems unlikely that all but two projects have a load factor of 56–57 percent (except Kunar A at 69 percent and Bagdhara at 53 percent—close to the recent FS estimate of 49 percent). It is likely that further refinements would result from size optimization analysis based on inflow hydrology and alternative machine configurations and reservoir sizes.

Table A2.2 displays the results of a simple comparison of a hydro project (using Bagdhara as the example, with capital costs and energy according to table A2.1) and a gas-fired plant at Sheberghan. Other assumptions include:

- Hydro construction time 5 years; gas engine 2 yearss
- Hydro O&M costs at 3 percent of capital cost per year

62. There are many good texts that discuss the subject in depth. T. Copeland and V. Antikarov, *Real Options: A Practitioner's Guide*, Texere, New York, 2001 is one of them.

- Gas engine cost $1,000/kW, with Afghanistan construction premium at 1.6
- Sheberghan gas price $4/mmBTU (see next section for details)
- Gas engine life is 20 years, so a second gas engine is built in years 18 and 19.

At 10 percent discount rate, the hydro project is considerably more expensive, with an LCOE of 10.3 US¢/kWh (row 10 of table A2.2) and gas at 7.71 US¢/kWh (row 26 of table A2.2). Even at 6 percent discount rate, the hydro project at 7.40 US¢/kWh is more expensive than the gas project at 6.83 US¢/kWh.

Table A2.2. Hydro Versus Gas Engine Generation at Sheberghan: LCOE Comparisons at 10 Percent Discount Rate

				2019	2020	2021	2022	2023	2024	2025	2026
			NPV	1	2	3	4	5	1	2	3
[1] Hydro											
[2] Installed capacity	210	[MW]									
[3] Annual capacity factor	0.52	[ ]									
[4]	2857	[$/kW]									
[5] Disbursement pattern		[ ]		0.2	0.2	0.2	0.2	0.2			
[6] Capital investment	600	[$USm]	*455*	120.0	120.0	120.0	120.0	120.0			
[7] O&M	0.03	[$USm]	*101*						18.0	18.0	18.0
[8] Total cost		**[$USm]**	**556**	**120.0**	**120.0**	**120.0**	**120.0**	**120.0**	**18.0**	**18.0**	**18.0**
[9] Total annual energy		[GWh]	*5,399*						958.0	958.0	958.0
[10] LCOE		[USc/kWh]	*10.30*								
[11] Gas @ Sheberghan											
[12] capital cost	1600	[$/kW]									
[13] Disbursement pattern		[ ]					0.5	0.5			
[14] Capital investment	249.9	[$USm]	*163*				125.0	125.0			
[15] Installed capacity	156.2	[MW]									
[16] Annual capacity factor	0.7	[ ]									
[17] Annual energy	957	[GWh]	*5064*						958.0	958.0	958.0
[18] Fixed O&M	30	[$USm]	*25*						4.7	4.7	4.7
[19] Heat rate	10,000	BTU/kWh									
[20] Heat requirement		mmBTU.10^6							9.6	9.6	9.6
[21] gas volume		10^6 CM									
[22] gas price @Mazar		[$/mmBTU]							4.0	4.0	4.0
[23]		[$/1,000 CM]							126.0	126.0	126.0
[24] fuel cost		[$USm]	*203*						38.3	38.3	38.3
[25] Total cost		**[$USm]**	**390**				**125.0**	**125.0**	**43.0**	**43.0**	**43.0**
[26] LCOE		[USc/kWh]	*7.71*								

Table A2.3. APSMP Assumptions: Average Monthly MW

	Installed capacity MW	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Darunta	12	3	3	6	12	12	12	12	7	4	3	3	3
Sarobi	22	5	5	12	22	22	22	22	13	8	7	6	5
Pul-e-Khumri	8	2	2	5	8	8	8	8	5	3	2	2	2
Naghlu	100	22	24	55	100	100	100	100	60	35	30	26	24
Mahipar	66	15	16	36	66	66	66	66	40	23	20	17	16
Existing Kabul candidates		46	50	114	208	208	208	208	125	73	62	54	50
Baghdara	210	69	74	76	155	210	210	210	101	55	50	44	69
Kunar_A	300	66	72	165	300	300	300	300	300	300	180	105	90
Surobi	180	40	43	99	180	180	180	180	108	63	54	47	43
Kilagai	60	14	13	14	33	60	60	60	6	36	21	18	16
Kama	45	10	11	25	45	45	45	45	27	16	14	12	11
Gulbahar	120	26	29	66	120	120	120	120	72	42	36	31	29
Kukcha	445	107	98	107	245	445	445	445	45	267	156	134	160
Kunar_B	300	66	72	165	300	300	300	300	180	105	90	78	72

Source: APSMP.

However, the further problem is that the benefits are not the same. Table A2.3 shows the expected annual generation for all prospective hydropower plants in APSMP. Seventy percent of the Bagdhara energy will be generated during the 5 wet months (April–August). If it is assumed that the avoided cost during winter peak hours is the cost of diesel self-generation (for example, 25 USc/kWh, for a $75/bbl world oil price);[63] and the cost of off-peak winter power is 8.5 USc/kWh (the presumed cost of firm imports from Turkmenistan or Uzbekistan); and that in summer, the avoided cost of peak and off-peak energy is 6 USc/kWh, then under these dispatch conditions, the net benefit (as NPV) for the hydro project is $24 million, but that of the gas engine is $84 million (table A2.4).

Even if all summer energy could be exported to Pakistan at 10 US¢/kWh, the gas engine option is still preferred (with an NPV of $247 million compared with hydro at $170 million). More importantly, presentation of comparisons of levelized costs of energy is of very limited value: it is always net benefits that matter. Note also that these results can only be illustrative: this analysis needs to be updated when an FS for Sheberghan is available.

63. See table 6.10, for details of this calculation.

Table A2.4. Hydro Versus Gas Engines: Comparison of Net Benefits

				2019	2020	2021	2022	2023	2024	2025	2026	2027
			NPV	1	2	3	4	5	1	2	3	4
[1] Hydro												
[2] Installed capacity	210	[MW]										
[3] Capacity factor	0.52	[ ]										
[4] Cost of capacity	2857	[$/kW]										
[5] Disbursement		[ ]		0.2	0.2	0.2	0.2	0.2				
[6] Capital investment	599.9	[$USm]	455	120.0	120.0	120.0	120.0	120.0				
[7] O&M	0.03	[$USm]	101						18.0	18.0	18.0	18.0
[8] Total cost		**[$USm]**	**556**	**120.0**	**120.0**	**120.0**	**120.0**	**120.0**	**18.0**	**18.0**	**18.0**	**18.0**
[9] Total anuual energy		[GWh]	5399						958.0	958.0	958.0	958.0
[10] LCOE		[USc/kWh]	10.30									
[11] GWh by load block												
[12] Summer:peak	685	[GWh]							142.7	142.7	142.7	142.7
[13] Summer: off-peak		[GWh]							542.3	542.3	542.3	542.3
[14] Winter:peak	273	[GWh]							220.5	220.5	220.5	220.5
[15] Winter: offpeak		[GWh]							52.5	52.5	52.5	52.5
[16] Economic Value												
[17] Summer: peak	0.085	[$USm]	68						12.1	12.1	12.1	12.1
[18] Summer: off-peak	0.060	[$USm]	183						32.5	32.5	32.5	32.5
[19] Winter: peak	0.250	[$USm]	311						55.1	55.1	55.1	55.1
[20] Winter: offpeak	0.060	[$USm]	18						3.1	3.1	3.1	3.1
[21] Total		**[$USm]**	**580**						**102.9**	**102.9**	**102.9**	**102.9**
[22] Levelized benefit		[USc/kWh]	10.75									
[23] Net benefit		[$USm]	24									
[24] Gas @ Sheberghan												
[25] Cost of capacity	1600	[$/kW]										
[26] Disbursement		[ ]					0.5	0.5				
[27] Capital investment	249.9	[$USm]	190				125.0	125.0				
[28] Installed capacity	156.2	[MW]										
[29] Capacity factor	0.7	[ ]										
[30] Annual energy	957.9	[GWh]	5399						958.0	958.0	958.0	958.0
[31] Fixed O&M	30	[$USm]	26						4.7	4.7	4.7	4.7
[32] Heat rate	10000	BTU/kWh										
[33] Heat requirement		mmBTU.10^6							9.6	9.6	9.6	9.6
[34] Gas volume		10^6 CM										

(continued)

Table A2.4. Continued

				2019	2020	2021	2022	2023	2024	2025	2026	2027
			NPV	1	2	3	4	5	1	2	3	4
[35] Gas price @Mazar		[$/mmBTU]							4.0	4.0	4.0	4.0
[36]		[$/1000CM]							126.0	126.0	126.0	126.0
[37] Fuel cost		[$USm]	216						38.3	38.3	38.3	38.3
[38] Total cost		**[$USm]**	**432**				**125.0**	**125.0**	**43.0**	**43.0**	**43.0**	**43.0**
[39] LCOE		[USc/kWh]	8.00									
[40] GWh by load block												
[41] Summer:peak		[GWh]							117.2	117.2	117.2	117.2
[42] Summer:off-peak		[GWh]							53.4	53.4	53.4	53.4
[43] Winter:peak		[GWh]							164.0	164.0	164.0	164.0
[44] Winter:offpeak		[GWh]							623.3	623.3	623.3	623.3
[45] Economic Value												
[46] Summer:peak	0.085	[$USm]	56						10.0	10.0	10.0	10.0
[47] Summer:off-peak	0.060	[$USm]	18						3.2	3.2	3.2	3.2
[48] Winter:peak	0.250	[$USm]	231						41.0	41.0	41.0	41.0
[49] Winter:offpeak	0.060	[$USm]	211						37.4	37.4	37.4	37.4
[50] Total		**[$USm]**	**516**						**91.6**	**91.6**	**91.6**	**91.6**
[51] Levelized benefit		[USc/kWh]	9.56									
[52] Net benefits		[$USm]	84									

A2.3. The Status of Detailed Feasibility Studies

In in 2004, in its major recommendations, the Norconsult master plan called for the preparation of a feasibility study of the 280 MW Bagdhara hydro project and, depending on its results, to then prepare a further FS on the 180 MW Surobi 2 hydro project that is downstream of Bagdhara.

The Norconsult report also recommended a FS be conducted for Kokcha and for the development of the 20,000 MW of hydro projects on the Amu/Panj rivers that constitute the Afghanistan/Tajikistan border. Work on neither of these FS appears to have been initiated. The master plan noted that the prospects for Kunar A, with its large dam, would stand little chance of being implemented if the smaller Bagdhara project were turned down for environmental reasons—and implied that the development of Kunar A should await the results of the Bagdhara FS.

Bagdhara

A consultant was commissioned by MEW to undertake a "project definition study" for Bagdhara in 2005, and several reports entitled *Bagdhara Feasibility Study* were issued in January 2007 (volume 1 on hydrology; volume 2 on a preliminary social impact assessment, and volume 3 on a preliminary environmental assessment). The main conclusion of these preliminary studies was to limit the full reservoir level to 1,420 masl in order to avoid the resettlement of 20,000 people in the originally intended level of 1,460 masl. The consultant was then asked by MEW to draw up the terms of reference for a detailed FS, which included a requirement for detailed onsite geological and geotechnical investigations.

The Kunar River projects

In 2009, a feasibility study for the 798 MW Shal Hydro project on the Kunar River (which is called Kunar A in the APSMP) was submitted to MEW by consultants. This estimated capital costs of $1.6 billion (at 2009 prices) or $2,000/kW for a project with average energy of 3,600 GWh. Updated to 2015 prices (at 1.5 percent per year), this results in a levelized economic cost of 7.26 USc/kWh (at 10 percent discount rate and 30 year life).

In 2013, Pakistan and Afghanistan signed an agreement to jointly develop the hydro potential of the Kunar River, and requested the World Bank provide technical assistance to develop the cascade. The World Bank has now completed the first step in this process with an initial assessment of the options for cascade development of the river, with projects to be built in Pakistan and in Afghanistan and including the prospects for multi-purpose projects to meet water supply and irrigation needs. This assessment recommended that Afghanistan proceed with a detailed cascade development study and a detailed feasibility study, whose total costs are estimated at $5 million (though this estimate is a bit vague in that it states it is preliminary and would depend on the number of projects proposed for the cascade).

The assessment observes that Pakistan's involvement in a cascade development of the Kunar River is vital, preferably in a development scenario that would include a project on the Pakistani part of the river, or in a scenario in which the Kunar project extended into Pakistani territory to achieve a larger storage reservoir. However, "Pakistan's interest in the cascade development," either by one of these options or by its willingness to import electricity from Afghanistan "has a fundamental bearing on the configuration of the development of the hydropower resources on the Kunar River, and needs to be clarified before the commencement of the FS for the Cascade Development."

Even under the best of circumstances, international cooperation on a jointly developed project on an international waterway is a very slow process indeed, subject to a range of exogenous geopolitical considerations that tend to get in the way of rational economic reasoning. The necessary clarifications sought in the above recommendation may take years to achieve, and general expressions of willingness to consider future imports have little significance because they will always be contingent upon "reasonable price." And even if it were true that the Shal project were only feasible if its summer surplus can be exported to Pakistan, without better information than what is in the existing FS, general assurances of a willingness to buy, even if given, are also of marginal value. Indeed, in our view, the best way of eliciting Pakistan's interest is precisely by a credible demonstration of the benefits.

A2.4. The Real Option Methodology

The question to be answered is, given the information presently available, and given the uncertainties, whether or not to proceed with a FS today, or whether one should wait one year and then reconsider. For sake of illustration, assume the question is whether to proceed with a FS for Kunar B, which is the first hydro project in the sequence recommended by the APSMP, notwithstanding that an FS for Bagdhara is now available (the consequences of which are discussed in more detail below). From table A2.1, this is shown as 300 MW generating 1,485 MWh/year, with a capital cost of $2,000/kW.

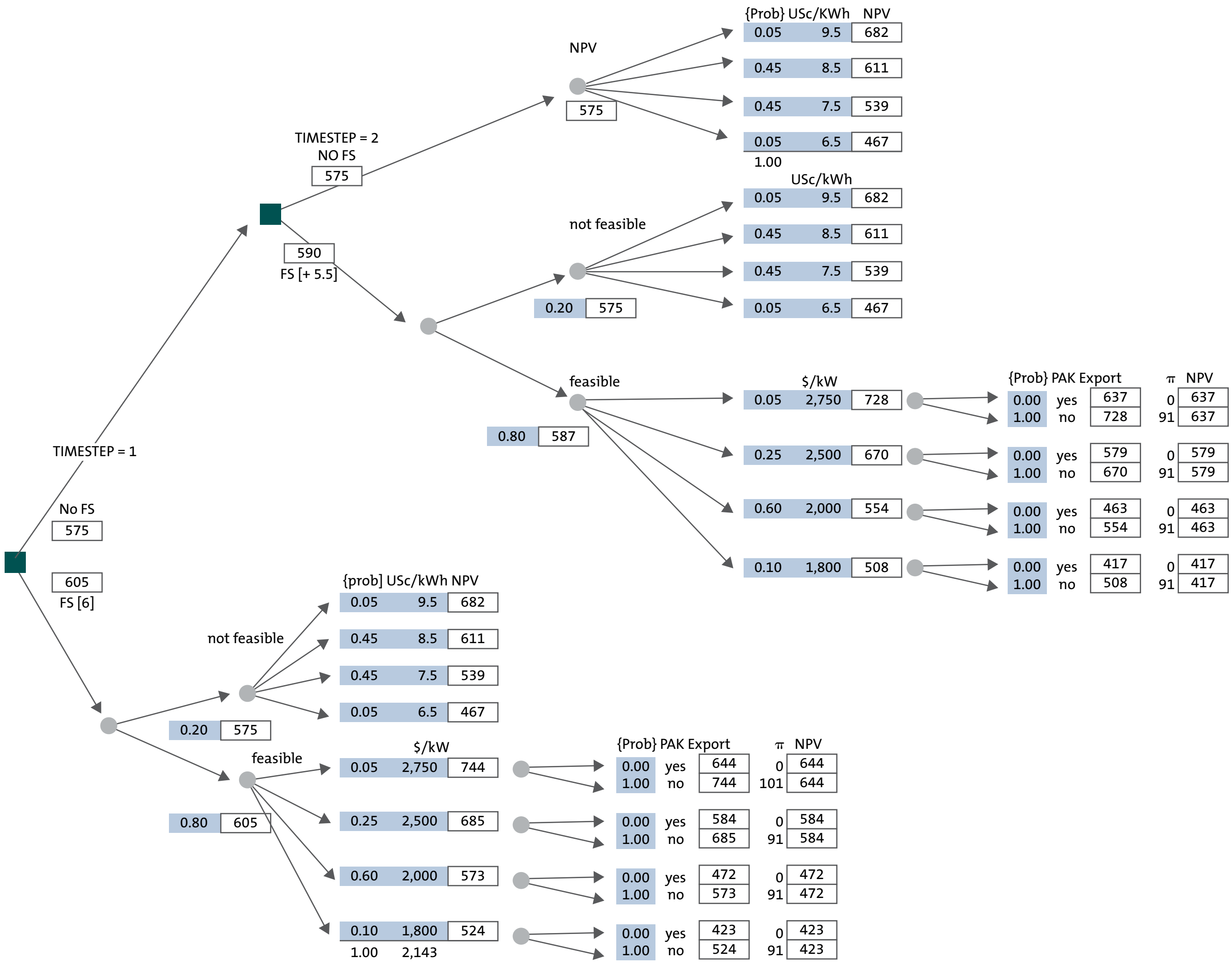
Figure A2.3 shows the decision tree for this problem. At time step T=1 one can take the decision to conduct an FS, assumed to cost $6 million, or to wait one year, and reconsider the same question at time step T=2.

At time step 1, if the FS proceeds, there is no guarantee that the project is in fact found to be technically feasible. It is assumed that the probability of feasibility is 80 percent; if not found feasible, then the energy is presumed to be supplied by imports—about which the assumed uncertainty is as shown in table B.5. The probabilities here are based on the expectation that the Turkmenistan PPA under negotiation will likely be in the range of 6.5–9.5 US¢/kWh. If the project were found to be feasible, the main uncertainty is the investment cost, whose uncertainty is again shown in table A2.5: here the assumption would be that the capital costs estimated for hydro projects as given in the APSMP are reliable, so the most weight (60 percent) is given to the $2,000/kW estimate.

Table A2.5. Uncertainties

Cost of Imports			Hydro project		
Cost (USc/kWh)	Probability [ ]	NPV ($USm)	Capital cost ($/kW)	Probability [ ]	NPV ($USm)
9.5	0.05	682	2,750	0.05	744
8.5	0.45	611	2,500	0.25	685
7.5	0.45	539	2,000	0.60	573
6.5	0.05	467	1,800	0..10	524
Expected value		575			605

Figure A2.3. The Decision Tree



For each of the branches that represent the outcome of the FS, the expected value can be calculated: for example, in the case of the feasible hydro project, the expected value is:

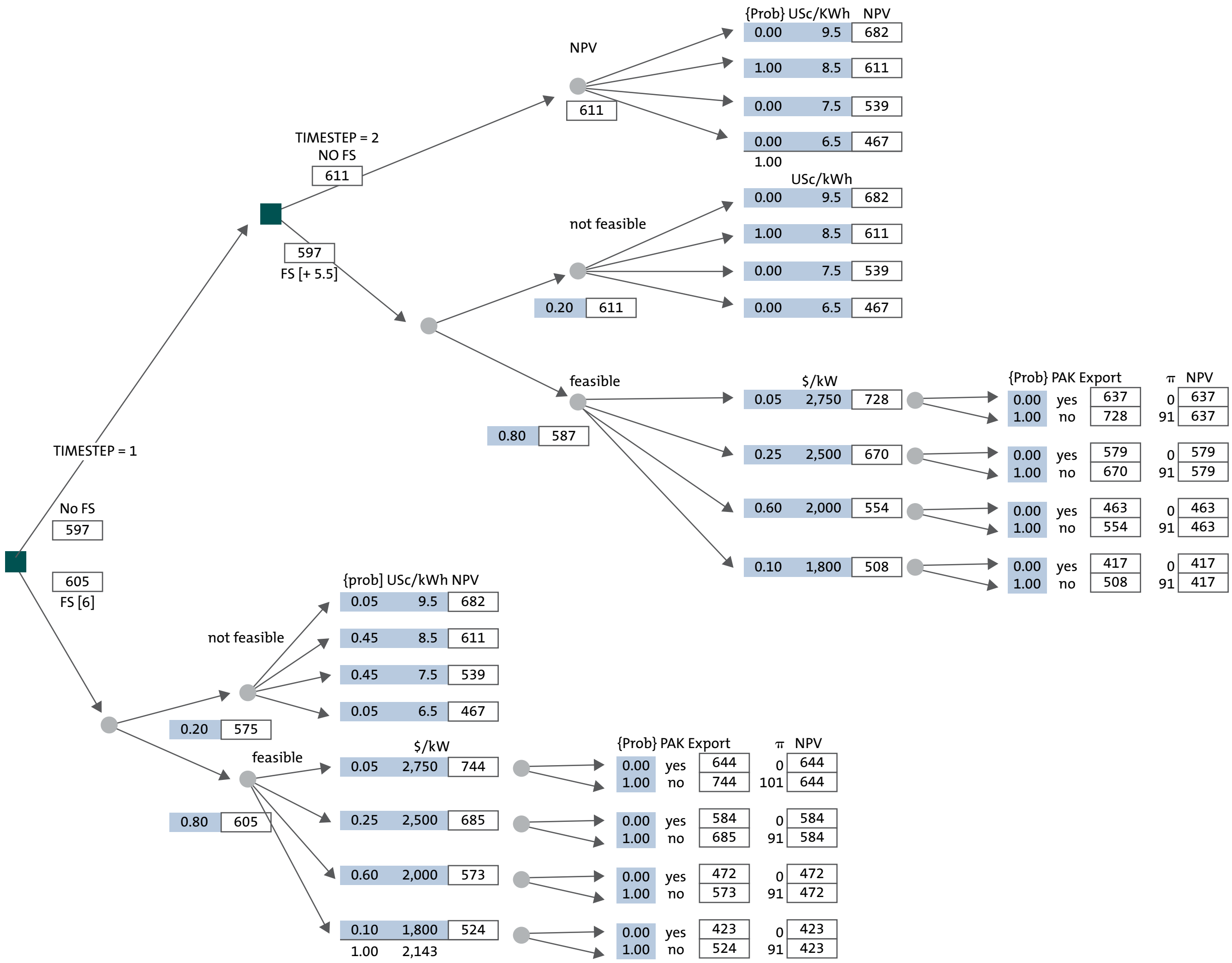
E{ }=$605m=0.05*$744m+0.25*$685m+0.6*$573m+0.1*$524m

This can be folded back to calculate the expected value before the outcome is known (at time step t-1), namely

E{FS}=0.2* $575 million + 0.8* $605 million + $6million=$574million

Where the $6 million represents the cost of the FS.

Figure A2.4. The Decision Tree with Learning



The NPVs are calculated on the assumption that the FS takes 2 years, and construction (if found feasible) takes 5 years, and that the hydro project has a life of 30 years—in other words, it estimates the cost of power from the two sources from year 8 to year 38. If the hydro project is delayed one year, then for the first year the energy would also have to be imported—which explains why the NPV of the hydro option at time step 1 is different than the NPV one year later.

However, in the case of the hydro project, these NPVs must be adjusted to account for the uncertainty regarding exports of the surplus summer hydropower to Pakistan. Since a comparison is being made based on the least-cost option to meet a specified demand—1,485 GWh—the presumption is that the benefits are the same for both. But that is not the case here, because 70 percent of the total hydro energy is generated in summer, when it has less value than the firm and dispatchable energy provided by imports. If the surplus can be exported to Pakistan at a price comparable to Afghanistan's imports from Turkmenistan, then one can assume equivalence of benefits. But if that is not the case, then one must adjust the NPVs by a penalty charge that reflects the lower value of summer surplus power (shown as π in the decision-tree figures).[64]

The branches at the decision node at time step 1 is repeated at time step=2 in the upper half of figure B.3—and indeed could easily be extended to cover further time steps were the decision at time step 2 to be delayed again.

The result is that at time step=1, the FS has an expected value of cost of preparing the FS at time step 1 of $605 million (which is written as **E{FS,t=1}**, but delaying the decision to the next time period has a lower expected value of **E{delay, t=1}**=$575 million. The rational decision is to delay until the following year.

Certainty that Pakistan will take the summer surplus does not change the decision. The expected value **E{FS,1}** of $524 million is lower because of the additional export revenue from Sales to Pakistan; but **E{delay,1}** is also lower at $517 million. (The decision tree for this case is shown in annex 6, case A.) The robustness of the decision is easily demonstrated by varying some of the key assumptions: for example, decreasing the probability that the FS will demonstrate technical feasibility could be lowered to 50 percent (from 80 percent in figure 4.3): in this case **E{FS,1}}** increases to $596 million; and even if this were set at 100 percent, the **E{FS,1}**=$611 million—so in both cases more costly than the delay **E{FSdelay,1}**=$575 million.

The delay FS decision is unchanged by changes in the discount rate: if the discount rate is lowered to 6 percent, then the **E{FS,1}** is $929 million, but the expected value of delay, **E{FSdelay,1)**=$892 million.

The Impact of Learning

For the real option approach to be useful, there has to be learning. In other words, the only reason for delay is if by waiting one has the option of implementing a better project in the future—and that will only be the case if some of the uncertainties can be resolved over time. One of the important uncertainties that has been resolved in part is the price of imports: PPA negotiations with Turkmenistan are now complete. Had this been signed at 8.5 US¢/kWh, then the decision tree would appear as shown in figure A2.4: Now on the top right hand corner the probability of the import price is seen as

64. This penalty is calculated as the present value of the summer generation (assumed at 70 percent of the annual total) penalized at 2 USc/kWh (which is roughly the difference between the average cost of current summer imports and of firm power provided from Uzbekistan. At time step=1 this NPV is $101; at time step=2 the NPV is lower ($92 million) become the stream of penalty payments is delayed by a year.

8.5 US¢ (with the others at zero): the resulting **E{noFS,2}** is now $611 million, as against the hydro FS of $597 million, so the decision would then be to *proceed* with the FS.

If, in addition, Pakistan were to make, for example, an in principle commitment to take the summer surplus, the probability of export sales can be adjusted to 50 percent—only once a PPA is signed would there be certainty. In this case, the expected value of the FS falls further to $524 million. Under these assumptions, one can conclude that the decision to proceed with the FS is not sensitive to assurances provided by the government of Pakistan (if the price of imports is 8.5 USc/kWh). At the end of this annex, some revised decision trees are shown. Case A gives the changes that result from increased certainty of summer sales for Pakistan; case B shows the effects with and without knowing the outcome of import prices; and case C shows the impact of a change.

In June 2015, the Bagdhara hydro project feasibility study was presented to the government of Afghanistan. With the benefit of some additional geotechnical exploration, the FS concluded that the project was "technically feasible under consideration of the prevailing hydrological, topographic, geological, infrastructure, environmental and social conditions." Of particular note is the conclusion that a lower full reservoir level of 1,375 masl would will avoid resettlement completely as well as the inundation of fertile Bagram/Gulbahar Plain. A maximum resettlement of 10 households is required for the overhead transmission line.

