DEVELOPING THE TECHNOLOGY MATRIX FOR INDIA AND UKRAINE

Draft Report

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Introduction

Over the last decade, concern about the issues of global climate change and rising greenhouse gas emissions has grown significantly. This concern has spurred an elaborate series of international meetings and agreements seeking to stabilize atmospheric greenhouse gas concentrations. In 1992, at Rio de Janeiro, more than 160 countries, including the United States, signed the United Nations Framework Convention on Climate Change (UNFCCC). The signatories were in agreement regarding the potential negative effects of climate change under a business as usual future. Under the Convention, the developed countries (referred to as Annex I countries) were assigned primary responsibility for addressing the climate change issue. However, at the first two Conferences of Parties[1] called to discuss methods for implementing the Convention, a strong debate ensued regarding what policy instruments should be used to curb global climate change, and what, if any, targets and timetables should be set for achieving emission reductions. Most Annex I nations announced a series of voluntary targets and initiatives for meeting emission reduction goals.

By 1996, it had become clear that greenhouse gas emission levels in most Annex I countries were rising despite voluntary efforts to reduce emissions. A consensus for firmer targets and timetables was building. At the Third Conference of Parties, held in Kyoto, Japan in December 1997 a series of firm emission reduction targets were agreed to by the Parties. Developed countries agreed to reduce their greenhouse gas emissions by an average of 5.2 percent from 1990 levels by 2008-2012. While the resulting "Kyoto Protocol" was signed in 1997 by the United States and other industrialized countries, it was never ratified by the U.S. Senate, and the Administration recently announced its intention of dropping out of the negotiations surrounding the Protocol. Nonetheless, the general scientific consensus that global warming is a real, significant issue is not in dispute. The Administration is calling into question only the appropriate response to the issue, while explicitly recognizing the need for some response. Regardless of whether this response takes the form of a domestic voluntary program, an international treaty, or something in between these two extremes, it is likely that it will incorporate "market mechanisms" in some form or another. The concept of flexible, market-based mechanisms is an essential element to the Convention and the Kyoto agreement. Market mechanisms are designed to facilitate low-cost solutions to environmental problems. This new concept awards credits for emission reduction activities undertaken beyond a country's boarders.

The emission reduction activities could take the form of carbon-offset projects initiated between two developed countries or between a developed country and a developing country. Either way the host country receives the benefits of the technology transfer resulting from the project while the project developers receive any emission credits resulting from the project's emission benefits. It is important to recognize that market mechanisms are *not* designed to reduce global greenhouse gas emissions

1 The Conference of the Parties (COP) is the supreme body of the United Nations Framework Convention on Climate Change established in 1992. The body meets annually and its primary responsibility is to oversee the implementation of the Convention and the Kyoto Protocol. The Fifth Conference of Parties (COP5) is scheduled for October 25, 1999 to November 5, 1999.

beyond any potential emission reduction targets specified in an international agreement. Rather, the purpose of market mechanisms is to increase flexibility and reduce the *costs* associated with meeting emission reduction targets. As envisioned market mechanisms provide a one-to-one trade between host countries and project developers. Thus, at least in the ideal, market mechanism projects will yield no net change in global emissions. In short, it is the emission reduction targets, and not the market mechanisms that will act as the driving force for reducing global greenhouse gas emissions.

Under the Kyoto Protocol, for example, the market-based, flexible mechanism approach was manifested in the clean development mechanism (CDM). The CDM is defined as an emissions reduction project between a developed country and a developing country that provides the developing country with project financing and technology and allows the developed country to acquire emission reduction credits. The credits may be applied to the developed country's emission reduction goals. While the Kyoto Protocol, and therefore the CDM, may not come to pass, it is very likely that a mechanism similar to the proposed CDM will be incorporated into whatever climate change program, treaty, or agreement is accepted.

In order to estimate emission reductions arising from such market-based emissions reduction projects, the emissions generated by the project itself must be measured and subtracted from some baseline representing what emissions would have been in the absence of the project. The technology matrix, originally proposed by the National Energy Technology Laboratory (NETL) in the report *Developing Emission Baselines for Market-based Mechanisms: A Case Study Approach*, is a potential method for estimating the baseline. It consists of a selected list of greenhouse gas abating technologies, along with emission rate benchmarks for each technology.

In this document, a technology matrix was developed for ten selected technologies, for the countries of India and Ukraine. The basic technology matrix development approach was the same for all of the stated technologies, and for both countries. For a technology to "qualify" for the selected list of greenhouse gas abating technologies, it must first be subjected to a rigorous test to demonstrate that projects utilizing the technology are "additional" to those that would have been implemented under "business as usual" circumstances.

Once a technology has been qualified as additional, a benchmark was developed for that specific technology based on the emissions performance of a counterfactual technology(ies). The counterfactual technology represents the technology most likely to be utilized, if the corresponding advanced-technology project were to be foregone. In essence, the benchmark for a particular technology is a carbon dioxide emission rate that can be used to compute the baseline emissions for any project utilizing that technology. There are three basic steps to estimating the benchmark. First, the most likely alternative to the project must be defined in a qualitative manner. Second, the data required to quantify the benchmark must be collected for each technology/country combination. Finally, the collected data is analyzed, and used to compute the benchmark.

The technology matrix represents a cost-effective, objective, transparent, and reasonably accurate approach to quantifying project emission baselines. As a supplement to the project-specific approach, it offers significant cost advantages to projects meeting certain criteria, without eliminating from consideration projects that do not meet these criteria. In particular, it is similar to other benchmarking approaches, but with the addition of an effective, rigorous, true test for additionality.

The study documented in this report builds upon the earlier report cited above. Its purpose is to illustrate the development of the technology matrix for ten selected technologies in India and Ukraine. By undertaking the process of actually building the matrix for a few specific examples, key issues that must be addressed during matrix development are highlighted, data requirements are identified, availability of data to meet those requirements is determined, and the quality of the available data is assessed. Furthermore, through the development process, the strengths and limitations of the technology matrix approach are brought into sharper focus.

This initial attempt at matrix development is offered as a starting point for further discussion and debate on the merits and limitations of the technology matrix approach, and on ways to improve the approach. Judgments are made for illustrative purposes, and should not stand as the final basis for the technology matrix. The goal of the study is not to quantify the final, definitive benchmarks, but rather to illustrate, in a general sense, the procedures for benchmark development, to determine the extent to which the available data can support these procedures, and to identify the improvements in the existing data that would need to be made before full-scale technology matrix development could begin.

As stated, ten technologies for the countries of India and Ukraine were selected for inclusion in the initial technology matrix. The technologies selected for initial consideration include five electric power generation technologies, three transportation/transportation fuel technologies, and two other technologies. The specific technologies are as follows:

- Power generation:
  - Supercritical coal
  - Integrated Gasification Combined Cycle (IGCC)
  - Natural gas combined cycle
  - Fuel Cells
  - Wind turbines

- Transportation
  - Compressed Natural Gas (CNG) vehicles
  - Hybrid (electric-gasoline) vehicles
  - Gas-to-Liquids (new diesel)

- Other
  - Coalbed methane recovery
  - Energy-plex projects

Additionality Analysis

Under the guidelines established by the Kyoto Protocol, an eligible flexible, market-based project must result in emission reductions that are additional to any that would occur in the absence of the certified project activity (referred to as additionality) [Article 12 (5. c)]. In terms of the Kyoto Protocol, then, an additional project is defined as a project that will never be implemented unless the Protocol enters into force and the project acquires favorable financing, technology transfer, or other project-specific assistance. Again, while it is uncertain whether the Kyoto Protocol will enter into force, it is highly likely that flexible, market-based emission reduction projects will play a large role within whatever treaty, program, or agreement is ultimately accepted. Thus, the concept of "additionality" may still bear much significance.

Under NETL's proposed technology matrix, the additionality test is based on (1) an assessment of the technology's economic viability vis a vis current commercial technologies, and (2) a consideration of the market penetration achieved by the technology, throughout the world and in the country in question. If, based on these two tests, the technology is determined to be non-commercial in a particular country, it is judged additional; projects utilizing such "qualifying technologies" will automatically qualify for emission reduction credits under the technology matrix approach.

The failure of a technology to qualify as additional means only that project developers using the technology cannot rely on the technology matrix to demonstrate additionality. However, these project developers will be offered the opportunity to demonstrate the additionality of their projects using the project-specific approach. Furthermore, if the project developers can demonstrate additionality, they will still be able to use the benchmarks provided by the matrix to quantify their project baselines. This approach allows even project developers using commercial technologies to reap a substantial portion of the cost benefits provided by the technology matrix approach.

Additionality analyses of the ten selected technologies for the countries of India and Ukraine were conducted. All but one of the ten technologies qualified as additional for India and Ukraine. The sole exception, supercritical coal in Ukraine, does not qualify as additional because the technology is already an important part of the country's coal-fired power generation mix.

Development of the Qualitative Baseline

After establishing the additionality of the selected technologies, the next step in the technology matrix development process is to establish the qualitative baseline for each technology. Here, it is necessary to determine the most likely alternative to projects utilizing the technology in question. This determination defines the qualitative baseline, and provides the basis for quantifying the emission rate benchmarks to be included in the technology matrix.

The above determination was made for each of the ten technologies in India and Ukraine. Although utilizing available data and information, the qualitative baselines established through this process are inherently subjective in nature. The core hypothetical in the determination was addressed explicitly, based on informed opinion and expert judgment, for each individual technology and country. In this way, the unique characteristics of each technology/country combination were captured. Because they are based on subjective opinion, the qualitative baselines presented in this document are not offered as definitive or final, but rather as a starting point for further discussion, debate, and hopefully, the development of improved qualitative baselines rooted in a broad consensus.

The Qualitative Baseline for Power Generation Projects

In order to determine, qualitatively, the counterfactual for a qualifying power generation technology, it is first necessary to posit a project utilizing that technology. This hypothetical project should represent the "typical" application for the technology in question, because it must stand for all capacity expansion projects utilizing the technology, to be undertaken under a flexible, market-based carbon offset program. This hypothetical project is referred to as the "model project." Each qualifying technology will have its own model project, and that project will represent the typical or most common project likely to utilize the qualifying technology.

However, for benchmark purposes, the focus is not so much on the model project, but on the "model counterfactual." The model counterfactual is defined as the most likely alternative to the model project. The model counterfactual will represent the host of real world alternatives to the real world projects utilizing a particular technology. The goal is to define the model counterfactual such that it typifies these real world alternatives.

To define the model counterfactual, a number of key questions were addressed, including the following:

- Is the qualifying technology designed to meet baseload, intermediate, or peaking demand?
- What conventional technologies are being utilized to meet these load demands?
- What fuel type(s) will the qualifying technology utilize?
- Based on the above, what are the technology/fuel alternatives to the qualifying technology?

In order to provide a degree of standardization and objectivity in the counterfactual definition process, these and other key questions were incorporated in a series of “decision tables,” found in Chapter 3. Essentially, the decision table provides a means of defining, clarifying, and organizing the issues that must be addressed to define the model counterfactual. The decision table approach, however, is relatively inflexible and thus not applicable to all technologies. Wind turbines and fuel cells are difficult to address within the confines of the decision table approach; hence, these two technologies were considered separately.

A summary of qualitative baselines using the technology matrix approach is presented in Table 1. In this table, the qualitative baseline--i.e. the most likely alternative to the projects utilizing a particular technology--is defined for each technology/country combination. Technology/country combinations that were determined as non-additional are indicated by light shading. Projects utilizing these technologies may still qualify under the project-specific approach. Non-shaded technologies were determined to be additional; projects utilizing these technologies will automatically qualify for emission reduction credits under the technology matrix approach.

In a number of instances, separate qualitative baselines have been developed for different applications of the same technology. For example, two qualitative baselines are provided for wind turbine technology, depending on whether the turbines are to be used for off-grid or on-grid

Table 1. The Technology Matrix: Summary of Qualitative Baselines

Technology	Application/Gas	Country	
		India	**Ukraine**
Supercritical Coal	All	Steam turbine plant with subcritical, PCF boilers	Coal-fired steam turbine plant
IGCC	All	Steam turbine plant with PCF boilers	Coal-fired steam turbine plant
Natural Gas Combined Cycle	All	Gas-fired steam turbine plant	Gas-fired steam turbine plant
Wind Turbine	Off-grid	Diesel generators	Diesel generators
	On-grid	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
Solid Oxide Fuel Cells	Commercial cogeneration	Diesel generators	Diesel generators
	Low-cost fuel	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
	Distributed generation	**USE PROJECT-SPECIFIC APPROACH**	**USE PROJECT-SPECIFIC APPROACH**
CNG Vehicles	Passenger Cars	Composite of gasoline and diesel vehicles	Composite of gasoline and diesel vehicles
	Transit buses	Composite of diesel vehicles	Composite of diesel vehicles
Hybrid (gasoline/electricity) vehicles	Passenger Cars	Composite of gasoline and diesel vehicles	Composite of gasoline and diesel vehicles
	Transit buses	Composite of diesel vehicles	Composite of diesel vehicles

Technology	Application/Gas	Country	
		India	Ukraine
Gas-to-Liquids			
Coalbed Methane Recovery	Methane	**BENCHMARK NOT REQUIRED**	**BENCHMARK NOT REQUIRED**
	CO_2/Onsite electricity generation	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
	Transfer of gas to pipeline	**USE PROJECT-SPECIFIC APPROACH**	**USE PROJECT-SPECIFIC APPROACH**
Energy-Plex	All	**BENCHMARK NOT PROVIDED**	**BENCHMARK NOT PROVIDED**

applications. Furthermore, in a few cases (denoted by dark shading), it was decided that a benchmark should not be developed for a particular technology/application. For example, in the case of sulfur oxide fuel cells to be used in distributed generation applications, it was decided that the project-specific approach should be employed to compute emission reductions rather than the technology matrix approach. The energy-plex concept is also excluded from the matrix because this technology has not reached a level of maturation sufficient to warrant its inclusion at this point in time. And a benchmark is not provided for estimating the methane emission reductions resulting from coalbed methane recovery projects, because a benchmark is not required: the methane reductions can be measured directly for such projects.

The Qualitative Baseline for Transportation Projects

Qualitative baselines were also developed for the three transportation technologies: gas-to-liquids (new diesel), compressed natural gas (CNG) vehicles, and hybrid (electric/gasoline) vehicles. The inherent difference in the emissions scenario of each transportation technology as they are applied to different vehicle types, such as light-, medium-, and heavy duty-vehicles, trucks, and busses, requires that a counterfactual and an emissions benchmark are quantified for each vehicle category and each transportation technology.

A determination of which specific conventional transportation technologies would have been used in the absence of the model project was made. This determination included an analysis of the types and fuel source of the counterfactual vehicles that would have been purchased. To the extent possible, the analysis targeted transportation data for the major cities of Ukraine and India, where the development of large-scale, market-based carbon offset transportation projects are most likely to occur.

The three advanced technologies included in the technology matrix were divided into two main categories. The first includes CNG and hybrid vehicles, which involves the deployment of a new type of low emission vehicles. The second category involves the introduction of a new fuel source, i.e. gas-to-liquids (diesel-based).

In the case of CNG vehicles, the most advanced vehicle applications on the market today are CNG passenger cars and transit buses. Therefore, those two CNG technologies were the focus in this study. In the hybrid vehicle category, hybrid electric/gasoline passenger cars have reached the highest stage of commercialization and should thus be considered for inclusion in the technology matrix. Other technologies, including electric/diesel, hydrogen, fuel cell, or solar powered vehicles, are being tested but are at an earlier stage of development. Of these technologies, hybrid electric/diesel transit buses were chosen as the second model project technology for hybrid vehicles. For each of the two vehicle categories, two model counterfactuals were developed -- one for passenger cars and one for transit buses.

The development of the model counterfactuals for both CNG and hybrid passenger cars and buses involved determining which type(s) of vehicles and fuel sources represent the most likely alternatives to these technologies. In India and Ukraine, each vehicle type is represented by a number of different vehicle models with different emissions qualities. The vehicles are also fueled by different energy sources, including diesel, natural gas, liquified petroleum gas (LPG) and CNG. The most likely alternatives consist of conventional transportation technologies powered by commercial fuel sources. The model counterfactuals were thus defined as a composite of all recently purchased conventional vehicles in a given vehicle category (Table 1). For passenger cars, this includes both diesel- and gasoline-powered vehicles. Vehicles powered by non-commercial fuel sources, such as LPG, were not included in the counterfactual. In the case of transit buses, the model counterfactual for CNG and electric/diesel buses was based on a composite of all new diesel-powered transit buses in India and Ukraine. Ideally, these averages or composites for the model counterfactuals should be separated into two additional categories, one for urban driving and one for country (highway) driving.

Gas-to-Liquids (GTL) technology involves the conversion of natural gas to a number of liquid synthetic fuels. GTL technology provides three potential methods for reducing greenhouse gases, including; (1) a cleaner burning diesel that will facilitate fuel replacement, (2) a means for converting natural gas that would otherwise have been flared, and (3) a low-sulfur fuel that allows for the development of advanced, fuel-efficient compression-ignition diesel engines. However, at this time, none of these potential emission reduction methods will require the development of an emissions benchmark for inclusion in the technology matrix. Fuel replacement projects are not likely to qualify as additional under a flexible, market-based carbon offset program because traditionally such projects are developed in response to local air quality regulations. Flared natural gas projects do not require the development of an emissions benchmark because the metered amount of gas recovered will provide an estimate of the greenhouse gas reductions. Finally, advanced clean-burning diesel-engines have not yet reached beyond the early development stage, making it unnecessary to develop an emissions benchmark at the present time.

The Qualitative Baseline for Coalbed Methane Recovery

In some countries, such as India, interest in coalbed methane recovery is growing because it is seen as a means of recovering a potentially valuable, indigenous source of energy. Given India's interest in coalbed methane as a potentially large, valuable resource, and the current circumstances surrounding the country's mining industry, it is quite possible that, in India, coalbed methane recovery efforts may proceed independently of mining. It was thus necessary to consider both possible types of coalbed methane recovery projects: those carried out independently as well as those undertaken as a concomitant to mining.

It was concluded that a benchmark (and a model counterfactual) is not required to estimate the methane emission reductions resulting from these projects. If a particular coalbed methane recovery project is undertaken in association with a mining operation, the resulting methane emission reductions can be estimated on the basis of measurements of the quantity of methane recovered. If a project is undertaken independently of mining, it will not reduce methane emissions (unless and until the seam is mined).

The model counterfactual for estimating the carbon dioxide emission reductions resulting from a coalbed methane recovery project depends on the uses to which the methane is put:

- If the recovered gas is used to generate electricity on-site, either for on-site use or for sale to the grid, the composite approach used to define the model counterfactual and benchmark for other small-scale power generation projects (e.g., wind turbine projects) should be applied. Specifically, for India the counterfactual should represent a composite of all recently-built capacity, with a benchmark equal to the average heat rate for this new capacity. For Ukraine, the model counterfactual should be a composite of all existing capacity, with a benchmark equal to the average emissions rate for the Ukrainian electricity sector.

- A benchmark cannot be supplied for coalbed methane recovery projects involving the transfer of the recovered gas to a natural gas pipeline, due to the high degree of uncertainty surrounding the nature of the model counterfactual, and the ultimate uses of the recovered gas, for such projects. However, project developers may use the project-specific approach to demonstrate their claim to carbon dioxide emissions resulting from such projects.

The Qualitative Baseline for Energy-Plex Projects

The concept of the energy-plex forms the core of "Vision 21," NETL's program for developing clean energy plants for the twenty-first century. Essentially, an energy-plex is conceived of as an advanced, ultra-high efficiency, fully-integrated energy production facility capable of producing multiple energy products (e.g., electricity, steam, liquid transportation fuels, chemicals, hydrogen, etc.) from a variety of fuel inputs. Energy-plex plants would be designed to maximize efficiency, by maximizing the utilization of the various fuel inputs. The ultimate goal would be to use as much of the energy in the fuels as possible. The energy-plex would utilize advanced technologies such as IGCC, fuel cell/turbine hybrids, and indirect liquefaction. These technologies would be developed as modular components, which could be combined in a variety of ways to meet site-specific market requirements.

Rather than attempting the full-scale development of quantitative benchmarks for energy-plex projects, it became necessary to consider, in broad outline, a potential benchmark development approach geared to this highly complex set of technologies. The energy-plex concept is a very advanced idea that remains at this point in the initial "drawingboard" stage. Because any benchmark developed at this point would prove obsolete by the time it is used, benchmark development for the energy-plex concept should be postponed until that concept has reached a more mature stage of development.

However, future development of benchmarks for energy-plex projects must differ from that used for the other technologies covered in this document, as the energy-plex concept represents an integrated system of advanced technologies. The project-specific approach is a very reasonable option for the energy-plex concept, and should be given careful consideration as the concept matures and moves closer to deployment. However, the technology matrix approach may also be worthy of consideration, if it can be tailored to provide a set of benchmarks for each of the modules comprising the energy-plex, rather than a single benchmark.

Data Analysis and Benchmark Development

Following the definition of the model counterfactuals, these counterfactuals were quantified by estimating the emission rate (or heat rate) benchmarks for each technology/country combination. The benchmarks were developed based on an analysis of data collected for the electricity and transportation sectors in India and Ukraine. Subsets of the databases that meet the criteria necessary for benchmark development were identified and selected for further analysis. In some cases, data were rejected because they were determined to be outliers, or because they appeared to be suspect in some way. The remaining data were used to compute the benchmarks. In general, the benchmark was computed as the average emission rate (or heat rate) for the facilities or vehicles included in the final data subset.

Benchmarks have not been computed for many of the technology/country combinations, because the data required to compute the benchmarks were not available in time for this draft report. Data collection is proceeding in both Ukraine and India, and new benchmarks will be added to Table 15 of Chapter 4 in later versions of this report. Benchmarks were, however, developed for two of the electricity generation technologies in India, as described below.

Electricity Generation Technologies in India

Two separate databases were obtained on Indian power plants. The first of these was the Utility Data Institute (UDI) database, which includes both operating and planned units. For each generating unit, the UDI database provides data on a variety of items, including: utility, power plant, and unit name or identifier; unit location (city and State); operating status; prime mover; nameplate capacity; year of commissioning; primary fuel type; and, alternate fuel type. Shortcomings of the database include: lack of data on power plant efficiency or heat rates; and lack of data on the two items that could be used to compute heat rates--fuel consumption and net generation. Since estimation of the benchmarks requires heat rate data, the UDI database was not sufficient in and of itself for our purposes.

The second database was originally developed in support of a U.S. Environmental Protection Agency (EPA) study of the benchmarking approach to flexible, market-based carbon offset project analysis. This "EPA database" does not cover the entire population of generating units. Furthermore, the database provides data at the power plant level, and it is limited to coal-fired plants. The informal data gathering technique utilized for this database falls short of a statistical sampling approach. Nonetheless, the EPA database provides excellent coverage of India's coal-fired power plants. Furthermore, the EPA database provides a time series of fuel consumption and net generation data for each generating unit. Specific items provided by the EPA database include: power plant name; number of generating units and unit capacities; location (State); prime mover; year of commissioning; average calorific value of the coal consumed; coal consumption; and net generation. The coal consumption and net generation data are provided on an annual basis for the period 1990-99. Use of this database allowed for computation of annual heat rates for each power plant. However, one serious drawback of the database is that it provides only a single calorific value for the coal used by each power plant.

Two of the power generation technologies (i.e., supercritical steam and IGCC) require benchmarks representing the average or typical heat rates for newly-built, subcritical steam turbine units utilizing pulverized coal as the primary fuel. While the EPA database provides the necessary data to support benchmark development for these two technologies, it will not support the development of benchmarks for the three remaining power generation technologies. Since the EPA database covers only coal-fired plants, and the model counterfactual for natural gas combined cycle technology was defined as a gas-fired steam turbine plant, a benchmark for this counterfactual could not be developed. Because the limitations of the EPA database do not allow the development of alternatives to coal-fired benchmarks, the focus was limited to the development of the standard country-wide benchmarks for supercritical steam and IGCC. In defining the group of power plants that will form the basis for the benchmarks (i.e., the "benchmark group") for both of these technologies, this study was limited to recently built plants—specifically, plants opened in the last five years.