The recommended installed capacity is 226.5 MW rather than the previous estimate of 210 MW of the master plan. Energy generation is 876 GWh, slightly lower than the previous estimate of 968 GWh because the new design also contemplates a drinking water supply to Kabul. Total EPC cost (at constant 2014/2015 prices) is $562 million, slightly lower than the $600 million of the 2012 APSMP. A six-year construction period is envisaged, with civil works beginning in 2017 and completed in 2022. The report cautions that "depending on the security situation there is an unpredictable risk of potential increase of cost and construction time."

These more recent findings, which became available after the original analysis, would not appear to change the probabilities noted in the decision-trees of this annex nor the conclusion that the magnitude of the investment required prevents any early implementation of this (or any other) large hydro project. Given the high uncertainties of the deteriorating security situation, the emphasis for developing Afghanistan's domestic resources should continue to be on smaller projects commensurate with the risk appetite of potential investors—which means small hydro projects, PV, and gas-engine scale development of the Sherberghan gas reserve.

A2.5. Conclusions

This analysis shows how decisions can be made under uncertainty. One may conclude that:

- A FS has value only if technical feasibility can be demonstrated. There is no point in commissioning any further detailed FS in Afghanistan unless the consultant is willing to conduct detailed geotechnical investigations onsite (as has been done at Bagdhara). The idea that the geological risk can be assumed by the EPC contractor and factored into the EPC tender price is not credible: no competent contractor would accept such risks, and no IFI would be willing to provide finance in the absence of demonstrated technical feasibility at site.
- Declarations of interest from the government of Pakistan about its willingness to purchase surplus power form the Kunar River hydro projects need not be made a precondition for the proposed cascade development study. Such declarations of intent can only be made with any credibility once the benefits of the projects can be demonstrated—which requires the FS to be done and will be driven by the price offered for the power. Economic feasibility will be demonstrated in light of the alternatives, now known to be the Turkmen imports. The analysis shows that under current assumptions, the decision to proceed with an FS depends on other factors; moreover, as more information is now available, the analysis could be usefully repeated.
- In any event, the Bagdhara FS shows an economically attractive—if complex and costly—project; hence, establishing the Kunar River projects becomes less urgent. Its more advanced status worsens the case for proceeding with Kunar. Bagdhara, like Kunar, must find a suitable market for the summer surplus and must therefore compete with other projects, including CASA-1000. To state the previous conclusion another way, whether Bagdhara is able to sell its summer surplus will depend on the price at which it can offer the power to Pakistan.
- The uncertainties for Baghdara and the project cost are significant and will probably not be attractive to potential private investors—at least until there has been further experience in Afghanistan. Hence, it may be most appropriate to proceed with efforts to sound out the level of interest among IFIs to finance it.

Figure A2.A. Certainty Of Sales Of Summer Surplus To Pakistan [Timestep=1]

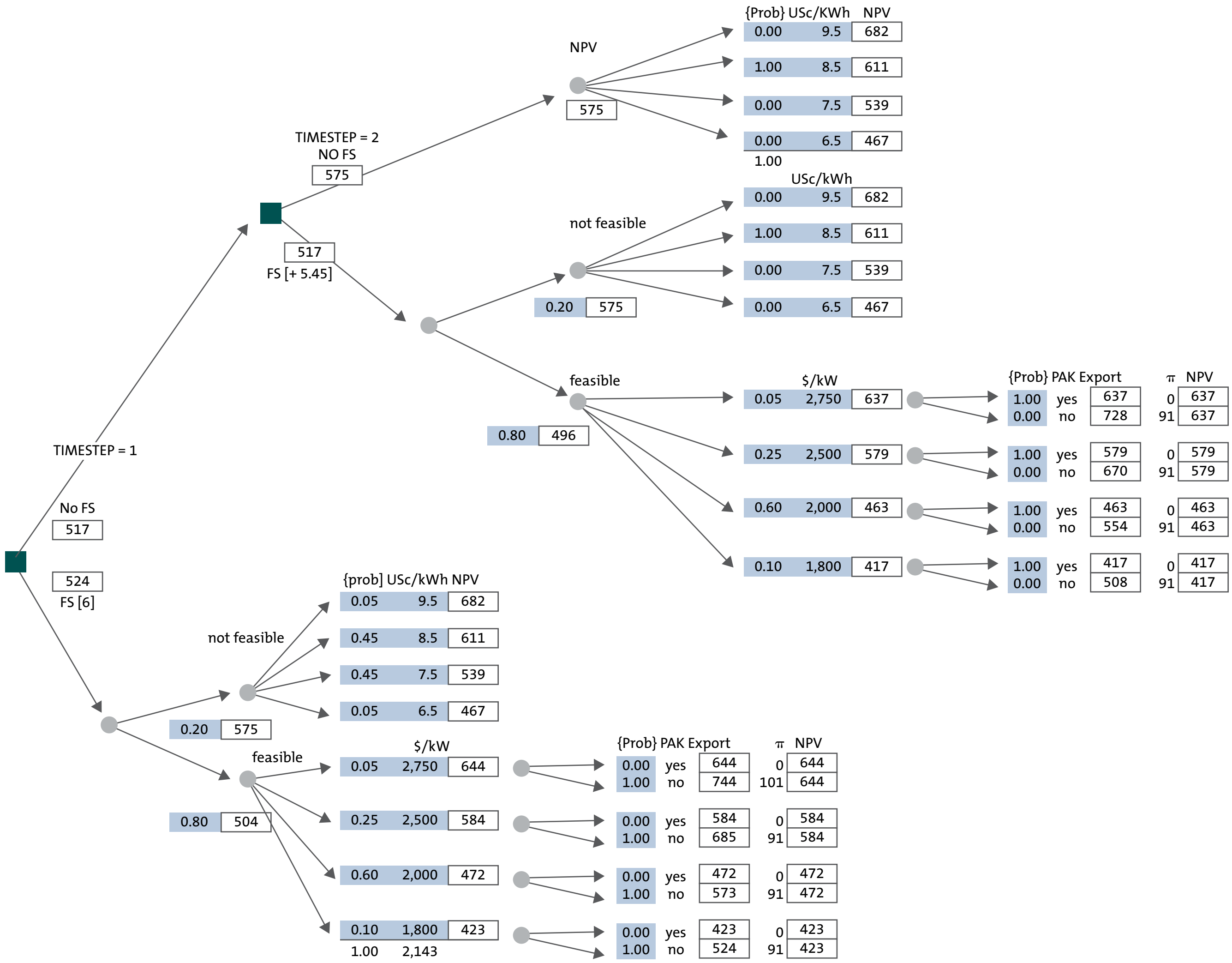


Figure A2.B. Impact of Learning: PPA for Imports from Turkmenistan and Statement of Intent from Pakistan to Purchase Surplus Power [Timestep=2]

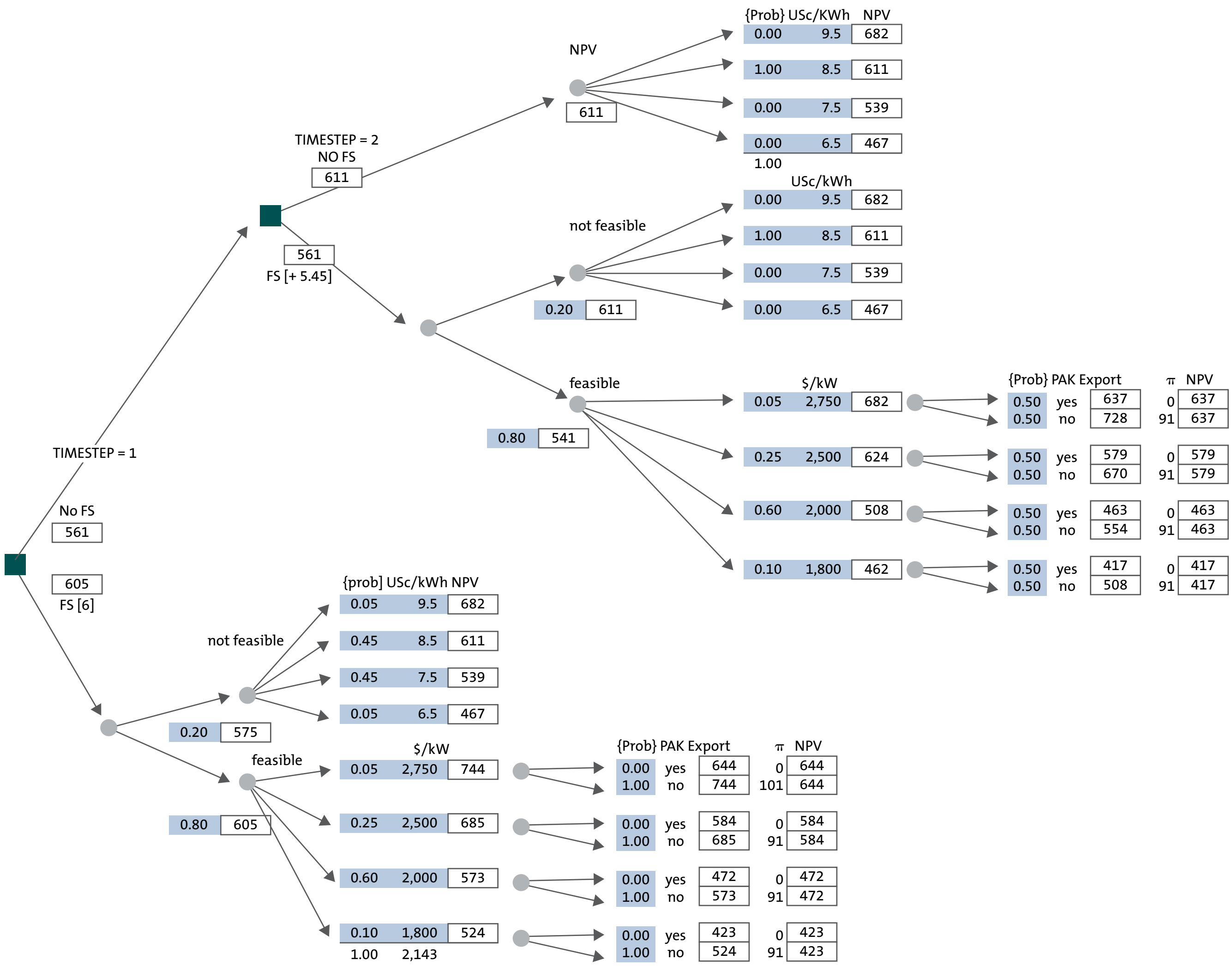
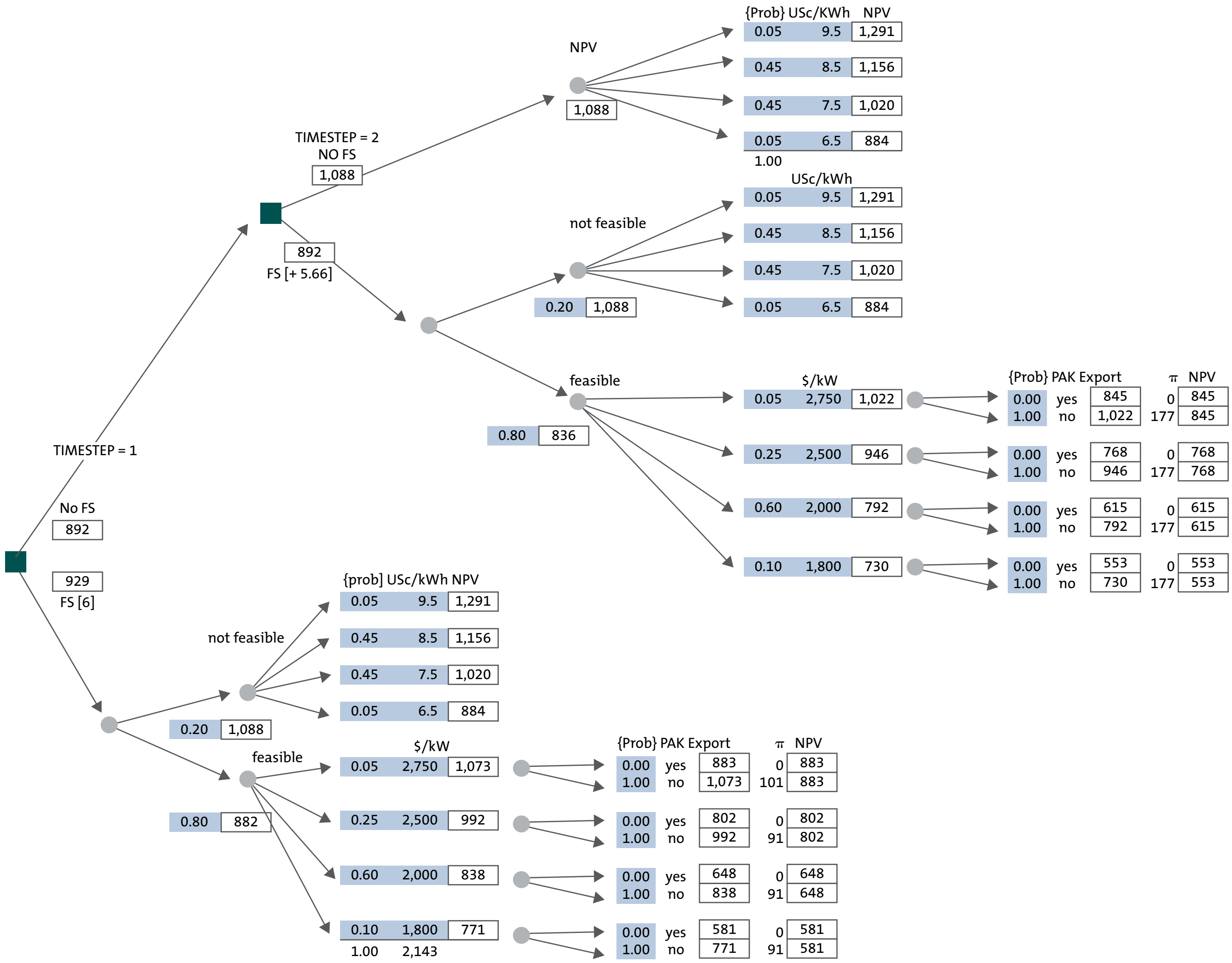


Figure A2.C. Lower Discount Rate (6 Percent)



Annex 3. Case Study: Developing Afghanistan's Coal Resources

A3.1. Background

With the increasing concern over the role of coal as the most GHG emission-intensive form of power generation, any discussion of the use of Afghanistan's coal resources for power generation requires caution. The World Bank, which is now generally unwilling to finance coal projects, concedes that under exceptional circumstances, a case for coal may be warranted. The World Bank's screening criteria set out several tests. Two are especially relevant when undertaking planning studies: a base-load thermal project in Afghanistan for which there is no practicable renewable energy alternative and assuming gas is not viable at the scale required (discussed in annex 4):[65]

- There is a demonstrated developmental impact of the project, including improving overall energy security, reducing power shortage, and increasing access for the poor.
- After full consideration of viable alternatives to the least-cost (including environmental externalities) options and when the additional financing from donors for their incremental cost is not available.

Given the priority that the global community gives to Afghanistan's economic and social development and the importance of electricity at a reasonable price and accessible to all to support these objectives, the question of whether coal-based power generation is a viable option commands attention. Moreover, the question is not simply one of whether or not to build a coal-burning power station, but how coal fits into a strategic vision of the environmentally sustainable evolution of the energy sector. Much coal is already used in households and industry, where it is burnt inefficiently and without pollution controls, hence contributing significantly to indoor and urban air pollution. Of course, it is true that gas would be a much cleaner fuel for power generation than coal, but it does not follow that this would necessarily be the best solution from a local and national environmental point of view.

65. World Bank, 2010. *Criteria for Screening Coal Projects under the Strategic Framework for Development and Climate Change, Operational Guidance for World Bank Group Staff*. According to the World Bank's Energy Sector Directions Paper of 2013, the criteria have "effectively seen WBG financing for coal limited to rare circumstances (pressing needs, no other source of energy available and no other source of funding for that energy). Since 2013 … there has been no lending for "greenfield" coal-fired power plants."

For example, Afghanistan's gas could be used not for power generation, but instead brought to Kabul where it could be used to displace diesel for self-generation, petroleum for transportation, and coal and fuel wood for heating and cooking. Meanwhile coal could be used for base-load power generation in modern facilities in relatively remote areas. This would bring very significant improvements to urban air quality.

Afghanistan's GHG emissions are among the lowest in the world, both in absolute and per capita terms (shown in table A1.4 above). Afghanistan ranks at the bottom of the list with emissions less than 0.1 tons CO_2 per capita, together with four of the poorest African countries.[66] It can be stated with confidence that Afghanistan's GHG emissions will remain negligible, even if by 2030 several thousand MW of coal base load capacity were in operation.[67] In short, if there is one place in the world where power generation from coal is still a reasonable choice, it would be Afghanistan—and this is true regardless of the source of financing.

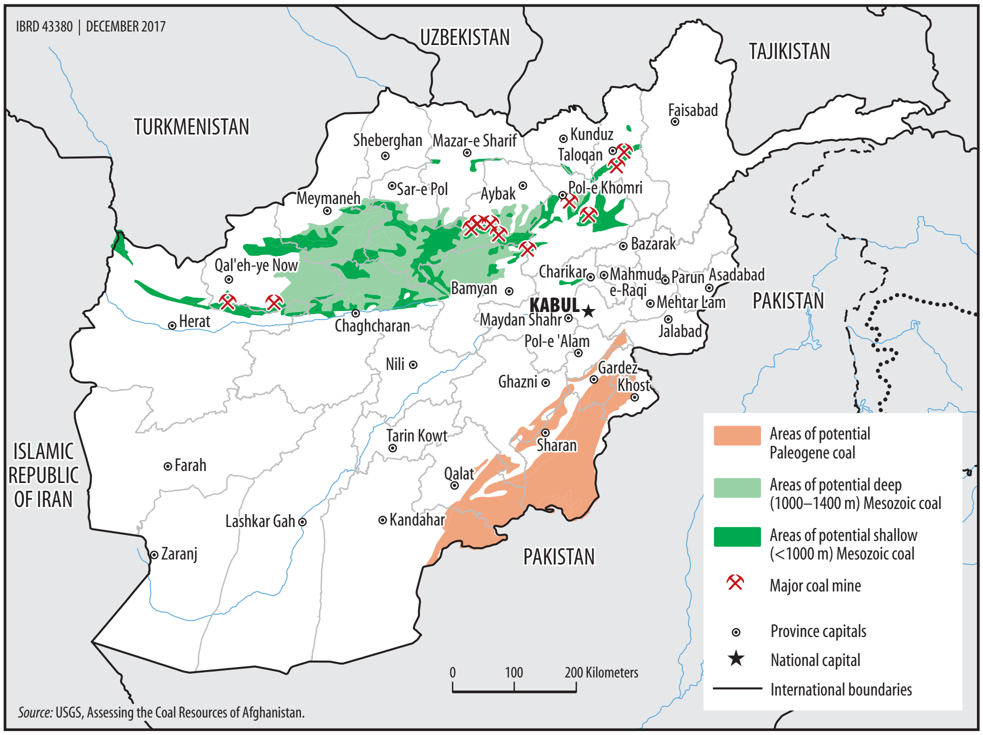
For these reasons, it is not surprising that successive master plans have proposed coal as a source of low-cost power generation in Afghanistan. However, none of the past power sector master plans have examined basic questions about the practical feasibility of this option: they have simply assumed a large coal burning power plant can be commissioned by a certain date. The 2004 Norconsult report included an "unlimited coal scenario" with a 7 x 50 MW project at Shabashak; the APSMP has a 400 MW coal project in 2027 and 800 MW in 2029 (see table 2.1). In 2011, the China Metallurgical Group Corporation (GMGC) examined the possibility of a 400 MW coal project in Bamyan province (Ishpushta and Qaleech coal fields) under the terms of the Aynak copper mine concession.

To some extent, these questions about whether or not coal should or should not be used for power generation are academic because there is no assurance that there are coal fields of the necessary size to support large-scale use. Figure A3.1 maps the known coal deposits in the country. They have allowed significant coal production, much of which is used in Kabul. However, much of this mining is artisanal (and outside the control of the authorities) in nature, for which reliable statistics are simply not available.

66. Mali, Chad, Burundi, and the Democratic Republic of Congo.

67. There is much uncertainty about population size. The World Development Indicator (WDI) database gives the 2010 population as 34.4 million—which value is used in this report unless stated to the contrary.

Figure A3.1. Coal Resources in Afghanistan

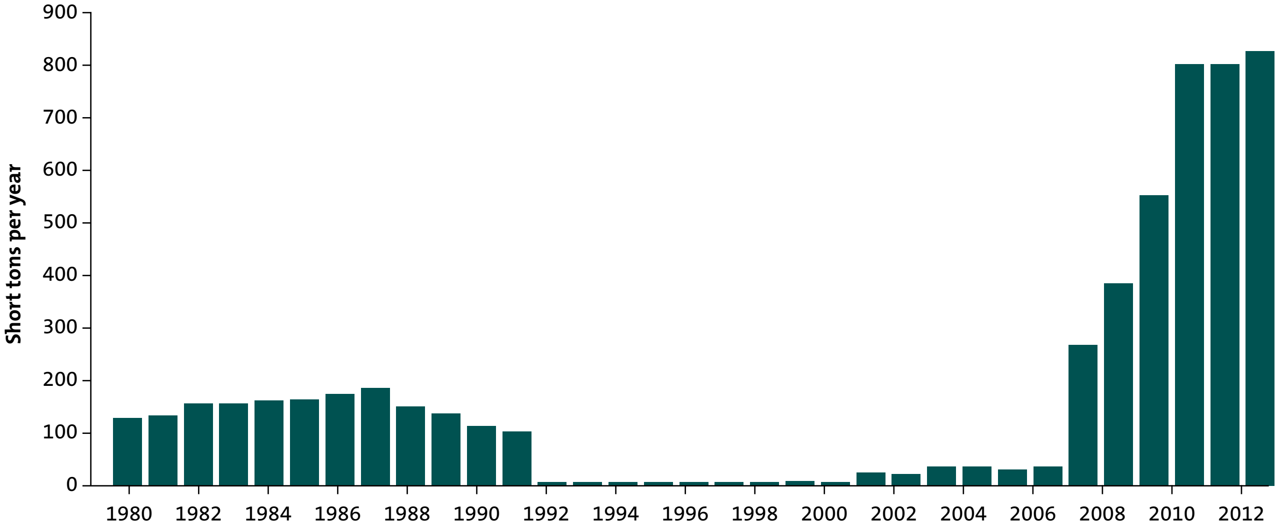


Some sources suggest recent production of some 800,000 tons per year (figure A3.2),[68] others that similar quantities are exported to Pakistan, which suggests the official figures are significantly understated. As a yardstick, a 100 MW coal-burning power plant would need some 300,000 tons of coal per year depending on coal quality (see box A3.1 for more detail).

CMGC's 70 km^2 concession area is about 18 x 4 km, wherein it is reported some 200 small coal pits are operating. The stated aim of CMCG's drilling program was to identify a resource that could supply 1.5 million tons of coal per year over a 30-year period. Drilling work began in 2009 and by 2011, it was reported that CMGC had completed 18 boreholes with total drilling length of 5,000 meters. In the western part of the concession, CMGC predicted 78 million tons of coal reserves, with another 12 million tons in the east. It now seems that geological work has subsequently been suspended for security reasons, with only 10 percent of the planned work completed. How much reliable information will be

68. Commodity production and trade statistics are tabulated based on self-reported numbers. In countries where economic reporting is reliable, it is possible to accurately estimate production and trade and to verify these numbers by collecting proxy statistics (e.g., the coal trade can be estimated based on an assessment of the coal import statistics provided by trading partners in combination with coal deliveries to export terminals, tax records, and freighter loading records). However, when there is an incentive to obscure these figures by either or both trading partners, it becomes significantly more difficult to obtain accurate production/trade records.

Figure A3.2. Annual Coal Production in Afghanistan



Source: U.S. Energy Information Administration.

provided on the work performed to date is unclear. Some anecdotal reports say that the results did not meet GMGC's expectations: there is no information on the status of the status of the copper concession agreements or on CMGC's current view of the feasibility of a power generation project.

Remote sensing evidence[69] indicates and brief field surveys suggest that there may be coal in the Cretaceous section. These coals are unproven, and their quality and abundance are unknown. Determining if these coals actually exist will significantly impact the thermal power generation sector. The Cretaceous section is relatively undeformed, so Cretaceous coals, if they exist and are thick enough to constitute a resource, will be easier to mine underground and could potentially be strippable at some localities. For an explanation of different geological ages, see figure A3.3.

There are places across the North Afghan Platform where the Cretaceous section is deeply eroded, suggesting the possibility that Jurassic sediments are not far below. Inboard of the outcrop belt, the Jurassic section may not be as severely deformed than further south. If this is correct, it is possible that there may be virgin Jurassic coal close enough to the surface to be accessed via shaft mine in some places. If this can be proven,

69. Sabins, F.F., and Ellis, J.M., 2010, *Coal resources in Balkhab AOI—Remote Sensing Reconnaissance*. Report prepared for the Task Force for Business Stability Operations, 38 pp. and Sabins, F.F., Ellis, J.M., and Wnuk, C., 2013, *Reconnaissance Survey of Coal Resources in Northwest Afghan Basin*, Report prepared for the Task Force for Business Stability Operations, 218 pp.

Box A3.1. Coal Requirements for Power Stations

The amount of coal required for a power station depends mainly on: (1) the coal calorific value; (2) efficiency (and hence heat rate, BTU per kWh), which is a function of the technology employed; and (3) station own use (a project fitted with flue gas desulfurization will require more coal than one that is no so fitted). In the table below, the lifetime coal requirement for three typical projects is calculated:

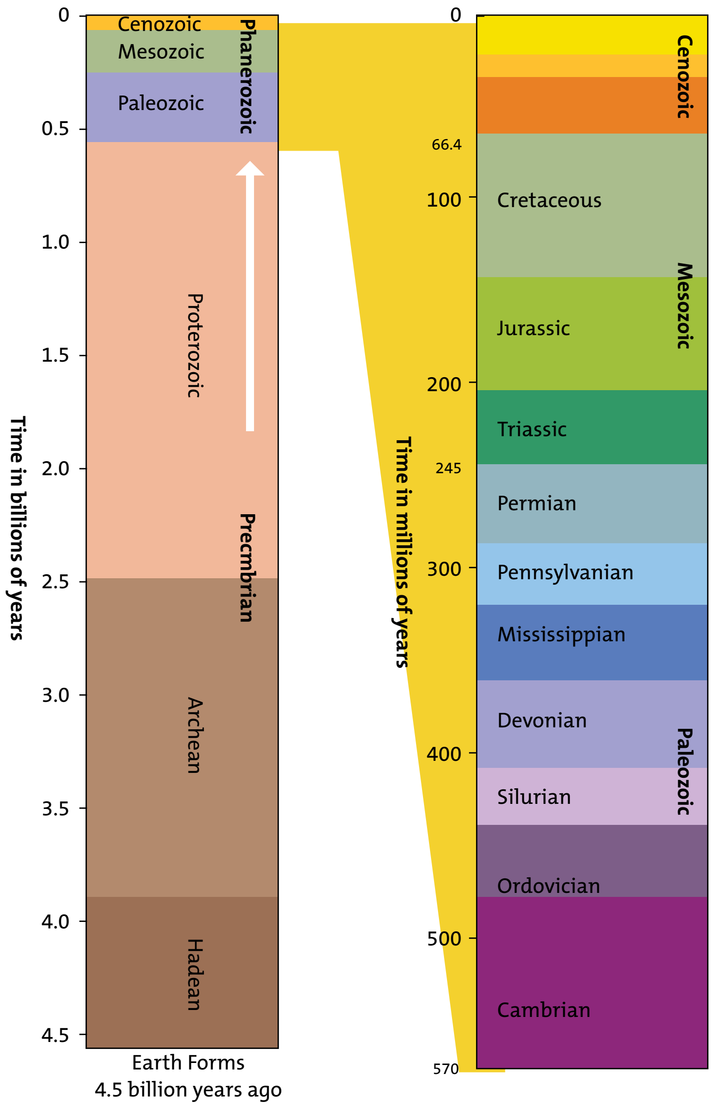
1. A 300 MW scale project as recently built by the Chinese at Puttalam, Sri Lanka, using Indonesian coal at 5,900 Kcal/Kg.
2. A 400 MW scale project as likely planned by CGMC, assuming a lower calorific value of 5,000 Kcal/kg.
3. A typical small 2 x 50 MW scale project (with lower efficiency than the larger projects).

		Sri Lanka [1]	CMGC [2]	Small 2 x 50 MW [3]
Installed capacity	MW	300	400	100
Load factor	[ ]	0.75	0.9	0.7
Annual generation	GWh	1,971	3,154	613.2
Equiv full load hours	[hours]	6,570	7,884	6,132
Efficiency	[ ]	0.3823	0.36	0.33
Heat rate	BTU/kWh	8,925	9,478	10,339
	Kcal/kWh	2,249	2,389	2,606
Coal calorific value	Kcal/kg	5,900	5,000	5,000
Coal consumption	kg/kWh	0.38	0.48	0.52
	tons/hour	114.4	1,91.1	52.1
	million Kg/year	751	1,507	320
	mtpy	0.75	1.51	0.32
Lifetime	years	30	30	30
Lifetime coal requirement	million tons	22.5	45.2	9.6

it opens the possibility of building large-scale mechanized mines that can supply sufficient coal for thermal power plants in the range of 1,000 MW or more.

In short, the question of whether a coal power generation option is feasible for implementation in Afghanistan remains subject to high uncertainty. The objective of this section is to lay out the basic steps necessary to resolve these uncertainties, which will require a significant expenditure by the various government agencies for an exploration program that will provide the answers.

Figure A3.3. Geological Eras



This is another classical example of a decision problem under uncertainty. The expenditure of $25 million to mount an exploration program may or may not be successful in establishing a high likelihood of a satisfactory resource. If an adequate resource is found, the potential benefits of a low-cost source of power generation may be very high. Moreover, it reduces the dependence on electricity imports, and frees up the domestic gas resource for use in higher value uses than power generation, particularly to replace diesel and petroleum products in Kabul, as discussed in annex 4.

A3.2. Coal Reserve Assessments

Afghanistan has never had a proper coal resource assessment. The earliest coal availability studies in Afghanistan were made by the *Survey of India* during the 1880s. The most extensive subsequent work was done between 1965 and 1974, when the government of Afghanistan commissioned V/O Technoexport of the USSR to carry out geologic mapping studies across large parts of Afghanistan. Virtually all of the detailed information known about Afghan coal derives from a dozen Technoexport studies that survived the civil war period. These and other coal reports have been digitized and are available in the USGS Data Series 317.

All of the existing coal investigations were commissioned to answer a single question: "where can we find mineable coal in Afghanistan?" Because all of these studies were of limited scope and of short duration, every prospector followed the same methodology. They looked for new, mineable coal beds adjacent to areas where coal had been found previously. No effort was made to collect the kind of data needed to improve exploration success, such as the stratigraphic information needed to interpret depositional environments in order to build more effective exploration models. This shortcoming is true of the Technoexport work as well.

The difficulty with this strategy is that prospectors have found more coal that has the same technical mineability problems that plagues all of the current mining operations: structurally complex coals that are irregular and of unpredictable thickness. The structural complexity limits the size of mineable blocks. Faulting moves the mined bed up or down. In many cases, the movement is great enough that it becomes uneconomical to chase the bed across the fault. Where this is not the case, the disturbance makes the rocks around the fault highly unstable, making mining conditions more dangerous. Because of the intensity of the structural disturbance, it is difficult to find areas that have continuous coal beds that contain enough reserves to justify the expense of building a mechanized mine. Thirty years of high-volume mining cannot be guaranteed, and without a guaranteed supply of approximately uniform quality coal, it is difficult to finance and engineer thermal power plants.

Type and Quality of Afghanistan's Coal

According to one report,[70] Afghan coal consumers are aware that there are significant differences in coal quality from one mine to the next. Consumers are known to request purchasing of production from specific mines which they identify by name. Such specifications are presumably based on their empirical experience with the performance of different coals when they are burned. Afghanistan has no operating laboratory facilities (certified or otherwise) capable of conducting a coal quality analysis. Technoexport established a coal lab at the Afghan Geological Survey (AGS), but much of the equipment was lost during the civil war period. The instruments that remain are mostly obsolete.

70. Adam Smith International, November 2010, *Assessment of and Restructuring Options for the Northern Coal Enterprise*, Report to DIFD.

Donors have provided some newer instruments, but the laboratory staff is not trained in their proper use or procedure, and the available instrumentation cannot provide the full suite of quality tests needed to properly characterize coal.

The majority of the available coal quality data derives from the work of Technoexport. The analyses were conducted at AGS with a smaller subset of samples sent to the USSR for quality assurance testing. Samples were properly collected as channel samples strictly in accordance with standard collection methodologies. Quality testing was limited to detailed petrographic analyses; proximate/ultimate testing (though complete results are not typically offered for every sample tested); and sometimes determinations of total sulfur, phosphorus, calorific value, and coking potential. The reasons for such spotty quality reporting are unknown.

From 2004 to 2008, the U.S. Geological Survey (USGS) worked with the AGS to provide coal quality analyses for coal samples collected from working mines, both artisanal and those operated by Northern Coal Enterprise (NCE). According to AGS, samples were collected using standard channel sampling methodology. These samples were shipped to the United States. Basic coal quality testing was done in commercial labs. USGS labs provided the trace element analyses.[71]

Before discussing the quality of Afghanistan's coal, several caveats are required. Technoexport admitted that many of the samples that it collected were weathered. Analysis of weathered samples provides some indication of coal characteristics, but, overall, the results do not provide accurate quality assessments. One needs only to look at the range of reported heat contents of coal samples collected in the same area from the same bed or from closely spaced beds. Samples in close proximity sometimes return analyses that range from lignite equivalent to high volatile bituminous. This is a geologic impossibility if these samples do indeed come from the same bed. Such results indicate that the "lignite" is really a highly weathered and degraded bituminous coal. All of the chemical analyses are impacted by weathering.

Analyses of coal from deep mines and core sampling should provide the most reliable results. Typically, Technoexport reports do not identify where samples were collected. Sometimes, their reports lump trench, pit, and adit sample results together, making it hard to understand the true quality of each coal bed away from the zone of weathering. Analysis of core samples collected below 80 to 100 meters should yield definitive analyses. Unfortunately, core recoveries in the coals are often so low (13 percent in one case) that the analyses are not representative of the bed and could, in fact, be significantly misleading if an anomalous section of the core was the only part recovered.

71. Tewalt, S. J., Belkin, H. E., SanFilipo, J. R., Merrill, M. D., Palmer, C. A., Warwick, P .D., Karlsen, A. W., Finkelman, R .B., and Park, A .J., comp., 2010, *Chemical Analyses in the World Coal Quality Inventory*, version 1: U.S. Geological Survey Open-File Report 2010–1196, 4 p.

Based on conversations with the AGS geologists that collected the samples sent to USGS, most of them were reported collected from adits and deeper mines, so the analytical results should be more reliable. But even in this data set, some of the samples were likely to have been weathered since some geologists indicated that there was an understandable reluctance to enter too deeply into unstable adits.

A bigger problem with Afghan coal is its ash content. Contents above 30 percent are not uncommon. Coals above 45 percent ash are considered uneconomical. Much of this ash occurs as thin clay partings that were deposited in the precursor peat swamp during flood events. Thicker coals often contain numerous partings, but in places, two to three meter thick coals are almost parting-free. Such coals have ash contents of under 10 percent. Since there is no understanding of the environments in which these coals formed, there is no model to help in the search for low ash coal occurrences. Based on the available evidence, low ash coals are of limited distribution.

Selective underground mining to limit the amount of parting material entering the production stream is not possible, especially given the primitive mining techniques being employed. A coal washing system will be needed to produce a uniform quality, low-ash product suitable for use in a thermal plant. This will require a significant amount of water, which could be problematic in places where water is not overly abundant. Wash water will have to be purified prior to disposal; otherwise, downstream farms will be very negatively impacted, particularly during periods of low stream flow when there is little water in the discharge basin to dilute toxic materials in the wash plant discharge. Alternatively, power plants can be designed to accommodate high ash coals, but then an environmentally secure ash disposal facility must be built.

Except for the USGS work, nothing is known about the minor and trace element profiles of Afghan coals. Depending on the specific combustion technology used, coal boilers can be sensitive to fouling caused by high concentrations of certain elements or combinations of elements. To some degree, this can be mitigated by the combustion technology selected, but once a thermal plant is designed, the feedstock that is burned must conform within the range of the chemical profile that the plant was designed to handle. For this reason, it is important to have a dedicated coal supplier that delivers a uniform product. Buying whatever coal happens to be available in the market place at any given time can have catastrophic consequences for the power plant operations and reliability.

Coal Transportation

In the absence of a rail network, the only option in Afghanistan is supply by road. A 100 MW coal power station operating at 75 percent plant factor needs roughly 300,000 tons of coal per year (see box A3.1). A typical coal truck is presumed to carry 40 tons, so to supply this project would require an average of 7,500 loads per year, or 21 trucks a day. For this reason, large coal plants are invariably sited either at the mine-mouth, on the coast, or on a major river where it can be supplied by sea. Over long distances, it is far cheaper to move coal by wire (i.e., by HVAC or HVDC).

Coal Production Costs

Consultants have studied cost structures at NCE, the state-owned coal mining entity. They determined that, for a variety of reasons, NCE has no clear understanding of its operating costs. NCE is not an autonomous entity. It is an operating division within the Minstry of Mines and Petroleum (MOMP) and is subject to MOMP procurement regulations. Purchases of mine supplies are handled at the ministerial level. Purchases may or may not be handled in a timely manner and may or may not be for the full requisition amount, depending on the state of ministry finances.

The cost of NCE coal is set by the national government based on presumed fixed costs (salary, operating budgets, and mine technical budgets). These operational costs are routinely underestimated by a factor of two or more. NCE coal is sold (regardless of quality) for Af2100 per ton ($35 per ton). This cost is significantly below current world coal prices (current Australian coal exported in the Asia-Pacific market is around $60/ton). To partially compensate for cost overruns, certain operational costs are being passed on to customers. These include transportation costs and customs duties. Payment to miners is also off-loaded to the coal buyers both to minimize operational cost overruns and to reduce threat of attacks on the mines because the majority of the mines are in insecure areas. The mine operators find it too dangerous to keep cash on hand to pay laborers.

NCE does not employ miners directly; therefore miners do not benefit from the worker protections that accrue to permanent employees of NCE. Miners are contract labor hired from the surrounding villages. They are not professional miners and have no underground experience. All learning is on-the-job. Workers must supply their own tools. Minimal safety equipment may be provided (hard hats and dust masks), but ventilation and lighting are poor. Safety statistics are not kept, but anecdotal reports indicate a high rate of injury and death. Mine crews are hired in groups of 6 to 10 individuals per crew. Customary payment is Af400 per ton of coal mined in mechanized mines (though it is not clear what constitutes a mechanized mine since mechanization in the western sense is not currently known in Afghanistan. Miners in semi-mechanized mines are paid Af500 per ton and, in unmechanized mines, miners are paid Af600 per ton.

Artisanal/extra-legal mine operators are almost certainly knowledgeable of their operating costs, but there has never been an assessment of mining costs or coal sales price from any of these operations. In all likelihood, these are the most efficiently run mines, so their cost structures most nearly reflect true market conditions. However, one might anticipate that worker protections are minimal in these private enterprises, thus potentially contributing to below-market costs for coal mining.

A3.3. The Timeline and Cost of Mine Construction

Estimating the time and cost of building a coal mine of a size sufficient to support a large scale coal-burning power plant is subject to high uncertainty. Unlike other coal fields with producing coal mines, as of today, the nature of the coal resource in Afghanistan is completely unknown. In a developed coal field, sufficient exploration and development has occurred, such that prospective new mine developers have some basic understanding of whether or not a prospective mine lease block has a reasonable probability of containing sufficient coal to support a mining operation. As a result, the time and dollar cost of exploration and the exploration risk itself is greatly reduced. Only a few holes will be needed to determine if a block is likely to contain a mineable resource.

This does not hold in Afghanistan. The location of a mineable tract is a major undertaking that could take years and cost tens of millions of dollars because, to a large degree, holes are being drilled at random until a mineable occurrence is encountered. The CGMC exploration effort at Ishpushta and Qaleech coal fields exemplifies this approach. The background information needed to quickly zero-in on a mineable block does not exist, so exploration success depends on luck. Perhaps the first hole will identify a potential deposit (assuming it can be found at all), but it is equally possible that 10 or 20 holes will be required to find that deposit. Mine planning and costing cannot begin until that deposit is found and defined by drilling. Over time, as information from such wildcat exploration holes accumulates, geologists will be better able to define the geometry of the coal bed distribution, exploration success will improve, and exploration time requirements will decline.

A typical timeline for mine development is shown in figure A3.4. One can say with certainty that this would be the lower bound for mine development in Afghanistan: Given that a comprehensive program of exploration drilling would unlikely be put in place before 2017, the earliest possible date for a coal project of this size would be 2025.

In other words, for the large coal projects to be built to the timetable proposed by the APSMP—namely a 400 MW unit to be in place by 2027 followed by another 800 MW in 2029—a comprehensive coal exploration program must be started as soon as possible.

It is conceivable that one could begin much sooner by importing coal for the first few years (see box A3.2) until a large-scale domestic mine has been developed. This option can safely be rejected, not merely on the grounds of the precarious supply chain and unknown future costs of imported coal, or on the energy security aspects, but on practical grounds of finance. It will be difficult enough to finance a mine-mouth coal IPP in Afghanistan even with bankable coal supply and power off-take agreements, but with an imported coal supply chain, even for the first few years, such a project becomes impossible. A public project would be equally difficult to finance. In any event, a mine-mouth location for the coal project would depend on the ultimate coal mine area to be known at time of financial closure.

Box A3.2. Imported Coal

Could imported coal be used in Afghanistan? As of April 2015, Australian steam coal cost $62/ton FOB. In July 2008, steam coal peaked at $192/ton. Bulk shipping costs are currently at an all-time low, about $10 per ton for a Capesize vessel, even more for smaller boats. During periods of peak cost, shipping rates as great as $50 to $70 per ton were charged.

Coal freight, $/metric ton

	Vessel size	October 2014	February 2015
Australia-China	Capesize*	11.5	4.65
	Panamax*		6.90
Richards Bay-Rotterdam	Capesize	10.50	4.60
	Panamax		7.25
Queensland-Rotterdam	Capesize	17.20	6.95
	Panamax	10.35	
Queensland-Japan	Capesize	10.45	4.55
	Panamax	10.35	

Source: Coal Trader International (McGraw-Hill)
*See glossary for definition.

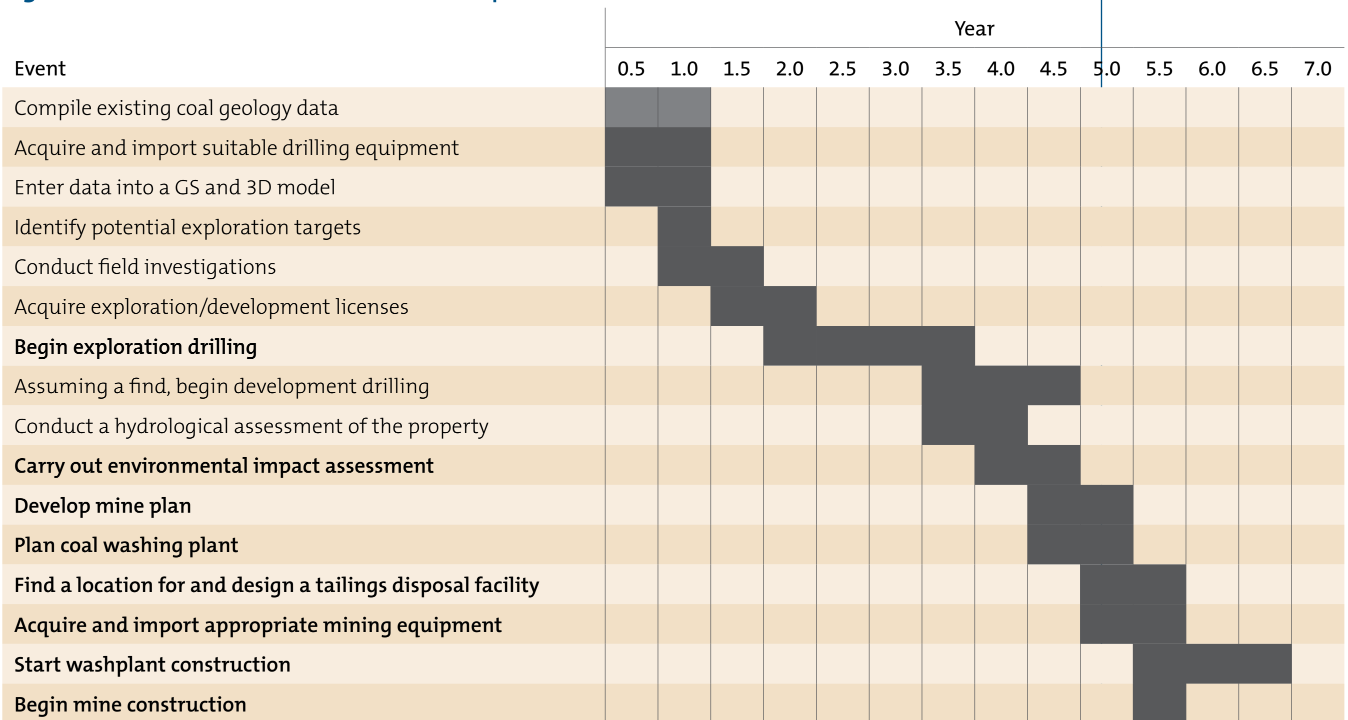
The logical port of import would be Gwadar (a port newly developed expressly to better serve Western and Northern Pakistan as well as Afghanistan as alternatives to Karachi and Port Qasim). Trucking costs from Gwadar to Kabul are highly uncertain: based on older trucking rates adjusted for inflation, these probably now range in the $25–50 per ton range. The costs of customs and duties along the transit route are unknown, but it would be wise to add another $10–20 per ton.

Thus, at current prices, Australian 6,000 kcal/kg, low ash, low sulfur coal can be delivered to Kabul for perhaps $110 per ton. At costs prevailing in 2008 (at the height of the speculative commodity boom), the same coal delivery would have cost potentially as much as $250 per ton or more.

While it is conceivable that a mineral mining concessionaire would build a power plant for his own use (or do a deal with a power IPP to build and operate one for him), the reverse is not true: an IPP will not undertake a coal mining development to supply a coal project unless the coal resource is proven.

There is an alternative strategy that could be used to locate suitable coal resources. The entire exploration process could be turned over to the private sector, at least for a time until AGS coal exploration capabilities are strengthened. Unfortunately, the current

Figure A3.4. The Timeline for Mine Development



mining law is such that no private sector mining company will take on the exploration risk, because it does not guarantee development rights to the exploration company at the time of discovery. Unless the exploration contract specifically allows seamless development rights on the exploration lease by eliminating the legal requirement to offer the explored property to open tender for development, it will be impossible for exploration companies to get exploration financing.

In short, the realistic options for the government are:

- Modify the mining law to encourage junior coal companies to assume the mining risk.
- Hope that if the CMGC development does not proceed as previously expected, that some other mining concessionaire would develop a coal power project.
- Assume the exploration risk itself.

This last option is examined in the following section.

A3.4. Structuring a Government Exploration Program

In the expectation that the Afghan government chooses not to change how the current mining law is implemented as it relates to coal, strengthening the capabilities of the AGS to conduct coal exploration is the only option available to the government to promote mine development on the scale needed to power a thermal power plant. Furthermore, even if the government were to allow contractual exceptions to the mining law, strengthening AGS exploration capabilities is to its advantage. The more information that the government provides to bidders during lease auctions, the more bidders are willing to pay for the leases because exploration risk is reduced.

The Technoexport coal resource assessment is almost 50 years old. During their investigations, Technoexport and AGS geologists identified significant areas that were potentially coal-bearing. Since the Technoexport assessment, there have been no follow-up studies. Local artisanal miners have used the same techniques used by Technoexport to locate coal beds and mine them. Thus, some unknown portion of the reserves identified by Technoexport have now been extracted or spoiled for further mining. New reserves must be found to replace these, if a coal industry capable of supplying thermal power generation is to be established.

National geological surveys like AGS ordinarily have responsibility for finding areas that have a demonstrated coal potential. Prospective areas identified by AGS would then be tendered to the private sector for further exploration and possible development. Because of the extended conflict, AGS has lost the capability to carry out coal exploration work. These capabilities must be rebuilt before the AGS can again become effective in finding coal.

Technoexport executed its coal outcrop exploration plan well. Over the following five decades, AGS and knowledgeable locals used the same exploration strategies to locate additional coal occurrences. There is a strong likelihood that additional coal outcroppings remain to be discovered. However, these will all have the same characteristics as known coal deposits—they will be highly deformed and difficult to mine. The search for less deformed deposits will require a new exploration strategy, one that relies on drilling to evaluate subsurface coal beds inboard of the outcrop belt.

Afghanistan does not have indigenous private sector drilling capability able to attain the depths required for coal exploration. Furthermore, since the mining law is unattractive to the junior mining industry, there is little likelihood that small exploration companies will come to Afghanistan, so there will be little work to sustain an Afghan contract drilling company. Under the prevailing conditions, AGS capability for exploration drilling must be rebuilt. This will entail:

- Supplying AGS with effective drilling equipment.
- Training the AGS drillers to use it.
- Supplying borehole geophysical logging equipment.
- Training AGS professionals to operate the equipment and interpret the resulting data.
- Ensuring that the AGS drilling group has an adequate budget to regularly purchase repair parts and consumable supplies.

A3.5. The Cost of Exploration and Production

Drilling Costs

Coring costs for shallow holes at current market rates generally average between $100 and $200 per meter. Rotary rates are lower. Thus, a 400 m deep hole cored for its entire length will cost somewhere between $40,000 and $80,000, plus the cost of mobilization, demobilization, and any rig downtime that may accrue. Since it may not be possible to contract for geophysical logging services in Afghanistan, the cost of purchasing, training, operating and maintaining logging capabilities (which are essential) will be additional. With mobilization and demobilization and rig downtime costs, it should be possible to drill a dozen coal exploration holes for $1–2 million.

CBM test holes, because they are drilled to greater depths, are considerably more expensive. Exploration holes are likely to cost $600,000 to $1,400,000 each, though recently developed technologies may reduce these costs. These new small hole-diameter drilling technologies will require the purchase of specialized drilling equipment and geophysical logging tools specifically adapted for use with small diameter holes.

Once regional stratigraphy is better understood, coring will be limited to the coal-bearing interval. Less expensive rotary drilling will be used for the barren parts of the section, thus reducing cost per hole. In this scenario, geophysical logging will become an even more critical requirement.

The Cost of Providing AGS with Drilling Capability

There are many variables involved in budgeting the cost of acquiring relatively standard drilling equipment and delivering it to Afghanistan. The budget defined below should be regarded as a general indication of the range of expenses that might be incurred in developing drilling capability in AGS. Major equipment purchases are negotiated with the manufacturer at the time of purchase because equipment configurations and capabilities are not designed until then. Because of the small number of industry participants and the intensity of the competition between them, price structures and purchase incentives are regarded as highly proprietary, so what follows is a best estimate, which will be modified by the level of global demand and suppliers' perceptions of market conditions in Afghanistan at the time of procurement.

The range of costs for providing a drilling capability to AGS will be:

- A used track mounted self-contained drill rig capable of NX to HQ[72] coring to depths of 1,200 m: $250,000–300,000.
- A truck mounted drill rig capable of reaching maximum CBM development depths (2,200 m) with a production diameter drill hole. Three rigs with this capability were in the possession of the U.S. Army in Afghanistan as of 2012, but they have since been returned to the United States: $850,000–1,000,000.
- Drill rig downtime is expensive and can lead to the loss of the hole and all downhole equipment (e.g., rods, bits, and core barrels). Ordinarily, such large inventories of spare parts are unnecessary because: (1) parts are easily acquired from suppliers and (2) companies have the cash flow to purchase these parts as needed. Neither situation applies to AGS. Parts will be unavailable in Afghanistan and AGS does not have the budget resources to purchase them: $2,000,000–5,000,000.
- Consumables. This includes things like drill bits, muds, polymer muds, batteries, hydraulic fluid, lubrication oil and grease, and fuel: $1,500,000–3,000,000.
- Geophysical logging truck equipped with gamma-gamma density tool (radioactive source), neutron log (radioactive source), gamma log, 3-arm caliper, resistivity log, sonic log, lateral log, and inclinometer. Other probes may also be desired: $500,000–2,000,000.
- Two years on-the job training in geophysical logging, truck operations, and equipment maintenance: $750,000–1,250,000.
- Three years on-the job training for drillers: $750,000–1,250,000.
- Self-contained drilling base camp facility: $500,000–1,000,000.
- All of the equipment and supplies need to be shipped to Afghanistan, which will include a complex chain of road, rail, and ocean shipping as well as duties and taxes that may be assessed at various points along the way: $1,000,000–2,000,000.
- Security costs. Drill camps are fixed installations that may be stationary for months at a time. These need to be protected in hostile environments: $1,000,000–4,000,000.
- Rig mobilization and demobilization costs: $1,500,000–3,000,000.

Thus, the total cost to create a three-to-five-year sustainable drilling capability at AGS will be between $10.6 and $23.8 million.

72. Coring drill sizes are designated by two letters. NX is 2.9 inch outside diameter and HQ is 3.7 inch outside diameter.