Five power plants formed the final benchmark group for supercritical and IGCC technology in India. With one exception, these plants comprise two generating units; there are a total of 11 units. Furthermore, most of the units (6) are 210 MWs in size, suggesting that they may to at least some degree utilize a standardized design. The total capacity of the five plants is 2970 MWs. This represents 3.0 percent of India's total coal-fired capacity, and 24.4 percent of coal-fired capacity opened since 1995—a good-sized sample.

Because the EPA database does not provide the data necessary to compute accurate annual heat rates, for benchmark development purposes, the study was limited to the computation of an average life-of-plant heat rate (possibly excluding the first year of operation) for each plant. The benchmark for supercritical coal and IGCC technology was found to be 10,211 Btus/kWh (10.211 MMBtus/MWh), the average life-of-plant heat rate for the five benchmark power plants. A heat rate value, rather than an emissions rate value, is used as the benchmark to enable a more accurate computation of baseline emissions using coal-rank specific emission factors.

Updating the Benchmarks. It will be necessary to select a new benchmark group of power plants on a periodic basis, to reflect changes or improvements in the operating efficiencies of new coal-fired power plants. It is believed that re-estimation once every 5 years will be sufficient to keep the benchmark up to date, since the average heat rate of new conventional steam turbine plants tends to be fairly stable over time.

The benchmark group of power plants provides a means of benchmarking projects, not just at project initiation, but throughout the projects' lives. By continually updating the data on the average heat rate for the five Indian power plants selected as the benchmark group, systemic changes in heat rates over time can be captured. The benchmark group provides a means of quantifying what would have happened in the absence of the project, not just at project initiation but throughout the project's life.

Data Quality Assessment. It is clear that the EPA database, used as the basis for the benchmark, is problematic and suspect in a number of respects. This reality resulted in the elimination of two of the seven potential candidates for inclusion in the benchmark group, thereby significantly reducing the size and scope of the sample. The benchmark estimate of 10.211 MMBtus/kWh may suffice for the purpose of this report—i.e., to explain the technology matrix concept and to illustrate, in broad outline, the procedure for developing the matrix. However, given both the known and potential unknown data problems, this benchmark does not likely meet the criteria for application to actual flexible, market-based carbon offset projects. The data upon which it is based must first be improved.

Beyond the immediate data problems, it is clear that what is really required of India is not simply a better database, but the institutional capacity needed to support the data requirements expected to be necessary for the successful implementation of an international carbon offset program. Informally obtained, un-verified, ad hoc databases cannot serve the long-term requirements of benchmarking. For one, the data collection effort must be extended to include all of India's power plants, or at least a statistically representative sample of plants. Further, the needed data must be collected on a regular, periodic basis to support the benchmark updating process. Most importantly, the data must be subjected to validation and verification procedures, to ensure a reasonable degree of accuracy. To support benchmark development for the Indian power sector, some sort of data collection agency will need to be established. To build this institutional capacity, India and other developing countries planning to participate in an international carbon offset program may require both financial and technical assistance from developed countries.

Conclusion and Recommendations for Further Work

Summary

This report illustrates the development of the technology matrix for ten selected technologies in India and Ukraine. For each technology/country combination, additionality (or non-additionality) was established. Then, the model counterfactual—the most likely alternative to projects utilizing the technology—was defined. Data of the type required to estimate emission rates were collected for the two countries. The available databases were analyzed, and subsets of the data that could be used to represent the model counterfactuals were selected. These data subsets were checked for outliers and suspect data. Finally, the "cleaned" data subsets were used to compute emission rate (or heat rate) benchmarks for each technology and country.

The results of this process are shown in Table 2. This table *is* the technology matrix for the ten selected technologies in India and Ukraine. The table indicates which particular technology/country combinations qualify as additional, and which are non-additional. It also provides an emissions benchmark for each combination.

The technology matrix is designed to significantly reduce the costs associated with the evaluation of flexible, market-based carbon offset projects. It is therefore very simple to use. Project developers would first determine whether or not their projects meet the criteria that would allow them to use the technology matrix. Essentially, projects involving the development of *new* capacity, to meet *new* demand, qualify for use of the technology matrix. On the other hand, the project-specific approach should be used to estimate the baseline for projects involving modifications to existing facilities or vehicles. If a particular project meets the criteria, the developers would then refer to Table 2 to determine whether or not the project utilizes qualifying technology. If the project technology does not qualify as additional in Table 2, the developers still have the opportunity to demonstrate the project's additionality using the project-specific approach. If the project does utilize technology identified as qualifying in Table 2, it would presumably automatically qualify for emission reduction credits under a flexible, market-based, international carbon offset program.

Once a project has been demonstrated to be additional, using either the technology matrix or the project-specific approach, the appropriate benchmark from the technology matrix can be used to estimate the project's emission baseline for each year the project is in operation. The project's actual emission reductions are subtracted from the emissions baseline to yield the estimated emission reductions in any given year. The developers would receive emission reduction credits equal to the estimated emission reductions.

The technology matrix approach offers a number of potential advantages. It is designed to substantially reduce the costs of project evaluation to project developers. It is similar to benchmarking, but with the addition of a stringent, true test for additionality based on economic and market evaluations of project technologies. Furthermore, the focus on individual technologies rather than sectors or sub-sectors enables the tailoring of benchmarks to groups of projects characterized

Table 2. The Technology Matrix for Ten Selected Technologies in India and Ukraine

Technology	Application/Gas	Country	
		India	Ukraine
Supercritical Coal	All	10.211 MMBtus/MWh	DNA
IGCC	All	10.211 MMBtus/MWh	DNA
Natural Gas Combined Cycle	All	DNA	DNA
Wind Turbine	Off-grid	DNA	DNA
	On-grid	DNA	DNA
Solid Oxide Fuel Cells	Commercial cogeneration	DNA	DNA
	Low-cost fuel	DNA	DNA
	Distributed generation	**UPS**	**UPS**
CNG Vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Hybrid (gasoline/electricity) vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Gas-to-Liquids			
Coalbed Methane Recovery	Methane	**BNR**	**BNR**
	CO_2/Onsite electricity generation	DNA	DNA
	Transfer of gas to pipeline	**UPS**	**UPS**
Energy-Plex	All	**BNP**	**BNP**

DNA: Data Not Available; may become available for subsequent version of this draft report.
UPS: Benchmark Not Provided, use Project-Specific Approach
BNR: Benchmark Not Required
BNP: Benchmark Not Provided

by similar technological characteristics. The resulting benchmarks exhibit a high degree of specificity with respect to both the technological and market characteristics of individual projects.

The technology matrix approach is designed as a supplement to, rather than a substitute for, the project-specific approach. Projects that do not meet the criteria for technology matrix utilization--mainly projects involving modifications to existing facilities or vehicles—would be required to use the project-specific approach. Because the project-specific approach remains the default, the technology matrix approach would presumably not in and of itself eliminate any projects from participation in an international carbon offset program; project developers always have the opportunity to use the project-specific approach if they cannot use the technology matrix.

Again, the technology matrix developed in this report, and presented in Table 2, is for illustrative purposes only. It is not intended to represent the final, definitive technology matrix for the ten selected technologies in India and Ukraine. Rather, the goal has been to highlight the main issues associated with matrix development, and to bring the strengths and limitations of the technology matrix approach into sharper focus, through the development of a concrete, illustrative example.

Recommended Technology Matrix Development Improvements

Through this approach, we have been able to identify two key areas where further improvements in the technology matrix development process are needed. First, the process of defining the model counterfactual is highly subjective, relying as it does on expert opinion and judgment. Given the subjective nature of the model counterfactuals, it is important that they be selected based on a broad consensus rather than the opinions of a few individuals. Thus, we would recommend the use of a Delphi approach to define the model counterfactuals for any future versions of the technology matrix.

Second, the data available to support baseline development is not adequate to the task, at least in the case of India. We wish to emphasize that, in our belief, this conclusion holds not only for the technology matrix approach, but also for *all other* baseline development approaches that have been discussed in the literature. Although the specific data requirements will vary somewhat from one approach to another, we believe that all of the various approaches will have some basic requirements in common.

All baseline development approaches will require data on a *continuing* basis, so that the emission baselines can be updated periodically. India does not at present possess the institutional capacity required to provide the needed data updates. To meet the expected data needs of a flexible, international carbon offset program, either the existing data collection agency must be upgraded, or a new agency must be established to collect and validate the needed data. To build this institutional capacity, India and other developing countries planning to participate in such a program may require both financial and technical assistance from developed countries.

Recommendations for Further Work

Rather than further development of the technology matrix at this point in time, we recommend a shift in focus to the *marketing* of the technology matrix concept. As yet, this concept is not well known beyond NETL. The marketing effort could begin with the wider dissemination of the report *Developing Emission Baselines for Market-based Mechanisms: A Case Study Approach*. This report lays the groundwork for the technology matrix approach, and is in many ways a prerequisite to the present report. Dissemination of the earlier report should be followed up with the finalization and dissemination of this present report. The preparation of one or more papers summarizing the key findings in the earlier and the present report would be a logical next step. Conferences, where these papers could be presented, should be identified. In addition, one or more articles summarizing the reports might be prepared for publication in appropriate journals. NETL attendance at flexible, market-based program-related conferences and workshops should perhaps be stepped up, and full advantage should be taken of any opportunities to disseminate the reports, papers, and articles at such events. Finally, some consideration might be given to the possibility of an NETL-sponsored workshop, to explore various approaches to flexible, market-based carbon offset project evaluation, including the technology matrix.

1. INTRODUCTION

Background: Market Mechanisms

Concern about increasing atmospheric concentrations of carbon dioxide and other greenhouse gases, and the potential impact of these increases on the earth's climate, has grown significantly over the past decade. This concern has led to a series of international meetings and agreements seeking to stabilize atmospheric greenhouse gas concentrations. In 1992, at Rio de Janeiro, more than 160 countries including the United States signed the United Nations Framework Convention on Climate Change (UNFCCC). There was widespread agreement among the signatories on the potential negative effects of climate change under a business as usual future. Under the Convention, the developed countries (referred to as Annex I countries) were assigned primary responsibility for addressing the climate change issue. However, at the first two Conferences of Parties[2] called to discuss methods for implementing the Convention, there were strong disagreements on what policy instruments should be used to curb global climate change, and what, if any, targets and timetables should be set for achieving emission reductions. Most Annex I nations announced a series of voluntary targets and initiatives for meeting emission reduction goals.

By 1996, it had become clear that greenhouse gas emission levels in most Annex I countries were rising despite voluntary efforts to reduce emissions. A consensus for firmer targets and timetables was building. At the Third Conference of Parties, held in Kyoto, Japan in December 1997 a series of firm emission reduction targets were agreed to by the Parties. Developed countries agreed to reduce their greenhouse gas emissions by an average of 5.2 percent from 1990 levels by 2008-2012. However, the U.S. Senate never ratified this agreement and international negotiations on this agreement have stalled. Yet, a key element to the Convention and the Kyoto agreement is the introduction of a new concept, market mechanisms, designed to facilitate low-cost solutions to environmental problems. This new concept awards credits for emission reduction activities undertaken beyond a country's boarders.

The emission reduction activities could take the form of carbon-offset projects initiated between two developed countries or between a developed country and a developing country. Either way the host country receives the benefits of the technology transfer resulting from the project while the project developers receive any emission credits resulting from the project's emission benefits. It is important to recognize that market mechanisms are *not* designed to reduce global greenhouse gas emissions beyond any potential emission reduction targets specified in an international agreement. Rather, the purpose of market mechanisms is to increase flexibility and reduce the *costs* associated with meeting emission reduction targets. As envisioned market mechanisms provide a one-to-one trade between host countries and project developers. Thus, at least in the ideal, market mechanism projects will

[2]The Conference of the Parties (COP) is the supreme body of the United Nations Framework Convention on Climate Change established in 1992. The body meets annually and its primary responsibility is to oversee the implementation of the Convention and the Kyoto Protocol. The Fifth Conference of Parties (COP5) is scheduled for October 25, 1999 to November 5, 1999.

yield no net change in global emissions. In short, it is the emission reduction targets, and not the market mechanisms, which will act as the driving force for reducing global greenhouse gas emissions.

The Technology Matrix

Developing accurate estimates of the emission reductions arising from carbon-offset projects is perhaps the most challenging – and problematic – issue surrounding the market mechanisms. In order to estimate these reductions, the emissions generated by the project itself must be measured and subtracted from some baseline representing what emissions would have been in the absence of the project. Because it requires estimating the emissions that *would have* arisen absent the project – i.e., it requires the estimation of a hypothetical – baseline development in particular is a difficult and complex task, fraught with uncertainty. A number of potential methods for estimating the baseline have been proposed and assessed in the literature. In the U.S. Department of Energy National Energy Technology Laboratory's (NETL) report *Developing Emission Baselines for Market-Based Mechanisms: A Case Study Approach* (February 2000), one of these methods is explored and recommended for further development: the modified technology matrix.[3] The present report builds on this prior report, by providing an illustration of the development of the technology matrix for two developing countries: India and Ukraine.

The modified technology matrix, proposed by NETL and illustrated in Table 3, consists of a selected list of greenhouse gas abating technologies. For a technology to "qualify" for the list, it must first be subjected to a rigorous test to demonstrate that projects utilizing the technology are additional to those that would have been implemented under "business-as-usual" circumstances. This "additionality" criteria is a key concept for project certification within a market mechanism environment. For the technology matrix, the additionality test should be based on factors such as the commercial viability and market penetration of the candidate technology. The test would be designed to ensure that only advanced, non-commercial technologies qualify as additional in the matrix.

Once a technology has been qualified as additional, a stipulated benchmark will be developed for that specific technology based on the emissions performance of a counterfactual technology(ies). The counterfactual technology would represent that technology most likely to be utilized, if the corresponding advanced-technology project were to be foregone. To qualify their projects for credit, project developers would simply demonstrate that the proposed project technology is included in the technology matrix. The stipulated benchmark from the matrix would then be used to calculate the project's emission reductions.

Advantages of the Technology Matrix Approach

The modified technology matrix is not a panacea. Because it focuses on advanced, non-commercial technologies, it cannot be used to qualify projects utilizing conventional commercial technologies.

[3] We will refer to the modified technology matrix simply as the technology matrix in this report.

Since some of these projects may in fact be additional, the technology matrix approach must be supplemented with another approach to assess projects utilizing conventional technologies.[4] However, despite this limitation, the technology matrix offers a number of potential advantages over other proposed approaches. First and foremost is cost. The technology matrix approach dramatically reduces the project evaluation costs that must be incurred by project developers. To demonstrate additionality, the project developers need only provide evidence that they are utilizing one of the qualifying technologies included in the matrix. No analysis is required.

Furthermore, the matrix will provide project developers with a benchmark emissions rate for their technology; using this emissions rate, the development of a baseline will be reduced to a trivial exercise. Project evaluation requirements have proven substantial for many projects undertaken under Joint Implementation (JI). The JI projects were not evaluated according to any pre-specified protocols; rather individual ad hoc emission reduction estimation procedures were tailored to each project. This "project-specific" approach enables project developers to capture and incorporate the impact of site-specific factors into their emission reduction estimates. However, the costs of developing and implementing a detailed project evaluation procedure, incorporating numerous site-specific factors, have proven to be quite high. There is concern that high evaluation costs could act as a significant barrier to the implementation of emission reduction projects. By reducing project evaluation costs, the technology matrix will help to lower the cost barrier and foster investment in advanced, emissions-reducing technologies.

While the costs of *using* the technology matrix, incurred by project developers, will be small, developing and maintaining the matrix will require significant expenditures.[5] However, total transaction costs, summed across project developers and governments, should still be substantially lower for the technology matrix approach than for the project-specific approach, because with the former costs are in effect shared for all projects using a particular technology. Using the project-specific approach, each individual project will incur significant costs; using the technology matrix approach, there are substantial up-front costs involved in developing the matrix, but transaction costs for individual projects are negligible.

Another key advantage of the technology matrix is that it provides an effective, rigorous test for additionality. Only projects utilizing advanced, non-commercial technologies will qualify as additional using the technology matrix. Yet while this additionality test is rigorous, at the same time the technology matrix is "forgiving." The technology matrix does *not* eliminate projects using conventional non-qualifying technologies. Instead, project developers will be offered the opportunity to demonstrate the additionality of these projects using the project-specific approach.

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[4] In the above-referenced NETL report, the project-specific approach is recommended for evaluating commercial-technology projects.

[5] These costs will presumably be borne by governments and, perhaps, international aid organizations.

Table 3. Example of a Portion of the Technology Matrix

Countries / Qualifying Technologies	India	China	Argentina	South Africa	Egypt	Philippines	Indonesia	Brazil
Super-Critical Steam Cycle Technology (SCSC)	B_{SCSC-I}	B_{SCSC-C}	NA	$B_{SCSC-SA}$	NA	B_{SCSC-P}	$B_{SCSC-In}$	B_{SCSC-B}
Coal-Fired Integrated Gasification Combined Cycle (IGCC)	B_{IGCC-I}	B_{IGCC-C}	NA	$B_{IGCC-SA}$	NA	B_{IGCC-P}	$B_{IGCC-In}$	B_{IGCC-B}
Solid Oxide Fuel Cells (SOFC)	B_{SOFC-I}	B_{SOFC-C}	B_{SOFC-A}	$B_{SOFC-SA}$	B_{SOFC-E}	B_{SOFC-P}	$B_{SOFC-In}$	B_{SOFC-B}
Phosphoric Acid Fuel Cells (PAFC)	B_{PAFC-I}	B_{PAFC-C}	B_{PAFC-A}	$B_{PAFC-SA}$	B_{PAFC-E}	B_{PAFC-P}	$B_{PAFC-In}$	B_{PAFC-B}
Molten Carbonate Fuel Cells (MCFC)	B_{MCFC-I}	B_{MCFC-C}	B_{MCFC-A}	$B_{MCFC-SA}$	B_{MCFC-E}	B_{MCFC-P}	$B_{MCFC-In}$	B_{MCFC-B}
Photovoltaics (PV)	B_{PV-I}	B_{PV-C}	B_{PV-A}	B_{PV-SA}	B_{PV-E}	B_{PV-P}	B_{PV-In}	B_{PV-B}
Pressurized Fluidized Bed Combustion (PFBC)	B_{PFBC-I}	B_{PFBC-C}	NA	$B_{PFBC-SA}$	NA	B_{PFBC-P}	$B_{PFBC-In}$	B_{PFBC-B}

Notes: 1) B = Benchmark value for estimating project baseline emissions.
2) Shaded Areas = Not Qualifying. Represents technology choices that do not qualify as additional in a given country.
3) NA = Not Applicable. Represents country/technology combinations that do not fit national sustainable development objectives.
4) This table represents a hypothetical selection of host countries, technologies, and benchmarks that are included mainly for illustrative purposes.

Furthermore, if the project developers can demonstrate additionality, they will still be able to use the benchmarks provided by the matrix to quantify their project baselines. Thus, even project developers using conventional technologies will still be able to reap a portion of the cost benefits provided by the matrix. In effect, the technology matrix approach is offered as a cost-cutting supplement to the project-specific approach. No one is excluded from participation in the market mechanisms on the basis of the technology matrix alone. Project developers *may* use the matrix if their project meets certain rigorous additionality criteria; if not, they can still fall back on the project-specific approach to prove additionality.

Unlike the project-specific approach, the technology matrix approach is amenable to a high degree of standardization. Use of the matrix will help to ensure a "level playing field" both within and across countries. Furthermore, the technology matrix provides a relatively objective, transparent approach to baseline development.

The benchmarks included in the technology matrix should provide a reasonably accurate basis for quantifying the baseline. It should be emphasized that use of these benchmarks will be restricted to projects for which more accurate, site-specific data will be lacking. For example, in the power generation sector only projects involving the opening of new capacity will be allowed to use the benchmarks. Projects involving modifications to existing capacity (e.g., heat rate improvements) will be required to use the project-specific approach. The rationale behind this rule is that, for a project involving a modification to an existing power plant, it should be possible to compute a more accurate baseline using historic data for the plant than using a sectoral benchmark. On the other hand, for projects involving the opening of new power plants, relevant site-specific data will not exist; in such cases a sectoral benchmark will offer as accurate an approach as is obtainable, assuming that the benchmark is developed in a careful manner.

While the benchmarks included in the matrix will necessarily be generic, they will nonetheless be based on a careful consideration of likely counterfactuals for specific technologies, if not specific projects. For this reason, the technology matrix benchmarks should prove more realistic, and accurate, than the sectoral benchmarks that have been proposed under the benchmarking approach. The latter benchmarks are neither project- nor technology-specific, and this will likely prove a source of errors. Under the technology matrix approach, it is recognized that the counterfactual for a natural gas combined cycle project may differ from the counterfactual for an IGCC project; separate benchmarks for these two technologies are thus provided. Thus, although the detailed specifics of each individual project are not considered when developing the benchmarks, the broad technological characteristics of groups of similar projects are considered. This ensures that the benchmarks will be based on realistic counterfactuals, and that they will provide a reasonable degree of accuracy.

The Technology Matrix and Additionality. But most importantly, the technology matrix approach provides an effective, rigorous additionality screen that directly addresses the core issue underlying the additionality concept: would the project have occurred anyway absent the favorable developed-country financing attainable via the market mechanism(s)? Because only advanced, non-commercial technologies will qualify as additional under the technology matrix approach, virtually all projects that do *not* require the financial assistance provided by the developed country sponsors will be screened out by the matrix.

This is in direct contrast to many of the other benchmarking approaches that have been proposed for carbon-offset project evaluation. These approaches rely on a simple numeric comparison of a project's emission rate with a benchmark emission rate to determine additionality. If the project emission rate falls below the benchmark, the project is deemed additional; otherwise, the project is assumed to be non-additional. This simple numeric comparison of two emission rates does not address the core issue of the project's economic viability. For this reason, it is anticipated that, if used, a simple benchmarking approach will result in the misclassification of a large number of non-additional projects as additional (and vice versa). For example, in the power sector all projects involving new and existing hydroelectric and nuclear facilities will qualify as additional, without even considering the question of whether or not they represent "business-as-usual." Depending on how the benchmark is set, many natural gas projects will also qualify as additional, regardless of their viability absent market mechanism incentives. On the other hand, coal-fired projects involving advanced technologies such as IGCC will probably be classified as non-additional, even though such technologies are not commercially viable at present.

Here it is important to recognize the primacy of the additionality issue. The most important factor influencing the level of error in credits generated is the treatment of additionality during the process of baseline development. A fundamental dilemma presents itself when assessing potential tests for additionality. This dilemma is illustrated in Figures 1 and 2, which provide a hypothetical distribution of GHG reduction projects once market mechanisms enters into effect. In the figures, we imagine the potential universe of carbon-offset projects, distributed according to the relative ease or difficulty of demonstrating additionality.

In Figure 1, a rigorous test for additionality is applied; only those projects to the left of the dashed line will qualify to receive credits under this test. As shown, many additional projects will be mis-classified as non-additional. In Figure 2, the test for additionality is relaxed. As a result, most additional projects now qualify for credits, but a large number of non-additional projects will be mis-classified as additional.

Faced with this dilemma, it might be thought that the best additionality test is one that is not too rigorous and not too relaxed. Such an approach, illustrated in Figure 3, will lead to a random distribution of classification errors, in which the number of non-additional projects mis-classified as additional will approximately equal the number of additional projects mis-classified as non-additional.