Mining Coal

The next big uncertainty is the kind of mine that is to be built. Mines fall into three general categories: underground adit; underground shaft; or open cast. Currently, all coal mines in Afghanistan are adit mines that enter the coal bed at the point where the bed is exposed at the surface. Adit mines are less expensive to build, because coal production starts almost from the first shovel dug to start mine construction. If bed characteristics are favorable, with uniform thickness, good roof conditions, and little structural complications, these mines can be built out at low cost and employ more productive mining techniques, such as long-wall rather than the room and pillar method used in underground mines with more difficult conditions. Long-walls are initially expensive to build because a single long-wall machine can cost $10–20 million or more. A small long-wall mine can probably be built for $25–30 million. Because of the large capital cost involved in designing a long-wall, small volume mining operations like those supplying a 100 MW power plant requiring about 300,000 tons of coal per year are not likely to be cost effective on a cost per ton mined basis.

A 1,000 ton per day (TPD) mine, about what is needed for a 100 MW power plant, using room and pillar design in the outcrop belt accessed by adit portal, would cost $26–46 million broken down as follows:

- Two continuous mining machines: $1–2 million.
- One 1 km long conveyer system: $3 million.
- Rock bolting rigs: $1–2 million.
- Muckers, water pumps, ventilation system, haulers, and other ancillaries: $2–3 million.
- Spare parts and supplies: $3–5 million.
- Construction of a shaft or incline if coal is not exposed at outcrop: $2–4 million.
- Coal washing plant for minimal preparation level: $3–5 million.
- Engineer and construct earthquake resistant tailings pond: $5–10 million (though depending on capacity requirements, this may be significantly more).
- Water treatment facility if needed: $5–10 million (this may also vary depending on volume of water needed).
- Environmental reclamation bond: $1–2 million.

Shaft mines are expensive to build. These are necessary when the coal to be mined does not outcrop at the surface and a shaft has to be dug to reach it. There will be no coal production during the entire construction process. For safety reasons, a second escape shaft must also be built. Shafts can be vertical or inclined, and if coals are deep, they can easily exceed a kilometer in length. Since the shaft is the only point of access, the structure must be highly reinforced, so that there is minimal risk of collapse. Engineering and building a shaft or incline will cost several million dollars.

Open cast mines can be inexpensive. If coal is near the surface and overburden is thin, $1–3 million may be sufficient to buy the equipment necessary to remove overburden and mine the coal. Costs mount in proportion to the size and complexity of the open cast. More complex open cast mines capable of producing 5,000 TPD are estimated to cost $20 million to build in developed mining areas. Costs for the same facility in Afghanistan would be higher. Given the observed conditions in Afghanistan, coal near enough to the surface to mine with such simple mining systems may very well be of degraded quality, and not really economical to mine.

Given Afghanistan's geology as it is presently understood, unless there are significant Cretaceous coal reserves waiting to be discovered, it is unlikely that there are many areas where open cast mining will be possible. Even in the Cretaceous, most mining will be underground.

Environmental compliance of the surface footprint of the mining operation will incur additional cost, especially for spoil disposal, waste water control, and tailings pond engineering. Since the environmental compliance regulations have not been defined for the mining industry, estimating these costs is much more speculative. Because the Jurassic coal outcrop belt is on the fringe of one of the most seismically intense zones in the world, the mines themselves and engineered structures like spoils piles and especially tailings disposal facilities will have to meet high earthquake resistance standards. Otherwise the risk will be serious of downstream contamination by acid rock drainage from the mines or of the release of toxic materials from the tailings ponds due to earthquake damage. Seismic considerations will add to engineering costs.

It must be emphasized that the cost estimates presented here are generalized and speculative based on experience of the different possible mining scenarios in Afghanistan. Much more information will be needed to estimate costs more realistically. The assumption is made that new equipment will be preferred over used equipment, because used equipment maintenance costs will necessarily be higher. Because there is no functioning repair or replacement infrastructure in Afghanistan, it will be critical to maintain a major parts inventory until a supply chain is developed. Otherwise, economic losses due to nonproduction while waiting for parts to be imported will be prohibitive and could potentially impact power plant operations.

The cost estimates made here assume that protecting the miner from injury is a primary consideration. Costs can be reduced significantly by reducing the degree of mechanization in the mine, and using more miners to do the physical excavation of the coal using 19th century techniques. This is a values choice that will have to be made by the Afghan government.

Other Data Needs

Since it is considered illegal, it has been difficult to study private sector coal mining activities in Afghanistan. The following information would be useful in better understanding the coal market in Afghanistan and the potential dislocations that introduction of a major new consumer of coal (a power plant) may have on other parts of the national coal market:

- Cost structures in private sector mines.
- Organization of the coal transportation networks.
- The quality of the coal being sold in the Afghan markets.
- The uses for coal in Afghanistan.

A3.6. Alternatives to Coal As A Solid Fuel

Coal Bed Methane

In planning its energy mix, Afghanistan's focus on coal has been exclusively from the perspective of coal as a solid fuel. Coal has always been known to contain significant amounts of methane. Historically, the methane was regarded as a dangerous by-product that poisoned miners and caused mines to explode. By the early 1980s, the energy exploration community realized that improvements in oil-well stimulation technology (fracking) could also be applied to coal beds to accelerate the release of the contained methane known as coal bed methane (CBM).

CBM production depends on the rank and the porosity of the coal. Mid to low volatile bituminous coals contain the most methane, but even lignite deposits contain economic concentrations of gas. Currently, the deepest economic CBM wells are 2,200 m. Methane is still abundant in more deeply buried coals, but the rate of methane extraction is not economical. However, over geologic time, even such deeply buried coals will release methane. If the coal beds are covered by suitable trap and reservoir rocks, these coal beds will act as source rocks for vast "conventional" gas deposits.

Afghanistan's Jurassic coals are regionally extensive. Jurassic coals are known as far north as southern Russia, Georgia to the west, and Kyrgyzstan to the east. Seventy five percent of Turkmenistan's gas deposits, more than half of Uzbekistan's and a significant proportion of Afghanistan's are known to be sourced from the same coal that is being mined in the Jurassic outcrop belt. Given the documented distribution of Jurassic coal across the region, there is every possibility that much of Afghanistan north of the Herat River is underlain by Jurassic coal. There is a lesser possibility that this same area may also be underlain by important Triassic coal deposits and an even more remote possibility that there may be Mississippian coal occurrences below these. If these speculations are correct, there may be deep conventional gas reservoirs in many places across Northern Afghanistan in addition to CBM plays.

No deep test holes have ever been drilled anywhere on the North Afghan Platform. Until exploration test holes are drilled, the potential cannot be known. Ideally 6–10 holes should be drilled at carefully selected locations across the platform to test for deposits. Because at present no detailed understanding of the regional stratigraphy is available, these early holes should be drilled as core holes. These early exploration holes will test two other geologic possibilities besides the CBM potential:

- The possibility that conventionally mineable Cretaceous coals exist; and
- The possibility that virgin, conventionally mineable, shaft-accessible Jurassic coals can be found inboard of the outcrop belt.

In general, the best CBM wells occur in coals that are too deep to mine, so they develop an energy resource that would otherwise be unproductive. Economical CBM wells can contain reserves that range between 0.5 Bcf and 10 Bcf gas per well. The gas is sweet (contains no hydrogen sulfide) and tends to be low in impurities, though the percentage of carbon dioxide is variable and can be quite high. Ordinarily, the gas can be processed at the well site into a product suitable for use in a gas-fueled distributed power generation system to supply electricity at the village level. Wastewater, if it is unsuitable for agricultural use, can be disposed of in an onsite reinjection well.

The Cost of a CBM Project

The amount of exploration conducted and infrastructure put in place to create a generation capacity able to supply local users depends entirely on the productivity of each well and the number of wells that have to be drilled to define the required reserves. Sample costs are likely to be as follows:

- $5 million to develop a five well field with an onsite gas separation facility and wastewater disposal. The exploration success ratio is assumed to be 20 percent: the result is assumed to be one producing well with an average production of 800 Mcf/day. This is adjusted for the assumed 1.6 Afghanistan premium.
- $0.30/Mcf for gas treatment (primarily CO_2 removal) and compression costs.
- $37,000–50,000 per km gas transmission infrastructure construction: the calculation below assumes 10 km @ $50,000/km x (1.6 Afghanistan multiplier)=$800,000.

Table A3.1 shows the estimated levelized cost of gas based on these figures and a typical production pattern of a gradual increase over first few years, followed by gradual decline as shown in row 1 of the table. An average production of 800 Mcf/day over 20 years is assumed, in line with the average production in U.S. CBM wells. The resulting $7.5/mmBTU is significantly higher than the likely cost of gas from the large fields in the Sheberghan area. However, for rural application in remote areas, the competing fuel is diesel, which even at $40/bbl world crude oil price is around $15/mmBTU (delivered in rural areas).

Table A3.1. Levelized Cost of CBM Production

			NPV	1	2	3	4	5	6	7
[1] Gas volume	800	Mcf/day				600	800	1,000	1,100	1,057
[2] Annual production		mMcf/year				219	292	365	402	386
[3]		mMCM/year	31.6			6.2	8.3	10.3	11.4	10.9
[4] Field development cost		$USm	6.5	4.0	4.0					
[5] Gas transmission		$USm	0.6		0.8					
[6] Gas treatment and compression	0.3	$USm	0.3			0.07	0.09	0.11	0.12	0.12
[7] Total cost		$USm	7.4	4.0	4.8	0.06	0.087	0.1095	0.12	0.1125
[8] Levelized cost		$/MCM	235.0							
[9]		$/mmBTU	7.5							

Note: Calculations assume 20 year life, and a 15 percent WACC.

Geothermal Potential

There are several active volcanic systems near Afghanistan's borders. Tor Zawar, 475 km SSW of Kabul in Pakistan experienced a fissure eruption in 2010 and Koh-e-Taftan near to the juncture of the Afghanistan-Pakistan-Iran borders is reported to have had a lava flow in 1993. Other volcanoes in these border areas have been dated as active within the past 10,000 years. Afghanistan has three volcanoes that are classified geologically active but dormant. Kaneshin last erupted 620,000 years ago and Vakak (120 km west of Kabul) and Dasht-e-Nawar (160 km SE of Kabul) erupted within the past 10,000 years. Of these, Dasht-e-Nawar is considered the most prospective geothermal site in Afghanistan. It is a 20 km long, 10 km wide volcanic caldera. Remote sensing studies and site visits to this location confirm that there are flowing hot springs along its entire western margin. If this site has no geothermal potential, then Afghanistan's other hot springs are less promising candidates.

A substantial number of warm water and hot water springs are known across Afghanistan, first documented by Technoexport. More recently, their potential as geothermal resources have been considered.[73] None of these springs have ever been tested as potential energy resources. The presence of hot springs is not definitively indicative of geothermal potential. It is entirely possible that the magmatic systems that warm these waters have cooled below the temperature needed to efficiently power a geothermal plant. The geothermal potential should not be discounted out of hand. Drilling a geothermal test well will cost about the same as a deep CBM test well.

73. Saba, D.S., Najaf, M.E., Musazai, A.M. and Taraki, S.A., 2004. *Geothermal Energy in Afghanistan: Prospects and Potential. Prepared for Center on International Cooperation*, New York University, New York and Research Institute for Economic Development and Social Policy, Kabul, Afghanistan, 38 pp.

Shale Gas Potential

It will likely be a long time before Afghanistan is in a position to develop any shale gas potential it may have. When Afghanistan was being mapped in the 1960s and 1970s, the technology to develop shale gas did not exist, so the stratigraphic studies needed to identify potential shale gas reservoirs were not conducted. However, for the same reasons that Afghanistan's coal potential is much greater than surface evidence would indicate, there is a significant possibility that Afghanistan hosts shale gas deposits. Future geologic investigations should include a search for evidence that such a resource exists.

A3.7. Decision Analysis

The reality is that without confirmation of the coal resource, one cannot realize the future benefits of coal generation. Compared with the cost of imported electricity, even the most pessimistic assumptions about the cost of setting up a coal mine and the construction cost of the coal generating plant shows a very large benefit. Table A3.2 shows a calculation of the cost of electricity imports under different sets of assumptions, ranging from 7.5 to 9.5 US¢/kWh as the PPA price, plus the incremental cost of transmission, compared with a 100 MW coal project, again under different assumptions, from a favorable capital cost of $1,000/kW to an unfavorable cost of $1,400/kW. All the capital costs (coal mine, transmission, and coal generating plant capital costs are adjusted for a (pessimistic) Afghanistan cost premium of 60 percent.

The levelized cost of electricity imports is 9.1–12.7 US¢/kWh, whereas that for coal generation is 5.0–7.5 US¢/kWh. In other words, even under the most optimistic assumptions for electricity imports and the most pessimistic assumptions for the cost of coal generation, coal generation would be preferred over imports.

The decision problem is straightforward: given the uncertainties of the outcome of an exploration program, what is the maximum amount that the government should invest today in an exploration program? This should obviously be less than the expected value of future benefits of having coal available as an option to meet base-load requirements.

Table A3.3 shows the net economic benefit, as NPV at 10 percent discount rate. For example, under expected conditions for imports, the NPV is $676 million (table A3.2); under expected conditions for coal projects, the NPV is $384 million. Therefore, the net benefit of coal is $292 million.[74]

74. I.e., $676 million–384 million=$292 million.

Table A3.2. Cost of Imports and Coal Generation Under Different Assumptions

Future>		Favorable	Expected	Unfavorable
[1] Imported electricity				
[2] PPA price	$USc/kWh	7.50	8.50	9.50
[3] Served energy	GWH	657	657	657
[4] Total variable cost	$USm	49	56	62
[5] As NPV	$USm	465	526	588
[6] Capital costs				
[7] Incremental transmission cost	$USm	100	150	200
[8] Total cost as NPV	$USm/year	565	676	788
[9] Equivalent USc/kWh	USc/kWh	9.1	10.9	12.7
[10] Coal Project				
[11] Installed capacity	MW	100	100	100
[12] Load factor	[ ]	0.75	0.75	0.75
[13] Annual generation	GWh	657	657	657
[14] Equiv full load hours	[hours]	6,570	6,570	6,570
[15] Efficiency	[ ]	0.3823	0.3823	0.3823
[16] Heat rate	BTU/kWh	8,925	8,925	8,925
[17]	KCal/kWh	2,249	2,249	2,249
[18] Coal calorific value	KCal/kg	5,900	5,900	5,900
[19] Coal consumption	kg/kWh	0.38	0.38	0.38
[20]	Tons/hour	38.1	38.1	38.1
[21]	mtpy	0.25	0.25	0.25
[22] Coal production O&M cost	$/ton	50	60	70
[23] Fuel cost/year	$USm	12.5	15.0	17.5
[24] Total variable cost as NPV	$USm	118	142	165
[25] Coal mine cost (see Para 167)	$USm	26	36	46
[26] AGF premium	[ ]	1.2	1.4	1.6
[27] Adjusted for AFG premium	$USm	31	50	74
[28] Capital costs of generating plant				
[29] Capital cost	$/kW	1,000	1,200	1,400
[30] Adjusted for AFG premium	$/kW	1,600	1,920	2,240
[31] Total capital cost	$USm	160	192	224
[32] Total cost	$USm	309	384	463
[33] Per kWh	USc/kWh	5.0	6.2	7.5

Table A3.3. Net Benefits, NPV—$, millions (10 percent, 30 years)

		Imports		
		Favorable 7.5 USc/kWh	Expected 8.5 USc/kWh	Unfavorable $9.5USc/kWh
	Import NPV>	565	676	788
	coal NPV			
Favorable[a]	309	255	367	479
Expected[b]	384	180	292	404
Unfavorable[c]	463	102	214	326

a. Coal cost $50/ton, capital cost 1,600 $/kW.
b. Coal cost $60/ton, capital cost 1,920 $/kW.
c. Coal cost $70/ton, capital cost 2,240 $/ton.

The calculation has to take into account that the costs of the exploration program are required today, whereas the benefits will only be realized in the future: even if the exploration program is successful, as shown in table A3.4, there will be a time lag between the demonstration of the resource and the earliest date that coal can be produced. In this analysis the following assumptions are made:

- Funds for the AGS program committed: 2016.
- AGS exploration program begins: 2017.
- A potential resource identified: 2019.
- Financial closure of the project: 2021.
- Construction time: three years, COD 2024.

In other words, the NPVs shown in table A3.3 are to the beginning of 2024, and must be brought back to the NPV in 2016, at which point they can be compared with the outlay required in 2016 for the proposed AGS exploration program. It is also the case that the outcome of the exploration program has potentially many outcomes: there may be no coal at all (of sufficient size for a 100 MW project)—but there may also be enough coal for 1,000 MW or more.

Table A3.4 shows the calculations necessary to assess the NPV of the AGS exploration program in the existing coal areas. Row 1 shows the estimated costs of the program: these costs are certain. Row 3 shows that the probability that the exploration program is wholly unsuccessful is 5 percent—it contributes nothing to the expected NPV. Row 4 shows the outcome as finding just enough coal for a single 100 MW project as 25 percent. The benefits are realized only in 2024—which under the most pessimistic circumstances

Table A3.4. NPV of the Exploration Program in Known Coal Fields

	NPV	Prob. (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
			Exploration			PS	Financial Closure	Construction			COD 1st Project		COD 2nd Project		COD 3rd Project		COD 4th Project		COD 5th Project
[1] AGS exploration program 1	-24.8	100	-7.5	-15	-7.5														
[2] Outcomes:																			
[3] unsuccessful, no coal	0.0	5																	
[4] 100 MW	10.8	25									102								
[5] 400 MW	75.0	50									102		305						
[6] 700 MW	35.7	15									102		305		305				
[7] 1000 MW	9.3	3									102		305		305		305		
[8] 1,300 MW	6.2	2									102		305		305		305		305
[9] Total NPV	112.2	100																	

yields a net benefit of just $101 million (in 2024). When this is discounted back to 2016, and multiplied by the 25 percent probability, the contribution to NPV is $10.8 million.

The chances of finding enough coal for 400 MW is 50 percent. It is assumed that the first project would still be 100 MW, but that two years thereafter a 300 MW project is built, recognizing the difficulties of financing large projects. Therefore the net benefit will be 3 x 102=$305 million; another conservative assumption since scale economies would reduce the capital costs per kW assumed in table A3.2. This calculation is repeated for the other exploration outcomes, from which the total expected NPV, including the upfront costs of the AGS program is $112 million. Under the expected net benefits of coal power generation v. imports, $292 million (see the entry in table A3.3), the NPV of the AGS program is $365 million.

The robustness of this AGS program NPV can be tested by calculation of the switching value for the probability of no coal being found.[75] This calculates to 83 percent (see table A3.5) for the most unfavorable benefit of coal generation (i.e., under a favorable cost of future imports and unfavorable costs of the coal project.[76] In other words, the probability of finding enough coal for a 100 MW project would have to be 17 percent or less for the exploration program to have negative returns. This can be regarded as extremely unlikely.

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75. This is a simple task in EXCEL, by using the *backsolve* function.

76. One may also note that the probabilities of import costs and of costs of a coal generation project are independent of the probability of exploration success: in other words, even if electricity imports were cheap and coal *generation* projects expensive, one could still have a good outcome in the exploration program.

Table A3.5. Switching Value for the Success Probability

	NPV	Prob. (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
			Exploration			PS	Financial Closure	Construction			COD 1st Project		COD 2nd Project		COD 3rd Project		COD 4th Project		COD 5th Project
[1] AGS exploration program 1	-24.8	100	-7.5	-15	-7.5														
[2] Outcomes:																			
[3] Unsuccessful, no coal	0.0	83																	
[4] 100 MW	2.0	5									102								
[5] 400 MW	13.6	9									102		305						
[6] 700 MW	6.5	3									102		305		305				
[7] 1,000 MW	1.7	1									102		305		305		305		
[8] 1,300 MW	1.1	0									102		305		305		305		305
[9] Total NPV	0	100																	

Table A3.6. Expanded AGS Exploration Program

	NPV	Prob. (%)	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
			Exploration			PS	Financial Closure	Construction			COD 1st Project		COD 2nd Project		COD 3rd Project		COD 4th Project		COD 5th Project
[1] AGS exploration program 1	-24.8	100	-7.5	-15	-7.5														
[2] Outcomes:																			
[3] Unsuccessful, no coal	0.0	5																	
[4]	100 MW	10.8	25									102							
[5] 400 MW	75.0	50									102		305						
[6] 700 MW	35.7	15									102		305		305				
[7] 1,000 MW	9.3	3									102		305		305		305		
[8] 1,300 MW	6.2	2									102		305		305		305		
[9] Total NPV	112.2	100																	
[10] AGS exploration program 2	-18.7	100				-7.5	-15.0	-7.5	0.0	0.0	0.0								
[11] Unsuccessful, no coal	0.0	10																	
[12] 100 MW	3.2	10												102					
[13] 400 MW	16.9	15												102		305			
[14] 700 MW	44.8	25												102		305		305	
[15] 1,000 MW	44.8	25												102		305		305	
[16] 1,300 MW	26.9	15												102		305		305	
[17] Total NPV	136.5	100																	
[18] Total program NPV	248.7																		

Thus, it is seen that under the most pessimistic outcomes for the cost of coal generating projects relative to imports, the expected NPV for an exploration program in the known areas of coal resources is $112 million; under expected conditions of coal generating costs and imports, the NPV is $369 million. Potential benefits of this magnitude warrant immediate implementation of the proposed AGS program.

These results apply just to an AGS program limited to the known coal areas in Afghanistan. In a second phase, the program could be extended to the deep coal North Afghan Platform, in which case table A3.4 extends as shown in table A3.6. The expected NPV of the combined program under worst case conditions (unfavorable coal generation costs and low import costs) is $248.7 million; for expected conditions, this rises to $760 million.

A3.8. Conclusions

The use of coal for power generation is in principle an attractive option for Afghanistan, but until the resources to fuel these options are identified, mine and power plant planning are premature. Nobody knows exactly where the coal resources needed to fuel either of these options might be located. A concerted exploration effort will be needed to answer this question, the importance of which should not be underestimated. When Aynak was initially offered for tender around 2006, one of the main impediments to negotiating the final agreement was identifying an adequate source of coal to fuel a power plant needed to provide electricity to operate the mine. A decade later, Afghanistan still has no answer to this question. There are only two options to answer the question of resource availability: either the private sector explores for and develops the resources it needs. or the public sector funds the exploration and then either develops the resource itself or auctions the proven resource.

The current mining law is so unfavorable to private sector participation that no junior exploration company could ever be financed by international investors to pursue projects in Afghanistan. Thus, the only option open to the Afghan government is to self-finance to do the exploration work itself. Several of these actions are low cost options and can be taken up immediately to start the exploration process. Others are more expensive but must occur if Afghanistan expects to seriously develop its coal resource potential.

Given that the private sector will avoid participating in exploration under the current mining law, if the Afghan government has a serious intent to locate developable coal resources, the following recommendations are made:

- The Afghanistan Geological Survey is the de facto exploration arm of the Afghan government. A permanent AGS coal team needs to be constituted. It will require up to three years of intensive training and practical on-the-job training to become fully operational and effective. It will require A highly experienced coal exploration geologist with a proven track record of coal discovery should be retained to provide this training. Training in coal geology field methods is critical. Given current security considerations in the coal fields, to be effective, this training may need to be provided in third country venues.

- AGS needs to compile all of the existing coal data into modern digital data files. Gathering and including coal geology data from NCE mines will provide important information about the coal bed geometry needed for resource assessments. Within the Afghan government, NCE has the best understanding of the geologic conditions underground and hence can make an important contribution to the NCE in the coal resource assessment process. Representative samples of coal for sale in marketplaces across Afghanistan should be collected to get a basic understanding of the quality of coal currently offered for sale and to learn more about its origin.
- Until AGS has the ability to conduct required analyses in-house, a budget to pay for critical laboratory work outside Afghanistan is essential. The AGS coal team will also need a reliable field budget. The AGS coal geology team, working with its international trainer, must lay out a wildcat coal exploration program based on the best available geologic information. With training, the AGS coal team can begin collecting essential stratigraphic and sedimentological data needed to understand depositional environments. These data are an essential input for developing more successful exploration strategies.
- Afghanistan needs to develop an effective drilling capability, requiring suitable drilling equipment to be purchased, together with an adequate inventory of spare parts and consumables.[77] Drillers need to be trained by an experienced master driller retained for a minimum of three years. A dedicated budget to pay for labor, field expenses, rig mobilization, and consumables must be consistently allocated. The AGS drill team, working with their international trainer, needs to drill the targets identified by the coal geology team. Once initial discoveries are made, prospects can be better defined with additional drilling or blocks can be offered for development tender. A geothermal test hole can be drilled at Dasht-e-Nawar.

The analysis demonstrates that the expected value of future benefits far outweighs the upfront costs of the exploration program. Under the most pessimistic outcomes for the cost of coal-generating projects relative to imports, the expected NPV for an exploration program in the known areas of coal resources is $112 million; under expected conditions of coal-generating costs and imports, the NPV is $369 million. Potential benefits of this magnitude warrant immediate implementation of the proposed AGS program. Indeed, if extended to the presently unexplored areas of the deep coal North Afghan Plateau, the NPV rises by $762 million. It also follows that even if the AGS program proved to be two to three times more expensive than estimated here, the benefits remain very high indeed.

77. Note that fully training an AGS coal exploration team but not providing it with the required exploration tools (the capability to drill) will not shift the status quo. At best, the AGS might be able to demonstrate the presence of Cretaceous coals using surface field methodologies, but no meaningful description of coal bed geometry needed for resource evaluation will be possible without drilling.

Annex 4. Case Study: Thermal Generation Options

A4.1. Background

Both coal and gas generation feature prominently in the APSMP scenarios. A gas CCGT at Sheberghan appears at 400 MW scale in most of the APSMP addendum scenarios with a commercial operation date (COD) of 2020, and coal generation appears in the original APSMP at 400 MW at Aynak, and another 800 MW at Haji Gak,[78] both at $1,700/kW, albeit with the qualification that "It is unknown if the necessary coal reserves exist in Afghanistan." In the APSMP addendum, just a single 400 MW project appears at Bamyan (equivalent to Aynak since the CMGC concession includes coal mining at Bamyan). Exploitation of the gas reserves has attracted the most attention, including several studies that examine uses other than for power generation, including exports, and a gas pipeline to Kabul where gas would displace diesel fuel.

While the gas project has been considered for many years, decisions have been delayed as a result of continuing uncertainty over the actual size of the resource, the appropriate technology to be applied if gas were to be used on a large scale for electricity generation, and the ability to finance a project such as an IPP. Most recently, there is a proposal for a 50 MW gas engine IPP project in Mazar to be supplied by a refurbished gas pipeline from the Sheberghan gas field.

A4.2. The Gas Resource

The prospects for gas production in Northern Afghanistan have been reviewed by consultants.[79] Table A4.1 shows the consultants' estimate of remaining reserves (as of 2003) to be 77.4 billion cubic meters (BCM). By contrast, the reserves in Uzbekistan are estimated to be some 1,900 BCM, and those of Turkmenistan to be 8,000 BCM.[80]

78. APSMP, table 6.1.2–5.

79. Gustavson Associates, *Assessment of the Potential for Gas-fired Power and its Contribution to the Resource Growth Corridor*, Report to the World Bank, July 2012.

80. Turkmenistan is the major producer and exporter of natural gas in the region, producing some 76 BCM of natural gas in 2014, of which 45 BCM was exported. In 2015, production is expected to increase to 80 BCM, according to figures from the Petroleum and Mineral Resources Ministry. Most of Turkmen gas exports go to China through the Central Asia–China gas pipeline, which is currently able to handle as much as 55 BCM of gas per year. The CASA-1000 study quotes the gas reserves of Uzbekistan at 66 tcf and of Turkmenistan 280 tcf. Turkmenistan is becoming a major supplier of natural gas into China.

Table A4.1. Consultant Estimates of Remaining Reserves, Billion Cubic Meter (BCM)

Field	BCM
Khoja Gogerdak	16.77
Jarquduq	9.77
Yatimtaq	7.36
Juma	21.82
Jangalikolon	13.38
Bashikurd	6.37
Khoja Bulan	1.95
Total	77.40

Source: Gustavson Associates, *Assessment of the Potential for Gas-fired Power and its Contribution to the Resource Growth Corridor*, Report to the World Bank, July 2012.

The review concludes that the amount of gas-fired power generation that will be installed in Northern Afghanistan crucially depends on whether or not further exploration of these two basins occurs, and if so, on the degree of the exploration's success. If there is very limited success, then there could be enough gas supplies from previously discovered fields to meet limited gas needs and power demand in Northern Afghanistan alone. If there is success only in the Afghan-Tajik basin, then about 200 MW of power could be available for export from the region to other parts of Afghanistan or internationally in about ten years. With substantial exploration success in the Amu Darya basin, power generation in the region could be as high as 1,000 MW. There are likely to be challenges in coordinating hydrocarbon exploration and development activity with increases in demand for power and natural gas. Oil and gas firms may be reluctant to explore and develop when there is substantial uncertainty about demand for gas, while industrial developers (and power plant developers) may be reluctant to invest without assurance of energy availability.[81]

A number of potential options has been proposed on how best to use this gas. While the use for this gas for power generation is the most frequently proposed, other options include:

- Exporting the gas to Tajikistan (which would require the construction of a pipeline from the Sheberghan (and other) fields to the Tajik border.[82]
- Expanding the fertilizer plant at Mazar-e-Sharif and other industrial and commercial uses of the gas there, which would require additional pipeline capacity to accommodate the increased volumes of gas to be supplied. Pipeline options are shown in figure A4.1.
- Building a gas pipeline from the northern gas fields to the Kabul area, where the gas would displace diesel oil (and fuel wood) for domestic and household use (which would require, in addition to the main gas pipeline, the development of gas distribution infrastructure in the Kabul region). Pending the gradual development of the gas distribution infrastructure, gas could also be used for power generation at one of the existing thermal generating stations in Kabul (again displacing expensive diesel oil). This pipeline option is shown in figure A4.2.

81. Gustavson, op.cit, Executive Summary.

82. Gas export markets may also exist among Afghanistan's other neighbors. Pakistan has a significant shortage of gas forecast far into the future and is considering pipeline imports from Iran as well as LNG imports at prices in excess of $10/mmBTU. However, exporting to Pakistan would involve additional investment costs for the extension of the gas pipeline from Kabul to Peshawar.

Box A4.1. Gas Pricing and Conversion Factors

Three main units are used in the practice of gas pricing: dollars per thousand cubic meters ($/MCM), dollars per thousand cubic feet ($/MCF), and dollars per million British Thermal Units ($/mmBTU).[a] In the Central Asian gas trade, most prices are quoted as $/MCM.[b] Reserves are typically denominated as trillion cubic feet (tcf), or billion cubic meters (BCM).[c]

There are few data on calorific value of Sheberghan gas, and the estimates that do exist vary widely. A 2006 feasibility study[d] states a calorific value of 33.2 MJ/m^3 (expressly stated as LHV), or 31,468 BTU/m^3; the 2011 report by the same consultant states the heat value of the gas to be supplied to the proposed Sheberghan 200 MW IPP power generation project as 32,171 BTU/m^3.[e] The Sheberghan risk analysis states the calorific value as 9,520 Kcal/m^3, equal to 37,775 BTU/m^3.[f]

$/MCM	$/mmBTU
14.1	0.4
50.0	1.6
100.0	3.2
150.0	4.8
200.0	6.3
250.0	7.9
300.0	9.5
350.0	11.1
400.0	12.7
450.0	14.3
500.0	15.9
550.0	17.5
600.0	19.0
650.0	20.6

The table shows the conversion between $/mmBTU and $/MCM for a conservative assumption for heat value (31,500 BTU/m^3).

a. The APSMP quotes gas prices as $/ MWh (see e.g. table 6.1.2–2). This risks confusion between gas price and electricity price and makes difficult a comparison with costs of other fuels. 1 kWh=3,412 BTU, so the gas price of $3.9/ MWh cited by APSMP as applying to existing wells converts to $1.14/mmBTU; "gas price, refurbished well" of 10.4$/ MWh converts to $3.05/mmBTU.
b. Again care is required: some reports use "MCM" to denote millions of cubic meters. However, the universal practice is to use "mm" to denote millions of BTU.
c. How much energy there is per m^3 depends on whether the heat content is specified as lower heating value (LHV) or as higher heating value (HHV). In Central Asia it seems the energy content is denominated as LHV (as in Russia and Europe)—whereas in the U.S., HHV is used (e.g., as in Henry Hub prices). For natural gas, the difference between HHV and LHV is about 10 percent. There is a corresponding difference in the way heat rates of power plants are stated: efficiency based on LHV is thus 10 percent higher than based on HHV (so for example, 55 percent rather than 50 percent).
d. AEAI, *Feasibility of Development of a Gas-fired Thermal Power Facility in Sheberghan*, Pakistan, report to USAID and Ministry of Energy and Water, March 2006.
e. AEAI, *Gas/Power and Related Infrastructure Assessment*, *Report to USAID*, 5 April 2011 (table 3).
f. AEAI, *Sheberghan Gas Field Development Project: Risk Analysis Report*, 23 May 2010.

These options are not mutually exclusive, and combinations of these projects could be implemented in sequence as the gas supply increases. For example, one could begin with a pipeline to Mazar-e-Sharif to allow increased use for fertilizer production, then build an export pipeline to the Tajik border, and then build a series of power generation projects. The choice is bounded by the amount of gas actually available in each year and the investment capital that may be available to the government of Afghanistan from the international community. Table A4.2 and figure A4.3 show the consultant gas production scenarios.

Figure A4.1. Gas Pipeline to Mazar-e-Sharif

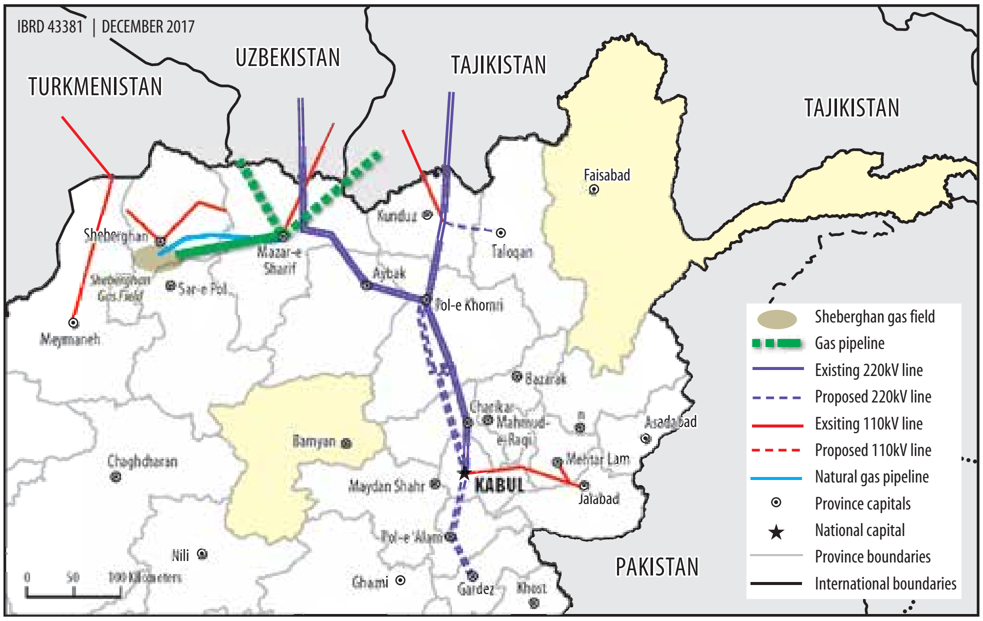
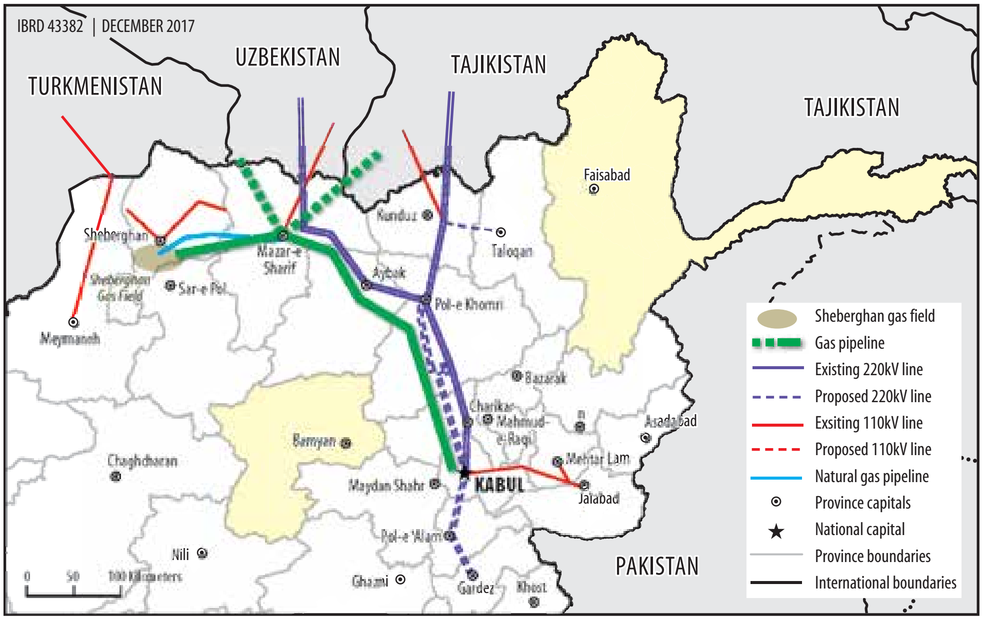


Figure A4.2. Gas Pipeline to Kabul



Uncertainty surrounds both the choice of technology and the capital cost as well as the location. Both CCGT and reciprocating gas engines have been proposed (assumed in the APSMP at $1,700/kW for the former, and $1,200/kW for the latter).

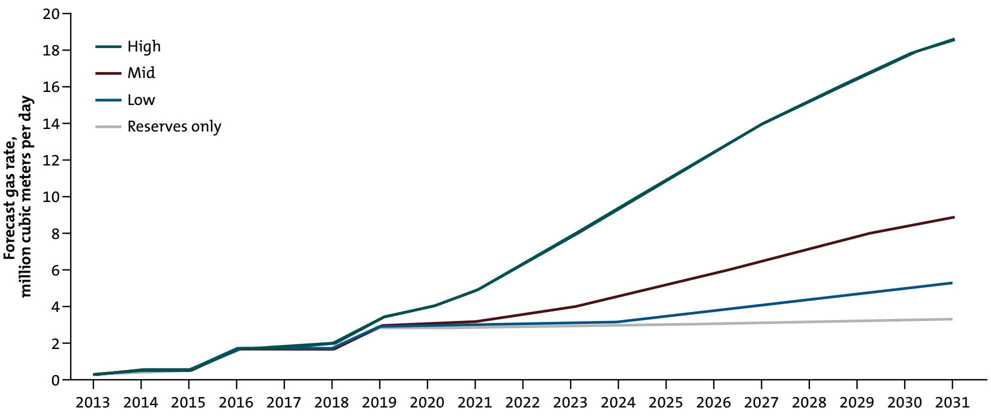
The 2005 Sheberghan FS for USAID recommended reciprocating gas engines with waste heat recovery be used for the power plant, with gas treatment consisting of hydrogen

Table A4.2. Gas Production Scenarios

	Million CM/day			BCM/year		
	Low	Mid	High	Low	Mid	High
2016	1.8	1.8	1.8	0.66	0.66	0.66
2017	1.8	1.8	1.8	0.66	0.66	0.66
2018	1.8	1.8	2.0	0.66	0.66	0.73
2019	3.0	3.0	3.2	1.10	1.10	1.17
2020	3.0	3.3	3.3	1.10	1.20	1.20
2021	3.0	3.6	4.4	1.10	1.31	1.61
2022	3.0	3.9	5.6	1.10	1.42	2.04
2023	3.0	4.2	6.8	1.10	1.53	2.48
2024	3.0	4.5	8.0	1.10	1.64	2.92
2025	3.0	4.5	8.0	1.10	1.64	2.92
2026	3.0	4.5	8.0	1.10	1.64	2.92
2027	3.0	4.5	8.0	1.10	1.64	2.92
2028	3.0	4.5	8.0	1.10	1.64	2.92

Source: Gustavson Associates, *Assessment of the Potential for Gas-fired Power and its Contribution to the Resource Growth Corridor*, Report to the World Bank, July 2012.

Figure A4.3. Gas Production Scenarios, MCM/day



Source: Gustavson Associates, *Assessment of the Potential for Gas-fired Power and its Contribution to the Resource Growth Corridor*, Report to the World Bank, July 2012.

sulfide removal using amine scrubbing, water removal using glycol dehydration, solids filtration, and preheating. The main advantage of such gas engines is the fact that they can be installed in small 5 MW modules. With the necessary gas conditioning facilities now proposed as part of the gas production, the APSMP assumes use of CCGT.[83]

83. Though at the same time noting that "It is not known by the consultant which type of power plant is preferred for the Sheberghan power plant."

Table A4.3. Capital Costs for CCGT

Installed Capacity, Adjusted to Site Conditions (MW)	Capital Cost (Economic) ($/kW)
215	1,100
458	911
707	867

Source: SNC-Lavalin, Pakistan: National Power System Expansion Plan, 2010–2030, Final Report, Annexure A2: Generation Planning.

There exist significant economies of scale, and a 200 MW CCGT has a significantly higher unit cost than the 400–800 MW units common in international practice, as shown in table A4.3.

In the more recent evaluation of the Sheberghan project, the consultant reports that recent experience of construction projects in Afghanistan suggests that the substantial incremental security and logistics costs add 60 percent to general international price levels for power generation equipment: it estimates international cost for a 200 MW size CCGT at $1,000/kW, when adjusted by a 1.6 multiplier equal to $1,600/kW (slightly lower than the APSMP estimate of $1,700/ MW).

A4.3. The Basic Question: Gas Generation Versus Imports

In the absence of energy security constraints and geopolitical considerations, the question of whether Afghanistan should use its gas resources for power generation are easily answered. A project in Afghanistan will have higher costs because:

- ***Scale economies.*** Because even a 200–400 MW CCGT in Sheberghan will have higher investment costs per kW than an 850 MW scale project in Turkmenistan. The smaller project will also have a poorer heat rate.
- ***Security related construction premia.*** As noted, costs for the Sheberghan project are estimated to be 60 percent higher than international levels.
- ***Gas quality.*** The gas in Sheberghan is sour and of lower quality than in Turkmenistan, which will incur an additional cost for gas treatment.
- ***Gas field development costs.*** Gas field development will be more costly than in the CARs: One study estimates a premium of 60 percent just to account for the more mountainous terrain (rather than flat, smooth steppe), the lack of supply equipment and materials, and the inability to provide many of the necessary specialized personnel. Moreover, this premium does not account for any de-mining or security expenses, which might also be necessary for an upstream project in Afghanistan.

A project in Afghanistan will have lower costs because:

- ***Avoided power transmission costs.*** The distance from the generation point in Turkmenistan to Sheberghan is several hundred kilometers. This involves transmission losses and the cost of the transmission line itself.

There is also the question of the benefit of the resource rent. Imports of gas-based electricity will be based on the market price of gas in Turkmenistan (set largely by China's willingness to pay), not on the actual production cost of gas. If the market price of gas is, for example, $8/mmBTU but the LRMC is only $1/mmBTU, then the resource rent that accrues to the government of Turkmenistan (or to the production entity involved) is $7/mmBTU. So even if the LRMC in Afghanistan is triple that of Turkmenistan, generation in Afghanistan still brings a resource rent of $5/mmBTU. Of course, that rent would also be available if the gas were used to supply Kabul to displace diesel oil and petroleum-based LPG: while that would entail a significant additional gas transmission cost, the value of gas is highest where it displaces oil (diesel cost in Kabul is about $17.50/mmBTU at an oil price of $40/bbl). However, it is worth noting that the very low LRMCs in the CARs (table A4.4) are a result of the very large size of their gas fields and production volumes: these are not achievable in Afghanistan even under the consultant's high scenario. At the same time, this explains the interest of Turkmenistan in selling gas-based electricity to Afghanistan: it thereby captures a significant resource rent.

Table A4.4. LRMC of Gas Production in Other Countries

Producing Area	$/mmBTU
Iran	0.3
Qatar	0.3
United Arab Emirates	0.35
Libya (LNG)	0.4
Oman	0.4
Russia NadymPurTaz	0.4
Turkmenistan (via Caspian)	0.4
Algeria	0.45
Azerbaijan	0.5
Iraq	0.5
Libya (pipe)	0.5
Russia Volga/Urals	0.5
Turkmenistan via Russia	0.5
Yemen	0.5
Egypt	0.6
Nigeria	0.6
Trinidad and Tobago	0.6
Venezuela	0.6
Russia Barents Sea	0.8
Russia Yamal	0.8
Norway Barents Sea	1.2
Norway Norwegian Sea	1.2
Norway North Sea	1.3
United Kingdom	1.7

Source: Energy Markets Limited, *Natural Gas Supply Pricing Report*, Report to ADB, April 2006 (table 3)

Gas Pricing

Table A4.5 shows estimates of the LRMC of gas production from four fields in Afghanistan.[84] These exclude any gas transmission costs (but include gas treatment) and are calculated as the revenue necessary to generate the required cash flow, assuming a 14.5 percent return on investment.

At the higher discount rates that may be necessary to attract the necessary capital, the LRMCs increase as shown in table A4.6. Even under conservative assumptions, the gas price at Sheberghan, before any onward transport to the point of utilization, should be no more than $2/mmBTU. These are based on a 2006 study, so at current prices, $3/mmBTU is assumed.

84. Energy Markets Limited, *Natural Gas Supply Pricing Report*, Report to ADB, April 2006.

The Cost of Imported Power to Afghanistan

Table A4.7 shows the import prices assumed by the APSMP. These appear to be quite low, particularly for the major additional imports envisaged from Turkmenistan: 1,000 MW of firm capacity from generation in Turkmenistan must inevitably come from dedicated export projects, which means the export price must also recover capital costs.

Table A4.5. LRMC of Gas Production

Field(s)	CAPEX ($m)	OPEX ($m)	Total ($m)	Rev ($m)	Cash Flow	LRMC ($/MCM)	LRMC ($/mmBTU)
Bashi Cord	112.0	32.9	144.9	256.8	111.9	49.4	1.51
Juma	141.8	50.2	192.0	354.4	162.4	31.1	0.95
Bashi Cord and Juma	233.0	62.4	295.4	559.1	263.3	33.6	1.03
Jangali Kalon Base case	172.8	36.7	209.5	330.4	120.9	27.9	0.85
Jangali Kalon upside case	254.8	52.2	307.0	504.4	197.4	28.7	0.88

Source: Energy Markets Limited, Natural Gas Supply Pricing Report, Report to ADB, April 2006.

Table A4.6. LRMC as a Function of Discount Rates

Field(s)	8%	10%	12.5%	15%	20%
Bashi Cord	1.24	1.35	1.51	1.67	2.02
Juma	0.78	0.85	0.95	1.06	1.29
Bashi Cord and Juma	0.83	0.91	1.02	1.14	1.39
Jangali Kalon Base Case	0.68	0.73	0.85	0.88	1.03
Jangali Kalon Upside Case	0.75	0.81	0.88	0.96	1.12

Table A4.7. Price of Imported Electricity

Import	Source	Grid_ Segment	Capacity (MW)	Tariff ($/MWh)	Price Escalation (1/a)	Decision	General Availability (a)
TKM_2_Herat_import	TKM	Herat	45	28	1	fixed	2011–19
TKM_2_NEPS_TKM_import	TKM	NEPS_TKM	40	28	1	fixed	2011–17
TKM_2_NEPS_UZB_import	TKM	NEPS_UZB	500	55	1	candidate	*
TKM_2_NEPS_UZB_add_import	TKM	NEPS_UZB	500	55	1	candidate	*
UZV_2_NEPS_UZB_import	UZB	NEPS_UZB	300	60	1	fixed	2011–32
TAJ_2_NEPS_TAJ_import	TAJ	NEPS_TAJ	300	35	1	fixed	2011–32
IRAN_2_Herat_import	Iran	Herat	83	30	1	fixed	2011–19
IRAN_2_Nimruz_Import	Iran	Nimruz	70	30	1	fixed	2011–26

*Candidate
Source: APSMP, table 10.2.6–1.

Table A4.8. Generation Cost Versus Gas Price

Case	Proxy	Date	Price ($/MCM)	Generation cost[a] (USc/kWh)
Base case	Purchase Price of Uzbek gas by TTG (Tajik Trans Gaz)	Average 2011	268	7.79
Case 1	Purchase Price of Uzbek gas by TTG	Q1 2012	300	8.39
Case 2	Purchase Price of Uzbek gas by TTG	Q1 2010	218	6.86
Case 3	Purchase Price of Uzbek gas by Gazprom	2009	340	9.14

a. Including 2.29 UScents/kWh to recover fixed costs.
Source: UAP-EST, table 4.2.

Moreover, it is hard to see why Turkmenistan would build such projects based on a gas price that is far below the border price. 5.5 US¢/kWh would cover just the variable fuel cost at $268 /MCM ($7.50/mmBTU), which is the 2011 gas price assumed in the UAP-EST project proposal for a dedicated gas project in Uzbekistan. Recovery of fixed costs (CAPEX and fixed O&M) would add at least another 2–3 US¢/kWh. Table A4.8 gives the results of a sensitivity analysis in the UAP-EST report, which shows the power price as a function of different natural gas prices.[85]

Table A4.9 presents the baseline comparison between imports and power generation using gas engines, assuming an import cost of 8 US¢/kWh and a gas price of $4.00/mmBTU (assuming another $1/mmBTU for gas transmission). This shows the gas projects have lower costs than imports.

But with slight changes in assumptions, imports are more cost effective. For example, if the gas price is $4.5/mmBTU, then the gas option levelized cost is 8.5 US¢/kWh—more expensive. The problem is that in this calculation there are some 15 different assumptions, all of which are uncertain. A conventional sensitivity analysis can show switching values for each assumption one at a time, but in reality, most variables will show some deviation from the best estimate made today. A Monte Carlo risk assessment can provide a probabilistic assessment of the NPV (or IRR, but requires that one make assumptions about the probability distribution of each variable—but who can credibly make statements that the probability of the world oil price being $x five years hence will be y percent?

85. The fixed cost recovery assumes CCGT. There are anecdotal reports that the Turkmen exports to Afghanistan will be generated at low cost using open cycle gas turbines.

Table A4.9. Comparison: Sheberghan Gas Engine Versus Imports

			NPV	2015	2016	2017	2018	2019	2020	2021	2022
[1] A. Imports											
[2] 50 MW units installed	1	[ ]									
[3] Total installed capacity	200	MW									
[4] Capacity factor	0.7	[GWh]	8,313			1,226	1,226	1,226	1,226	1,226	1,226
[5] Security outage	0	[days]				0	0	0	0	0	0
[6] Total energy delivered		[GWh]	8,313			1,226	1,226	1,226	1,226	1,226	1,226
[7] Import price		[$/kWh]				0.08	0.08	0.08	0.08	0.08	0.08
[8] Import cost		**[$USm]**	**665**			**98.1**	**98.1**	**98.1**	**98.1**	**98.1**	**98.1**
[9] Levelized cost		[USc/kWh]	8.0								
[10] B. Gas											
[11] 50 MW units installed	1	[ ]									
[12] Total installed capacity	200	MW									
[13] Capacity factor	0.7	[GWh]				1,226	1,226	1,226	1,226	1,226	1,226
[14] Security outage	0	[days				0	0	0	0	0	0
[15] Total energy delivered		[GWh]	8,313			1,226	1,226	1,226	1,226	1,226	1,226
[16] Capital cost	1,000	[$/kW]									
[17] Afghanistan premium	1.6	[ ]									
[18] Investment cost	1,600	[$USm]		160	160						
[19] Gas cost		[$/mmBTU]				4.0	4.0	4.0	4.0	4.0	4.0
[20] Heat rate	10,345	BTU/kWh									
[21] Heat requirement		10^6 mmBTU				12.7	12.7	12.7	12.7	12.7	12.7
[22] Gas volume		10^6 CM/day				1.1	1.1	1.1	1.1	1.1	1.1
[23] Fixed O&M	28.8	[$/kW/y]									
[24]		[$USm]				5.8	5.8	5.8	5.8	5.8	5.8
[25] Fuel cost		[$USm]				50.8	50.8	50.8	50.8	50.8	50.8
[26] Total cost		**[$USm]**	**661**	**160**	**160**	**56.5**	**56.5**	**56.5**	**56.5**	**56.5**	**56.5**
[27] Levelized cost		[USc/kWh]	7.9								

Modelling Energy Security

The comparison is made more difficult by the different security attributes of each option. The calculations shown in table A4.9 deal with this by specifying for each option the number of days per year that power is not delivered (other than the usual scheduled and forced outage rates that are allowed for in the plant capacity factor). For the gas option, this would apply to disruption of the gas supply and power transmission (for example, to Kabul across the Salang Pass). For the import option, it would apply to disruptions to the transmission line from the generating station in Turkmenistan.