Figure 1. Projects Qualifying as Additional Under a Rigorous Additionality Test

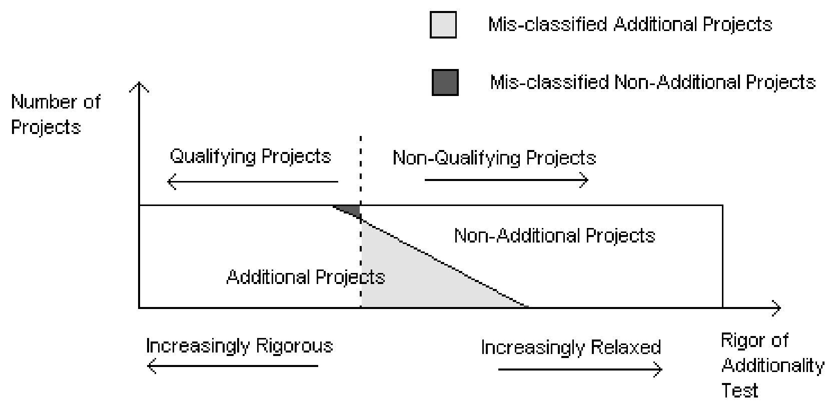


Figure 2. Projects Qualifying as Additional Under a Relaxed Additionality Test

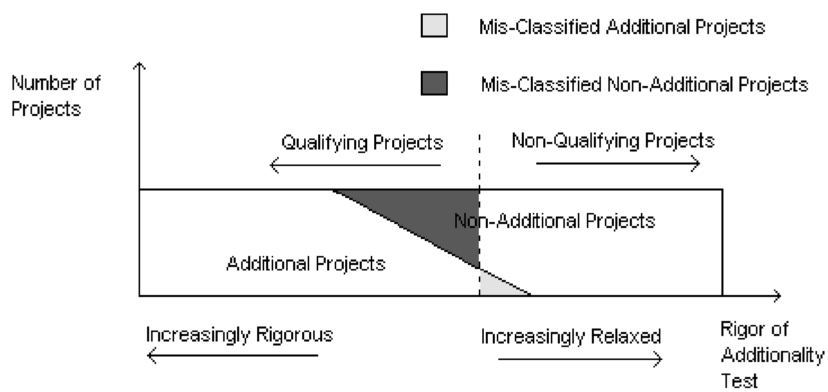
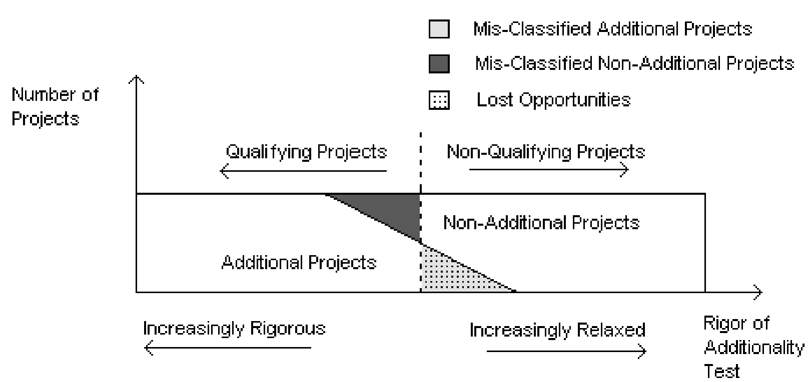


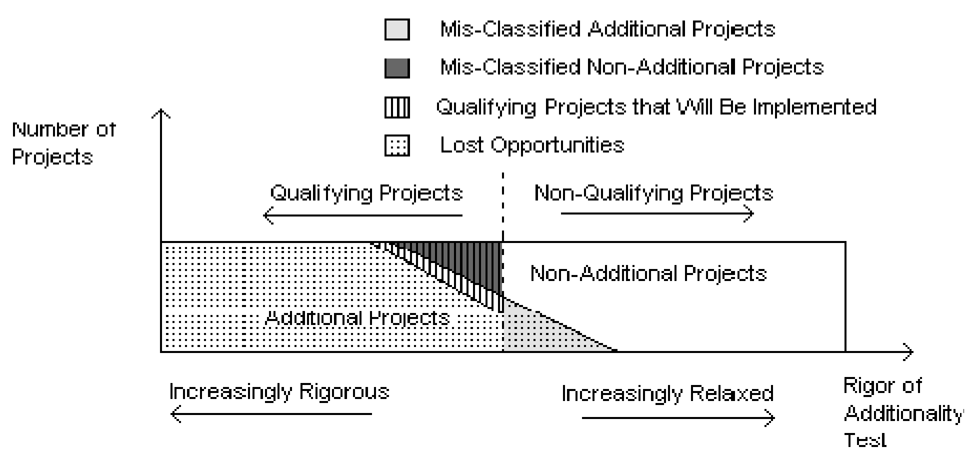
Figure 3. Classification Errors and Lost Opportunities Under a "Mid-Range Additionality Test



This approach might be regarded as the ideal, because the classification errors will cancel each other out. But, a closer analysis will reveal that the errors will not cancel. In fact, *random* errors in the classification of projects according to their additionality status will lead directly to *systematic* errors in emission reduction estimates. Why? If a non-additional project is approved as additional, it will be undertaken, and it will be awarded credits. However, if an additional project is mis-classified as non-additional, it will not be undertaken, because by definition an additional project will not be implemented absent the awarding of credits. The resulting "lost opportunities" (Figure 3) will drive up the costs of meeting emission reduction goals, but the estimation of total emission reductions will remain unaffected. However, when a non-additional project is mis-classified as additional, emission reductions are overestimated, and global reduction efforts may consequently fall short of reduction targets. This asymmetry, arising from the very definition of additionality, ensures that even randomly distributed classification errors will lead to biased emission reduction estimates.

However, this is not the only source of biases. Given a relatively "loose" additionality test, that mis-classifies significant numbers of non-additional projects as additional, project developers will preferentially invest in these non-additional projects at the expense of additional projects. By definition, additional projects require the financial and other aid provided by Annex I countries in order to be viable. Non-additional projects, by definition, do not require this aid in order to be viable. In short, non-additional projects tend to be more economically attractive than additional projects, and the former will be preferred over the latter. These investor biases will lead to further lost opportunities (Figure 4), and further systematic errors in the estimation of emission reductions.

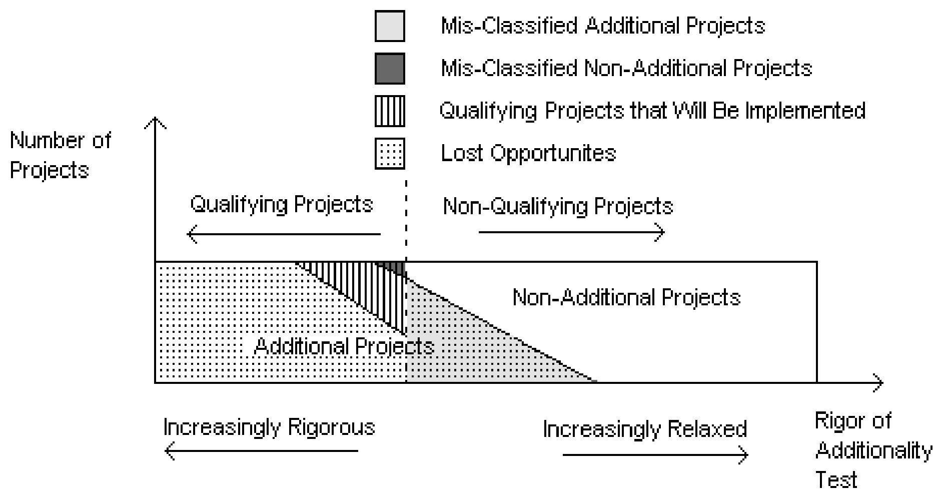
Figure 4. Investor Preferences for Qualifying Non-Additional Projects



Finally, for all projects that are ultimately implemented, additionality classification errors *always* lead to emission reduction estimation errors equal to 100 percent of the estimated project reductions.

To summarize, additionality classification errors lead to estimation errors that are highly systematic and very large in magnitude. These estimation errors can be minimized, but only through the application of rigorous additionality tests (as illustrated in Figure 5). It should be noted that the costs of rigorous testing, measured in terms of “lost opportunities,” should not differ greatly from the costs of “looser” testing. This can be seen by comparing the lost opportunities shown in Figure 4 with those shown in Figure 5. These figures illustrate that, regardless of the rigor of the additionality test, the “borderline” additional projects falling in the middle third of the diagram are to a large extent lost opportunities. Given rigorous additionality rules, these projects will fail to qualify for crediting; given more relaxed rules, they will be foregone by project developers in favor of non-additional projects. It is true that transaction costs will be lower under less rigorous testing regimes, but these low costs may primarily benefit project developers seeking to qualify non-additional projects.

Figure 5. Use of a Rigorous Additionality Test to Minimize Emission Reduction Estimation Errors



Rigorous additionality testing should thus prove both cost-effective, and the best means of guarding against large systematic biases in emission reduction estimates. Unlike other types of benchmarking approaches, the technology matrix approach provides a rigorous, cost-effective screen for additionality.

In short, the technology matrix represents a cost-effective, objective, transparent, and reasonably accurate approach to quantifying project emission baselines. As a supplement to the project-specific approach, it offers significant cost advantages to projects meeting certain criteria, without eliminating from consideration projects that do not meet these criteria.

Objectives of the Present Study

As noted above, NETL has already proposed and evaluated the technology matrix in an earlier report. The purpose of the study documented in this report is to build on that earlier report, by illustrating the development of the technology matrix for a few selected countries and technologies. By undertaking the process of actually building the matrix for a few specific examples, we hope to highlight the key issues that must be addressed during matrix development, identify the data requirements, determine the availability of data to meet those requirements, and assess, in broad terms, the quality of the available data. Furthermore, through the development process the strengths and limitations of the technology matrix approach will be brought into sharper focus.

We wish to emphasize that this initial attempt at matrix development is exclusively illustrative in nature; it is *not* intended to rise to the level of accuracy or peer acceptance necessary to provide a basis for the transfer of emission reduction credits with monetary value. On the contrary, this report is offered as a starting point for further discussion and debate on the merits and limitations of the technology matrix approach, and on ways to improve the approach. As shall be discussed in greater detail in Chapter 3, many of the judgments made during the development of the matrix, concerning the nature of the project counterfactuals, are necessarily subjective in nature. This subjectivity reflects the fact that the judgments address a hypothetical issue; namely, what *would* have happened in the absence of the project. The authors by no means wish to suggest that the judgments made herein, for illustrative purposes, should stand as the final basis for the technology matrix. Rather we would encourage evaluation and discussion of these judgments, as a means of moving towards a peer consensus on the project counterfactuals.

Similarly, the data used as the basis for the benchmarks derived in Chapter 4 are deficient in a number of respects (as shall be discussed in greater detail in that chapter). Again, the goal is not to quantify the final, definitive benchmarks, but rather to illustrate, in a general sense, the procedures for benchmark development, to determine the extent to which the available data can support these procedures, and to identify the improvements in the existing data that would need to be made before full-scale technology matrix development could begin. In short, this report is offered as an initial exploration of the technology matrix approach, to introduce the concept in a concrete manner, through illustrative examples, to define the key issues associated with matrix development, and to suggest possible options for further development of the concept.

Two countries and ten technologies have been selected for inclusion in the initial technology matrix. The two countries are India and Ukraine. As a large country with a rapidly growing economy and a heavy reliance on coal, India offers innumerable opportunities for reducing greenhouse gas emissions in the coming decades. Furthermore, NETL is already involved in emission-reducing projects in India, and thus has extensive contacts in-country. These contacts should, among other things, help to ensure the timely collection of the data needed for matrix development.

Similarly, key contacts have already been established in Ukraine, which should help during the data collection effort. Furthermore, although the Ukrainian economy has not yet recovered from the breakup of the former Soviet Union (FSU), Ukraine is likely to offer significant low-cost emission-reducing opportunities in the coming years. These opportunities arise in part because Ukraine is heavily dependent on coal, and also because the FSU was and still is highly inefficient in its use of energy.

The ten technologies selected for initial consideration include five electric power generation technologies, three transportation/transportation fuel technologies, and two other technologies. The specific technologies are as follows:

- Power generation:
  - Supercritical coal
  - Integrated Gasification Combined Cycle (IGCC)
  - Natural gas combined cycle
  - Fuel Cells
  - Wind turbines

- Transportation
  - Compressed Natural Gas (CNG) vehicles
  - Hybrid (electric-gasoline) vehicles
  - Gas-to-Liquids (new diesel)

- Other
  - Coalbed methane recovery
  - Energy-plex projects

Outline of the Study Approach and Overview of the Report's Organization

The basic technology matrix development approach is the same for all of the above technologies, and for both countries. First, the additionality of each technology is determined, based on (1) an assessment of the technology's economic viability vis a vis current commercial technologies, and (2) a consideration of the market penetration achieved by the technology, throughout the world and in the country in question. If, based on these two tests, the technology is determined to be non-commercial in a particular country, it is judged additional; projects utilizing such "qualifying technologies" will automatically qualify for emission reduction credits under the technology matrix approach.

Following this test for additionality, the appropriate benchmark(s) is developed for each technology/country combination. In essence, the benchmark for a particular technology is a carbon dioxide emission rate, which can be used to compute the baseline emissions for any project utilizing that technology. There are three basic steps to estimating the benchmark. First, the most likely alternative to the project must be defined in a qualitative manner. For example, the most likely alternative to a coal-fired IGCC power plant might be defined as a conventional pulverized- coal-burning (PC) power plant.

Second, the data required to quantify the benchmark must be collected for each technology/country combination. Returning to our example, if the most likely alternative to an IGCC plant in India is a conventional PC plant, then data on the heat rates of existing Indian PC plants might be used as the basis for the benchmark.

Finally, the collected data is analyzed. In addition to actually computing the benchmarks (based, e.g., on the mean of the collected heat rate or emission rate data), the number and types of benchmarks required for each technology/country combination is determined during the data analysis step. For example, the need for separate benchmarks by region, or by project size, is determined through data analysis. Furthermore, the specific facilities that will serve to benchmark projects throughout their lives are selected during the data analysis step.

The organization of this report is as follows. Chapter 2 documents the additionality analyses for the ten technologies. Chapter 3 defines the qualitative baselines for the technologies in each country, and documents the rationale for our selection of these baselines. Chapter 4 presents the results of the data analyses, including the actual benchmark emission rates. It also identifies data deficiencies and possible options for addressing these deficiencies; it documents the procedures and algorithms that a project developer would use to convert the benchmarks into baseline emission estimates; and it outlines possible options for updating the benchmarks. Finally, Chapter 5 provides a brief overview of the report's main findings and conclusions.

2. ADDITIONALITY ANALYSIS OF POWER GENERATION, TRANSPORTATION, AND OTHER TECHNOLOGIES FOR INDIA AND UKRAINE UNDER THE MODIFIED TECHNOLOGY MATRIX

Introduction

Market mechanisms can provide an opportunity for developing countries to achieve sustainable development and contribute to the objectives of the United Nations Framework on Climate Change, while providing developed countries with a means to comply with greenhouse gas emission reduction commitments. In short, emission reduction projects developed under a market-based mechanism environment provide host countries with project financing and technology and allows project developers to acquire emission reductions credits, which may be applied to its emission reduction goals. A key component of developing market mechanism projects it that they must result in emission reductions that are additional to any that would occur in the absence of the certified project activity (referred to as additionality).

The additionality requirement is particularly important as a means of ensuring the environmental integrity of the credits assigned under carbon-offset projects. Additionality refers to the issue of whether a greenhouse gas abatement or sequestration project will produce emission benefits in addition to those that would have occurred otherwise. In other words, to receive credits for an emission-reducing project, it will be necessary to demonstrate that the project would not have been undertaken were it not for the credits. An additional project is defined as a project that will never be implemented unless the project acquires favorable financing, technology transfer, or other market mechanism-specific assistance. In this context, demonstration of additionality becomes the *de facto* test for determining whether or not a project qualifies for credits. Therefore, procedures for developing emission baselines should include an appropriate method for distinguishing additional from non-additional projects.

Under the modified technology matrix approach to emission baseline development, the test for additionality is based on an examination of the commercial viability (economic feasibility) and market penetration of individual technologies. Technologies that are determined to be commercial on the basis of these two tests are deemed non-additional, while non-commercial technologies are judged additional. The economic feasibility test entails comparing the cost of a specific technology to the cost of alternative technologies to determine if the technology is commercially viable or not. Besides accounting for the cost of implementing the technology itself, factors to be considered include energy costs, environmental regulations, cost of capital, demand growth, tariff structures, etc.
Other considerations to be taken into account include whether construction costs can be predicted with reasonable certainty and whether operational performance can be guaranteed. If the technology is found to be economic without the favorable financing provided via the market mechanism, it will not pass the financial additionality test.

However, if the technology proves to be unable to compete with current market technologies in the same sector, it should qualify as additional. A second additionality test, based on market penetration, can also be applied to account for other barriers to implementation that are more difficult to measure and verify. These other barriers could include risks associated with installing and operating locally unknown technologies, institutional barriers or internal organizational structures that discourage investment in energy sector improvements, and poorly functioning capital markets. If a given technology is determined to have little or no market penetration, it will qualify as additional.

Ideally, the economic feasibility and market penetration tests should work together to establish additionality; however, in some cases, a technology may be commercially viable and any number of non-financial barriers could prevent the technology from being adopted. In this scenario, the market penetration test can be used by itself to establish additionality.

The following sections provide additionality analyses of the ten selected power generation, transportation, and other technologies for India and Ukraine. The power generation technologies examined include supercritical coal, integrated gasification combined cycle, solid oxide fuel cell, natural gas combined cycle, and wind turbine. The transportation technologies include gas-to-liquids, compressed natural gas, and hybrid vehicles. The remaining other technologies are coal bed methane and energy-plex. The results of our analyses are summarized in Table 4. For the power generation technologies, all but one qualifies as additional for India and Ukraine. The sole exception, supercritical coal in Ukraine, does not qualify as additional because the technology is already an important part of the country's coal-fired power generation mix. For the transportation and other technologies, all qualify as additional for India and Ukraine, with the exception of compressed natural gas in Ukraine.

Here it is important to note that the failure of supercritical coal and compressed natural gas to qualify as additional does not bar Ukrainian projects utilizing these technologies from qualifying for credits. Rather, the failure of a technology to qualify as additional means only that project developers using the technology cannot rely on the technology matrix to demonstrate additionality. However, these project developers will be offered the opportunity to demonstrate the additionality of their projects using the project-specific approach. Furthermore, if the project developers can demonstrate additionality, they will still be able to use the benchmarks provided by the matrix to quantify their project baselines. Developers of supercritical coal projects in Ukraine will have to utilize the project-specific approach to prove the additionality of their projects; however, once additionality has been demonstrated, they will be able to use the benchmark for Ukrainian supercritical coal to compute their emissions baseline. This approach allows even project developers using commercial technologies to reap a substantial portion of the cost benefits provided by the technology matrix approach. Projects must still meet the basic criteria outlined in the next chapter in order to use the benchmarks included in the matrix; however, commercial- as well as advanced-technology projects can meet these criteria. In short, the technology matrix approach has wide applicability to projects utilizing both commercial and non-commercial projects, although the former will realize only a portion of the cost savings benefits.

Table 4 . Additionality Analysis for Technologies in India and Ukraine

Technologies		India		Ukraine	
		Additional	Non-Additional	Additional	Non-Additional
Power Generation	Supercritical Coal	X			X
	Integrated Gasification Combined Cycle (IGCC)	X		X	
	Solid Oxide Fuel Cell (SOFC)	X		X	
	Natural Gas Combined Cycle (NGCC)	X		X	
	Wind Turbine	X		X	
Transportation	Gas-to-Liquid (GTL)	X		X	
	Compressed Natural Gas (CNG)	X			X
	Hybrid Vehicles	X		X	
Other	Coal Bed Methane (CBM)	X		X	
	Energy-Plex	X		X	

Power Generation Technologies

Supercritical Coal Technology Additionality Analysis

Economic Feasibility: Supercritical coal-fired power plants are similar in design and operation to subcritical coal-fired plants. The main difference is that supercritical plants operate at higher steam temperatures and pressure, ultimately resulting in higher operating efficiencies. State-of-the-art supercritical coal-fired power plants can reach efficiencies ranging between 42-45 percent, with ultrasupercritical designs achieving up to 48 percent efficiencies. Conventional subcritical plants are between 35-38 percent efficient.

With 350 supercritical plants world wide, the technology is considered to be commercial. Most of these plants are located in countries of the former Soviet Union, with the rest scattered across the United States, Europe, and Japan. Ukraine currently has 12 supercritical units in operation while India does not have any. However, India does have one plant under development (North Madras, Cheyyar, Tamil Nadu) that is slated to use supercritical technology.[6] The 500-MW plant received techno-economic clearance from India's Central Electricity Authority in August 1998 and is being developed by Malaysia's Tri-Sakthi Energy Pvt. Ltd. The project is estimated to cost $500-$600 million.[7] The 12 supercritical units in Ukraine total 6,600 MW, which accounts for nearly 36 percent of Ukraine's total coal-fired generating capacity.

Capital costs of supercritical plants are at least competitive if not equal to conventional, subcritical plants. Capital costs for both technologies range between 800 and 1,200 $/kW. One study on India put the capital costs at 1,000 $/kW for subcritical and 1,150 $/kW for supercritical.[8] Moreover, because higher operating efficiencies result in lower fuel costs, supercritical plants have the capacity to reduce the total cost of electricity generation. In a 1998 report, the IEA estimated electricity generation costs for conventional, subcritical power generation between 4.0 and 6.8 cents/kWh as compared to supercritical power generation estimated at 3.9 – 6.5 cents/kWh. IEA based its analysis on higher and lower fuel and capital cost cases for a 600 MW PC-fired plant in an Asian location. In each instance, the costs of electricity generation for supercritical was lower than subcritical[9]

Based on these numbers, we conclude that supercritical coal technology is indeed commercial and its capital costs are competitive with subcritical technology. With 12 units currently operating, supercritical technology clearly passes the economic feasibility test for Ukraine and cannot be considered additional. For India however, the economic feasibility is not as clear. As noted, one report indicates slightly higher capital costs for supercritical technology in India. Capital costs tend to be very important to a developing country like India when it considers developing new power generation capacity even if a technology like supercritical coal has the potential to lower fuel and electricity generation costs, resulting from higher efficiencies. India needs to continue adding generating capacity in order to meet increasing demand for power, and with limited financial resources to accomplish this, savings on short-term construction costs will likely outweigh saving on long-term operational costs. Because the economic feasibility analysis does not offer a clear picture of additionality for India, we turn to market penetration for further evidence of additionality.

Market Penetration: Since the economics of supercritical technology is competitive with subcritical technology, it would be reasonable to expect the market penetration of supercritical technology to be high. But as noted above, there are only 350 supercritical plants operating world wide (12 units in Ukraine and none in India), and IEA notes that virtually all of the coal-fired power plants scheduled to come on-line in the next five years in non-OECD countries will utilize subcritical technology. Ukraine currently has no coal-fired plants under development and India has only one plant slated to use supercritical technology. The market penetration dominance of subcritical over supercritical

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[6] Couch, Gordon R., *Non-OECD coal-fired power generation – trends in the 1990s*, IEA Coal Research, The Clean Coal Center, June 1999.

[7] India Brief, UDI/The McGraw-Hill Companies, November 22, 1999.

[8] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

[9] Torrens, Ian M. and William C. Stenzel, "Appendix V. Increasing the Efficiency of Coal-fired Power Generation, State of the Technology: Reality and Perceptions," in "Regional Trends, in Energy-Efficient, Coal-Fired Power Generation Technologies," International Energy Agency, Coal Industry Advisory Board, 1998.

technology may have more to do with problems of perception rather than reality. In its 1998 report, IEA notes that a perception exists that supercritical technology is more expensive, riskier, and less reliable than subcritical technology. However, IEA concludes that experience with supercritical technology over the last 30 years shows that its availability and reliability are as good as subcritical technology, and early technical problems stemming from higher operating temperatures have been overcome by metallurgy and equipment design improvements.[10] Moreover, as noted above, the capital costs demonstrate that supercritical technology is not significantly more expensive.