Table A4.10. The Cost of Diesel Self-generation

[1] World Oil Price	$/bbl	55	75	150
[2] Gulf spot price, gasoil	$/bbl	66	90	180
[3]	bbl/ton	7.4	7.4	7.4
[4]	$/ton	488	666	1,332
[5] Afghanistan premium	$/ton	275	275	275
[6] Border price	$/ton	763	941	1,607
[7] Import duty @Hairatan	$/ton	100	100	100
[8] Transport Haraitan-Kabul	$/ton	130	130	130
[9] Local margins	$/ton	50	50	50
[10] Delivered in Kabul	$/ton	1,043	1,221	1,887
[11] Density	liters/ton	1,176	1,176	1,176
[12] Cost per liter	$/liter	0.887	1.038	1.605
[13] Heart value	BTU/liter	37,500	37,500	37,500
[14] Cost per mmBTU	$/mmBTU	23.7	27.7	42.8
[15] Cost per liter	Af/liter	51.3	60.0	92.7
[16] Efficiency	liters/kWh	0.24	0.24	0.24
[17] Generation cost	$/kWh	0.213	0.249	0.385

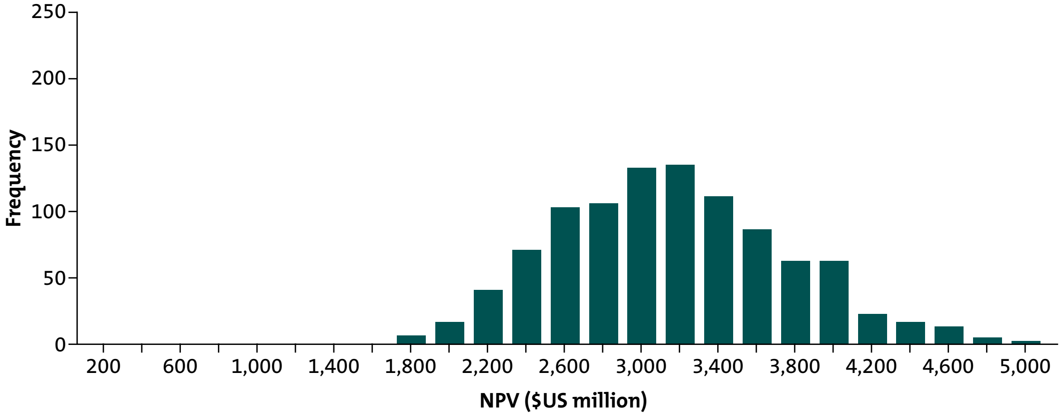
Since these security costs vary across the choices, to compare like with like, one needs to include the different amounts of unserved energy associated with each choice, and its cost, which is taken here as the cost of diesel self-generation, which will be a function of the world oil price assumed (table A4.10).

A4.4. Testing Robustness

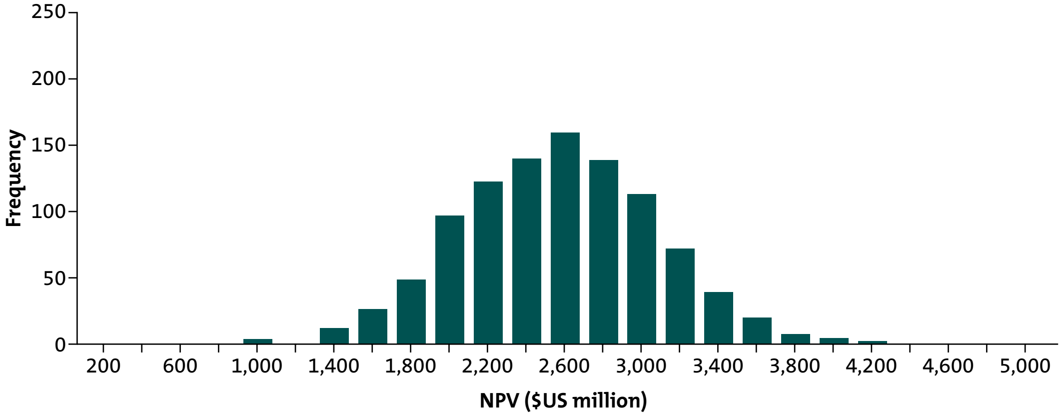
Instead of making a decision based on "predict-then-act," where the essential question is how to make the best estimate of the future and then chose the least-cost option, the better approach is to ask: "Given the difficulties of predicting the future, which option is more robust to these uncertainties?" This implies looking at the performance of each option in all plausible futures (which may well run into the tens of thousands, each reflecting different combinations of individual input assumptions), and then examining the vulnerability of a particular option to identified risks. The trick is to do this without necessarily needing to say anything about the probability of an input assumption being at a particular value. Table A4.11 shows the plausible ranges of uncertainty set for the analysis of the gas generation decision.

Figure A4.4. Probability Distribution of NPVs

A. Imports



B. Gas Engines for Power Generation



C. Comparison of NPV Probabilities of Imports and Gas Engines

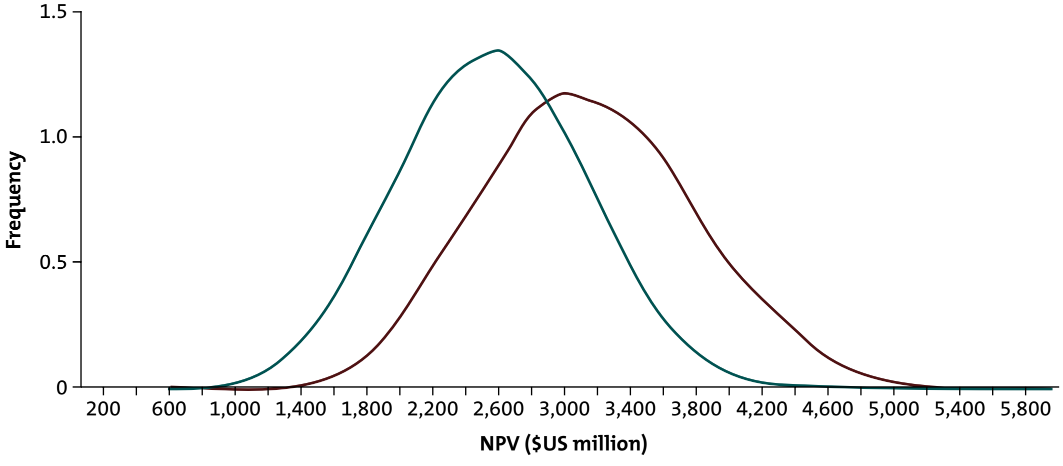


Table A4.11. Plausible Ranges of Uncertainty

Uncertainty		Minimum	Maximum
Imported electricity price	USc/kWh	2.0	12.00
Capital cost multiplier (Afghanistan premium)	[ ]	1.0	2.00
Self Gen cost (function of world oil price and diesel imports)	USc/kWh	0.2	0.35
Sheberghan Gas price (delivered)	$/mmBTU	2.0	12.00
Demand uncertainty	annual load factor	0.9	0.65
Import security proxy	days/year	5.0	80.00
Gas field security proxy	days/year	5.0	80.00
Transmission security proxy (Salang pass)	days/year	5.0	80.00

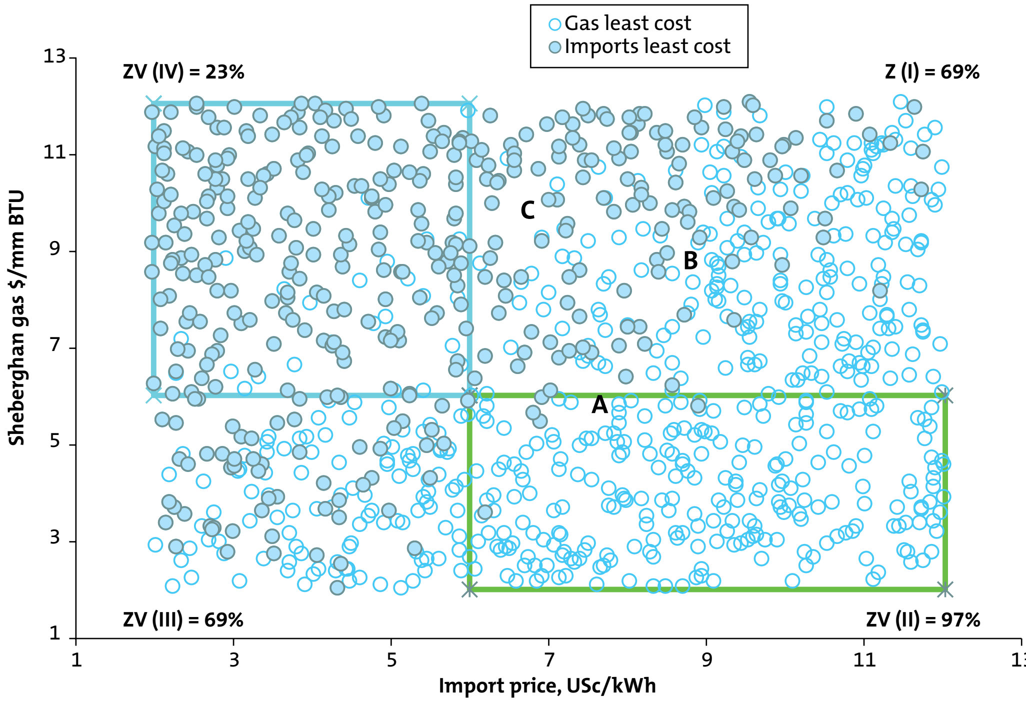
By sampling these ranges of uncertainty, one can easily generate the probability distribution of NPVs, as shown in figure A4.4. The expected value of cost for imports is $2.78 billion, compared with $2.29 billion for gas engines. For the 1,000 sample futures calculated here, gas generation is the better option in 775 cases. Nevertheless, a comparison of the two probability distributions suggests considerable overlap.

But now the following question is asked: Under what combinations of input variable assumptions (or "scenarios") would a decision taken for the gas engine option prove to be the wrong decision? Put another way, under what conditions would imports have been better? Although the two probability distributions suggest considerable overlap, when one looks at the individual calculations, a different picture emerges.

Figure A4.5 shows a plot of a 1,000 such futures. The dark (blue) dots are the combination of gas price ($/mmBTU) and import price (US¢/kWh), for which imports are the preferred option; the light (green) circles represent those for which the gas generation is the preferred option. The robustness of the decision, that is, the proportion of cases in which the right decision is made in quadrant II, is high: if the import price is greater than 6 US¢/kWh and the gas price less than $6/mmBTU, then whatever the combination of all other uncertainties (security outages for gas supply and transmission corridors, capital cost escalations, world oil prices, capacity utilization, demand uncertainty, and heat rate), there is a 97 percent chance of Sheberghan power generation being the correct decision. The *Z(j)* shown in this figure is the percentage of cases in each quadrant *(j)* in which Sheberghan gas is the preferred option. The points marked A, B, and C reflects the judgment of individuals as to what are the "most likely" set of future conditions.

The model is easily updated to reflect the views and questions of stakeholders. For example, a stakeholder might argue that the Sheberghan gas price would unlikely be higher than $7.5/mmBTU. As shown in the redrawn figure A4.6, gas will still be the least-cost option in 74 percent of the futures.

Figure A4.5. Scenario Discovery



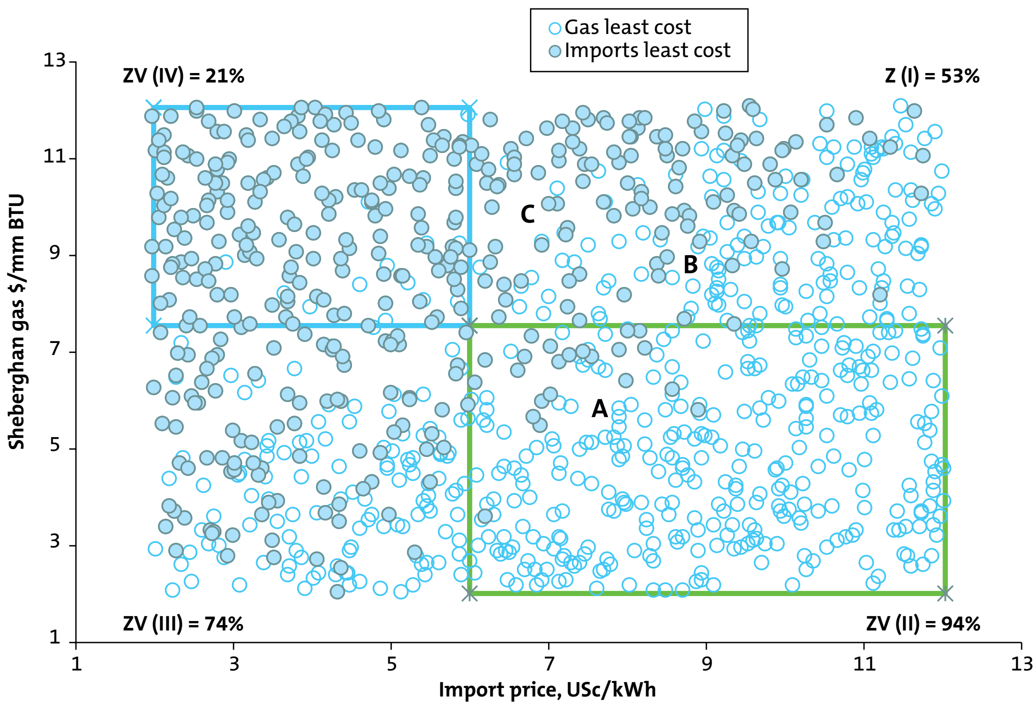
Note: the Z( ) probabilities indicate the likelihood that Sherberghan gas is least cost in that quadrant. The likelihood of imported electricity being least cost in each quadrant is 1-Z( )

The scenario discovery method illustrated in these figures was generated with a simple heuristic implemented in a spreadsheet, and the sampling across the ranges specified in table A4.7 is based on Monte Carlo sampling. In other applications of this technique,[86] more sophisticated methods have been used, including the Patient Rule Induction Method (PRIM) for scenario discovery[87] and Latin Hypercube sampling of the variable space. For this application, it was preferable to include the entire set of calculations and all graphics in a single spreadsheet for demonstration and discussion at the May 2015 Workshop. This enabled easy discussion with stakeholders.

86. See e.g., Stéphane Hallegatte, Ankur Shah,Robert Lempert, Casey Brown and Stuart Gill, 2012. *Investment Decision Making Under Deep Uncertainty: Application to Climate Change*, World Bank Policy Research Working Paper 6193, and Laura Bonzanigo and Nidhi Kalra, *Making Informed Investment Decisions in an Uncertain World: a Short Demonstration*, Policy Research Working Paper 6765.

87. Friedman, J.H., Fisher, N.I., 1999. *Bump Hunting in High-dimensional Data*. Stat. Comput. 9, 123–143. doi:10.1023/A:1008894516817.

Figure A4.6. Adjustment for Stakeholder Assessments



Note: The Z( ) probabilities indicate the likelihood that Sherberghan gas is least cost in that quadrant. The likelihood of imported electricity being least cost in each quadrant is 1-Z( ).

A4.5. Conclusions

At the time this analysis was developed in early 2015, there was still considerable uncertainty about the price of imports from Turkmenistan since the PPA was still under negotiation—and the negotiations for renewal of the Uzbekistan PPA were expected at 8–8.5 US¢/kWh. Moreover, there is continuing uncertainty about the production cost of Sheberghan gas—the only way of resolving that uncertainty is to proceed with the necessary further gas field development. The gas master plan for Afghanistan has yet to be completed, which should provide guidance on what the gas production costs will likely be and whether that gas should be used to displace diesel use in Kabul or for power generation.

The results suggest that if indeed import prices were above 6 USc/kWh, a decision to proceed with Sheberghan gas would be low risk—if the delivered gas price is below $6/mmBTU, then there is a very low probability of a negative rate of return. LRMC estimates of the gas cost (in table A4.5) suggest costs of around $3/mmBTU, so these could be 100 percent greater to reach the $6/mmBTU threshold.

In early November 2015, the PPA between DABS and the Turkmenenergo State Power Corporation of Turkmenistan was signed. This covers imports of electricity from Turkmenistan from January 1, 2018, to December 31, 2027. The price is 5 US¢/kWh in 2015, rising by three percent per year (7.13 US¢/kWh in 2027), with agreed volumes of 899 GWh in 2018, increasing to 1,516 GWh in 2027. By comparison, the estimated energy from the Bagdhara hydro project is 968 GWh; and total energy imports in 2014 were 3,814 GWh, of which 1,426 GWh were from Uzbekistan and 1,103 GWh from Tajikistan. A 50 MW gas engine project at Sheberghan would produce 300 GWh at a 0.7 load factor, representing only a small fraction of imports.

This is a low price that is clearly to Afghanistan's advantage and at first glance makes the development of the gas engine project at Sheberghan less pressing. However, the probability that a Sheberghan gas project would deliver negative economic returns is small. The International Finance Corporation (IFC) of the World Bank Group is considering supporting a 50 MW gas engine project in Mazar-e Sharif. This analysis concludes that the proposed project should be still be supported since it is of reasonable scale, and that gas engines are the most robust technology given the likely operating environment. Moreover, if this relatively modest-sized project cannot be done as an IPP, then other IPP development projects (including hydro) would be even less likely to attract private sector interest. Efforts to confirm the size and cost of the gas resource also remains a policy priority even with the next tranche of imports becoming available at a low cost.

This case study illustrates the power of new approaches to assess planning decisions under high uncertainty. The focus is no longer on trying to predict the future, but on looking at possible options and then assessing the vulnerability to the most important sources of variation.

Annex 5. Case Study: Transmission Planning

A5.1. Background

The status of power system development in Afghanistan is outlined in the earlier World Bank study[88] that describes the development of the electricity sector up until 2013 and reviews options for accommodating power transit operations. That report covered power planning up to the time when NATO, backed by a substantial donor aid program, began to wind down its operations in anticipation of the change of government in 2014. In summary, the report noted that the last decade of power sector development had been characterized by significant investments by IFIs in the rehabilitation of the urban electricity networks in the larger cities and towns, along with new investments in transmission and isolated rural electrification/renewable energy projects. Subsequently, during the last 18 months, there has been a major commitment of about $2.2 billion, particularly by ADB, USAID, and the World Bank, to support transmission projects that are currently being developed, generally in line with the recommendations of the APSMP.[89]

In the context of this particular study, there were important technical decisions taken in the transmission planning process that perhaps may have been evaluated differently if the broader perspective of a real-options analysis had been employed. Given the status of these ongoing projects, particularly in terms of the constraints of their financing and the restrictions of the respective IFI procurement processes, any suggestion of revisiting those decisions would be counterproductive, especially in light of the uncertainties that still prevail in the Afghan power sector. This annex therefore identifies areas of continuing uncertainty in aspects of the key planning assumptions that need to be addressed in order to reduce the risk of choosing less desirable outcomes in the future.

It is important for Afghan planners to recognize that there will be limitations in their ability to secure large grants to support their ambitious concept for the establishment of a 500 kV regional power market. Accordingly, it would be premature to invest $3–4 billion in 500 kV transmission if in the next decade the grid was mainly used to serve a relatively small domestic power market. It is accepted that in $/kW terms,

88. John Irving, Peter Meier, and Vijay Prasher: *Technical and Economic Options for Power Transit Operations Through Afghanistan*: 10 Feb 2014.

89. The APSMP finalised in May 2103 by Fichtner was revised with some important changes and published in an addendum to the report that was finalised in August 2104. Currently the APSMP is being revised by DABS to incorporate the scope of new plans driven by the promise of substantially increased imports from Turkmenistan.

transmission is generally the smallest component of a power sector lending portfolio.[90] However, there are large demands on IFI grants worldwide, and available funds would probably be better spent on urban distribution and RE expansion along with the development of domestic generation. In terms of the complementary transmission development over the next decade, it is important to separate the needs of supporting the domestic program from the investment requirements peculiar to power transit operations in Afghanistan. A summary of the issues to be resolved before further transmission investment decisions are taken, preferably using a real options analysis, is given in chapter 4 of the main text.

A5.2. Current Plans

The ongoing process of updating the APSMP[91] will necessarily take into account the impact of the new transmission projects that are expected to be commissioned by about 2020. This planning process will also help refine the strategy for further network expansion that optimizes the use of existing transmission assets over the longer term. Currently the major ongoing grid investments include: (1) the 500 kV line from Pul-e-Khumri to South Kabul, (2) the CASA-1000 HVDC project, and (3) the SEPS/NEPS 220 kV interconnection.

A revised APSMP will also need to consider how to incorporate a growing number of isolated power networks generally supplied by diesel generation or imports, along with MEW's rural electrification (RE) microgrid systems, most of which are expected to eventually be interconnected with the main grid. The latter RE development program is expected to promote the greater use of renewable energy to expand the number and efficacy of isolated micro grids—expected to be supplied mainly by micro hydros and PV solar power systems.

The $220 million Pul-e-Khumri to Kabul 500 kV project comprises the construction of a single circuit 500 kV overhead line (on towers equipped for a second circuit), including a Kabul SW substation with 400 MVA 500/220 kV transformers, at Arghandi. The project is complemented by a separate project to construct 500 kV substation at Dashte Alwan at the northern end of the transmission line. Both projects have been conceived as part of the APSMP strategy to provide a direct 500 kV link from Turkmenistan to Kabul and eventually onward to Pakistan. The implementation of the Pul-e-Khumri to Kabul link earlier than might have been expected has been justified as a means of relieving the

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90. Typically, average generation costs about $2,000/kW; transmission, $300/kW and distribution, about $800/kW. On the other hand, component costs of transmission are highly susceptible to price variations. Typically, components comprise 30 percent conductors and fittings, 30 percent foundations and towers, 30 percent construction and stringing, and 10 percent right-of-way issues—all variable and location-specific, depending on world market prices, access, and environment.
91. The dedicated Energy Masterplanning Secretariat (EMPES) will be established and accountable for making changes to the APSMP to make it a living document that reflects changes in the agreed priorities and implementation of the energy sector projects between the government and its international development partners.

loading on the existing 220 kV circuits from Pul-e-Khumri to north Kabul.[92] These lines are currently constrained in their ability to transfer 300 MW from Uzbekistan by a lack of reactive capacity support.

Because of financing limitations and concerns about security issues on a more desirable alternative western route via Bamyan, the new 500 kV transmission line to south Kabul will share the same right-of-way as the existing Pul-e-Khumri to north Kabul 220 kV double circuit line. This line provides the only source of imported power supply to the Kabul load center and follows a route that passes through the notoriously avalanche-prone Salang Pass. While there are strong arguments for the alternative Bamyan route for the new 500 kV line to provide increased diversity in supplying Kabul and facilitate the possible development of a coal-fired power station at Ishpushta, the uncertainty of the latter development and the additional $45 million cost involved were considered compelling reasons to proceed with the current design.

The major avalanche on February 23, 2015, which knocked out three towers of the 220 kV line in the Salang Pass, resulted in severe power curtailment in Kabul for about two months. This served to remind planners of the value of diversity in transmission systems; this disruption was the first such catastrophic event in the seven years of operation of the 220 kV line. During the power disruption,[93] supplies in Kabul were partly provided by the existing 105 MW Tarakhil diesel power station, along with about 100 MW from local hydro (Naghlu, Mahipar, and Sarobi). In addition, many Kabul consumers were reportedly able to meet their electricity requirements either from a number of self-operated petrol (under 3 kW) or from larger diesel backup generators. This mix of consumer-owned backup power (estimated to be about 30 MW in aggregate) indicates that the economic value of unsupplied energy can be computed from the cost of power generated by diesel.

CASA-1000

The objective of the ongoing CASA-1000 project is to create the conditions for sustainable electricity trade between the Central Asian countries of Tajikistan and the Kyrgyz Republic and the South Asian countries of Afghanistan and Pakistan. It also serves to demonstrate the best way of promoting a power transit operation at minimal cost to Afghanistan. In particular, it reduces the risks to the export and import parties by providing a lower-cost, more secure link that can function independently of the Afghan system. The deployment of HVDC termination facilities within the import and export countries, along with the proposed installation of an intermediate terminal at Kabul, minimize the

92. Two other transmission projects are expected to complete the remaining 250 km interconnection between Pul-e-Khumri to Sheberghan and Andkhoy West by 2019. This line will thereby facilitate the initial 300 MW supply from a new CCGT being built in Turkmenistan.

93. One temporary 220 kV circuit was restored by DABS after about two weeks, but it took two months to restore the 220 kV line to full capacity. See: https://www.afghanistan-analysts.org/a-perfect-snow-storm-what-can-be-done-against-avalanche-damage-in-afghanistan/.

cost to Afghanistan and avoids the complications of synchronization between grids. The alternative of constructing a high capacity 500 kV domestic network designed to cater for a future regional power market could well be considered in terms of a *real options study* of the risks of stranded investment in a regional power facility.

The CASA-1000 project comprises four subcomponents:

1. The construction of about 750 km of 500 kV HVDC overhead transmission line to interconnect the electricity network of Tajikistan from the Sangtuda converter station to the Pakistan network at the Peshawar converter station and the Afghanistan network at the Kabul converter station. About 120 km of the line will be in Tajikistan, 560 km in Afghanistan, and 70 km in Pakistan
2. HVDC/HVAC converter stations: at (a) Sangtuda (1,300 MW) in Tajikistan; (b) Kabul (300 MW) in Afghanistan; and (c) Peshawar (1,300 MW) in Pakistan
3. Construction of about 475 km of 500 kV HVAC overhead transmission line to interconnect the electricity network of the Kyrgyz Republic at Datka substation to the Tajikistan network at the Khudjand substation. About 450 km of the line will be in the Kyrgyz Republic and 25 km in Tajikistan
4. The construction of about 115 km of 500 kV line from Regar substation to Sangtuda substation and other parts of the network necessary, along with associated substation equipment to ensure transfer of Tajik and Kyrgyz export power. This project, conceived in 2007 and revitalised in 2011, has involved significant negotiations between the parties in developing bankable legal agreements to ensure the project's financial viability for at least the first 10 years of operation.

The experience with the CASA-1000 highlights the difficulties and uncertainties faced by MEW/DABS planners in trying to facilitate regional market by: (1) seeking cooperation by transnational parties concerned by the risks of transit operations through Afghanistan; (2) building complex equipment in locations where security considerations are considered problematic for international contractors; and (3) ensuring there are ways to mitigate the concerns by people living within or near the line right-of-way.

NEPS-SEPS Interconnection

Connecting Afghanistan's North East Power System (NEPS) from Kabul to the South Eastern Power System (SEPS) in Helmand and Kandahar is a priority for government.[94] The project will construct: (1) the 490 km transmission line connecting NEPS to SEPS from Arghandi to Kandahar; (2) a substation at the Salang Tunnel to provide power and displace high-cost diesel generated power serving the tunnel and local loads; (3) the rehabilitation of medium-voltage transmission lines, substations, distribution

94. In the revised version of the APSMP, DABS is also planning to extend the 220 kV NEPS/SEPS line by building a 500 kV line from Khandahar to Herat (approximately 600 km), thereby completing the loop and facilitating interconnection of the Afghan grid with Iran.

systems, and power facilities in Kabul to increase reliability and reduce power outage; and (4) facilitate the construction of a 10 MW solar power plant in Kandahar. The project began in 2012 and is scheduled to be completed by December 2018.

The NEPS/SEPS component will provide an opportunity for DABS to synchronously interconnect six existing isolated systems en-route to the SEPS system that is currently supplied by diesel and the Kajaki hydro power plant. The project will therefore provide DABS with an opportunity to develop a secure transmission network that retains the ability of the existing mini-grids to disconnect and continue to operate in the case of major disruption from imports. However, the implementation of the project will require the relevant sections of the grid code to be developed in advance of interconnections to address the issues relating to the inability of DABS to parallel a local generation plant with imported generation emanating from the CAR states.

Connecting Isolated Grids

To improve the efficiency of the mini-grids, there appears to be considerable scope for retrofitting an existing abdiesel plant with PV solar power, which has steadily become competitive with other technologies. Biomass for power, hydropower, geothermal, and onshore wind can all now provide electricity competitively compared with fossil fuel-fired power generation. Most impressively, the levelized cost of electricity (LCOE) of solar PV has halved between 2010 and 2014. Installed costs for onshore wind power, solar PV, and CSP have continued to fall, while their performance has improved. Nevertheless, the problem remains that renewable energy resources are often located far from load centers and have special transmission needs. Intermittent renewables such as wind are not dispatchable, so comparisons of LCOE as shown in figure A5.1 need to be viewed with some caution: comparisons should be on the basis of net benefits rather than cost. The possibilities of renewable and decentralized generation add an additional dimension of uncertainty to the transmission planning process.

In addition to transmission investments, MEW has also been developing approximately 5,000 small isolated microgrids, particularly in areas that unlikely to be connected to the grid in the near term.[95] With an aggregated capacity of 55 MW, the average size of each microgrid is about 11 kW, many of which are very small PV facilities, with a few others ranging as high as 1 MW.[96] The bulk of the microgrid capacity is sourced from microhydros supplies (2,677), averaging 22kW each. While too small to make much of a contribution to the power system, their interconnection with the grid will provide a means of increasing security and reliability to the rural areas.

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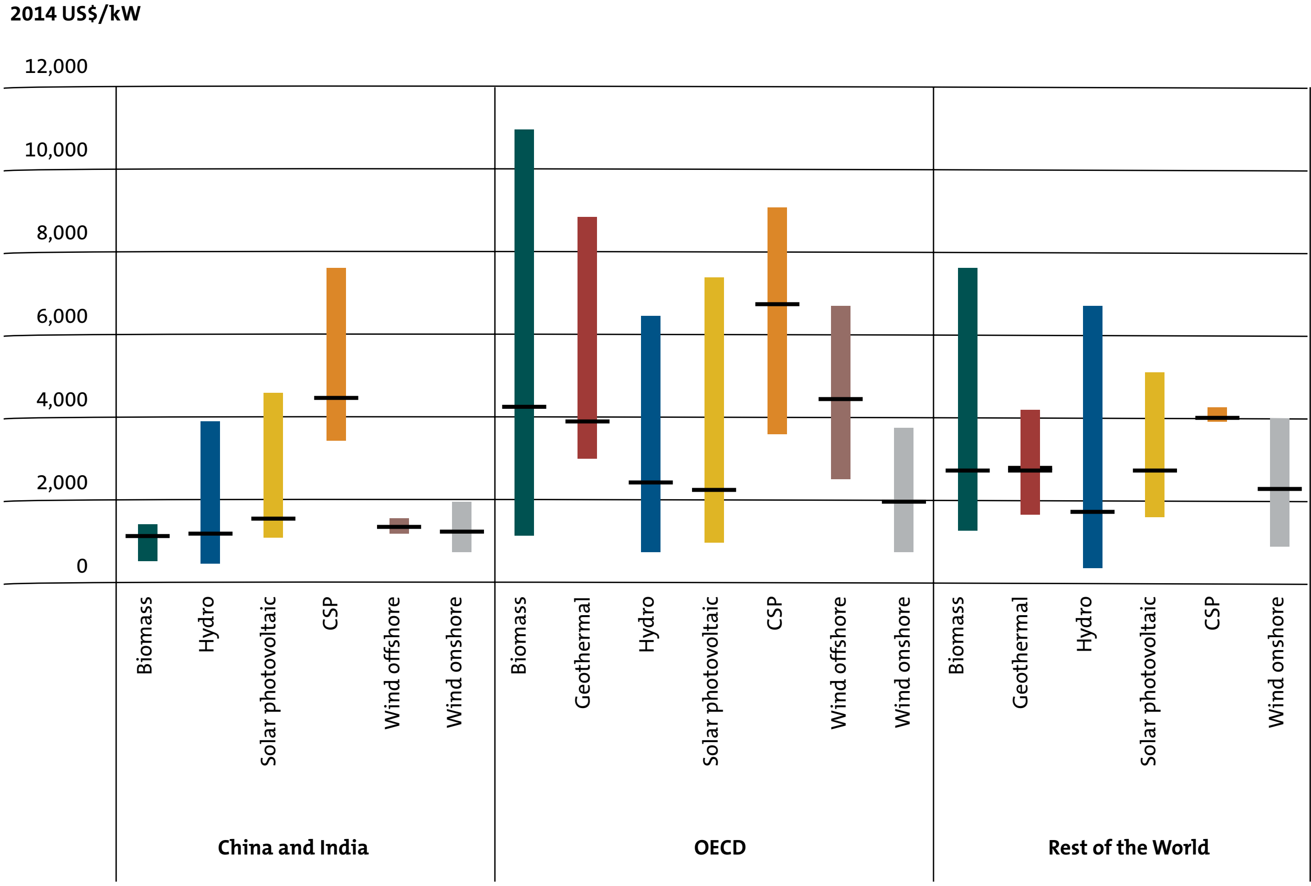
95. The MEW renewable energy microgrid development program are provided in http://www.red-mew.gov.af/. A GIS database showing the locations and characteristics of the microgrids is available at http://red-mew.gov.af/red/index.php/login.

96. Two notable PV projects include the 1 MW Bamyan PV-diesel hybrid station funded by NZAID and the 300 kW PV installation at Kabul airport funded by JICA.

Figure A5.1. Typical Ranges and Weighted Averages of Total Installed Costs of Utility Scale Generation Technologies by Region (2013/2014)



Source: IRENA, 2014 Renewable Power Generation Costs, January 2015

The strategy for future development of the larger mini-grids could also take into account technological advances that are now driving structural changes in the power sector worldwide.[97] Despite some lingering skepticism of industry advisors, there is no doubt the technological advances are real and can be expected to have a profound impact on power sector development in future. For Afghanistan's existing isolated grids, there will be opportunities to retrofit existing diesels with low cost PV solar or wind facilities. The emergence of the off-the-shelf "plug-in" battery technology is likely to minimize the need for standby diesel generation in urban systems and reduce the high cost of meeting peak demand.

97. See *Report Microgrids for Rural Electrification: A Critical Review of Best Practices*, United Nations Foundation Feb 2014 University of California, Berkeley and Carnegie Mellon University.

Another technology that could be used in Afghanistan to extend electricity supplies to remote villages could be the introduction of shield wire electrification and single wire earth return (SWER) lines fed from nearby there phase medium voltage lines.[98] These are mature technologies widely used in circumstances similar to those that exist in Afghanistan to supply small loads in the vicinity of transmission lines. This as an effective way of mitigating local opposition to a transmission line that would otherwise be perceived as having no benefit to locals. Technical details of how such a connection can be arranged are given in appendix 1 of this annex.

A5.3. Unresolved Transmission Issues

There are three key issues that need to be addressed and resolved in the context of future decision making for transmission system development.

Synchronization Strategy

Afghanistan's synchronization strategy is probably the most important technical issue that needs resolution in the next five years—certainly before the three major transmission projects are commissioned. It is generally accepted that HVAC power systems must be synchronized for safe and optimal management of generation and power flows under various operational conditions.[99] In Afghanistan, currently an 800 MW system, the situation is complicated by DABS continuing to take the bulk of its power supplies from CAR countries. These countries were once integrated in the 350 GW Soviet grid system, but they no longer operate synchronously, although they claim to observe some of technical aspects of the Russian IPS/UPS Grid Code.[100] The other two dominant neighboring power blocks are Iran—currently synchronized with Turkmenistan (65 GW) and Pakistan (24 GW), each of which have their own grid codes.

In the APSMP addendum, the earlier proposal for Afghanistan to invest around $600 million to interconnect the CAR countries through an HVDC b/b facility in Pul-e-Khumri is much modified. This approach had been intended to enable Afghanistan to isolate its power system from its neighbors. Instead, the revised report proposes a complex interim arrangement to separate Uzbek and Turkmen supplies using the double busbar facilities in Pul-e-Khmri and Kabul. However, this appears to be a dangerous

98. A good summary of SWER systems is given in http://en.wikipedia.org/wiki/Single-wire_earth_return.
99. The ability to synchronize all types of electricity generation plant within an integrated AC power system is key to ensuring the most economic operation of a country's generation plant. For a small AC system, it is relatively easy to lock generators together by carefully controlling their respective speeds until they are identical and then quickly connecting them together. For a larger power system, interconnection must be made according to an established grid code for the network to ensure failure of any unit or line does not adversely impact other units in the system. Once interconnected, the respective generators can be readily coordinated by observing common market rules to serve an aggregated regional demand, according to their economic or technical advantages.
100. The former USSR-governed IPS/UPS philosophy of centralized power system operation differs markedly from the European ENTSO-E decentralized system.

mode of operation requiring operators to take great care in effecting normal switching operations. The report also recommends that synchronizing between Uzbekistan and local generation can be effected using simplified power-frequency control and Emergency Control Systems (ECS) as an effective inexpensive option for faster implementation. While the report indicates this mode of operation may be acceptable to Uzbek authorities, it has not suggested how and when the operating procedures proposed for Afghanistan should be incorporated in a national grid code acceptable to the other CAR countries—Iran and Pakistan. Developing a grid code for Afghanistan is discussed in appendix 2 to this annex.

The immediate problem for Afghanistan is how to continue to import about 300 MW power from Uzbekistan while at the same time being able to expand its networks to supply the greater NEPS Kabul/Jalalabad area using both its domestic generation and import sources operating synchronously. By 2020, when the new 500/220 kV lines are in place, there should be an additional 300 MW available from Turkmenistan—with promises to increase Turkmen exports to Afghan by 1000 MW before 2030.

Also by 2020, transmission facilities are expected to be available to connect NEPS to the southern Kandahar (SEPS) region and on to the western part of the country now supplied from Iran. It therefore appears practical for Afghanistan to plan to interconnect most of the NEPS/SEPS system synchronously with Turkmenistan before 2020—especially assuming that country continues operate synchronously with Iran. There should be no insurmountable technical difficulties in synchronizing NEPS/SEPS with either of these two larger suppliers (Turkmenistan and Iran)[101] or using a HVDC b/b or preferably VFT[102] connection to enable Uzbekistan to continue to export 300 MW to Afghanistan as shown in figure A5.2.

Facilitating Domestic Generation

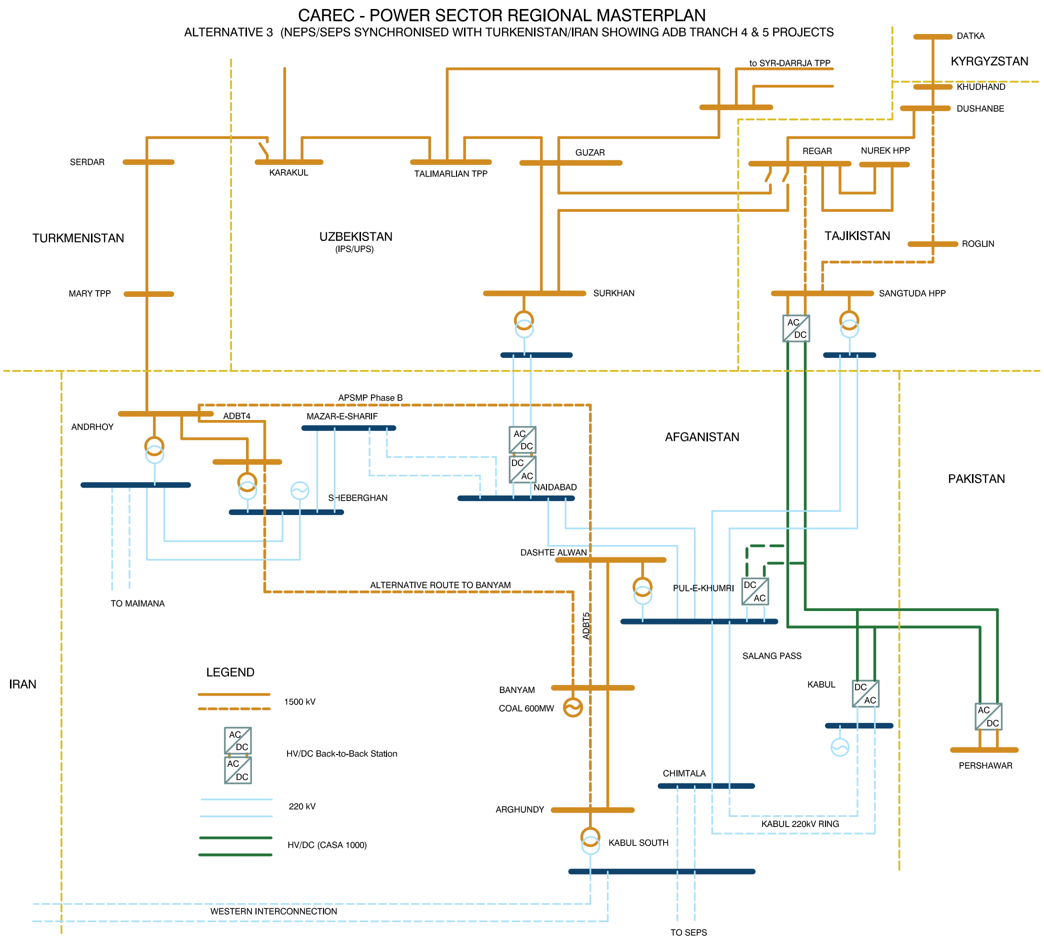
The various domestic generation facilities would give more flexibility to DABS in its operations if they were synchronized with the power supplies from the exporters.[103] The APSMP addendum (section 5.5 page 93–94) includes a discussion of the way in which an ECS approach might work to enable local generators to share load. However, although the report has suggested this could be in place in 17 months, it has not explored whether such an interconnection is acceptable to the IPS/UPS regulators (or for that matter if an interconnection through an HVDC b/b or VFT HVDC facilities could be accepted). Clearly, the development of the necessary operational elements of the grid code satisfac-

101. See USAID RESET report April 1 2012: *Possibility of Turkmenistan's Participation in CASA-1000 as Power Supplier*.

102. VFT—Variable Frequency Transformer see http://en.wikipedia.org/wiki/Variable-frequency_transformer This is a new technology providing a similar capability to HVDC but using conventional motor technology to rotate the electrical fields so as to match frequencies of interconnectable systems. It appears to have significant advantages for interconnection of smaller network using a the more familiar motor technology that should be easier for DABS to maintain.

103. It is understood that DABS operators have already successfully tested for a short period the capacity to connect Naghlu with the Uzbek supply on an unofficial basis.

Figure A5.2. Proposed Interconnect Strategy with Potential CAR/Iran Exporters



tory to Afghanistan's neighbors is necessary condition for developing a synchronization strategy for the longer term.

In recent years, grid codes have been established by several countries, mainly to document the basis for interconnection of new generation to existing power systems. Grid codes are often designed to accommodate new technologies. In many cases, they are necessary to satisfy the requirements for interconnecting intermittent forms of generation, such as wind and solar power, where special procedures are needed for invoking system support in case of sudden changes of output. A grid code with the necessary standards is specifically needed to enable Afghanistan to negotiate its operating arrangements with its neighbors and to determine the relatively small investment necessary to ensure domestic plant, protection, and control equipment function effectively according the agreed rules.

For Afghanistan, a grid code should therefore focus on the following major issues: (1) formalizing electrical standards for all transmission and distribution operations (in particular, taking into account the variety of mountainous environmental conditions transmission lines are expected to traverse); (2) establishing operational security and reliability criteria satisfactory to neighboring states to enable interconnection of domestic generation and imports; and (3) defining basic generation and transmission planning criteria and data sharing for evaluating of least-cost generation expansion planning.

Security and Diversity of Transmission Routing

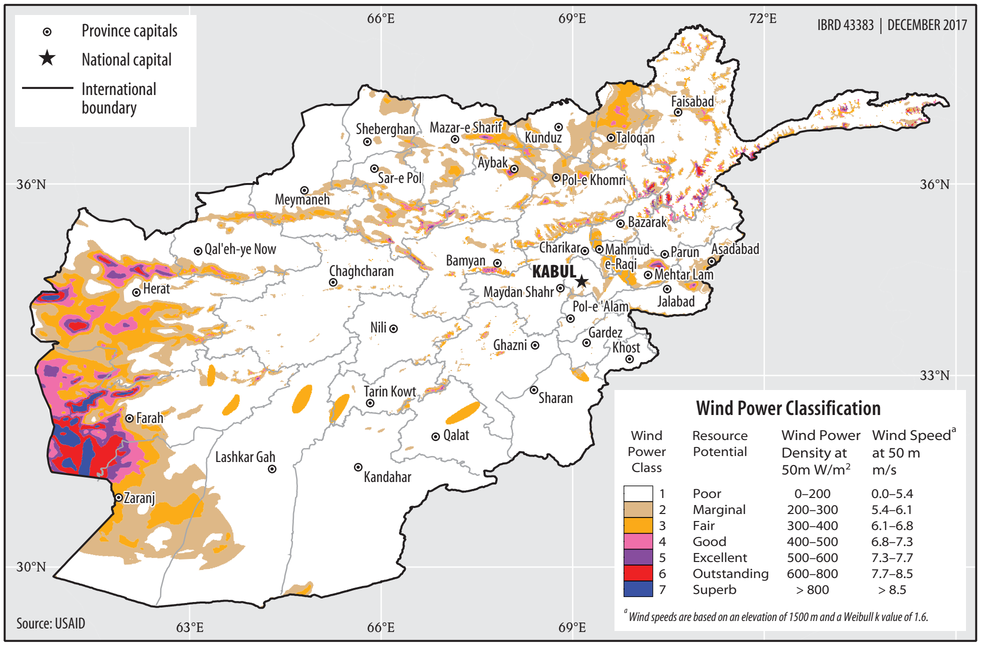
The security and reliability of a transmission network is considerably enhanced if diverse transmission line alignments are used, each preferably taking the shortest route between the generation sources and the main load centers. It is also important to limit the numbers of transmission lines terminating in one substation so as to minimize the impact of a local substation equipment failure. With Afghanistan's transmission system still at an early stage of its development, the present plans provide for very little redundancy to deal with a sudden loss of supply. In this respect, proposals to co-locate five separate lines at Pul-e-Khumri risk creating a critical node in the transmission network and rendering the whole power system vulnerable. A disruption in case of terrorist activity, equipment breakdown, or inclement weather could well result in prolonged system blackouts.

Ideally, in any transmission network for every generator, circuit, substation node, transformer, busbar, and switching facility there should be an alternative means of maintaining peak loads in the event of a disruption—the so-called "n-1" criterion.[104] While this involves some degree of duplication of transmission paths, with proper planning using modern least-cost reliability planning techniques, there are many ways of designing the network to minimize costs. Finding alternative routes for transmission lines near roads in Afghanistan is of course difficult and expensive because of the terrain and limited access through high mountain passes. Nevertheless, in making transmission planning decisions, it is important to move to an n-1 configuration as early as possible since it facilitates continued operations if repairs and routine maintenance are delayed.

At this early stage in the development of the Afghan transmission system, there is room to apply different levels of reliability for different subsystems to minimize costs. For example, there would be an argument for an *n-2* reliability standard to be applied to a major city like Kabul and an *n* standard for a small rural town where the cost of duplication is prohibitive. This does not mean that two other locations, both receiving an *n-1* standard, will have the same probability of service in terms of annual "unsupplied" energy statistics. This because the failure and repair rates of the transmission

104. The n-1 criteria is a generally accepted concept used for transmission planning. Hence the expression *n-1* refers to the failure of a single element like a transformer or generator, or *n-2* refers to, for example, a double-circuit transmission line or two generators at a power plant This distinction is not always correct because sometimes separate elements are either physically or electrically linked so that when element A fails, trips, or is disconnected, element B goes with it.

Figure A5.3. Afghanistan Wind Resources

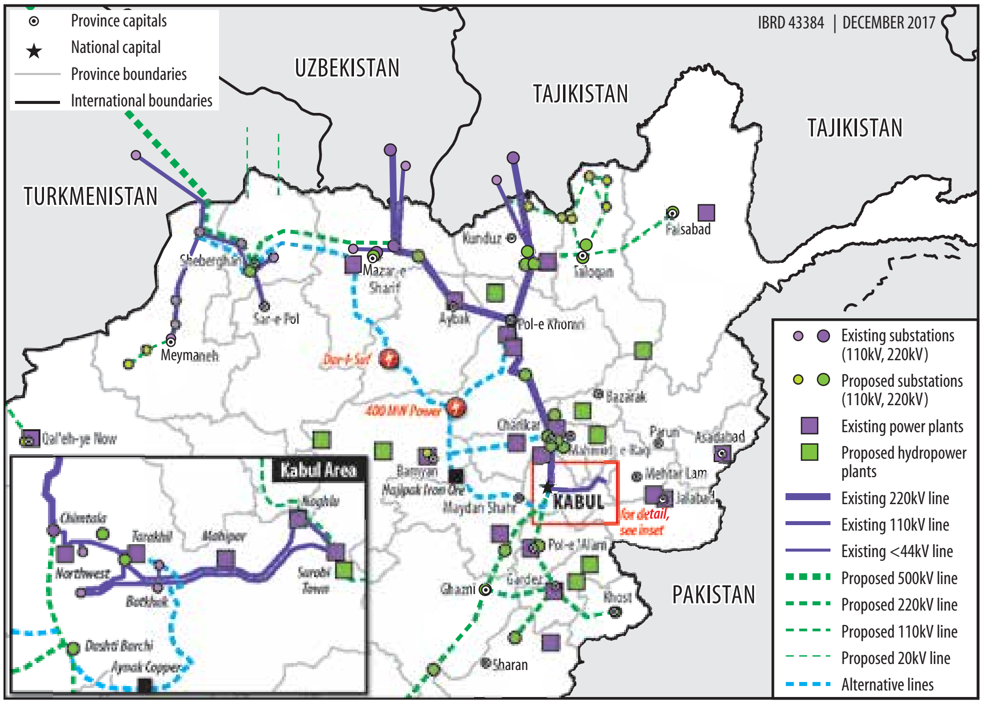


components such as lines and transformers are markedly different. For example, transmission line failures are usually weather dependent but quicker to reinstate, whereas transformer failures are usually load dependent and can take a year to replace; HVDC lines comprising two conductors are generally more reliable that the equivalent HVAC lines comprising six conductors. Since the value of "unsupplied" energy can be easily ascertained, this is an obvious area of decision making under a RO analysis process.

Planning for diversity can also be arranged to facilitate decisions to invest in a new generating plant by providing a means of power evacuation and thereby reducing one of the main avenues of uncertainty. This may well be an important factor in decisions regarding the development of the coal resources in the central parts of Afghanistan, as explained below. Likewise, the plan to extend the NEPS/SEPS line through to Herat would also facilitate decision making by IPP investors in developing the significant wind resources reputed to be located near Herat and Farah, as shown in figure A5.3.

Nowhere better is the case for transmission diversity better made than in considering the next round of imports from Turkmenistan due to start in 2018. If this is not done with HVDC—which seems unlikely, even though it in itself a means of technical diversification of transmission—several options are possible. The he new 500 kV lines from Sheberghan could be extended directly to South Kabul over the new Hindu Kush route. This proposal is shown in figure A5.4, indicating how a 500 kV ring design following the UAP_EST route could complement the 500 kV proposals in the APSMP. It has the advantage for the project developers in both diversifying the routing of power supplies

Figure A5.4. Alternative Transmission Routes to Provide Diversity in NEPS



from Pul-e-Khumri to Kabul and having 500 kV transmission capacity in place to enable the connection of two major coal-fired power stations that are proposed by investors interested in developing Afghanistan's coal and copper mines.[105]

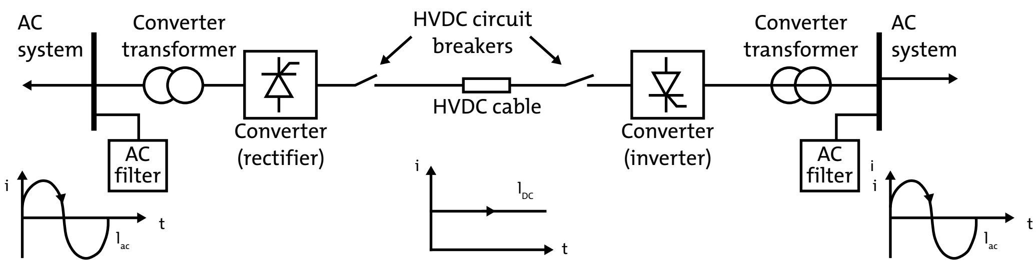
Nevertheless, the cost of the additional transmission routing will not be negligible, and the tradeoff between a shorter and lower cost route in the short run compared with a longer route that provides additional options in the future should be examined. This problem would lend itself well to a RO analysis.

A5.4. Facilitating Power Transit Operations

For point-to-point transmission of bulk power over 500 km or more, HVDC transmission links can normally be built at a lower overall cost than conventional HVAC lines. Although HVDC lines can be constructed at about 50 percent of the cost of an equivalent HVAC line, the cost of the necessary HVDC/HVAC converter stations are about \$120/kW, compared with \$20/kW for a conventional HVAC/HVAC substation. A typical HVDC interconnection arrangement is shown in figure A5.5.

105. See World Bank Report: *Afghanistan Resource Corridor Development: Power Sector Analysis*, July 2012. If indeed the two proposed Ishputa and Haji Gak 600–1,200 MW coal generation projects ever go ahead the alternative Hindu Kush 500 kV line via Banyam will certainly be required—with some of the cost expected to be partly met by the mining developers.

Figure A5.5. Typical HVDC Interconnection Arrangements



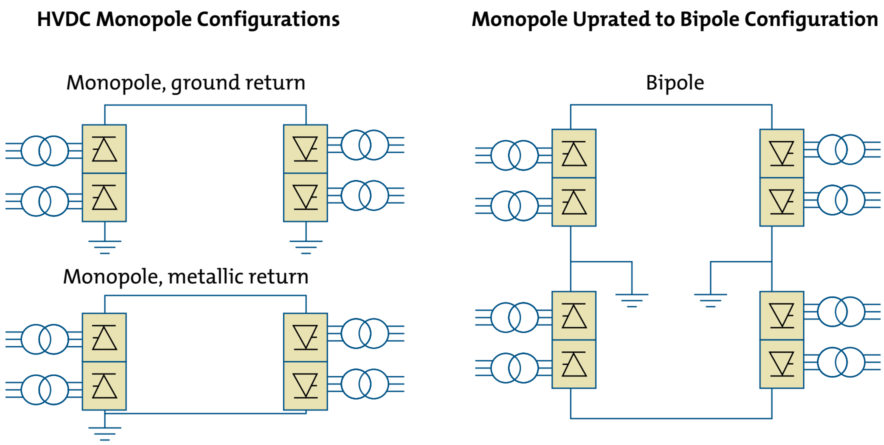
Various HVDC projects have been proposed to bring electricity generated in the Central Asian States to Pakistan. The CASA-1000 project would deliver up to 300 MW of surplus hydro power from Tajikistan and Kyrgyzstan; also by HVDC to Kabul; and a further 1,000 MW to Peshawar. Likewise, the Uzbekistan-Afghanistan-Pakistan Electricity Supply and Trade Project (UAP_EST) would deliver 100 MW (915 GWh) to DABS at a substation north of Kabul and 900 MW to Pakistan in the Peshawar area. Both projects offer technical advantages to Afghanistan, particularly in terms of how they may be used to deal with the synchronization problems and how they can supply a diversified source of bulk power over long distances to the major load center in Kabul. As the CASA-1000 experience has shown, import/transit schemes need considerably more analysis than presented thus far, particularly to ensure equity among the participants.