With all of the world's supercritical plants in FSU countries and the developed world, supercritical technology has had little impact on the developing world. IEA notes that developing countries may lack the technical capabilities to engineer and manufacture some components of a supercritical plant. Developing countries may also lack the trained personnel needed to operate a supercritical plant. This certainly is the case for India. In a 1999 report, IEA indicates that India would need to acquire a range of skills and expertise, including design and construction information, to begin widespread use of supercritical technology.[11] As noted, India has started to develop one supercritical plant and has therefore only begun the process of transferring these skills, expertise, and information. "The adoption of supercritical technology, as an indigenous technology in India, would require the acquisition of a range of skills and expertise. The competitiveness of clean coal technologies in India may depend on arrangements whereby information of commercial value can be transferred from the organizations that developed the technology."[12] The same cannot be said for Ukraine however, since it is currently operating 12 supercritical units. Ukraine clearly possesses the skills, expertise, and information necessary to operate and maintain supercritical coal technology.

Conclusion: The additionality of supercritical coal technology cannot be demonstrated though economic feasibility analysis or market penetration analysis for Ukraine. Supercritical technology already encompasses a significant portion of Ukraine's total coal-fired power generation, distinguishing it as economic and as an important part of Ukraine's power generation mix.

The situation in India, on the other hand, is not as clear-cut. Capital costs for supercritical technology are higher than subcritical technology and coupled with virtually no market penetration, the need for technology transfer and training, supercritical coal technology qualifies as additional.

Integrated Gasification Combined Cycle Technology Additionality Analysis

Economic Feasibility: Over the past two decades, numerous research programs and demonstration projects have been implemented to develop and commercialize integrated gasification combined cycle (IGCC) technology. Furthermore, there are five commercial scale coal-fired IGCC plants in operation worldwide. Three of these projects, the Wabash River Coal Gasification Power Plant, Tampa Electric Company's IGCC Project, and Piñon Pine IGCC Project, are in the United States and

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[10] Ibid.

[11] Scott, David and Per-Axel Nilsson, "Competitiveness of future coal-fired units in different countries," IEA Coal Research, January 1999.

[12] Ibid.

have been implemented with financial support from the U.S. Department of Energy's Clean Coal Technology Program. The two most recent plants are in Europe: the Puertollano coal- and petcoke-fired IGCC plant in Spain and the coal-fired IGCC plant in Buggenum, The Netherlands. The U.S. plants use General Electric (GE) gas turbines and have reached an average efficiency of around 40 percent. Both European plants use Siemens gas turbines. In 1998, the Buggenum plant reached an efficiency of 43 percent while Puertollano demonstrated a 47 percent efficiency rate.

In spite of these developments, IGCC technology is still not viewed as a proven, mature technology, particularly in developing countries. The construction costs and construction time of an IGCC plant cannot be predicted with certainty, and the plant's operational performance, such as plant availability, cannot be guaranteed either. Most importantly, IGCC capital costs are higher than the cost of building a conventional coal-fired power plant. Capital costs for an IGCC power plant currently range between 1,300 to 1,350 $/kW as compared to 1,000-1,200 for a conventional pulverized coal plant with flue gas desulfurization controls.[13] The capital costs of IGCC are even higher for developing countries like India. Capital cost estimates for coal-fired IGCC in India range as high as 1,500 $/kW.[14] In fact, IGCC technology currently is the most expensive option of all the advanced coal technologies available today, including atmospheric fluidized bed combustion technology and pressurized fluidized bed combustion technology.

IGCC technology becomes even less economic when compared to a natural gas-fired power plant. Presently a CT/CC power plant costs 400-500 $/kW to build, about one-third the cost of a coal-fired IGCC power plant. In India, capital costs of natural gas-fired technologies are higher, ranging between 700-800 $/kW,[15] but still less than a conventional coal-fired plant and significantly less than an IGCC plant.

Even though IGCC is the cleanest, most efficient coal-fired technology available today, and its capital costs are expected to decline in the future, it will not be utilized in countries like India and Ukraine unless it is affordable. In financially strapped countries like India and Ukraine, capital costs are a very important factor determining power plant development. India continues to experience power supply shortages of 5.5 percent (up to 11 during peak periods) and needs to add generating capacity, while Ukraine needs to replace old, out-dated, and deteriorating power plants. Faced with inadequate financial resources, both countries are likely to address these concerns with least cost alternatives. Bases on an economic comparison of IGCC technology with other coal-fired and natural gas-fired technologies on the market, it becomes evident that IGCC technology is not commercial in India or Ukraine. Unless favorable financing is provided through innovative market-based mechanisms, IGCC technology will continue to be viewed as too expensive and is not likely to be introduced in India or Ukraine on a wide scale. Thus, the economic feasibility test indicates that IGCC technology qualifies as additional for both countries.

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[13] Mollot, Darren J. USDOE, "Clean Coal Technologies & Beyond: The Status and Prospects of Coal Power," Presented at the Johns Hopkins University, School of Advanced International Studies, April 28, 1999.

[14] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

[15] Ibid.

Market Penetration: In support of our conclusion above, the market penetration test offers even more evidence of additionality. In the case of IGCC technology, it is fairly straightforward to establish the market penetration rate and demonstrate additionality, because no coal-fired IGCC power plants have been built in either India or Ukraine. In fact, according to an IEA report, Ukraine has not commissioned a new coal-fired power plant in at least the last decade. However, there have been a few studies examining the development of IGCC technology for India. In the early 1990s, Tata Energy Research Institute and National Thermal Power Corporation developed plans for the development of IGCC technology in India. Moreover, a 1998 report indicated that Ahemedabad Electric Company (AEC) and USAID were jointly developing a project report for a proposed 135 MW IGCC unit for AEC's Sabarmati power station.[16] As noted however, there are no IGCC plants under development in India.

Even on a worldwide basis, coal-fired IGCC technology is only slowly gaining ground. Of the five commercial scale coal-fired IGCC plants mentioned above, only the Dutch Buggenum plant has been built without receiving any public subsidy.[17] Most of the other non-coal-fired IGCC plants that have been constructed worldwide, without the receipt of public support, are fueled by cheap fuels, such as oil or petcoke, and/or rely on co-generation to improve the economics of electricity generation. Coal-fired IGCC technology has therefore not been able to reach a critical market penetration rate on the Indian, Ukrainian, or world markets. This confirms the results of the economic feasibility test that coal-fired IGCC technology is additional for India and Ukraine.

Solid Oxide Fuel Cell Technology Additionality Analysis

Economic Feasibility: Fuel cells operate by converting the chemical energy in hydrogen-rich fuels into electricity and heat, without combusting the fuel. In a conventional phosphoric acid fuel cell (PAFC), the required fuel is produced by a separate fuel processor through steam reforming of a fossil fuel, such as natural gas. However, one advantage solid oxide fuel cells (SOFCs) have is that due to their high operating temperatures, an internal reformer that uses heat from the fuel cell – along with recycled steam and a catalyst – can be incorporated into the fuel cell design. SOFCs operate at high temperatures (850-1000°C), and waste heat can be used to drive small gas turbines. Microturbines that could be combined with SOFCs to achieve overall system efficiencies of at least 60 percent, and perhaps more than 70 percent, are currently under development.

Like IGCC technology, SOFC technology is in early stages of commercialization. Several demonstration projects using SOFC technology have been implemented.[18] Westinghouse Electric Corporation's Science & Technology Center is the current leader in terms of the number and size of test units implemented. Among other activities, Westinghouse is installing an experimental 200-kW system in a cogeneration application in the Netherlands in cooperation with a consortium of Dutch

[16] Scott, David and Per-Axel Nilsson, "Competitiveness of future coal-fired units in different countries," IEA Coal Research, January 1999.

[17] Mollot, Darren J. USDOE, "Clean Coal Technologies & Beyond: The Status and Prospects of Coal Power," Presented at the Johns Hopkins University, School of Advanced International Studies, April 28, 1999.

[18] More, Taylor, "Market Potential High for Fuel Cells," *EPRI Journal*, May/June 1997.

and Danish utilities. Moreover, Westinghouse has built a $132 million pilot manufacturing facility, capable of producing about four MW of SOFCs a year. The company is also planning the construction of a commercial SOFC manufacturing facility to target mainly multi-megawatt systems in the range of 30-100 MW. These systems would combine fuel cells with a gas turbine (SOFC-GT) in packaged units, thus increasing efficiency to 60-70 percent. Other companies developing SOFC technologies include Ztek Corporation, which is working together with the Electric Power Research Institute (EPRI) and the Tennessee Valley Authority (TVA) to install experimental systems; SOFC; Technology Management Incorporated; and AlliedSignal Corporation. Moreover, at least seven companies in Japan, eight in Europe and one in Australia are working on developing SOFCs at the moment.

Even though the application of SOFC technology is growing in the distributed electricity market, it is still not considered a proven or mature technology. In addition, the operational performance of SOFC systems is still being tested, although results achieved so far promise acceptable component life characteristics. Moreover, the cost of SOFC technology is expected to be able to compete in high-cost, distributed electricity generation markets once it falls below $1,500 per kW. However, the price of fuel cells currently falls in the range of $3,000-$5,000 per kW. As a third generation technology, SOFC systems fall at the high end of this range.[19]

Based on these numbers, SOFC technology is clearly not economic, particularly in India and Ukraine. Neither country has adequate financial resources to meet the needs of its power sector. India needs to continue adding capacity to meet rising demand while Ukraine needs to renovate and refurbish existing power plants. Without financial assistance through vehicles such as market mechanisms, India and Ukraine are not likely to introduce SOFC technology to their power sectors. Even in developed countries, SOFC technology is still far away from being competitive with conventional technologies. Therefore, we conclude that SOFC technology, based on economic feasibility, is indeed additional for India and Ukraine.

Market Penetration: To strengthen our argument for additionality, we turn to the market penetration of SOFC technology in India and Ukraine. Like IGCC, establishing the market penetration rate of SOFCs is a straightforward process, because the technology currently is not being used in either country's power sectors. India has a State supported program to develop indigenous production of fuel cell power systems. Through its Chemical Sources of Energy Program, the Ministry of Non-Conventional Energy Sources is conducting research and development of fuel cell technologies for the power generation, transportation, and other sectors. One project involves the development of a 50 kW phosphoric acid fuel cell power plant. However, the project is still in the developmental stage and the Ministry's R&D program so far does not include SOFC technology.[20]

Solid oxide fuel cells have not reached a wide market penetration on a global basis either. As describe in the previous section, several companies are involved with developing SOFCs and the technology has been installed in numerous test sites and research facilities. However, these activities

[19] "Fuel Cells 2000: Frequently Asked Questions about Fuel Cells." http://www.fuelcells.org/fuel/fcfaqs.html.

[20] Ministry of Non-Conventional Energy Sources, New Technology Programmes, Chemical Sources of Energy, http://mnes.nic.in/frame.htm?majorprog.htm.

have mainly come about through public research support and other incentives. For example, the U.S. Department of Energy is heavily involved in the research and development of fuel cell technologies. The governments of Canada, Japan, and Germany are also promoting fuel cell development via tax credits, low-interest loans, and grants to support early purchases and lower costs. The strong public involvement in the development of SOFCs suggests that this is a technology that has not yet reached a fully commercial stage. Clearly, the market penetration analysis further demonstrates the additionality of SOFC technology and supports our conclusion that the technology qualifies as additional for India and Ukraine.

Natural Gas Combined Cycle Technology Additionality Analysis

Economic Feasibility: Natural gas plays an important role in the power generation mix for both India and Ukraine. India currently operates 158 natural gas-fired units. These units consist of 6,935 MW and account for about six percent of India's total installed capacity. Ukraine, meanwhile, currently operates 39 natural gas-fired units, consisting of 7,981 MW and accounting for about 15 percent of Ukraine's total installed capacity. Moreover, natural gas-fired units are among the least expensive power generation technologies on the market today, with capital cost ranging between $400 and $800 per kW. However, neither India nor Ukraine is currently using natural gas combined cycle (NGCC) technology in their operating natural gas plants.

For India, capital costs for NGCC, used for base load requirements, are estimated to be slightly higher ($815 per kW) than the range provided above, while capital costs for gas turbine technology, used primarily for peak load requirements, are estimated at $720 per kW.[21] Due in part to the capital cost advantages of gas-fired power generation technologies, India has been encouraging the construction of gas-fired power plants in recent years, particularly in coastal regions.[22] In the first half of the 1990s, natural gas-fired power experienced a 25 percent annual growth rate, and since 1988, domestic natural gas production has increased 150 percent. Because indigenous natural gas resources are limited, India is investing heavily in port facilities equipped to import liquefied natural gas (LNG) for use in new natural gas-fired power plants located in coastal regions. In addition, India is exploring options for international pipeline projects to transport natural gas to inland areas where LNG would not be as competitive. Natural gas supplies via pipeline could come from the Bay of Bengal off the coast of Bangladesh, Myanmar, or Turkmenistan.[23] India's consumption of natural gas has risen faster that any other fuel in recent years and India is projected to be one of the world's largest gas importers in the near future.[24] Currently, India has a number of gas-fired power plants at various stages of development including facilities in Dabhol, Jegurupadu, Ennore, Pipavav, Godavari,

[21] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

[22] U.S. Energy Information Administration, India Country Analysis Brief, February 2000, http://www.eia.doe.gov/emeu/cabs/india.html.

[23] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

[24] U.S. Energy Information Administration, India Country Analysis Brief, February 2000, http://www.eia.doe.gov/emeu/cabs/india.html.

Vijjeswaran, Paguthan, Vypeen, and Pillaiperumanallur. The capital costs of NGCC, coupled with the fact that India is heavily investing in LNG facilities and new opportunities for pipeline imports and is currently developing new gas-fired power plants, clearly indicate that NGCC is economic in India and therefore would not qualify as additional under the economic feasibility test.

In contrast to India, Ukraine's power sector is not in need of additional capacity to meet increasing demand, but is in need of modernization, rehabilitation, and renovation. Many of Ukraine's power plants are old and run down, with some units exceeding 250,000 hours on-line.[25] Since gaining independence in 1991, Ukrainian demand for power has fallen dramatically, mostly due to a collapse of the economy, with forecasts showing that demand is not expected to reach 1990 levels until 2010.[26] Moreover, Ukraine is estimated to have enough generating capacity for the next 10-15 years,[27] strengthening the notion that Ukraine currently does not need additional capacity. However, Ukraine lacks the financial resources to modernize its power plants. Ukrainian utility customers owe more than $1 billion in unpaid utility bills, leaving utilities without means to modernize or in some cases purchase fuel.[28] Over the years, Ukraine has also supplemented domestic oil and natural gas production with imports from Russia and Turkmenistan, accumulating energy debts of $1.7 billion[29] and making it even more difficult to locate funds for modernization. Despite the lack of funds to purchase fuel and modernize plants, natural gas already is an important part of Ukraine's power generation mix. In addition, Ukraine plans to increase domestic natural gas production by exploiting more of its own reserves. Under the Oil and Gas of Ukraine to 2010 program, the country expects to meet at least 50 percent of domestic demand for natural gas by 2010.[30] Clearly, natural gas will continue to play an important role in Ukraine's power sector and perhaps even an increasingly important role, leading to the conclusion that NGCC technology would not qualify as additional under the economic feasibility test.

Market Penetration: In some instances, if a technology fails to qualify as additional under the economic feasibility test, it may still qualify as additional if the technology has limited or no market penetration. This clearly is the case for NGCC technology in India and Ukraine. As we have noted, natural gas is an important part of the power generation mix in both countries with 158 and 39 operating natural gas-fired units in India and Ukraine respectively. However, none of these units employs NGCC technology. India has 54 planned units, totaling 19,488 MW of capacity, slated to use combined cycle technology, none of which are currently under construction. Of those 54 units, only 19, totaling 4,342 MW of capacity, will use natural gas technology. The remaining planned combined cycle units will use LNG, naptha, or oil as a fuel stock. Ukraine, on the other hand, has two combined cycle units planned, totaling 100 MW, but both units are slated to run on oil and

[25] Ukraine Brief, The McGraw-Hill Companies, March 24, 1998.

[26] Ryding, Helene, "Electricity Restructuring in Ukraine: Illusions of power in the power industry?" Centre for Economic Reform and Transformation, Department of Economics, Heriot-Watt University, Riccarton, Edinburgh, May 1998.

[27] Ukraine Brief, The McGraw-Hill Companies, March 24, 1998.

[28] U.S. Energy Information Administration, Ukraine Country Analysis Brief, June 1999, http://www.eia.doe.gov/emeu/cabs/india.html.

[29] Ukraine Brief, The McGraw-Hill Companies, March 24, 1998.

[30] U.S. Energy Information Administration, Ukraine Country Analysis Brief, June 1999, http://www.eia.doe.gov/emeu/cabs/india.html.

Ukraine has no plans to develop natural gas units. This indicates that the market penetration of NGCC technology in both countries is zero. Therefore, the market penetration test leads to the conclusion that NGCC technology will qualify as additional for India and Ukraine. This conclusion overrides the results of the economic feasibility test.

Wind Turbine Technology Additionality Analysis

Economic Feasibility and Market Penetration: Although still accounting for only a small percentage of worldwide generation, wind power has become one of the fastest growing sources of energy over the last decade due in part to improving technology and economics. In 1999, more than 3,600 MW of new generating capacity was installed worldwide, bringing the total world installed capacity to approximately 13,400 MW.[31] In the United States, the cost of wind power is now estimated to be competitive with other more conventional fuel types, such as coal and natural gas, even without the U.S. federal production tax credit, which is designed to enhance the competitiveness of U.S. wind power.[32] In 1999, five countries – Germany, Denmark, United States, Spain, and India – accounted for more than 80 percent of the world's installed wind capacity.[33]

India is the world's fifth largest wind power generator with 1,167 MW of installed capacity[34] and by far has the largest wind power program in the developing world. India's wind power accounts for approximately one percent of its total installed power generating capacity. According to the Ministry of Non-Conventional Energy Sources, India has the potential for around 45,000 MW of wind power and 192 potential wind farm sites have been identified. In addition, India's Ninth Five-Year Plan (1997-2002) calls for the addition of 1,000 MW (200 MW between 2000-2001) of new wind power capacity. The Ministry also indicates that the costs of wind power compare favorably with new conventional power projects with added advantages of shorter gestation periods and modularity. The Ministry estimates that the capital cost of wind power range between $900 to $1,000 per kW, with generation costs ranging between $0.04 and $0.06 per kWh.[35] However, a report by the Pew Center on Global Climate Change estimates higher capital costs for wind power in India ($1,045 per kW).[36]

These capital cost figures are at least competitive with conventional coal-fired power technologies, even a little less than supercritical coal technology, but significantly more than natural gas-fired technologies. However, because the generating capacities of individual wind farms are small and generally used to supplement load requirements, comparisons to coal and natural gas-fired facilities,

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[31] American Wind Energy Association, "Global Wind Energy Market Report," December 1999, http://www.awea.org/faq/global99.html.

[32] American Wind Energy Association, Wind Energy Fact Sheet, "Comparative Cost of Wind and Other Fuels."

[33] Allison, Rebecca, "Wind Generators Powering Ahead," The Press Association Limited, September 1, 1999.

[34] Government of India Ministry of Non-Conventional Energy Sources, http://mnes.nic.in/frame.htm?majorprog.htm.

[35] Ibid. (Also see: Tata Energy Research Institute and Operations Research Group, "Economics of Windpower: Impact of Fiscal Incentives," August 1997.)

[36] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

which have much larger capacities and generally used for base load requirements, may not be useful. "Power generation from non-conventional renewable sources has assumed significance for providing a viable option not as a substitute but as a supplement to conventional power generation."[37] When compared to other renewable technologies, such as solar photovoltaic and small hydro, capital costs for wind power compare favorably as well.[38] However, the Indian government heavily subsidizes wind power, and other renewables, through favorable financing terms and other incentives. In recent years, financial resources in India have been scarce, and without adequate funding for these subsidizes, India's wind industry struggles to continue developing. Despite wind power's competitiveness in terms of capital costs and its fairly impressive market penetration, the development of India's wind power relies on financial assistance. Therefore, we conclude that, even in the face of capital cost competitiveness and significant market penetration, wind power qualifies as additional for India because the technology requires some kind of economic incentive or favorable financing.

The situation in Ukraine is very different. Wind power in Ukraine is virtually non-existent with a mere 10 MW of installed capacity. This represents approximately 0.02 percent of Ukraine's total installed capacity. However, wind power has the potential to make an impact on Ukraine's electricity generation mix and there are at least a few wind projects currently operating. In 1993, the U.S. firm Kenetech Corporation formed a joint venture with Krimenergo called Windergo LTD. to develop a 500 MW wind plant on the Crimean Peninsula near Donuzlav Lake. By 1996 however, only 7.7 MW was in operation. In addition, a 600 kW wind farm is in operation at Nikolaev on the Dnieper River and a 200 kW wind farm is operating in Crimea.[39] The further development of Ukraine's wind power potential will, of course, depend on adequate financial resources of which Ukraine has very little. As we have noted previously, the financial health of Ukraine's power sector is very poor. Ukrainian utilities have run up huge debts, due in part to non-payments from customers, preventing them from keeping up with plant maintenance, modernization, and in some cases purchasing fuel stocks. In the absence of adequate financial resources, Ukraine is not able to develop alternative energy sources such as wind power. We conclude then that wind power will qualify as an additional technology for Ukraine.

Transportation Technologies

Gas-To-Liquids Technology Additionality Analysis

Introduction: Unlike liquefied natural gas processing where natural gas is cooled to form a liquid, gas-to-liquids (GTL) technologies chemically change the natural gas molecules, breaking them apart, and re-combining them with oxygen to form a mixture called synthesis gas. In turn, synthesis gas can be chemically converted into different types of hydrocarbon products like clean-burning

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[37] Government of India Ministry of Non-Conventional Energy Sources Annual Report Section 1.15, http://mnes.nic.in/frame.htm?publications.htm.

[38] Shukla, P.R., Debyani Ghosh, William Chandler, and Jeffrey Logan, "Developing Countries & Global Climate Change: Electric Power Options in India," Prepared for the Pew Center on Global Climate Change, October 1999.

[39] Ukraine Brief, The McGraw-Hill Companies, March 24, 1998.

transportation fuels (new diesel) or a variety of high-value chemicals. One of the potential uses for GTL technology and new diesel is as a replacement fuel for conventional diesel or as a blending agent with conventional fuels to help meet more stringent environmental regulations. However, before exploring the additionality analysis of gas-to-liquids (GTL) technology, it may be worth examining the potential greenhouse gas emission benefits associated with this technology. Unlike the other nine technologies we are analyzing, the greenhouse gas emissions benefits are not as evident for GTL technology. The modified technology matrix is specifically aimed at technologies that reduce greenhouse gas emissions, and if GTL does not reduce greenhouse gas emissions, the additionality analysis becomes unnecessary.

The driving force behind GTL as a transportation fuel is that emissions of sulfur, NO_x, and particulate matter are significantly reduced compared to conventional transportation fuels. However, none of these substances are greenhouse gases. In terms of greenhouse gas emissions, there is no difference between conventional and new diesel. Therefore, a project using the technology as a replacement fuel would not see any greenhouse gas emission benefits rendering the additionality analysis for the technology matrix unnecessary. However, there is a secondary effect to GTL that does reduce greenhouse gas emissions. An important benefit of GTL technology is that it provides a use for natural gas that otherwise would have been flared. In this context, an argument could be made that a project utilizing GTL technology presents an alternative to natural gas flaring which results in greenhouse gas emission reductions. Now that we have established a greenhouse gas emission benefit to GTL technology, we can move on to our additionality analysis.

Economic Feasibility and Market Penetration: As we have noted above, GTL technology is a process of chemically converting natural gas to liquid products such as alternative transportation fuels. The U.S. Department of Energy estimates that the costs of the chemical conversion process could be reduced by 25 percent if a one-step process can be developed to separate oxygen from the air and combine it with natural gas to form synthesis gas. It would bring gas-to-liquid technology into the $18 to $20 per barrel range, which is competitive with crude oil.[40]

There are approximately 12 GTL projects worldwide only two of which (both in South Africa) are currently operational. The remaining projects are considered potential and located in the United States, Venezuela, the United Kingdom, Nigeria, Norway, Qatar, Bangladesh, and Malaysia.[41] The locations of these operational and potential sites cover all the major regions of the world; however, none of them are located in India or Ukraine, leading to the conclusion that the market penetration rate for GTL technology in these two countries is zero. Despite the small number of projects, capital costs for a GTL project are becoming competitive with those associated with refining processes for conventional transportation fuel technologies. In order for GTL to be economical, capital costs need to be below $30,000 per barrel of daily capacity, with a goal of lowering capital cost to between

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[40] *DOE Fossil Energy Techline*, "University of Alaska-Fairbanks to Lead University, Industry Team, in Department of Energy Project to Develop 'Gas-to-Liquids' Technology," April 16, 1999, http://www.fe.doe.gov/techline/tl_akgastoliq.html.

[41] Agee, Mark A., President and CEO, Syntroleum Corporation, Tulsa, OK "Fuels for the Future," Paper presentation at the Energy Frontiers International Conference, Gas Conversion: Projects, Technologies, & Strategies, San Francisco, CA October 20-22, 1999, http://www.syntroleum.com/pdfs/sf_1099.pdf.

$12,000 and $14,000 per barrel of daily capacity. At the $12,000 to $14,000 level, a GTL refinery would be competitive with a conventional oil refinery.[42] One company, South Africa's Sasol, maintains that a 10,000 barrel per day GTL plant can be built at a capital cost of approximately $250-$300 million, which equates to about $25,000 per barrel of capacity. Sasol estimates that production costs would be approximately $10 per barrel and a premium would likely be added to the product price above conventional transportation fuels. For example, if crude oil were priced at $16 per barrel, a price of $22 per barrel for GTL products could be expected.[43]

GTL also has unique economic advantages over other alternative fuel technologies, such as compressed natural gas (CNG), on the distribution and end-use sides. First, GTL technologies yield products that can be used directly as fuels or feedstocks or they can be blended with crude oil products to help comply with more stringent environmental requirements. Second, use of GTL fuels would not necessitate the rebuilding of vehicle fleets and distribution systems. GTL fuels could be delivered through existing infrastructures and existing vehicles would not necessarily need extensive modifications.[44] Other alternative fuels like CNG require new distribution systems, fueling stations, vehicle modifications, and cannot be blended with other crude oil products.

Despite the improving economics of GTL technologies, it has not yet reached a competitive level with conventional technologies. Capital costs are still significantly higher for GTL technologies and conventional products are still cheaper to produce. For countries like India and Ukraine where financial resources are scarce and limited, the higher capital and production costs would prevent them from utilizing GTL technologies in the absence of some form of favorable financing. Therefore, the economic feasibility analysis demonstrates that GTL technology is additional for India and Ukraine. In addition, the zero market penetration rate of GTL technology in India and Ukraine solidifies the argument for additionality.

Compressed Natural Gas Vehicle Technology Additionality Analysis

Economic Feasibility and Market Penetration: In compressed natural gas (CNG) vehicles, the natural gas fuel is stored at a pressure of 2,400-3,600 pounds per square inch in one or more on-board cylinders. When the CNG leaves the cylinder tank, it flows through high-pressure fuel lines into one or more pressure regulators where it is condensed to low atmospheric pressure. CNG is already gaseous, so upon entering the combustion chamber, it is ignited to power the vehicle. CNG is

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[42] Agee, Mark A., President and CEO, Syntroleum Corporation, Tulsa, OK, "Gas to Liquids Technology – A New Tool for the Energy Industry," Paper presentation at AiC Gas to Liquids Conversion Conference, Singapore March 4-6, 1998, http://www.syntroleum.com/pdfs/singapore398.pdf.

[43] Hill, Cavan, Business Development Manager, Sasol Synfuels International, "What Makes a Natural Gas to Liquid Fuels Project Viable?" Paper presentation at the Middle East Petroleum & Gas Conference, March 15-17, 1998. http://www.sasol.com/sasolprocesses/papers/MPGC%2098%20-%20paper.PDF. and "Sound Investment Opportunities When The Right Factors Combine," http://www.sasol.com/sasolprocesses/slurry5.html.

[44] Agee, Mark A., President and CEO, Syntroleum Corporation, Tulsa, OK, "Economic Gas To Liquids Technologies – A New Paradigm for the Energy Industry," Paper presentation at Montreux Energy Roundtable VIII, Montreux, Switzerland, May 12-14, 1997, http://www.syntroleum.com/pdfs/montreux597.pdf and "GTL vs. Low Oil Prices – The Insulating Factors," Paper Presentation at Monetizing Stranded Gas Reserves '98 Conference, San Francisco, CA, December 14-16, 1998, http://www.syntroleum.com/pdfs/sf_1298.pdf.

the most common form of natural gas vehicles in use today, with more than 1.2 million CNG vehicles operating worldwide.

As early as 1986, several Indian energy companies initiated isolated trials, with no more than one or two vehicles, in an attempt to introduce CNG in India. However, it was not until 1992 that an organized pilot project was commissioned by the Gas Authority of India (GAIL) in Delhi, Mumbai, and Baroda. Around the same time, two more CNG programs were launched by Madras Refineries Ltd. (MRL) and Gujarat Gas Co. Ltd (GGCL) in Nagapattinam and Surat respectively. Since the inception of its program, GAIL has converted 12,000 vehicles in Delhi, Mumbai, and Baroda and helped to at least begin establishing CNG as a legitimate alternative transportation fuel for India. The program has made headway in breaking down some institutional barriers to widespread use of CNG such as apprehensions over safety, transmission and distribution, and storage of CNG. Furthermore, the economics of vehicle operation, in many ways, favor CNG over gasoline. On an energy equivalent basis, the cost of natural gas is approximately one-third the cost of gasoline; since natural gas is a cleaner burning fuel, vehicle maintenance costs are lower, and overall life-cycle costs of CNG vehicles are lower.[45]

Despite these early efforts, the growth of CNG vehicle usage in India has been slow. The vehicles converted in the GAIL program represent a very small percentage of the total number of vehicles for all of India, and all other CNG programs add virtually nothing to the total. Currently there are only 14 CNG buses running in New Delhi. For all of India, there are only 25 CNG fueling stations, nine in Delhi, nine in Mumbai, three in Vadodara, and four in Surat and Ankleshwar. Currently, CNG-dedicated vehicles are more expensive than basic gasoline or diesel vehicles and the cost of CNG conversion kits remains high due in part to the fact that India is still unable to produce the kits domestically, there are very few centers in India equipped to perform CNG conversions, and mechanics lack the necessary training to perform CNG conversions. However, the Indian government continues to push CNG vehicles. Recently, India's government has been developing plans to use CNG technology as a way to comply with several Supreme Court directives aimed at phasing out 2,000 pre-1990 and 2,000 post-1991 taxis and autorickshaws and eight-year-old diesel-engine DTC buses. In addition, the government has developed a plan to comply with another Supreme Court directive requiring the number of CNG fueling facilities in Delhi to increase from 9 to 80.[46]

Clearly, CNG vehicle technology has made some penetration into Indian transportation markets. However, the total number of CNG vehicles currently operating in India is very small. In addition, the cost of CNG dedicated vehicles and conversion kits are still prohibitive, and India's infrastructure is currently insufficient to support large numbers of CNG vehicles. Therefore, based on current economics and market penetration, CNG vehicle technology would qualify as additional for India.

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[45] Sharma, Rajeev, "Role of compressed natural gas in transport sector: challenges ahead," from *Clearing the air: better vehicles, better fuels*, Ranjan K. Bose, S. Sundar, and K. S. Nesamani, editors, Tata Energy Research Institute, New Delhi, 2000.

[46] Ibid and Tata Energy Research Institute, "Compressed Natural Gas: one for the Road," February 2000, http://www.teriin.org/energy/cng.htm.

CNG vehicle technology has an even longer history in Ukraine than that of India and is far more advanced in its market penetration. CNG technology has been available in Ukraine for decades dating back to the time when Ukraine was part of the Soviet Union. In 1999, there were 14,164 CNG vehicles in Ukraine representing 1.3 percent of all vehicles.[47] The vast majority of CNG vehicles are used for commercial purposes and there are approximately 80 refueling stations countrywide. Most major cities in Ukraine have one or two refueling stations, but they tend to be located on the outskirts of the cities making them somewhat inconvenient for users. In addition, the natural gas used to power the vehicles is very competitive with more conventional transportation fuels such as gasoline and diesel.[48] Clearly, CNG is readily available and competitive with conventional transportation fuels throughout Ukraine, leading to the conclusion that CNG vehicle technology would not qualify as additional for Ukraine.

Hybrid Electric Vehicle Technology Additionality Analysis

Economic Feasibility and Market Penetration: Hybrid electric vehicles (HEVs) combine the internal combustion (IC) engine of a conventional vehicle with the battery and electric motor of an electric vehicle, resulting in twice the fuel economy of conventional vehicles. This combination offers the convenience of using existing infrastructure to support the vehicles, i.e. refueling stations (hybrids can be designed to run on conventional fuels like gasoline and diesel or alternative fuels such as natural gas), with the energy and environmental benefits of an electric vehicle. HEVs have several advantages over conventional vehicles including a regenerative braking capability that recovers the energy used to slow or stop the vehicle. They consume much less fuel, greatly increasing fuel efficiency and decreasing emissions.[49] In addition, unlike pure electric vehicle, hybrids recharge themselves, eliminating the need to plug in the vehicle for long recharging sessions. In HEVs the IC engine generates the electricity needed to charge the electric motor and battery pack units.[50]

Currently, hybrids are only available in the United States, Japan, and Europe, with only two models, the Honda Insight and Toyota Pirus, having reached any level of commercialization. In the United States, the Insight hit the U.S. market in January 2000 with the Pirus becoming available as recently as June 2000. Between January and June 2000, Honda sold 1,600 Insights in the U.S and expects to sell 7,000-8,000 worldwide by the end of the year. Toyota's Pirus meanwhile, has been available in Japan since 1997, with 35,000 sold in Japan over the last three years. Toyota expects to sell 12,000 per year in the U.S. market.[51] Both models sell for approximately $20,000,[52] which is at least competitive with similar conventional vehicles. However, the market penetration of hybrid technology, even where available, is relatively minor. For countries like India and Ukraine, the

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[47] Numbers derived from Ukrainian transportation data provided by Dr. Natalya Parysuk.

[48] Information obtained via personal communication with Meredydd Evans, Associate Director, Advanced International Studies Unit, U.S. Department of Energy, Pacific Northwest Laboratory.

[49] http://www.ott.doe.gov/hev/hev.html

[50] Peters, Eric, "Hybrid Cars: The Hope, Hype, and Future," Consumers' Research, June 2000.

[51] Personal communication with Robert Kost, U.S. Department of Energy, Hybrid Electric Vehicles Program, http://www.ott.doe.gov/oaat/hev.html.

[52] Peters, Eric, "Hybrid Cars: The Hope, Hype, and Future," Consumers' Research, June 2000.

market penetration is zero, leading to the conclusion that HEV technology would qualify as additional for both countries.

Other Technologies

Coal Bed Methane Recovery Technology Additionality Analysis

Economic Feasibility and Market Penetration: Methane is a substance formed as a by-product of the coal formation process. During and after the coal mining process, methane, a potent greenhouse gas, is released and escapes into the Earth's atmosphere. Because methane is highly explosive, coalmines are ventilated to reduce the methane content in the mines and to reduce the potential for explosions inside the mine. Today, technologies are available to recover the trapped methane prior to and after mining by drilling boreholes into the mine and capturing the methane as it escapes the coal bed, thereby reducing methane emissions from coalmines. The recovered methane can then be used as an alternative energy source to conventional fuels such as oil or coal.

Coal is an important energy source for India and Ukraine and both countries have substantial coal reserves (70 billion tons and 38 billion tons respectively). India ranks third, behind China and the United States, in coal production, reaching an estimated 359 million short tons in 1998, while Ukraine's production for 1998 was estimated at 66 million short tons.[53] Although India and Ukraine have initiated programs to explore commercial development of coal bed methane reserves, it currently is a mostly untapped and unused resource in both countries.

We noted earlier that demand for natural gas in India has been on the rise in recent years, leading to increasing domestic production and foreign imports. Coal bed methane (CBM) development has started to take shape as an alternative means of meeting India's rising demand for natural gas.[54] India's Ninth Five Year Plan (1997-2002) identifies utilization of coal bed methane as a source of commercial energy as a priority for India's coal sector. Section 6.209 states, "Greater emphasis needs to be given to the area of Coal Bed Methane exploration in view of the large potential that has been estimated in the coal fields of the country and as a new resource of commercial energy which is environmentally-friendly."[55] In addition, pending legislation offers CBM projects a number of tax incentives to encourage development.[56] India's CBM reserves are estimated to be between 30 trillion

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[53] U.S. Energy Information Administration, India Country Analysis Brief, February 2000, http://www.eia.doe.gov/emeu/cabs/india.html and U.S. Energy Information Administration, Ukraine Country Analysis Brief, June 1999, http://www.eia.doe.gov/emeu/cabs/india.html.

[54] Sharma, N.K. and U.P. Singh, "Coalbed Methane: Development Status in India," Paper Presentation at the Second International Methane Mitigation Conference, Novosibirsk, Russia, June 18-23, 2000, http://www.ergweb.com/methane/pdf/sharma.pdf.

[55] Ninth Five Year Plan (1997-2002), http://www.nic.in/ninthplan/vol2/v2c6-2.htm.

[56] U.S. Environmental Protection Agency, Coalbed Methane Outreach Program, India Country Fact Sheet, September, 10, 1998, http://www.epa.gov/coalbed.

cubic feet and 144 trillion cubic feet,[57] and according to the Central Mine Planning & Design Institute, a subsidiary of Coal India Limited, coal bed methane resources could add approximately 400 billion cubic meters to India's conventional gas inventory. India has recognized CBM as a potential alternative energy source, but without access to recovery technologies and knowledge of the commercial viability of methane, the resource remains untapped and the fuel unused in India's energy markets.[58]

In recent years, several private initiatives attempted to begin CBM recovery programs in India including Essar Oil, Amoco India, and Reliance-Texaco, but these initiatives had little success due to institutional problems such as resource ownership questions and payments to nationalized companies. Perhaps the most comprehensive CBM program operating in India today is the Global Environment Facility (GEF) and the United Nations Development Programme's (UNDP) Coal Bed Methane Recovery and Commercial Utilization project. Initiated in 1997, the $19.2 million government-backed project is designed to demonstrate CBM recovery technologies and commercial uses for the recovered methane. It provides for technology transfer, training of key personnel, and seminars for end users to demonstrate methane utilization possibilities.[59] The project is scheduled to run for five years and is currently in the early stages of development, having received approval from the Indian Government on September 15, 1999.[60] The GEF/UNDP project proposal indicates that costs associated with CBM recovery technology are not yet competitive with other energy technologies, although finding costs, capital costs, and operating costs are all expected to decline following the completion of technology transfer and training of CBM recovery techniques. As India becomes more familiar with the technology, finding good sources of methane will become easier, costs for drilling wells will decline, and recovery operations will run more efficiently.[61] For the moment however, India's CBM industry is still in its infancy stage facing many challenges, such as firming up proven reserve estimates, identifying good reserve locations, and solving transportation and distribution problems.[62] Even if India had the ability to begin producing CBM at commercial level, it still lacks the infrastructure to deliver the gas to market. Clearly, higher costs and technology transfer difficulties have prevented the development of CBM recovery technology in India. Therefore, the economic feasibility and market penetration analysis demonstrate that CBM technology would qualify as additional for India.

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[57] Ibid.

[58] United Nations Development Programme Proposal for Review, Global Environment Facility, "India: Coal Bed Methane Recover and Commercial Utilization," http://www.gefweb.org/wprogram/july97/india.pdf.

[59] United Nations Development Programme Proposal for Review, Global Environment Facility, "India: Coal Bed Methane Recover and Commercial Utilization," http://www.gefweb.org/wprogram/july97/india.pdf.

[60] Ministry of Coal Annual Report, Chapter 4, Coal Exploration, Section 4.25, http://www.coal.nic.in/.

[61] United Nations Development Programme Proposal for Review, Global Environment Facility, "India: Coal Bed Methane Recover and Commercial Utilization," Annex 8, "Economic Viability of CBM Recovery and Utilization Project in India," http://www.gefweb.org/wprogram/july97/india.pdf.

[62] Sharma, N.K. and U.P. Singh, "Coalbed Methane: Development Status in India," Paper Presentation at the Second International Methane Mitigation Conference, Novosibirsk, Russia, June 18-23, 2000, http://www.ergweb.com/methane/pdf/sharma.pdf.

A similar situation exists in Ukraine, although Ukrainian CBM development is slightly ahead of India. Like India, Ukraine recently recognized the potential for CBM recovery technology to meet domestic demand for natural gas and more importantly mitigate the country's reliance on natural gas imports. Ukraine's National Energy Program calls for an annual CBM production target of 283 billion cubic feet by 2010 from estimated reserves of 42.4 trillion cubic feet. In September 1998, Ukraine's National Academy of Science (NAS) and the Ministry of Coal (MCI) established the Alternative Fuels Center (AFC) to promote the country's CBM objectives through legislative activities, oversight of developmental pilot projects, training for technology transfer, and private sector development. Since its creation, AFC has been working with NAS and MCI to implement a state-funded CBM drilling project, and with the World Bank and GEF on another CBM drilling project. In addition, AFC initiated a number of legislative packages designed to improve the economics of CBM investments for developers through government incentives, such as tax exemptions on profits, land fees, and equipment. However, all of the legislation is either pending or still in the developmental stage.[63]

There also are other CBM development projects in Ukraine unrelated to AFC's activities. Several private foreign companies have teamed with Ukrainian companies to begin exploiting Ukraine's CBM resources. All but one of these projects are either still negotiating for licenses or in the planning stages.[64] In June 1998, EuroGas, Inc. signed two separate agreements to develop CBM properties in Ukraine. The first agreement is with Makyivs'ke Girs'ke Tovarytstvo, a private Ukrainian company, to jointly explore and develop CBM in the Donez Coal Basin located in eastern Ukraine. The second agreement is with Zahidukrgeologia, the State-owned geological company, to explore and develop CBM in the Lviv-Volyn Coal Basin located in southwestern Ukraine. The Ukrainian Ministry of Coal estimates that CBM reserves for Donez and Lviv-Volyn are 13 trillion cubic feet and 350 billion cubic feet respectively. These two agreements represent the first efforts to develop CBM in Ukraine.[65] Drilling for Ukraine's first CBM well commenced in May 1999 in the area of the Tiahlivska No. 1 mine in the Lviv-Volyn Basin.[66] The well was completed in January 2000 and showed indications of gas from coal seams and associated sandstones. The venture currently is undergoing tests to determine the commercial prospects of the reserves.[67]

Despite significant efforts by AFC, EuroGas, and others, CBM technology is still in early stages of development in Ukraine. AFC acknowledges that incentives are needed to improve the economics of CBM production and clearly CBM has yet to penetrate the Ukrainian natural gas market. Therefore, CBM would qualify as additional for Ukraine.

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[63] Alternative Fuels Center of Ukraine, http://www.afc.kiev.ua.

[64] U.S. Environmental Protection Agency, Coalbed Methane Outreach Program, Ukraine Country Fact Sheet, September, 10, 1998, http://www.epa.gov/coalbed.

[65] U.S. Energy Information Administration, Ukraine Country Analysis Brief, June 1999, http://www.eia.doe.gov/emeu/cabs/india.html and Press Release, "EuroGas is First Foreign Company to Form Joint Venture to Develop Coal-Bed Methane Gas Properties in Ukraine," June 25, 1998, http://www.eugs.com/news/06-25-98.html.

[66] Press Release, "EuroGas Commences Drilling Operations in Ukraine," May 7, 1999, http://www.eugs.com/news/05-07-99.html.

[67] Press Release, "EuroGas Drills First Coal-Bed Methane Well in Ukraine," January 6, 2000, http://www.eugs.com/news/01-06-00.html.

Energy-Plex Technology Additionality Analysis

The concept of the energy-plex forms the core of NETL's "Vision 21" program for developing clean energy plants for the twenty-first century. Energy-plex is an advanced, ultra-high efficiency, fully-integrated energy production facility utilizing advanced technologies, such as IGCC, fuel cell/turbine hybrids, and indirect liquefaction, and capable of producing multiple energy products, (e.g. electricity, steam, transportation fuels, chemicals, hydrogen, etc.) from a variety of fuel inputs. These advanced technologies would be developed as modular components to the energy-plex, which could be combined in a variety of ways to meet site-specific market requirements. Energy-plexes would stand in contrast to today's power plants, typically designed to utilize one type of fuel and to generate one product (electricity). Two additional features further distinguish the energy-plex from current plants. First, it would be designed to maximize efficiency, by maximizing the utilization of the various fuel inputs, with the ultimate goal of using as much of the energy in the fuels as possible. Second, it would be designed to dramatically reduce or eliminate the various environmental impacts associated with energy production. The ultimate goal of the energy-plex concept is to achieve overall thermal efficiencies of 85 to 90 percent (as compared with the 33 to 35 percent efficiencies currently being attained by conventional coal-fired power plants).

Clearly the energy-plex concept is still in the infancy stage of development. The current research and development schedule calls for the completion of a computer-simulated demonstration by 2015.[68] Presumably the first pilot or demonstration project would be built at some point after 2015. Cost information is not even available for energy-plex technology at this point in time. Therefore, the energy-plex concept clearly qualifies as additional for both India and Ukraine.

[68] U.S. Department of Energy's National Energy Technology Laboratory, *Vision 21 Program Plan, Clean Energy Plants for the 21st Century*.

3. DEVELOPMENT OF THE QUALITATIVE BASELINE

Introduction

Having established the additionality (or non-additionality) of the selected technologies, the next step in the technology matrix development process is to establish the qualitative baseline for each technology. Here we ask the question "what is the most likely alternative to projects utilizing the technology?" The answer to this question defines the qualitative baseline, and provides the basis for quantifying the emission rate benchmarks to be included in the technology matrix.

The Approach to Qualitative Baseline Development

The following sections provide our detailed analyses of the above question, for each of the ten technologies in India and Ukraine. Although utilizing available data and information, our basic approach to qualitative baseline development relies primarily on expert judgment. Hence the qualitative baselines established through this process are inherently subjective in nature. This subjectivity is in part a reflection of the nature of the qualitative baseline question. We are dealing here with a hypothetical, a "what if" question: what if the project were not undertaken, what *would* happen in its place? This question can be discussed and debated, and informed opinion can differ on the answer. But in the final analysis, it is a question about an alternative future, and, worse, a future that will *never* occur (assuming the project is implemented). There *is* a correct answer to the question--*something* would happen in the absence of the project-- but this something is unknowable. Given these inherent difficulties, certainly one approach to the question is to provide an "educated guess," based on informed opinion and expert judgment.

It is also possible to develop a more objective approach to benchmark development. For example, some of the benchmarking approaches discussed in the literature effectively skip the step of developing a qualitative baseline, and instead establish set rules for the computation of benchmark emission rates. For example, the benchmark for power sector projects might be established as the average emissions rate of all generating units in a particular country, or, alternatively, the benchmark for *coal-fired* power projects might be set equal to the average emissions rate for all *coal-fired* units. Under this approach, the rules for computing the benchmark, once established, would be applied in the same manner across all developing countries.