An HVDC interconnection for interconnecting asynchronous systems is sometimes implemented as an HVDC back-to-back facility, thereby enabling both power systems to maintain their own system frequencies independent of the other. HVDC effectively enables two power systems to be interconnected without having to resynchronize at every forced or planned disconnection. In considering an HVDC back-to-back facility, it is prudent to consider building an HVDC interconnection instead to achieve the same objective at a much lower cost. HVDC is also used in many countries in parallel with HVAC systems to improve system stability at both ends of the HVDC line as well as moving power more economically over long distances. In effect, HVDC can be designed to act as a very fast FACTS operating device designed to inject power into the HVAC system and counteract inherent instability problems.

Although HVDC technology has had many years of operational experience,[106] new control systems have been developed recently that reduce cost and improve flexibility and performance. This is based on modern, newly developed voltage source

106. HVDC was originally developed to supply large volumes of power over long distances. The first large-scale commercial project was installed in 1965 in New Zealand where a 600 MW HVDC line was built to carry power from the South Island 600 km to the North Island. This has operated very reliably for over 45 years and was recently upgraded to 1,400 MW. Over 200 HVDC systems have been built over the years. The longest HVDC link in the world is currently the 2,071 km ±800 kV, 6,400 MW link connecting Xiangjiaba Dam to Shanghai in the People's Republic of China.

Figure A5.6. Uprating HVDC Interconnection from Monopole to Bipole Configuration



Source: IEEE power and energy magazine, March 2007.

converters (VSC[107]) with series-connected insulated gate bipolar transistor (IGBT) valves controlled with pulse width modulation (PWM) that have already reached levels of 1,200 MW and ±500 kV. Notably, HVDC can also be built in stages to match increased loading, as required. This can be done by first building the line for monopole operation, then later uprating to bipole operation and, if necessary, uprating again using a higher operating voltage. A diagram of this kind of scheme is in figure A5.6. Provided that the line is designed for its ultimate operating configuration (at little extra cost), the cost lies primarily in uprating the HVDC/HVAC terminals at each end of the lines.

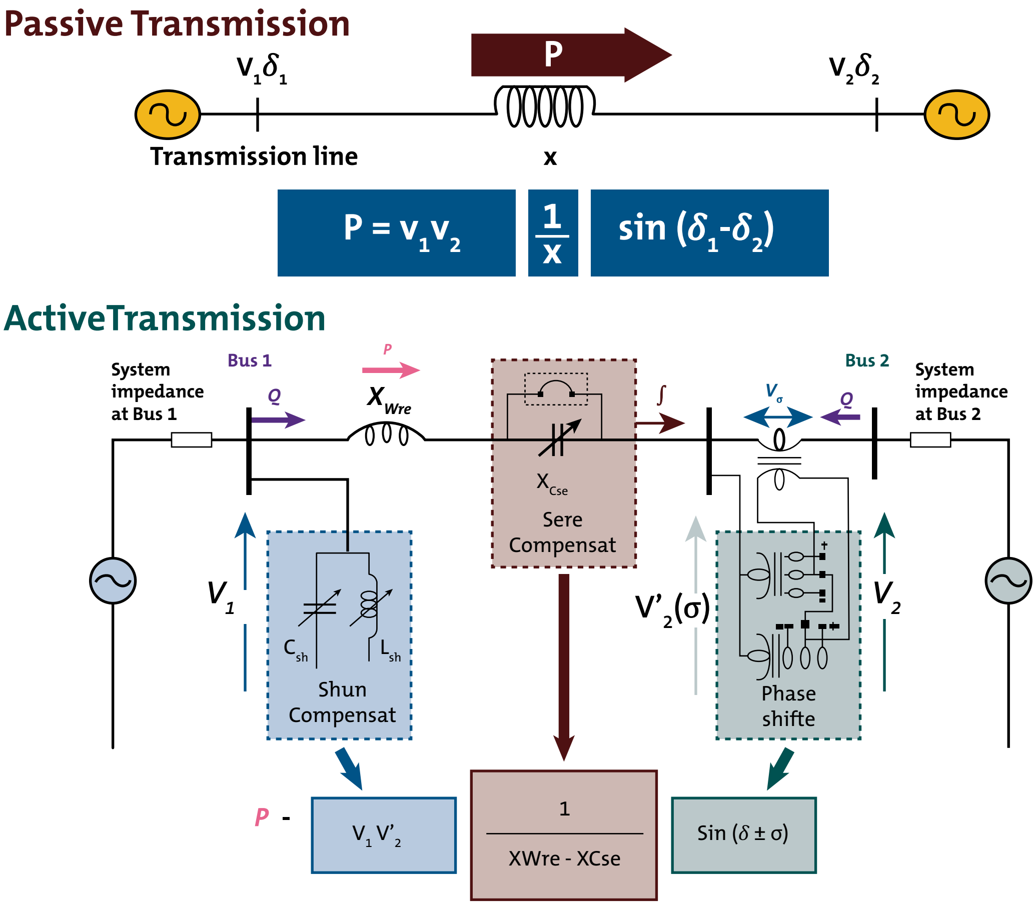
A5.5. Priorities for Next Decade

For the next decade or so, Afghanistan will depend on imported power that must be integrated with local generation, which is expected to increase over time. A key activity to improve power quality and reliability is to seek approval from the CAS countries to synchronize local generation to the import grids. Transmission planning in Afghanistan must also take into account the need for diversity and security of supplies, recognizing that in the short term the cheaper imported power from unsynchronized sources needs to be managed so as to maintain competitive prices through flexible off-take designs.

Given the country's synchronism issues, the long distances involved and the power transit opportunities, HVDC systems in some form or another must be an integral part of any future Afghanistan transmission system. In principle, HVDC transmission should be used to provide lower cost, greater security for transit projects, and supply and stability

107. E.g., ABB's HVDC Light, Siemens HVDC Plus, Alstom's HVDC Maxsine.

Figure A5.7. FACTS (Flexible AC Transmission)



Source: Electric Power Research Institute 2011.

advantages to Afghanistan. HVDC systems can be readily integrated into the design of the Afghanistan power system, either in parallel with the HVAC systems or via HVDC terminal and b/b facilities, but they must also be a consideration in developing the grid code.

In the near term, Afghanistan needs to develop its existing microgrids to increase diversity and security of supplies. Essentially, these should be seen as groups of interconnected loads and distributed energy resources within clearly defined electrical boundaries acting as a single controllable entity with respect to the grid. They should be able to connect and disconnect from the grid, operating in both grid-connected or island mode. There needs to be greater consumer engagement by DABS, with resources to solve power issues locally by enabling the penetration of local renewables in residential,

Table A5.1. Transmission Investment Issues for Consideration and Resolution by Real Options Analysis

Issue for Resolution	Alternatives Under Consideration	Preconditions	Compare Alternatives by ROA
Build 500 kV grid network with sufficient capacity for future power transit operations.	Build 220 kV for domestic growth using FACTS devices as necessary; use HVDC for transit operations funded by transit parties.	Estimate scope for future transit opportunities; synchronize domestic generation and imported power using VFT or HVDC b/b facilities as necessary. Grid code finalized and agreed on by CAR, Iran, and Pakistan.	Carry out load flow analysis to determine investment needs and sequence for each alternative. Compare NPV of investment in both alternatives assuming at least one transit project with same capability as CASA-1000.
Increase diversity in transmission planning for domestic growth.	Compare proposed investments in direct route of HVAC lines to Pakistan with using alternative routes to increase security and reliability.	Define minimum reliability standards; assume limited grant finance available for transmission development.	Determine least-cost investment to meet domestic load growth to 2030 and risk of over-investment if transit power not forthcoming.
Incorporate isolated grids and domestic generation into national grid.	Delay synchronization of domestic grids until adequate import power available; progressively synchronize grids before NEPS/SEPS is completed.	Add necessary control systems to existing generation-synchronizing facilities; policies for microsystem backup facilities to remain on standby.	Compare cost and reliability of supplying isolated systems from grid with retention of existing plant with grid to provide backup.
Encourage the greater use of demand-side management to reduce the cost of supplying peak load.	Consider tariff incentives to facilitate consumer investments in battery storage systems rather than backup diesels.	Change grid code to enable users to synchronize with distribution system.	Compute and compare cost of providing peak capacity by conventional gas turbines.
Develop southern transmission extensions to support increased imports from Iran and promote development of southern wind resources.	Determine priorities for investment of new transmission lines that may be able to support new generation investment.	Verify wind resource capability near Herat and Farah, and offer free transmission resources to potential IPP investors.	Compare wind development with hydro development, taking into consideration sequencing and interconnection opportunities.

commercial, and industrial areas. In this way, distribution can become a transmission resource with all its components are part of a cohesive system. This will, of course, require high dependency on standardization (physical and data) as established in the T&D Grid Code.

Changes to accommodate new technologies need to be recognized in the planning process to improve grid and micro-grid operations and lower overall costs. These include the deployment of a utility-scale and domestic PV solar plant along with distribution-level storage to replace backup diesel power. Likewise, in planning new HVDC schemes, it is important to recognize the current developments of new HVDC technologies that can facilitate an increased number of intermediate converters and provide stabilizing power to weakly interconnected systems. These include technologies such as LCC (line commuted converters) versus VSC (voltage source converters) and their competing technology VFT (variable frequency transformers. Other technologies can be used to increase the capacity of existing AC lines, usingFACTS (flexible AC transmission) equipment to compensate for the limitations of long lines and light loads and thereby avoid unnecessary investment in new lines, as shown in figure A5.7.

A5.6. Issues That Can Be Considered for Real Options Analysis

Table A5.1 indicates studies that could use ROA techniques to compare alternative strategies. Because they involve a sequence of investments, there would need to be a typical load flow analysis depending on the expected development of load.

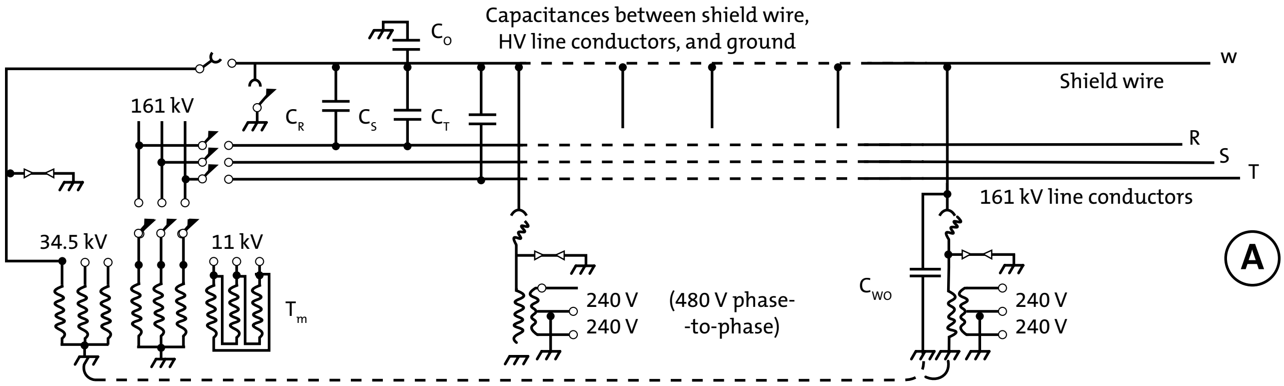
Appendix 1. Electrification Using Shield Wire and SWER Systems

Shield Wire System (SWS) is an innovative approach to grid-connected rural electrification using a standard single wire earth return (SWER) system. Many of DABS HVAC and the proposed HVDC transmission lines pass nearby villages that subsist without electricity. As a way to facilitate right-of-way compensation and to add value to the communities and people living around the proposed transmission line, SWS provides a means to provide electricity to the villages along the line.

The Technology

High voltage transmission lines have over head earth wires (OHEW) that are connected to a tower and grounded to provide protection to the transmission line from lightning strikes. They are mounted above transmission lines and thus attract the lightning away from the phase conductors, essentially shielding the transmission lines from lightning.

Figure A5.8. Single Line Diagrams of "Single-phase Ground-return" SWS



In shield wire systems, these shield wires are insulated from the tower and ground and provide a conductor for transmission of electricity. They are energized at MV (20–34.5 kV) from a HV/MV transformer stationed at one end of the HV line. MV/LV transformers are then added along the HV line to supply the loads. There are four main systems within SWS. They are:

- Single wire earth return (SWER).
- Single phase metallic return.
- V scheme.
- 3-phase scheme

The last three schemes are only applicable for transmission systems where there are two shield wires available. The recommended tower design uses one of the shield wires as a carrier for an optical fiber communications link. The second shield wire could be used to provide power along the line by implementing a SWER shield wire system.

Single-phase earth-return can be designed and implemented in transmission towers with only one OHEW. In this system, a single phase of power is transmitted through the single insulated OHEW and returned through the earth. This system works essentially like a SWER system, however, it utilizes the existing infrastructure of the towers and lines. The schematic diagram of the system is shown in figure A5.8.

SWER is one of the cheapest proven distributive rural electrification technologies. SWER systems are widely used in Australia and Canada, in areas with very low population densities. Another slightly more expensive but also very commonly used system of electricity distribution is the use of single phase system, which is commonly used in

Table A5.2. Operating Shield Wires Systems

Country	Description of SWS Use (latest information in 2005)
Ghana	■ First pilot project in the 1980's. Has about 1,000 km of SWS, half of which has been in operation more than 15 years.
Laos	■ Three "Single-Phase Ground Return" 25 kV SWSs in service since 1996. ■ Five "3-Phase" 34.5 kV SWSs in service since 2002 in 310 km of 115 kV transmission lines.
Brazil	■ 85 km of "3-Phase" SWS operating since 1995.
Sierra Leone	■ Implemented 150 km of "3-Phase" 34.5 kV.
Togo	■ "3-Phase" 34.5 kV SWSs is under construction on 265 km of new 161 kV. One of the OHEWs will be an insulated OPGW.
Benin	■ "3-Phase" 34.5 kV SWSs are under construction on 300 km of new 161 kV. One of the OHEWs will be an insulated OPGW.
Burkina Faso	■ 3-Phase" SWS planned for construction in new 225 kV–50 Hz–330 km line.
Mozambique	■ Feasibility study has been completed for the use of "3-Phase" SWS in about 550 km of existing 220 kV line in the north.
Zimbabwe	■ Has done a prefeasibility study into "3-Phase" SWS on a 400 km of 330 kV new lines.
Ethiopia	■ Three "Single-Phase Earth-Return" SWSs have been in operation since 2003. ■ Planning for Four "3-phase" SWSs under construction.

a. F. Iliceto, F.M. Gatta, S. Lauria, M. Debebe, and M. Hussen - Rural electrification in Ethiopia with the shield wire scheme, 18th International Conference and Exhibition on Electricity Distribution (CIRED 2005), (CP504), p. v5-45, Turin, Italy, 6-9 June 2005, ISBN: 0 86341 529 6.
b/ F. Iliceto, F.M. Gatta, S. Lauria and G.O. Dokyi - Three-phase and single-phase rural electrification in developing countries using the insulated shield wires of HV lines energized at MV. CIRED, Paper no 5/p. 10, Nice (France) Session, 1999.

North America.[108] A nonexhaustive list of countries using SWER systems is in table A5.2. Mainstream distributive technologies such as MV distribution can also be implemented, however these usually prove to be too cumbersome and expensive in rural areas.

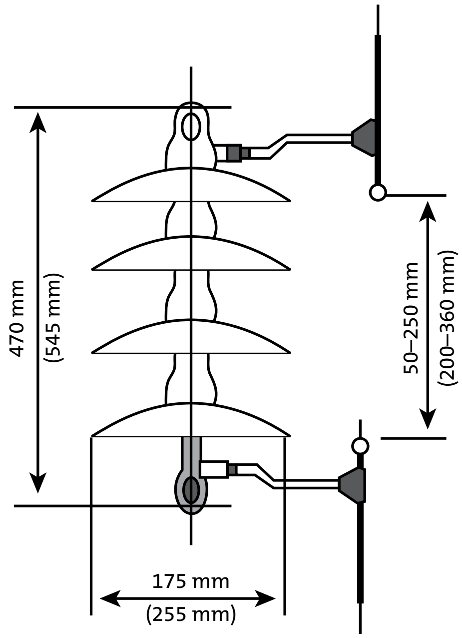
Lightning Performance of High Voltage

Normally, the OHEW is grounded and attracts the lighting, intercepting the strike to protect the phase conductors. In SWS, the OHEWs are insulated in a way so as not to compromise the effectiveness of the lighting protection. The proposed insulation for shield wire systems is a rigid string toughened glass insulator, with protective arcing horns (or rod gaps) as shown in figure A5.9. These rod gaps are installed across the shield-wire insulators to facilitate flash-over whenever necessary.[109]

The arcing horns are not a new concept. Along with insulating the earth wires in EHV, they also implement spark gaps. In order to maintain continuity along the shield wire,

108. F. Iliceto, F. M. Gatta, and E. Cinieri. *Rural electrification of developing countries using the insulated shield wires of HV lines. New design criteria and operation experience*, CIGRE paper 37/38–03, Paris Session, 1994.
109. F. M. Gatta, F. Iliceto, and S. Lauira. *Lighting performance of HV transmission lines with insulated wire(s) energized at MV. Analysis and field experience*. CIGRE Symposium, Cairns (Australia), Paper No 100–07, Sept 2001.

Figure A5.9. A Rigid String Toughened Glass Insulator String with Arcing Horns, As Used in Northern Ghana



■ Disc size [mm]	175	255
■ Dry impulse withstand* [kV crest]	210	260
■ Wet 1-minute 50 Hz withstand* [kV rms]		
■ Creepage distance	760	1,200
■ Electromechanical failing load [kN]	>40	>40

*Without arching horns

Source: F.M. Gatta, F. Iliceto and S. Lauria, 2002. Lightning Performance of HV Transmission Lines with Grounded or Insulated Shield Wires, Proceedings of 26th International Conference on Lightning Protection (ICLP 2002) Cracow, Poland, September 2-6 (2002), pp. 475-480.

the insulation level should be sufficient for flashover protection in continuous duty and for insulation dielectric strength recovery after clearing the fault. The arcing gaps should be between 100 and 300 mm, depending on the operation voltage. When the shield wire does experience a lighting strike, the closest insulating spark gaps will flash over.

For the protection of the system, the shield wires will appear to experience a phase to ground fault. The protection relays will trip, turning off the supply to the shield lines once the fault is identified. This protection is the typical operational method used in MV systems. Tripping off the SWL will extinguish the fault. After the line is tripped off, a secondary arc may flash over. This secondary arc is supplied by the residual capacitive and electromagnetic induction from the HV circuit. Laboratory testing and analysis of operating systems show that these secondary arcs self-extinguish in all cases. No decrease in reliability of the HV line has been experienced in the SWS schemes in Africa, Ethiopia, and Brazil. Reliability of the medium voltage SWS line has been shown to be similar to other medium voltage lines in the area.

Appendix 2. Developing a Grid Code for Afghanistan

Background

For a landlocked energy transit country like Afghanistan, surrounded by large asynchronous power systems, a grid code is required to allow the country to plan its power system development in a rational way. A grid code appropriate for Afghanistan should comprise: (1) a planning code that describes higher-level and common regional requirements, processes and criteria for joint planning; (2) an operation code, including scheduling and dispatch to make use of the advantages arising from the interconnected operation and define standards for reliability and quality of supply; (3) connection rules to define rules for connection to the transmission system on nondiscriminating terms; (4) a data exchange code to facilitate system analyses of the interconnected regional power system for dealing with balance and capacity problems and to control the distribution of the models that are used to analyze the regional power system; and (5) a metering code.

An Afghan grid code should also define the technical and operational specifications and parameters for domestic electricity generating plants and substation control systems. This will facilitate both synchronous and asynchronous interconnections to enable proper functioning of the electrical grid. The code will define appropriate power system design parameters and interconnection standards so as to minimize the use of different types of power equipment that are often introduced by donor countries. In this respect, Afghanistan's existing legacy of power system designs comprise a mixture of voltage levels; the MV/HV AC voltage levels include 35 kV, 44 kV, 110 kV, 132 kV, 220 kV, 500 kV, and HVDC systems. Distribution systems are supplied at 6 kV and 15 kV, with the latter built for eventual upgrading to 20 kV.

A key section of the grid code for Afghanistan is required to facilitate a synchronous interconnection between the Afghanistan and CAR/Iran power systems most probably based on simplified power-frequency control and emergency control systems (ECS) used by the UPS/IPS regulator. These control strategies are already applied for synchronous interconnections of large systems with peripheral systems of smaller capacity. In this respect it is unlikely that Afghanistan will participate in primary or secondary frequency control of the interconnected system but only be responsible for maintaining the scheduled flows using its own generation resources and discontinuous control.

It is expected that Afghanistan system interconnection shall at minimum be monitored from a regional dispatching center featuring real-time energy management functions, including state estimation and contingency screening. There will also be a requirement for power system stabilizers of major generation units to be tuned (or retrofitted) based on small signal stability studies supported by unit measurements and model identification. Fast controllable reactive power compensators (SVCs) at critical load or generation buses will be most likely be required.

Provisions should be made further to later develop the grid code to enable Afghanistan's to play a major role in the development of power transit operations. It will need take into consideration the security and economic obligations between exporters and importers that are likely to be incorporated in their respective PPAs.

Outline Scope of Work to Prepare a Grid Code

DABS and MEW would need to investigate the technical issues raised above and draw up a plan for the commercial operation of asynchronous interconnections between CAR/Iran and Pakistan, including the specification of a functional upgrade of a regional control center. Consultant support would likely be needed to develop and assist in agreeing and adopting technical and reliability standards, including ancillary services, and the roadmap for the transition from initial/current conditions to target standards. A reliability study of the power grid system will be required to assess system capacity and fragility, identify faults, recommend solutions and upgrading; and provide estimates for investment required to upgrade existing plants for secure, safe, and reliable operation.

The objective of the code is thus to set a common basis for satisfactory operational reliability and quality of supply for all participants in Afghanistan's electricity industry. The code should be designed to permit the development, maintenance, and operation of an efficient, coordinated, and economical system for the transmission of electricity, to facilitate competition in the generation and supply of electricity, and to promote the operation, data exchange, and metering codes.

While it will not be possible to provide a comprehensive grid code for Afghanistan in the near term, the investigation should recommend standards that are required to achieve the above objectives and include a program of further development of the grid code as generally outline under the following subject headings:

- Rights and responsibilities of the transmission enterprise; the power system operator, electricity generators, customers connected to the transmission system, the public provider, public suppliers, and electricity traders.
- Technical requirements for connection to the transmission system for both materials and staff.
- Procedures of transmission system development planning and use.
- Procedures of power system operation planning.
- Scheduling and control of power system (PS) operating mode; development and performance of a defense plan and of a plan for PS restoration.
- Procedures for mandatory data interchange and sequence of online data interchange and online power system control.
- Activities of the PS operator and of transmission system hsers related to the quality control of PS operation.
- Conditions and procedures of system tests and certification of systems.
- Provision of complementary services.
- A cost-effective framework for dispute resolution for all code participants.

- Adequate sanctions in cases of breaches of the grid code.
- Efficient processes for changing the grid code.
- Technical, safety, security, and performance standards with regard to the PS and protection systems.
- Codes of practice covering the construction, operation, and maintenance of electromechanical components of transmission and distribution systems.
- Codes of practice for customer services related to the electricity supply industry.
- Responsibilities in case of accidents.
- Responsibilities in case of losses and compensation.
- Other relevant activities related to the overall PS operation process.

Annex 6. Glossary

Basis Point (bp). A term used in banking and finance to describe small variations in interest rates: 100 basis points=1 percent. For example, 40 basis points=0.4 percent.

Border price. The value of a traded good at a country's border, namely free on board (fob) for exports; or cost, insurance, freight (cif) for imports.

Capesize. Dry bulk carrier with capacity of 100,000 dwt or more. The typical capesize vessel has a capacity of 140,000 dwt.

Coal Rank. The calorific value of coal increases with coal rank along a continuum, though at very high ranks, calorific value begins to decline. For historical reasons, coal rank names and the places along the calorific continuum where coal is recognized to change rank varies from country to country. North American naming conventions are shown below. Soviet naming conventions are used by *Technoexport*. Soviet conventions are significantly more complex than other naming conventions because they take into account the kinds of original plant material (stems, leaves, seeds, etc.) that constitute the coal. It is not possible to directly correlate Soviet naming conventions with other systems. The Soviet classification system tries to account for the fact that coals that seemingly have the same rank have, in reality, very different combustion properties.

	Calorific value (kcal/kg)	Calorific value (Btu/lb)
Meta-anthracite	7,560	13,600
Anthracite	8,000	14,400
Semi-anthracite	8,200	14,800
Low volatile bituminous coal	8,400	15,100
Medium volatile bituminous coal	8,200	14,800
High volatile bituminous A coal	8,000	14,400
High volatile bituminous B coal	7,800	14,000
High volatile bituminous C coal	7,150	12,900
Subbituminous A	6,500	11,700
Subbituminous B	5,800	10,500
Subbituminous C	5,300	9,500
Lignite A	4,550	8,200
Lignite B	3,300	6,000

GOST (Russian: ГОСТ). refers to a set of technical standards maintained by the Euro-Asian Council for Standardization, Metrology and Certification (EASC). GOST standards are considered comparable to ISO and ASTM standards.

ISO conditions. International Standards Organisation for the nameplate capacity of a thermal generating project at sea level and at 15oC.

Japan Crude Cocktail (JCC). The average monthly cif price of all crude oil imported into Japan. Used as a basis for LNG contracts in the Asia-Pacific market

Junior exploration company. A small, thinly traded resource exploration company with a market capitalization generally below $500 million. They are like tech start-ups to the extractives sector. They seek to acquire and explore properties believed likely to host large resource deposits.

Opportunity cost. The benefit lost from not using a good or resource in its best alternative use. Opportunity costs measured at economic prices should be used in economic analysis as the measure of benefits.

Panamax. Dry bulk carrier with capacity of 60,000–99,999 dwt (The maximum size that can pass through the Panama Canal).

Ramsey Formula. According to the noted British economist Frank Ramsey, social rate of time preference (SRTP) is the sum of two terms: first is a utility discount rate reflecting the *pure* time preference (r), and the second is the product of the elasticity of the marginal utility of consumption (q) and the annual growth rate of the growth of per capita real consumption (g): thus STRP=r+ qg.

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) use of the Ramsey Formula.

Pure rate of time preference. 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).

Shadow exchange rate (factor). The inverse of the SCF. The SER is often greater than the official exchange rate, indicating domestic consumers place a higher value on foreign exchange than is given by the official exchange rate.

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 CBA sensitivity analysis, the value of an input data assumption that brings the ERR to the hurdle rate (NPV to zero). In the switching value analysis of section 4, it indicates the value of as input assumption that changes a decision at one of the nodes in the decision tree.

Annex 7: Workshop Participants

Technical Workshop #1, December 7–8, 2014

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Habib Rahmat, Energy Advisor, MEW

Ahmad Abdullah, Head of Water Energy Program, MEW

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Musa Arian, Head of Sub Stations Department, MEW

Mohammad Nasser, Power Distribution Specialist, MEW

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Technical Workshop #2, May 10–12, 2015

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Amanullah Ghalib, Head of Renewable Energy Department, MEW

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