There are a number of potential advantages to such an approach. For one, once the computational rules are established, developing the benchmarks becomes a much simpler, straightforward process. Furthermore, the computational process and the results are objective, and for this reason the benchmarks may be less subject to political manipulation than they would be using a more subjective approach (although the establishment of the *rules themselves* could prove subjective and subject to manipulation). However, there are disadvantages as well. Foremost among these is that, under an objective benchmarking approach, the development of the benchmarks may tend to become divorced from the core question: what *would* happen absent the project? In fact, if this question is not in some way addressed during the establishment of the computational rules, then there is little reason to expect the benchmarks to provide a realistic representation of the project counterfactuals. And to the extent that this question *is* addressed during rules establishment, we are brought back to our initial dilemma--the need to answer a hypothetical. In this case, although the benchmark computation process may be objective, it will nonetheless be based on a subjective response to the same core, hypothetical question. Furthermore, by codifying this response into a set of rigid rules applicable to all countries, and to entire groups of technologies, the flexibility to tailor the benchmarks to the specific characteristics of individual technologies, and to the conditions pertaining in each country, is lost.

In short, there is no avoiding the core hypothetical. This being the case, we have opted to address it explicitly or "head on," by providing as an answer an "educated guess," based on informed opinion and expert judgment, for each individual technology and country. In this way we have sought to reflect and capture the unique characteristics of each technology/country combination in our proposed qualitative baselines. Nonetheless, we wish to emphasize that the technology matrix approach *could* readily accommodate an objective benchmarking approach of the type described above, if such an approach were ultimately deemed preferable to the one adopted in this report.

Furthermore, precisely because they are based on subjective opinion, the qualitative baselines presented in this chapter are by no means offered as definitive or final. On the contrary, the authors would encourage discussion and debate of these baselines, as a means of moving towards an improved set of qualitative baselines with consensus support. Again, it must be emphasized that the goal of this report is *not* to provide definitive benchmarks, but rather to illustrate the main issues that must be addressed in the development of the technology matrix, and to identify areas for improvement in the development approach. With this in mind, one such improvement can be proposed here. Although for our purposes it was sufficient to base the qualitative baselines on the informed opinions of a few individuals, the authors believe that benchmarks to be utilized as the basis for the awarding of emission reduction credits, with monetary value, should be founded on a much broader consensus view. We would therefore propose that, if the technology matrix were eventually to be developed and utilized for market-based carbon offset project evaluation, a Delphi approach to the establishment of the qualitative baselines should be used. Under this approach, international panels of experts would be brought together to decide upon the baselines for each technology and country. Separate panels would likely be required for each economic sector; furthermore it is important that each panel include expert representatives from a wide cross-section of countries, to lessen or at least balance-out the potential for political manipulation. Each panel would work towards reaching a consensus concerning the qualitative baselines under its purview. The results of such an approach would still be subjective, but they would represent a subjective *consensus* of the leading technology experts for each economic sector.

Results

The application of the approach described in the preceding subsection yielded the results presented in Table 5. In this table, the qualitative baseline--i.e., the most likely alternative to the projects utilizing a particular technology--is defined for each technology/country combination. Thus, for example, the table shows that the qualitative baseline, or most likely alternative, to an IGCC project in India is conventional coal-fired steam turbine power plant. Technology/country combinations that were shown to be non-additional in Chapter 2 are indicated by light shading. Although these technologies will not qualify as additional under the technology matrix approach, projects utilizing these technologies may nonetheless qualify under the project-specific approach. Therefore, qualitative baselines (and, in Chapter 4, benchmarks), are provided for these technologies, to benefit project developers who can demonstrate additionality using the project-specific approach. Non-shaded technologies in Table 5 were determined to be additional in the preceding chapter; projects utilizing these technologies will automatically qualify for emission reduction credits under the technology matrix approach.

The qualitative baselines shown in Table 5 are necessarily generic in nature. They represent the *typical* most likely alternative to the *group* of projects utilizing a particular technology. Obviously, the most likely alternative to a *particular* project may differ from the *typical* alternative selected as the qualitative baseline. However, the technology matrix approach is by nature a generic approach, under which it is possible to consider only the typical or most likely case. Exceptions will no doubt exist, but it is not possible to identify or separately address these exceptions within the context of the technology matrix.

Note that, in a number of instances, separate qualitative baselines have been developed for different applications of the same technology, or for benchmarking different gasses (e.g., methane and carbon dioxide). For example, two qualitative baselines are provided for wind turbine technology, depending on whether the turbines are to be used for off-grid or on-grid applications. The breakdown of a particular technology by application is necessary whenever the most-likely project alternative is expected to vary depending on the application. As Table 5 shows, there are a number of such cases.

Note, furthermore, that in a few cases (denoted by dark shading) it was decided that a benchmark should *not* be developed for a particular technology/application. For example, in the case of sulfur oxide fuel cells to be used in distributed generation applications, it was decided that the project-specific approach should be employed to compute emission reductions rather than the technology matrix approach. The energy-plex concept is also excluded from the matrix for a different reason: this technology has not reached a level of maturation sufficient to warrant its inclusion *at this point in time* (although, depending on its development course, it may be included in a future version of the matrix). And a benchmark is not provided for estimating the methane emission reductions resulting from coalbed methane recovery projects, because a benchmark is not required: the methane reductions can be measured directly for such projects. The specific reasons for excluding some technologies/technology applications from the matrix are discussed in more detail in the following sections.

Table 5. The Technology Matrix: Summary of Qualitative Baselines

Technology	Application/Gas	Country	
		India	Ukraine
Supercritical Coal	All	Steam turbine plant with subcritical, PCF boilers	Coal-fired steam turbine plant
IGCC	All	Steam turbine plant with PCF boilers	Coal-fired steam turbine plant
Natural Gas Combined Cycle	All	Gas-fired steam turbine plant	Gas-fired steam turbine plant
Wind Turbine	Off-grid	Diesel generators	Diesel generators
	On-grid	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
Solid Oxide Fuel Cells	Commercial cogeneration	Diesel generators	Diesel generators
	Low-cost fuel	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
	Distributed generation	**USE PROJECT-SPECIFIC APPROACH**	**USE PROJECT-SPECIFIC APPROACH**
CNG Vehicles	Passenger Cars	Composite of gasoline and diesel vehicles	Composite of gasoline and diesel vehicles
	Transit buses	Composite of diesel vehicles	Composite of diesel vehicles
Hybrid (gasoline/electricity) vehicles	Passenger Cars	Composite of gasoline and diesel vehicles	Composite of gasoline and diesel vehicles
	Transit buses	Composite of diesel vehicles	Composite of diesel vehicles
Coalbed Methane Recovery	Methane	**BENCHMARK NOT REQUIRED**	**BENCHMARK NOT REQUIRED**
	CO_2/Onsite electricity generation	A composite representing average emissions rate of recently-built capacity.	A composite representing average emissions rate of all existing capacity.
	Transfer of gas to pipeline	**USE PROJECT-SPECIFIC APPROACH**	**USE PROJECT-SPECIFIC APPROACH**
Energy-Plex	All	**BENCHMARK NOT PROVIDED**	**BENCHMARK NOT PROVIDED**

The qualitative baseline selections presented in Table 5, and the rationale behind these selections, are described in detail in the following sections. The first section deals with the five power generation technologies as a group, and the second section deals with the transportation/transportation fuel technologies. Coalbed methane recovery and energy-plex are considered separately in the last two sections.

The Qualitative Baseline for Power Generation Projects

In this section, we consider the development of the qualitative baseline for the five power generation technologies: supercritical boilers, IGCC, natural gas combined cycle, fuel cells, and wind. In order to develop quantitative emission benchmarks for these technologies, it is first necessary to define, qualitatively, the most likely alternative to projects utilizing each technology. These "most likely alternatives," or counterfactuals, must of necessity be broadly defined or generic in nature, since they will be applied to *all* projects utilizing each technology. There is, however, one set of bounds that will serve to the limit the types of projects to which the counterfactuals will be applied. These bounds are shown in Table 6, which is taken from the NETL report *Developing Emission Baselines for Market-based Mechanisms: A Case Study Approach.* Table 6 presents the basic criteria project developers should use in choosing between the technology matrix approach and the project-specific approach to baseline development. Within the power generation sector projects have been subdivided into three main types. As the table shows, the second and third types of projects (those utilizing conventional non-qualifying technologies and those involving retrofits of advanced technologies) should be analyzed using the project-specific approach.[69] The technology matrix should be applied only to projects utilizing advanced qualifying technologies *that involve the installation of new capacity.* New capacity projects are the specific focus of the technology matrix approach because these projects will, in general, require the use of some sort of sector benchmark as the basis for the baseline. Projects involving modifications or retrofits to existing facilities, on the other hand, do not require the use of a benchmark; in fact, a more accurate baseline for these types of projects can generally be developed based on the historical emissions rates of the affected facilities.

At this point, it will prove useful to introduce and define some new terminology. In order to determine, qualitatively, the counterfactual for a qualifying power generation technology, it is first necessary to posit a project utilizing that technology. This hypothetical project should represent the "typical" application for the technology in question, because it must, for technology matrix development purposes, stand for all capacity expansion projects utilizing the technology, to be undertaken under the carbon offset program. We will refer to this hypothetical project as the "model project." Each qualifying technology--i.e., each entry in the technology matrix--will have its own model project, and that project will be understood to represent the typical or most common project likely to utilize the qualifying technology.

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[69]Note that the *additionality* of retrofit projects may be determined using the technology matrix. However, baseline estimation for these projects, which is the subject of concern at present, should be performed using the project-specific approach.

However, for benchmark development purposes our focus is not so much on the model project, but rather on the "model counterfactual." The model counterfactual is defined as the most likely alternative to the model project. Just as the model project will be used, conceptually, to represent the host of real world projects utilizing a particular technology, the model counterfactual will likewise represent the host of real world alternatives to these projects. The goal is to define the model counterfactual such that it typifies these real world alternatives.

As noted above, the technology matrix should be applied only to power generation projects involving capacity expansion. In other words, for present purposes the model project is of necessity a capacity expansion project. Given this conception of the model project, the question becomes, what would happen if this project were *not* to be undertaken? The answer to this question in effect defines the model counterfactual for each qualifying technology.

This basic question can be broken down into two main components or issues. First, in the absence of the model project, will another project be undertaken to meet the same capacity expansion needs? In other words, if the model project is forgone will some other new capacity project be undertaken in its place? And second, if the answer to this question is "yes," then what technology will be utilized by the alternative project?

The following subsection will address the first issue. The resolution of the second issue, unlike that of the first, is both country- and technology-dependent. Therefore, in the second subsection this issue will be taken up for each of the five power sector technologies, and for India and Ukraine, separately.

Issue No. 1: Will the Capacity Still Be Built in the Absence of the Model Project?

The issue of whether or not the capacity will be built even in the absence of the model project--i.e., whether or not the model counterfactual is itself a capacity expansion project--can in turn be broken down into two questions or issues that must be addressed. These questions are as follows:

1. In the host country, is capacity expansion limited by demand or capital availability?

2. If the latter, will a certain amount of capital be "freed up" if the model project is foregone?

Question 1: What Limits Capacity Expansion, Demand or Capital Availability? When developing the qualitative baseline, it is important to draw a sharp distinction between developed and developing countries. In developed countries, electricity supply and demand are typically in balance, and the installation of new capacity keeps pace with demand growth. In these circumstances, if a decision is made to halt one project designed to meet new demand, it is likely that another project(s) will be implemented in its place. It is usually a given that the new demand will be met one way or another. Capital availability is typically not a constraint; if the demand exists, the capital required to build new capacity to meet that demand will generally be found.

The same is not true in the developing world. Capital availability acts a major constraint to capacity expansion. Demand is not always met, as evidenced by significant electricity supply shortfalls in a number of key developing countries (including India as well as China). In these circumstances, it cannot be assumed that another capacity expansion project would automatically rise up to take the place of a forgone model project. The possibility that the demand to have been met by the model project will simply go unmet is a real one.

This is certainly the case in India. Currently, India faces acute electricity shortages. Power outages average 20 percent of demand during peak use hours and 10 percent of off-peak demand. Furthermore, India's electricity demand is expected to grow by 7 percent per year through 2005, and 4.4 percent per year thereafter (through 2020). To alleviate the electricity shortages and meet new demand, the government plans to add 40,000 MW of capacity by 2002. About half of this total is expected to be funded by private--mostly foreign--sources, with the remaining half to be funded by the government (either directly, or through the various Federal and State utilities).

However, if past history is any guide, actual new construction will fall short of plans. In fact, the government itself questions the likelihood of meeting its own capacity expansion plans. In the government of India's Ninth Five-Year Plan, questions are raised as to whether the country's State Electricity Boards (SEBs) will be able to contribute their share of capacity additions as envisaged in the Plan and thereafter. Furthermore, the poor financial health of the SEBs is acting as a significant constraint on private investment in the power sector. The Eight Five-Year Plan called for an additional 2810 MW to be financed by the private sector; however, only half of this goal (1430 MW) was met. In assessing the reasons for this shortfall, the Ninth Plan states:

> The shortfall in the private sector was due to the emergence of a number of constraints which were not anticipated at the time the policy was formulated. The most important is that lenders are not willing to finance large independent power projects, selling power to a monopoly buyer such as SEB, which is not financially sound because of the payment risk involved if SEBs do not pay for electricity generated by the IPP.
>
> Some small projects were able to get financing because the payment risk was deemed acceptable. Five projects have received Central Government counter-guarantees and two more are eligible subject to resolution of other problems. The Central Government will not provide counter guarantees for power projects in the future. A number of private sector projects are seeking credit enhancement by escrowing certain receipts of the SEBs to assure payment of IPP dues. The scope for escrow arrangements is limited and in any case they do not increase the overall financial viability of the SEB. Rather, by earmarking part of the SEB's existing receipts for new private sector projects, they reduce the viability of the rest of the system.

Table 6. Criteria for Selecting an Approach to Baseline Development, for the Electricity Generation Sector

Project Type	Corresponding Approach	Exceptions
1. Projects involving the installation of new capacity, and utilizing advanced qualifying technologies	Modified Technology Matrix	a. Projects to be implemented in host countries without qualifying technology lists/sector benchmarks must use the project-specific approach b. Project developers *may* choose to use the project-specific approach to estimate the baseline, *if* they can demonstrate that the result is more accurate c. Projects designed to replace existing capacity rather than meet new demand should use the project-specific approach for baseline development, *if* the capacity to be replaced can be readily identified.
2. All projects utilizing conventional, non-qualifying technology	Project-specific	a. Projects involving the installation of new capacity to meet new demand should use a sectoral benchmark for baseline estimation, *unless* the project-developers choose to use the project-specific approach *and* can demonstrate that the result is more accurate.
3. Projects involving the retrofitting of advanced qualifying technologies to existing facilities, with no resulting change in capacity	Modified technology matrix to establish additionality; project-specific to estimate the baseline	None.

> The ability to attract private investment into the power sector on a significant scale in the future therefore depends crucially upon bringing about improvements in the financial condition of SEBs.[70]

According to the Tata Energy Research Institute (TERI), "the unsatisfactory financial health of the SEBs has acted as a constraint to provide adequate investments for improving the utilization of existing capacities and for new capacity creation."[71]

Given these financial constraints, it is a clear that a sizeable portion of future electricity demand, like current demand, may simply go unmet. For India, at least, the answer to Question 1 is "no": we cannot assume that demand will still be met in the absence of the model project.

The circumstances are different in Ukraine, although the conclusions to be drawn from these circumstances are similar. Unlike India, Ukraine is not experiencing a rapid rise in either GDP or electricity demand. On the contrary, Ukraine has not yet recovered from the sharp economic downturn following upon the breakup of the Soviet Union. GDP has dropped to 40 percent of its 1990 level, while electricity consumption dropped by 33.5 percent between 1993 and 1998. As a result Ukraine is characterized by excess capacity rather than under-capacity. Furthermore, this situation is not likely to change in the near term. In fact, by some estimates Ukraine has sufficient capacity to meet demand for the next 10 to 15 years.

This holds important implications for benchmark development. Whereas in India new capacity is desperately needed to meet new and growing demand, in Ukraine the urgent need is to rebuild, and in some cases replace, old and badly deteriorated power plants. The average age of Ukraine's thermal generating units is about 26 years. Many utilize obsolete technologies, and maintenance is often poor. Maintenance problems have been exacerbated by the difficulty of obtaining spare parts, due to the breakdown of trade among the republics of the FSU. The result has been a decline not only in unit efficiencies, but in unit availabilities and capacities as well. For example, at some of the older coal-fired plants air leaks in the boiler casings overload induced draft fans and effectively reduce unit capacities by 10 percent or more.

Ukraine's Ministry of Energy has a comprehensive, phased plan for unit modernization. These plans include the addition of 150-MW topping gas turbines on existing 800-MW units, repowering of existing 200- and 300-MW units with atmospheric fluidized bed combustion boilers and high efficiency fly ash collection equipment; installation of FGD scrubbers on units expected to remain in operation for at least 10 more years, and burner retrofits. In total, the ministry plans to modernize 6500 MW of existing capacity by 2001, at a total cost of $1 billion. Most of this investment will have to be raised outside of the country.

However, as in India, Ukraine's plans are jeopardized by irrational tariff structures, subsidies, and simple non-payment for electric services. Ukraine is moving towards market-based electricity pricing,

[70] Government of India, Ninth Five-Year Plan.

[71] Tata Energy Research Institute, "Indian Power Sector: Change of Gear," http://www.teriin.org/energy/power.htm.

but still has a long way to go. Electricity rates were raised 30 percent in 1996, but this hike still left rates about 20 percent below market levels. Furthermore, cross-subsidies for residential consumers were left untouched. Further rate hikes were promised, but when they still had not been implemented by 1997 the World Bank suspended a $317 million loan.

Furthermore, it is estimated that only 80 percent of Ukraine's electricity consumption is paid for, and of that only 10 to 20 percent is paid in cash. The remainder is exchanged for a wide variety of items, including coal, spare parts, repairs, and other services. In December 1996 electricity service was suspended for more than 36,000 consumers, ranging from large industrial enterprises to small private firms, due to payment delays.

Until these problems are resolved, Ukraine will find it difficult to raise the foreign capital needed to undertake its modernization program, either from public sources such as the World Bank or private investors. It is true that demand will likely still be met in Ukraine even in the absence of the model project, given the excess capacity that exists at present. However, as in India, the need for new capacity--in Ukraine's case to replace aging capacity--is great. Yet this need has largely gone unmet since the breakup of the Soviet Union, due to lack of capital. And capital availability will continue to act as the constraint limiting new capacity builds, in Ukraine as in India, for the foreseeable future.

Question 2: Will Foregoing the Model Project "Free Up" Capital? Therefore, we must address the second question, which is a financial question. In developed countries, a decision to forego a capacity expansion project will in effect "free up" a certain amount of demand; another project (or projects) will be undertaken to fill this freed-up demand. In India and Ukraine, will a certain amount of capital likewise be "freed up" when the model project is forgone? If the answer to this question is "no," then we may conclude that the total amount of capital available to build new capacity will remain unaffected by the foregone model project, and, given that capital availability determines the level of capacity expansion, there is no reason to believe that another project would be undertaken to replace the foregone project. If, on the other hand, forgoing the model project *would* free up capital for another capacity expansion project(s), then such a replacement project(s) might presumably be undertaken.

To further our analysis of this issue, let us consider two possible alternatives to model project financing. In Alternative A, we assume that most of the financing is provided by the model project's host country sponsors. The developed country sponsors provide a limited amount of additional financing in exchange for the emission reduction credits, but the host country sponsors retain all shares in the ownership of the project. What would happen if a decision were made to forego the project? In this particular situation, the capital that would have been provided by the host country sponsors would *probably* be freed up for another capacity expansion project. Possibly the loans and other financial instruments controlled by the host country sponsors might be lost once the model project is foregone, but given that model project technology is by definition not commercial at present it seems likely that the financing arranged for such a high-risk project could be retained for a project(s) utilizing conventional technology. Obviously, the host country sponsors could choose to invest the freed-up capital in projects other than capacity expansion projects, including projects in other sectors or countries. But again, if a capacity expansion project appears attractive despite its utilization of non-commercial, high risk technology, it seems plausible that the best alternative to such a project would be a capacity expansion project utilizing conventional technology. Obviously, the host country sponsors would lose the support of the developed country sponsors if they opted for a conventional power plant, since no emission reduction credits would be awarded for building such a plant. But since the capital costs associated with the construction of a conventional plant would generally be less than those required to build a comparable plant using non-commercial technology, and since the developed country sponsors are in any event providing only a small share of the required capital, it is likely that the host country sponsors could open a comparably-sized conventional plant.

In Alternative B, we assume that the developed country-sponsors, rather than the host country sponsors, are providing most of the project financing. In this case, the developed country sponsors would presumably receive a significant share of ownership in the project, as well as the emission reduction credits, in exchange for their financial contribution. Given the large amount of capital required to open a power plant, and the fact that the developed country sponsors are providing most of the needed capital, it is likely that the ownership stake rather than the emission reduction credits are the prime motivator for developed country participation in the project. Hence the developed country sponsors are presumably interested primarily in exploiting perceived economic opportunities in the host country's electricity sector. The perceived market opportunities could presumably be met, at lower cost and lower risk, by opening a comparably-sized conventional power plant. However, the added inducement of the emission reduction credits has caused the project sponsors to opt for an advanced technology plant rather than a conventional plant. Again it seems *plausible,* if not *probable,* that the next best investment alternative to the model project would be a conventional plant(s) in the host country.

In the case of financial arrangements lying somewhere between the extremes illustrated by Alternatives A and B, the argument, and the conclusions, would be similar.

Obviously, we cannot draw the conclusion that every foregone project would free up capital for conventional generating capacity; in at least some cases it is possible that the demand to be met by the advanced plant would simply go unmet in that plant's absence. In developing the technology matrix, we are of necessity constrained to consider entire categories of projects at once, rather than individual projects. Hence our conclusions must be general, reflecting the likely typical situation, without taking into account the possible exceptions. This being said, it seems reasonable to conclude that, *in general*, the foregoing of a model power generation project in India or Ukraine would free up the capital needed to build a roughly equivalent amount of conventional capacity.

Ukraine requires some special consideration at this point. In Ukraine, it is entirely plausible that the capital freed up in the absence of the model project would be used to refurbish existing plants, rather than to build a new conventional plant. However, while unquestionably much of the capital raised by the Ukrainian power sector in the near-term future will be invested in existing plants, in at least some cases it is likely that plants will be replaced rather than refurbished. Some of the existing Ukrainian plants are simply too old and obsolete to warrant further investment. It is projects to replace these plants that *may* qualify for emission reduction credits under the technology matrix approach. Refurbishment of existing plants, on the other hand, will generally involve conventional rather than advanced technologies, and will therefore not qualify for credits under the technology matrix approach. Therefore, for technology matrix development purposes, we must focus not on potential refurbishment projects, but on capacity replacement projects. If a model project which has as its goal the *replacement* of existing capacity is foregone, then it is likely that the capital thus freed up will still be applied to the goal of capacity replacement. In other words, in Ukraine as in India the most likely alternative to the construction of a new power plant using an advanced technology is the construction of a new plant utilizing conventional technology. Refurbishment of existing capacity is no doubt a possibility in some cases, but again we are constrained to consider only the general case or typical outcome, not the possible exceptions.

We may also conclude, for both India and Ukraine, that the capacity likely to be built in lieu of the typical advanced-technology plant would take the form of a comparably-sized conventional plant located on the same site. This conclusion follows from the arguments developed for Alternatives A and B above, and in particular from the fact that the investment capital to be freed up would remain under the control of the model project sponsors. These sponsors, having selected the site for the model project, would presumably favor the same site for the alternative plant. Again, these conclusions may be true in general, although they would not necessarily be true in every specific case.

Issue No. 2: Defining the Model Counterfactual

In the preceding subsection, it was established that, for power generation technologies covered in the technology matrix, the model counterfactual will be a new capacity project, of roughly the same size, and located on the same site as, the model project. However, the model counterfactual, unlike the model project, will utilize an existing commercial technology. Having established the basic features of the model counterfactual, the next step is to more fully define and characterize the counterfactual. Specifically, the technology and fuel type(s) to be utilized by the counterfactual plant must be defined. In addition, some sense of the types of “real world” plants that might be used to represent the counterfactual plant should be developed. For example, if the model counterfactual is to be a new power plant, then real world plants built within, say, the last 5 years might be used to represent the counterfactual. Finally, to the extent feasible we want to obtain some sense of the degree of disaggregation (by region, unit size, etc.) that will be necessary to adequately represent benchmarks for each qualifying technology. However, it must be emphasized that regional and other classification schemes can only be suggested in a rough, preliminary manner at this point in the analysis. The full development of the classification schemes must be based on the analysis of quantitative data for each country.

To better define the model counterfactual, we must address a number of key questions, including the following:

- Is the qualifying technology designed to meet baseload, intermediate, or peaking demand?

- What conventional technologies are being utilized to meet these load demands?

- What fuel type(s) will the qualifying technology utilize?

- Based on the above, what are the technology/fuel alternatives to the qualifying technology?

In order to provide a degree of standardization and objectivity in the counterfactual definition process, these and other key questions have been incorporated in a series of "decision tables" (Tables 7 through 12). Each country/power generation technology combination is covered by a separate table. Essentially, the decision table provides a means of defining, clarifying, and organizing the issues that must be addressed to define the model counterfactual. It also provides a means of organizing the thought processes involved in reaching conclusions concerning the model counterfactual, and it ensures that the resolutions to the key issues are developed and presented in a clear, orderly fashion. Each decision table is organized such that the resolutions and conclusions contained in each row build on those provided in the preceding row and, likewise, the conclusions contained in each column build on those of the preceding column. The final conclusions concerning the nature and characteristics of the model counterfactual are thus presented in the bottom right-hand cell of each table.

The decision tables for three of the five advanced power generation technologies, in India and Ukraine, are presented as Tables 7 through 12. These tables cover the following technologies: supercritical coal, IGCC, and natural gas combined cycle. A drawback of the decision table approach is that it is relatively inflexible and thus not applicable to all technologies. Wind turbines and fuel cells are difficult to address within the confines of the decision table approach; hence these two technologies are considered separately in later subsections. But first, the following short subsection summarizes our conclusions, from the decision tables, concerning the model counterfactuals for supercritical, IGCC, and natural gas combined cycle technology.

The Model Counterfactuals for Supercritical, IGCC, and Natural Gas Combined Cycle Technology. Tables 7 through 12 present the thought processes and conclusions concerning the model counterfactuals for supercritical, IGCC, and natural gas combined cycle technology in India and Ukraine. Our definitions of the model counterfactuals for these technologies, as arrived at through the process of completing the decision tables, are summarized below for each country.

In India, the model counterfactuals are defined as follows:

- For supercritical technology, the model counterfactual will be a steam turbine plant with subcritical, PCF boilers. Two exceptions may be made in the case of Kerala (possible oil) and Assam (possible gas), pending the results of the data analysis.

- For IGCC technology, the model counterfactual will be a baseload steam turbine plant, with PCF boilers. Again, Assam (gas) and Kerala (oil) are possible exceptions.

- For natural gas combined cycle, the counterfactual will be taken as gas-fired steam turbine plant.

In Ukraine, the model counterfactuals are:

- For supercritical coal, the model counterfactual is defined as a coal-fired, baseload steam turbine plant with AFBC boilers.
- For IGCC, the counterfactual is a coal-fired, baseload steam turbine plant with AFBC boilers.
- For natural gas combined cycle, the model counterfactual is a gas-fired steam turbine plant.

Table 7. Decision Table for Supercritical Coal Technology in India

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	In general, coal-fired power plants are designed to meet baseload needs, be they sub- or super-critical.	Throughout most India, this issue is moot because supply-demand gap requires constant operation of all plants. It may not be moot in a few states where supply-demand are in balance	Possible that smaller, older less-efficient coal-fired units may be used for intermediate loads in some countries. But in India, again, most plants are operated around the clock to meet heavy demand.	Counterfactual will operate as a baseload plant (i.e., around-the-clock).
2. What conventional technologies are being utilized to meet these load demands?	India relies primarily on steam turbines with PCF boilers. FGD is not required, due to low sulfur content of Indian coals.	There is much heterogeneity across different states. Many of the larger states rely primarily on PCF, steam turbine plants, but notable exceptions include: - Assam (gas & hydro) - Himachal Pradesh (hydro) - Jammu & Kashmir (hydro) - Karnataka (hydro) - Kerala (hydro) - Rajasthan (hydro) In addition nearly 60 percent of Assam's planned new capacity is to be gas-fired, and over 60 percent of Kerala's planned capacity is to be oil-fired. Gas and oil are less important than coal in the capacity expansion plans of other States.	In those states not relying primarily on coal, hydro is the primary generation option. Given the structure of the Indian power sector, it is unlikely that hydro would represent the most likely alternative to supercritical coal even in states that do not rely heavily on coal. Hydro plants are built and operated by a federal utility that specialize in those plants. Potential coal plant developers are thus unlikely to pursue hydro as a second choice. Note that a similar argument applies for nuclear--55 percent of the planned capacity of one State (Rajasthan) is nuclear.	For most states--including those that rely mainly on hydro as well as major coal consuming states--the counterfactual should be defined as a baseload steam turbine plant, with PCF boilers. The two possible exceptions are Assam (gas) and Kerala (oil).

Table 7. Decision Table for Supercritical Coal Technology in India (Continued)

Question	General Response	Regional Considerations	Other Exceptions	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Coal, by definition.	None.	None.	N/A
4. What other fuel/energy options are available?	Coal accounts for 60 percent of capacity in India. Hydro is significant (23 percent), but not a likely alternative (see Question 2 above). Compared to coal, India's reserves of oil and gas are limited and insufficient to meet domestic demand.	Oil and gas account for less than 30 percent of planned capacity in all significant electricity generating states except Kerala and Assam.	LNG is a possible option in Kerala. A couple of LNG power projects are planned by IPPs in Kerala, and the State government hopes that these projects will provide the basis for a new LNG terminal under development at Kochi, Azheekal Port.	Oil, gas and LNG are all possible alternatives, but they do not account for a percentage of capacity sufficient to warrant their use as counterfactuals. The possible regional exceptions are Kerala and Assam
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	In general, no.	Possibly in Kerala and Assam.	None.	The model counterfactual will be a steam turbine plant with subcritical, PCF boilers. Two exceptions may be made in the case of Kerala and Assam, pending the results of the data analysis subtask.

Table 8. Decision Table for Supercritical Coal Technology in Ukraine

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	In general, coal-fired power plants are designed to meet baseload needs, be they sub- or super-critical. Like the other FSU republics, Ukraine's power sector is based on standardized generating units in very large central stations. Future capacity expansion may, however, deviate from this old Soviet model, although supercritical coal will likely be applied to baseload needs.	None known.	In the Soviet Union, dispatching was based not on least cost, but on a variety of factors including, e.g., size of fuel stocks. Even today, least-cost dispatching is heavily distorted by severe fuel shortages.	In general, supercritical technology will be used for baseload applications; the counterfactual should therefore be presumed to be a baseload plant.
2. What conventional technologies are being utilized to meet these load demands?	Ukraine has significant nuclear capacity (25% of total), but most is thermal (65%). There are a number of supercritical units in operation at present. There are known to be at least 12 such units--6 oil-fired and 6 coal-fired. Ukraine's hydro potential has mostly been exhausted.	None known.	Nuclear is unlikely alternative to supercritical coal. Supercritcal cannot be its own counterfactual. Few of Ukraine's existing plants have modern pollution control equipment, but new capacity will likely have this equipment, given that plans to upgrade existing plants include installation of AFBC boilers at 200-300 MW units, FGD scrubbers, and high-efficiency fly ash collection equipment.	Counterfactual will be steam turbine plant with subcritical boilers.

Table 8. Decision Table for Supercritical Coal Technology in Ukraine (Continued)

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Coal, by definition.	None.	None.	N/A
4. What other fuel/energy options are available?	Both oil- and gas-fired units represent significant percentage of total capacity (each comprise 24% of total thermal capacity). However, coal is dominant at 52 percent of total thermal capacity.	Natural gas prices are lower near the Russian border. Polish coal can be imported relatively cheaply near the Polish border.	Ukraine must augment its own oil and gas production with imports from Russia and Turkmenistan, but its relation with both suppliers is strained and uncertain due to the mounting debt owed them. Gas deliveries to Ukraine have been halted on occasion in the past, due to payment concerns. On the other hand, coal production is insufficient to meet demand, and the average heat content of Ukrainian coal has dropped.	In general, coal will likely be favored over oil and gas due to the insecurity of the oil and gas supply, at least for near-term new capacity builds.
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	In general, no, due to security of supply concerns.	Security of supply concerns will likely outweigh regional price considerations.	None.	The counterfactual will be defined as a coal-fired, baseload steam turbine plant with AFBC boilers.

Table 9. Decision Table for IGCC Technology in India

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	Mainly baseload, possibly intermediate in some instances.	Throughout most India, this issue is moot because supply-demand gap requires constant operation of all plants. It may not be moot in a few states where supply-demand are in balance.	None.	Counterfactual will operate as a baseload plant (i.e., around-the-clock).
2. What conventional technologies are being utilized to meet these load demands?	India relies primarily on steam turbines with PCF boilers. FGD is not required, due to low sulfur content of Indian coals.	There is much heterogeneity across different states. Many of the larger states rely primarily on PCF, steam turbine plants, but notable exceptions include: - Assam (gas & hydro) - Himachal Pradesh (hydro) - Jammu & Kashmir (hydro) - Karnataka (hydro) - Kerala (hydro) - Rajasthan (hydro) In addition nearly 60 percent of Assam's planned new capacity is to be gas-fired, and over 60 percent of Kerala's planned capacity is to be oil-fired. Gas and oil are less important than coal in the capacity expansion plans of other States.	In those states not relying primarily on coal, hydro is the primary generation option. Given the structure of the Indian power sector, it is unlikely that hydro would represent the most likely alternative to supercritical coal even in states that do not rely heavily on coal. Hydro plants are built and operated by a federal utility that specialize in those plants. Potential coal plant developers are thus unlikely to pursue hydro as a second choice. Note that a similar argument applies for nuclear--55 percent of the planned capacity of one State (Rajasthan) is nuclear.	For most states--including those that rely mainly on hydro as well as major coal consuming states--the counterfactual should be defined as a baseload steam turbine plant, with PCF boilers. The two possible exceptions are Assam (gas) and Kerala (oil).

Table 9. Decision Table for IGCC Technology in India (Continued)

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Coal.	None.	None.	N/A
4. What other fuel/energy options are available?	Coal accounts for 60 percent of capacity in India. Hydro is significant (23 percent), but not a likely alternative (see Question 2 above). Compared to coal, India's reserves of oil and gas are limited and insufficient to meet domestic demand.	Oil and gas account for less than 30 percent of planned capacity in all significant electricity generating states except Kerala and Assam.	LNG is a possible option in Kerala. A couple of LNG power projects are planned by IPPs in Kerala, and the State government hopes that these projects will provide the basis for a new LNG terminal under development at Kochi, Azheekal Port.	Oil, gas and LNG are all utilized, but they do not account for a percentage of capacity sufficient to warrant their use as counterfactuals. The possible regional exceptions are Kerala and Assam.
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	In general, no.	Possibly in Kerala and Assam.	If gas were available to the project, there would be no need to utilize coal gasification technology. Thus the use of IGCC implies that gas is not a viable option. LNG could still be a possible option in Kerala, though.	The model counterfactual will be a steam turbine plant with subcritical, PCF boilers. An exception may be made in the case of Kerala, pending the results of the data analysis subtask.

Table 10. Decision Table for IGCC Technology in Ukraine

Question	General Response	Regional Considerations	Other Exceptions	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	Mainly baseload, possibly intermediate in some instances.	None known.	In the Soviet Union, dispatching was based not on least cost, but on a variety of factors including, e.g., size of fuel stocks. Even today, least-cost dispatching is heavily distorted by severe fuel shortages.	In general, IGCC technology will be used for baseload applications; the counterfactual should therefore be presumed to be a baseload plant.
2. What conventional technologies are being utilized to meet these load demands?	Ukraine has significant nuclear capacity (25% of total), but most is thermal (65%). Ukraine's limited hydro potential has mostly been exhausted. Although supercritical technology is utilized in Ukraine, it is not dominant.	None known.	Nuclear is an unlikely alternative to coal-fired IGCC. Few of Ukraine's existing plants have modern pollution control equipment, but new capacity will likely incorporate this equipment, given that plans to upgrade existing plants include installation of AFBC boilers at 200-300 MW units, FGD scrubbers, and high-efficiency fly ash collection equipment.	Counterfactual will be steam turbine plant with subcritical boilers.

Table 10. Decision Table for IGCC Technology in Ukraine (Continued)

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Coal	None.	None.	N/A
4. What other fuel/energy options are available?	Both oil- and gas-fired units represent significant percentage of total capacity (each comprise 24% of total thermal capacity). However, coal is dominant at 52 percent of total thermal capacity.	Polish coal can be imported relatively cheaply near the Polish border.	Ukraine must augment its own oil and gas production with imports from Russia and Turkmenistan, but its relation with both suppliers is strained and uncertain due to the mounting debt owed them. Gas deliveries to Ukraine have been halted on occasion in the past, due to payment concerns. On the other hand, coal production is insufficient to meet demand, and the average heat content of Ukrainian coal has dropped.	In general, coal will likely be favored over oil and gas due to the insecurity of the oil and gas supply, at least for near-term new capacity builds.
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	In general, no, due to security of supply concerns.	Security of supply concerns will likely outweigh regional price considerations.	If gas were available to the project, there would be no need to utilize coal gasification technology. Thus the use of IGCC implies that gas is not a viable option.	The counterfactual will be defined as a coal-fired, baseload steam turbine plant with AFBC boilers.

Table 11. Decision Table for Natural Gas Combined Cycle Technology in India

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	Baseload and intermediate	Throughout most India, this issue is moot because supply-demand gap requires constant operation of all plants. It may not be moot in a few states where supply-demand are in balance.	None.	Given the supply-demand gap in India, it is best to assume that the plant will be operated on an around-the-clock basis (baseload mode)
2. What conventional technologies are being utilized to meet these load demands?	India relies primarily on steam turbines with PCF boilers. FGD is not required, due to low sulfur content of Indian coals.	There is much heterogeneity across different states. Many of the larger states rely primarily on PCF, steam turbine plants, but notable exceptions include: - Assam (gas & hydro) - Himachal Pradesh (hydro) - Jammu & Kashmir (hydro) - Karnataka (hydro) - Kerala (hydro) - Rajasthan (hydro) In addition nearly 60 percent of Assam's planned new capacity is to be gas-fired, and over 60 percent of Kerala's planned capacity is to be oil-fired. Gas and oil are less important than coal in the capacity expansion plans of other States.	In those states not relying primarily on coal, hydro is the primary generation option. Given the structure of the Indian power sector, it is unlikely that hydro would represent the most likely alternative to supercritical coal even in states that do not rely heavily on coal. Hydro plants are built and operated by a federal utility that specialize in those plants. Potential coal plant developers are thus unlikely to pursue hydro as a second choice. Note that a similar argument applies for nuclear--55 percent of the planned capacity of one State (Rajasthan) is nuclear.	The counterfactual will be a steam turbine plant.

Table 11. Decision Table for Natural Gas Combined Cycle Technology in India (Continued)

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Natural gas (or LNG), by definition.	There are a number of states where gas is not utilized because it is unavailable or uneconomic; natural gas combined cycle is not an option for these states.	None.	N/A
4. What other fuel/energy options are available?	Coal is the main alternative.	Oil may be a viable alternative in Kerala.	None.	Oil in Kerala, and coal throughout the rest of India, are possible gas alternatives.
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	Coal is in general the dominant fuel in India, whereas in many cases natural gas may be either unavailable or uneconomic. However, in the case of a natural gas combined cycle project, either a gas-fired steam turbine plant or a gas turbine plant is always a viable alternative, in so far as gas is clearly available to the project.	Oil is the dominant fossil fuel in Kerala's future plans, and should be viewed as more preferable than coal (though not necessarily natural gas).	When gas is available at a particular plant site, it is likely to be preferable to coal (or oil in Kerala). Coal is widely used in India because it is abundant, but Indian coal is poor in quality (up to 50 percent ash) and difficult to clean. The use of this poor-quality coal causes a significant reduction in capacity factors--a major problem in a country facing acute electricity shortages. Furthermore, capital costs may be higher for a coal-fired plant, particularly when natural gas is already available on-site.	The counterfactual will be taken as gas-fired steam turbine plant.

Table 12. Decision Table for Natural Gas Combined Cycle Technology in Ukraine

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Technology Alternatives:				
1. Is the technology designed to meet baseload, intermediate, or peaking demand?	Baseload and intermediate.	None known.	In the Soviet Union, dispatching was based not on least cost, but on a variety of factors including, e.g., size of fuel stocks. Even today, least-cost dispatching is heavily distorted by severe fuel shortages.	Counterfactual should be based on existing or planned baseload/intermediate load technologies.
2. What conventional technologies are being utilized to meet these load demands?	Ukraine has significant nuclear capacity (25% of total), but most is thermal (65%). In addition to its coal-fired units, Ukraine has many oil- and gas-fired steam turbine units. Ukraine's limited hydro potential has mostly been exhausted.	None.	Nuclear is an unlikely alternative to coal-fired IGCC.	Counterfactual will be a fossil fuel steam turbine plant.

Table 12. Decision Table for Natural Gas Combined Cycle Technology in Ukraine (Continued)

Question	General Response	Regional Considerations	Other Considerations	Conclusions
Fuel Alternatives:				
3. What fuel type(s) will the technology utilize?	Natural gas	None.	None.	N/A
4. What other fuel/energy options are available?	Both oil- and gas-fired units represent significant percentage of total capacity (each comprise 24% of total thermal capacity). However, coal is dominant at 52 percent of total thermal capacity.	Natural gas prices are lower near the Russian border. Polish coal can be imported relatively cheaply near the Polish border.	Ukraine must augment its own oil and gas production with imports from Russia and Turkmenistan, but its relation with both suppliers is strained and uncertain due to the mounting debt owed them. Gas deliveries to Ukraine have been halted on occasion in the past, due to payment concerns. On the other hand, coal production is insufficient to meet demand, and the average heat content of Ukrainian coal has dropped.	*In general*, coal will likely be favored over oil and gas due to the insecurity of the oil and gas supply, at least for near-term new capacity builds. *However*, since the project itself is to utilize natural gas the supply security concerns may not apply in this particular case.
5. Are any of these other options likely to be preferable to the fuel of choice for the technology?	Coal is in general the preferred fuel alternative in Ukraine, and it offers greater security of supply. But given that the project itself will utilize natural gas, general concerns regarding security of supply must not apply in this particular case.	See Question 4 above.	It is likely that natural gas offers significant price or other advantages over coal in this case, in order to outweigh the general security of supply concerns and the economic advantages of coal in some regions.	The counterfactual will be a gas-fired steam turbine plant.

Wind Turbines. The technologies considered thus far--supercritical coal, IGCC, and natural gas combined cycle--have certain fundamental characteristics in common. These technologies are all deployed in relatively large-capacity applications, typically to meet baseload generation requirements. All require major capital investments. Hence a large quantity of capital would be freed if the model project utilizing one of these technologies were to be foregone. Furthermore, the specific baseload demand that was to have been met by the model project would still need to be met in the project's absence. For these reasons, it was reasonable to posit a single, discreet project as the model counterfactual--e.g., a baseload, coal-fired steam turbine plant in the case of IGCC.

However, the applications for wind turbine technology differ markedly from those for supercritical, IGCC, or combined cycle technology. First, the maximum capacity of an individual wind turbine generator is only 1.5 megawatts, and even large utility-owned wind farms are generally less than 100 MW in capacity. Furthermore, at least in on-grid applications, it is difficult to target wind energy to meet specific load requirements. For one, turbine siting is based on wind resources rather than the location of demand centers. Furthermore, because of the intermittent nature of wind turbine operations, the concepts of baseload versus peaking do not apply; rather wind farms supply power to the grid when the wind is blowing, regardless of demand fluctuations.

For these reasons, it is very difficult to identify a single, discrete project as the model counterfactual, at least for wind projects designed to supply power to the grid. It is likely that the foregoing of such projects will free up capital, just as is likely for other power generation projects. However, it is much more difficult, in the case of wind projects, to posit a single, likely alternative project. Given that a wind project is not geared to meet a specific, readily identifiable demand requirement, how can we decide how the capital would be used in the project's absence? Would it be used to install a gas turbine peaking unit? Would it be applied towards the costs of a large coal-fired baseload unit? Or would it be used to make capital improvements at a variety of existing power plants?

In short, we can make the reasonable assumption that the freed-up capital would be invested in existing or new generating capacity, but it is very difficult to make any further assumptions concerning the specific technologies involved. In light of this fact, we propose that, rather than a single, discrete project, the model counterfactual for on-grid wind turbine applications should instead represent a composite of existing power plants and generation technologies. In other words, we propose that the benchmark for wind turbines represent something approaching a utility industry emissions rate average, rather than the emissions rate for a specific generation technology. Implicit in this composite or sectoral approach is the assumption that the capital freed up by foregoing the project would be dispersed and applied towards a wide cross section of projects, rather than to any particular project. In effect, we are assuming that the freed-up capital would be invested in the same wide range of technologies, and in the same proportions, as overall past investments in the utility industry. This assumption, while clearly highly uncertain, is, in the circumstances, reasonable: in effect, we are using historical investment patterns as our guide to determining how the freed-up capital might be invested. Although this approach will undoubtedly introduce errors into the emission reduction estimates for individual wind turbine projects, we might expect the errors to tend to cancel out across all projects. In contrast, selecting a specific generation technology as the model counterfactual might be expected to lead to biased reduction estimates at the global level, given the lack of any clear basis for preferring one technology over another.

In the case of India, the composite emissions rate should be based on the average emissions rate of all new capacity recently built by Indian utilities. The assumption underlying this approach is that in India, the capital freed up by foregoing a wind turbine project would be more than likely dedicated to building other new capacity projects. This assumption reflects the large supply-demand gap in India, and the country's desperate need for more generating capacity.

In Ukraine, on the other hand, the composite emissions rate should be based on the average emissions rate for all existing capacity. In Ukraine, the primary focus is on refurbishing and modernizing old and worn out existing capacity, not on building new capacity. Hence capital freed up from other projects would most likely be applied to this goal.

Thus far, we have considered wind turbine projects designed to provide power to the grid. However, wind turbines may also be used in off-grid applications, e.g., to provide power to farms or villages in remote locations. These off-grid projects will tend to be small, typically 1 to 5 units with a total capacity ranging anywhere from 50kW to 1.5 MW. Because of the intermittent nature of the energy source, off-grid applications typically require some form of backup generation, and may also utilize storage technology.

Unlike projects designed to supply the grid, off-grid applications are designed to meet a single, readily-identifiable load. Furthermore, the alternatives for meeting this remote, off-grid demand, in the absence of the project, are limited. Diesel generators are the most likely conventional alternative to wind turbines, in India and Ukraine as elsewhere.

To summarize, we are distinguishing two different types of wind turbine projects--grid-connected and off-grid--and proposing a different model counterfactual for each type. The proposed counterfactuals are as follows:

- For off-grid applications, diesel generators.

- For grid-connected applications:

    - In India, a composite counterfactual representing the average emissions rate of recently-built capacity.

    - In Ukraine, a composite counterfactual representing the average emissions rate of all existing capacity.

Solid Oxide Fuel Cells (SOFCs). As in the case for wind turbines, the qualitative baseline for fuel cells (including SOFCs) will vary depending on the application. There are a number of potential stationary applications for fuel cells, ranging from very small off-grid residential units (2 kW) to larger

(1 to +100 MW) central fuel cell/gas turbine units serving industry or the grid. Given this wide range of possible applications, and the inherent difficulty of assessing the baseline for all of them, we will limit our attention to a few key applications that are likely to be significant in the near term. Additional applications can be readily added to the technology matrix in the future, as fuel cell technology develops and improves, and as the list of likely near-term applications expands.

According to a report prepared by Technology Transition Corporation, entitled *The Entry Market for Fuel Cells*, several fuel cell manufacturers expect their product to enter the market when it reaches a cost of $1500 per kW. However, at this cost, fuel cells cannot compete with conventional technologies in providing electricity for the bulk power market. Therefore, the report identifies a number of smaller, high-value niche markets that are most likely to provide the initial commercial opportunities for fuel cell technologies. Although the report deals specifically with the United States, if conclusions concerning likely early niche applications for fuel cells can, with some minor adjustments, be applied to India and Ukraine. Therefore, based on the report, the niche applications for these two countries are identified as follows:

- Cogeneration systems for commercial establishments (especially hospitals and tourist hotels)

- Distributed electricity generation

- Low-cost fuel exploitation opportunities. One of the basic advantages of SOFCs, in particular, is their flexibility. They have the potential to span the market for fuel cell applications, and thus could be applied to each of the three uses identified above. The qualitative baseline will be developed for each of these applications, in turn, in the following paragraphs.

<u>Commercial Cogeneration Systems.</u> Hospitals, along with hotels serving foreigners, require a highly-reliable source of electricity. In India and Ukraine, the required degree of reliability cannot be met by the electricity grid alone. Therefore these facilities must rely on their own generating systems, either as their primary power source or at least to back up the grid during power outages. Fuel cells, including SOFCs, offer significant efficiency advantages over other conventional power generation technologies. SOFCs can achieve simple system efficiencies of approximately 50 percent, and when the waste heat is captured and utilized (e.g., for water heating), significantly higher efficiencies are attainable.

What are the conventional alternatives to fuel cells for primary or backup electricity generation at hospitals, hotels and other commercial establishments? Coal-fired generation, or cogeneration, is unlikely. While coal-fired power plants are often the best choice for *industrial* applications, where the load can support the larger units required to optimize coal-fired generation economics, in most cases electricity demand at commercial establishments will be too small to justify a large coal-burning unit. Furthermore, the potential air quality problems associated with coal would mitigate against its use at both hospital and hotel environments.

Gas turbines can be more readily sized to meet commercial-scale load requirements. Furthermore, since the fuel of choice for SOFCs and other fuel cells is natural gas, it is likely that gas will be available at most fuel cell project sites.

However, while gas turbines are a possibility, diesel generators remain the option of choice for most commercial establishments. Diesel generators are available even in very small units, and they offer a degree of fuel supply reliability that even gas turbines may not be able to match. Therefore, the model counterfactual for SOFCs used in commercial cogeneration systems will be assumed to be diesel generators.

Distributed Generation. Distributed generation is certainly viewed as one of the main market applications--if not the main application--for stationary fuel cells. In high growth areas (characteristic of much of India), and in remotely located areas (which exist in both countries), distributed generation can reduce or eliminate the need for new transmission capacity. Furthermore, because distributed generation is by definition located close to demand centers, it reduces transmission line losses. This is a major advantage in developing and transition economies such as those of India and Ukraine, where line losses tend to be high due to inefficiencies and outright theft. Finally, if combined in sufficient numbers distributed generators are statistically more reliable than large, central power plants, because the probability of all distributed units failing at the same time and producing the same effect as a large generator failure is negligible. This again is a significant potential advantage for both India and Ukraine, given the maintenance and availability problems plaguing power plants in both countries.

Distributed generation is specifically designed to reduce or eliminate the need for new transmission capacity. Thus the obvious alternative to a distributed generation fuel cell project is the expansion of transmission capacity. Another possible alternative is the use of a conventional generation technology in a distributed mode; e.g., diesel generators. These two basic alternatives have drastically different emissions implications. The expansion of transmission capacity would enable increased utilization of existing generation. Specifically, the generation of the marginal unit(s) would increase. The marginal unit would vary depending, e.g., on the season and the time of the day; thus the affected generation might represent a mix of fossil-and non-fossil units. The appropriate benchmark would, in this case, be the average emissions rate of the marginal units, weighted by the amount of time each of these units operates at the margin. On the other hand, the appropriate benchmark for distributed diesel generation would be the emissions rate of the diesel generators.

The choice of one or the other alternative would depend on the economic specifics of the project. For example, if the project is located in a remote area, the cost of extending existing transmission lines, or building new lines, to serve the area could be very high. In this case, the capital freed up by foregoing the project would probably not suffice to support new transmission capacity. On the other hand, if the project is located relatively close to existing transmission lines the extension of these lines may be preferable to the use of distributed conventional generators.

In this case there is no clear-cut, dominant project alternative. Instead, the alternative will vary depending on site-specific economics. In such cases, the application of the project-specific approach is likely to yield a significantly more accurate emission reduction estimate than the technology matrix approach. Whenever the project-specific approach is likely to offer significant accuracy advantages over the technology matrix, it should be preferred and utilized as the default approach. Therefore, we recommend against the development of a benchmark for distributed generation fuel cell projects. Project developers wishing to submit such projects under an international carbon offset program may still use the technology matrix to prove the additionality of their projects; however, it is recommended that they employ the project-specific approach for baseline development.

Low-Cost Fuel Exploitation Opportunities. In addition to natural gas, SOFCs (and other types of fuel cells) can operate on other hydrogen-rich fuels, including, e.g., landfill gas, sewage treatment gas, and industrial by-product gas. Because these fuels are low-cost sources of energy, they can help to lower the total generation costs for fuel cells by offsetting their high capital costs. For this reason applications designed to exploit low-cost fuel opportunities represent a potential entry market for fuel cells.

Landfill gas, by-product gas, and other low-cost fuel SOFC applications share much in common with wind turbine applications. In both cases, the generating units must be located near the energy sources rather than the demand centers. Furthermore, both applications are designed to exploit the availability of low-cost energy, rather than to meet any *specific* load requirements. The generation from low-cost fuel SOFC applications, like that from wind turbines, will simply supply the grid; it is not likely to be targeted to meet specific demands.

Therefore, the model counterfactual for grid-connected wind turbines also applies to low-cost fuel SOFC applications. This model counterfactual, it will be recalled represents a composite of existing electricity generation technologies; the benchmark should represent some average of the emission rates of these technologies. Specifically, in the case of India, the composite emissions rate should be based on the average emissions rate of all new capacity recently built by Indian utilities. In the case of Ukraine, the composite emissions rate should be based on the average emissions rate for all existing capacity.

Summary. To summarize, the following conclusions have been drawn for three applications likely to represent early fuel cell entry markets:

- For commercial cogeneration applications, the model counterfactual will be diesel generators.

- For low-cost fuel applications, a composite model counterfactual will be utilized. Specifically:

    - In India, the composite counterfactual will represent the average emissions rate of recently-built capacity.

    - In Ukraine, the composite counterfactual will represent the average emissions rate of all existing capacity.

- For distributed generation projects, a benchmark will not be provided in the technology matrix. These projects should use the project-specific approach to establish the baseline (although they may still use the technology matrix to prove additionality).

The Qualitative Baseline for Transportation Projects

To date, only a few transportation projects have been developed with the specific purpose of reducing greenhouse gas emission reductions and participating in joint emission reduction efforts. Thus, little experience has been gained about the types of projects that would be appropriate for flexible, market-based carbon offset program participation and the issues that may arise during baseline development. The transportation sector is very different from other sectors that contribute to energy-related emissions, because transportation-related emissions sources, such as fuel pumps, pipelines, compressor stations, and individual vehicles, are both numerous and very small in terms of total emissions generated. As a result, most flexible, market-based offset projects in the transportation sector are likely to involve the deployment of an entire vehicle fleet, particularly because of the high transaction costs involved in developing and seeking approval for international GHG reduction projects.[72] Possible projects may include efforts such as the deployment of a new fleet of vehicles for an industrial park, a truck company, a taxi operator, or a bus company. With the exception of such large-scale projects, the project developers will not be able to recuperate the transaction costs of project development. Our discussion of baseline development in the transportation sector will therefore focus on large-fleet projects.

In this section, we seek to develop the qualitative baseline for three representative transportation technologies: gas-to-liquids (new diesel) vehicles, compressed natural gas (CNG) vehicles, and hybrid (electric/gasoline) vehicles. First, we propose a set of criteria for selecting a baseline approach for transportation projects. We will then go on to define, qualitatively, the most likely alternative, or the "model counterfactual," to the projects utilizing each transportation technology. These likely alternatives will be broadly defined and generic in nature as they must be applied to all projects utilizing each technology.

Selecting a Baseline Approach for Transportation Projects

Before we examine the model counterfactuals for the transportation technologies, we have proposed a set of criteria that will help project developers distinguish between the types of transportation projects that may or may not qualify for utilization of the technology matrix. These criteria are very similar to those applied to power generation projects in the previous section.

Table 13 presents the basic criteria that developers of transportation projects should use in choosing between the technology matrix approach and the project-specific approach to baseline development.

[72] During the Activities Implemented Jointly (AIJ) Pilot Phase, which was introduced to test the concept of jointly implemented projects, average transaction costs of project development and project approval have ranged in the area of $100,000 for each project.

In the table, projects have been divided into three main types; 1) projects deploying vehicles that are originally equipped with advanced technologies and/or use low-emission fuels, 2) projects using conventional transportation technologies, and 3) projects retrofitting advanced conversion technologies (e.g. conversion kits) to conventionally-fueled vehicles. As the table illustrates, the first type of project, involving the use of advanced vehicle technologies or low-emission fuels, should use the technology matrix. The second and third project types (conventional and conversion technologies) should use the project-specific approach for evaluating additionality and estimating the emissions baseline because, by definition, they would not pass the technology matrix additionality test. It should be emphasized, however, that although conventional and conversion transportation projects cannot apply the technology matrix for additionality evaluation they may still be able to use the matrix benchmarks for baseline evaluation. Specifically, projects involving the deployment of new vehicles to meet new demand would benefit from using the appropriate sectoral benchmark from the technology matrix.

The project-specific approach is recommended for advanced conversion technologies (for example, a conversion kit converting gasoline engines into CNG vehicles), because these tend to be deployed in a selected number of vehicles that are already known to the project developer. As the emissions scenario of these projects will vary widely depending on the vehicle type, model, age and the make of the conversion kit, the project specific approach would provide a much more accurate emissions baseline than would the benchmark derived through the technology matrix approach. However, it should be noted that, if desired, the technology matrix could be used to establish the additionality of such conversion projects.

As the technology matrix relies on sectoral benchmarks for baseline estimation, transportation projects that deploy new vehicles to meet new demand should be the major focus of the technology matrix approach. These projects will, in general, require the use of some sort of benchmark as the basis for the baseline.

Ideally, projects involving the replacement of existing vehicles with technologically advanced vehicles would benefit more from using the project-specific approach. For these replacement projects, a more accurate baseline can be developed by using the project-specific approach because the project developers would know specifically which existing vehicles will be replaced by the new vehicles and would thus be able to determine the age, fuel consumption, average mileage, and the historical emissions of the vehicles to be replaced. With this information on hand, the project-specific approach would provide a much more accurate method for establishing the emissions baseline than the technology matrix.

However, in many countries, emissions databases on specific vehicle models are not readily available. In India, for example, the Automotive Research Association of India (ARAI), keeps emissions tests for prototype approval and conformity of production tests confidential.[73] The technology to measure emissions is difficult to access as well. In many countries, it may therefore be necessary to develop

[73] Tata Energy Research Institute. "Vehicle Emission Control Strategies to Protect the Local and Global Environment: Challenges and Opportunities in India. http://www.teriin.org/discuss/environ/emission.htm

technology-based benchmarks for replacement projects if it can be established that inadequate vehicle emissions databases and technologies for measuring and monitoring emissions prohibit project developers from establishing accurate emissions baselines through application of the project-specific approach.

The following discussion will rely on similar terminology as that defined in the previous section on power generation projects, and will be divided into two subsections. We will use the term "model project" to represent the typical application for the technology in question; that is, all vehicle fleet expansion projects to be undertaken under a flexible, market-based carbon offset program that utilize the specific technology. Each qualifying transportation technology entered into the technology matrix will have its own model project for each vehicle category, and that model project will be understood to represent the typical or most common project likely to utilize the qualifying technology. Moreover, the term "model counterfactual" will be used to represent the most likely alternative to the model project. The goal of this section is to define the model counterfactuals in a fashion that typifies the most realistic alternative to the model project.

The model counterfactuals will be established through two steps. In the first step, we will propose what would have happened if the new vehicles using advanced technologies had not been purchased and deployed; that is, would another vehicle fleet have been purchased and deployed without this specific project or would the demand simply have gone unmet?

We answer this question by examining the general situation in the transportation sector in India and Ukraine. If it is determined that the answer to this question is positive, i.e. that another project will be undertaken in the absence of the flexible, market-based offset project, we will go on, in the second step, to examine what technology would have been utilized by the alternative project. This question can only be answered by looking at each specific country and technology in question. Consequently, the second subsection will examine each of the three transportation technologies individually and will be considered for India and Ukraine, separately.

Table 13. Criteria for Selecting an Approach to Baseline Development for the Transportation Sector

Project Type	Corresponding Approach	Exceptions
Projects involving the use of advanced/alternative fuels and vehicles	Technology Matrix	a. Projects to be implemented in host countries without qualifying technology lists/sector benchmarks must use the project-specific approach b. Project developers may choose to use the project-specific approach to estimate the baseline, if they can demonstrate that the result is more accurate c. Projects designed to replace existing vehicles rather than meet new demand should use the project-specific approach for baseline development, if the emissions of the vehicles to be replaced are readily identifiable
All projects using conventional transportation technologies	Project-Specific	Projects involving the deployment of new vehicles to meet new demand may use the appropriate sectoral benchmark from the technology matrix for baseline estimation, unless the project-developers choose to use the project-specific approach, and can demonstrate that the result is more accurate
Projects involving the deployment of advanced conversion kits/technologies to convert conventional vehicles	Technology Matrix to establish additionality, Project-specific to estimate the baseline	None

Issue No. 1: Will the New Vehicles Still Be Purchased and Deployed in the Absence of the Model Project?

As outlined in the previous section on power generation projects, the question of whether or not new vehicles will be deployed in the absence of the model project can be divided into two questions. These questions are as follows:

1. In the host country, is the deployment of new vehicles limited by demand or capital availability?

2. If the latter, will a certain amount of capital be "freed up" if the model project is foregone?

These questions are important to determining whether the model counterfactual is itself a project to deploy new vehicles or whether the demand that would otherwise been met by the project would simply have gone unmet – and no new project would have been implemented.

Question 1: What Limits the Deployment of New Vehicles, Demand or Capital Availability? The supply and demand for vehicles is pretty much in balance in both India and Ukraine. Indeed, vehicle manufacturers in India and Ukraine are operating in a saturated transportation market where manufacturers are competing to sell their excess capacity – in spite of growing automobile sales. In India, for example, demand for vehicles is growing by 25 percent annually, and none of this demand has gone unmet. Many of the domestic automobile manufacturers are operating at less than full capacity due to an oversupply of vehicles in the Indian market.[74] The transportation sector in Ukraine can also be characterized by excess capacity rather than excess demand. In spite of the economic problems which have plagued the country since independence in December 1991 car ownership has boomed. Vehicle manufacturers have managed to match this demand both through the construction of new manufacturing facilities in Ukraine and through imports of vehicles from a saturated European market.

In sum, we conclude that the purchase and deployment of new vehicles in India and Ukraine is determined by demand rather than limited capital availability.

Question 2: Will Foregoing the Model Project "Free Up" Capital? In a situation where supply and demand are in balance and where capital availability is not a constraint to project development, it is more than likely that a decision to halt one project designed to meet new demand will lead to the implementation of another project in its place. In the above discussion it was established that the deployment of new vehicles in both India and Ukraine is determined by demand and not restricted by capital availability. It is therefore likely that the foregoing of a model project in these two countries is likely to free up capital for developing another project.

Furthermore, it seems plausible that the type of project that would be implemented in place of the model project would be another transportation expansion project. As was illustrated in the discussion

[74] "Driving Uphill," The Hindu-Editorial, *The Hindu*, Madras, January 25, 2000.

of the model counterfactual for electricity generation projects, the foregoing of a flexible, market-based offset project will most likely lead to investment in another type of project in the same sector. The capital is already set aside for a transportation project, both on the part of domestic and international investors. However, without the favorable financing accessible through a flexible, market-based carbon offset program, the investors are more likely to invest in new conventional technologies/vehicles to meet growing demand instead of the advanced technologies. Conventional technologies will be less expensive to implement and thus the project risks will be lower. Moreover, the project developers are likely to choose the same project site and vehicle type (passenger cars, buses, trucks, etc.) as the one that would have been used for the market-based offset project. A demand for that particular type of vehicle has already been identified at the project site. Thus, it appears most plausible that the alternative project would be of a comparable size and vehicle type and would be located at the same project site.

Issue No. 2: Defining the Model Counterfactual

As was established in the above subsection, the model counterfactual for the transportation technologies included in the technology matrix is most likely a project involving the addition of a new fleet of vehicles of roughly the same size, and with the same location, as the vehicle fleet of the model project. However, the model counterfactual is expected to utilize commercial vehicle technologies rather than advanced technologies. Similarly, for fuel replacement projects the model counterfactual will be comprised of a commercial fuel source.

This subsection will take the previous analysis one step further and determine which specific conventional transportation technologies would be used in the absence of the model project. This will involve an analysis of the types of vehicles, and their fuel source, that would have been purchased as part of the counterfactual scenario. The analysis will be based on an examination of new vehicles purchased in India and Ukraine and will, to the extent possible, target transportation data for the major cities where the development of large-scale, flexible, market-based transportation projects are most likely to occur. However, the level of detail of this analysis will ultimately depend on the quality of the available quantitative data.

Before we continue, it should be emphasized that transportation technologies are quite different from most power generation projects. In general, the latter are large capacity projects with significant capital investment needs and are typically developed to meet specific baseload requirements. It is therefore fairly straightforward to establish the model counterfactual based on a single technology, such as a coal-fired steam turbine plant.

Transportation projects, on the other hand, are very different. First, the size of potential transportation projects are many times smaller, both in terms of energy use and potential emission reductions. Indeed, vehicle ownership and control is divided among millions of owners in each country and most potential flexible, market-based carbon offset projects will therefore range from the purchase of 100 to 500 low emissions vehicles, for use as taxis or buses. Projects that involve the replacement of fuels could potentially involve larger region or country-wide activities, however, this depends on available fuel supply and refueling infrastructure.

Second, each transportation technology can be applied to different vehicle types, such as passenger cars, light- and heavy-duty trucks, and/or buses, each creating a different emissions scenario and requiring a separate model counterfactual. As a further complication, each country, region, or city will have a number of different models of vehicles represented within each category or vehicle type. Ukraine, for example, utilizes more than 30 different models of passenger cars. Depending on the age and/or make of these models, their greenhouse gas emissions will vary widely, and it will often be difficult to determine which exact vehicle model(s) should be used as the model counterfactual. Consequently, we propose that, rather than using one specific fleet of vehicle models for baseline development, the model counterfactual for a given vehicle type and technology should instead be developed based on a composite of existing models.

The three advanced technologies to be included in the technology matrix can be divided into two main categories. The first includes CNG and hybrid vehicles, which involves the deployment of a new type of low emission vehicle. The second category involves the introduction of a new fuel source, i.e. gas-to-liquids (diesel-based).

Compressed Natural Gas (CNG) and Hybrid Vehicles

In the case of CNG vehicles, the most advanced vehicle applications on the market today are CNG passenger cars and transit buses. Therefore, in this study, we will only focus on those two CNG technologies (although it should be noted that other CNG applications are available as well). In the hybrid vehicle category, hybrid electric/gasoline passenger cars have reached the highest stage of commercialization and should thus be considered for inclusion in the technology matrix. Other technologies, including electric/diesel, hydrogen, fuel cell, or solar powered vehicles, are being tested but are at an earlier stage of development. Of these technologies, we have elected to look at hybrid electric/diesel transit buses as a second model project technology for hybrid vehicles.

Thus, for each of the two vehicle technologies, we will need to develop two model counterfactuals – one for passenger cars and one for transit buses.

The first step in the development of the model counterfactuals for both CNG and hybrid passenger cars and buses involves determining which type(s) of vehicles and fuel sources represent the most likely alternatives to the model project. In India and Ukraine, each vehicle type is represented by a number of different vehicle models with different emission qualities. The vehicles are also fueled by different energy sources, including diesel, natural gas, liquified petroleum gas (LPG) and CNG. As determined in the previous discussion, the model counterfactual will consist of conventional transportation technologies powered by commercial fuel sources. The benchmark should thus be based on the average fuel consumption and emissions of all recently purchased conventional vehicles in a given vehicle category (such as passenger cars or buses). For passenger cars this will include both diesel- and gasoline-powered vehicles as illustrated in Table 14. Vehicles powered by non-commercial fuel sources, such as LPG, will not be included in the counterfactual. In the case of transit buses, the model counterfactual for CNG and electric/diesel buses should be based on a composite of all new diesel-powered transit buses in India and Ukraine.

Ideally, these averages or composites for the model counterfactuals should be separated into two additional categories, one for urban driving and one for country (highway) driving. This separation is important because urban driving typically involves a larger amount of stop-and-go traffic that leaves the engine idle and results in increased emissions relative to country driving. However, the ability to distinguish between urban and country driving will depend on the quality of the data received from India and Ukraine.

In the following table we have outlined the different technology options available for each model counterfactual, as they are distinguished by vehicle type (Table 14).

Gas-to-Liquids (GTL)

Gas-to-Liquids (GTL) technology involves the conversion of natural gas to a number of liquid synthetic fuels. As such, it excludes the production of liquefied natural gas but includes the conversion of gas to petrochemicals – methanol and ammonia being the most common applications – and to transportation fuels. In this study we focus on the technology, known as the Fischer-Tropsch (FT) process, whereby natural gas is converted to diesel.

A Fischer-Tropsch diesel (FTD) production plant consists of three major steps; (1) production of synthesis gas by reforming natural gas through the addition of oxygen, (2) synthesis of middle distillates through the Fischer-Tropsch process, which converts the synthesis gas, in the presence of a catalyst, into synthetic waxy crude, and (3) upgrading of products. The final stage in an FTD plant, upgrading liquid products into useful fuels, is easier than refining crude oil because the synthetic products contain virtually no sulfur and fewer aromatics. Consequently the final products from FTD plants are considered to be a premium blendstock for diesel fuels. The FT reaction is exothermic, and the excess heat from the process can be recovered as steam.

The FT process has been around for a long time. It was first used by Germany to produce diesel fuel during World War II and, later on, by South Africa to ensure self-sufficiency during the oil embargo. Recently, interest in FTD has increased because it produces a much cleaner fuel than conventional diesel. The diesel from GTL plants has practically no sulfur (<5 ppm), no aromatics (<1 vol percent) and a high cetane number (>70). Using this middle distillate in compression-ignition engines helps reduce both NOx and particulate matter emissions. In addition, the FTD process allows for the recovery of natural gas in remote locations where limited pipeline infrastructure and high transportation costs have previously prevented the use of this fuel; i.e., it provides a method for using natural gas that would otherwise have been flared.

GTL technology thus provides three potential methods for reducing greenhouse gases, including: (1) a cleaner burning diesel that will facilitate fuel replacement, (2) a means for converting natural gas that would otherwise have been flared, and (3) a low-sulfur fuel that allows for the development of advanced, fuel-efficient compression-ignition diesel engines.

Development of the Model Counterfactual. As GTL technology provides opportunities for three different emission reduction project types, a separate model counterfactual will have to be developed for each application. In the following subsections we will consider first the estimation of greenhouse gas emission reductions from projects involving the replacement of FTD with conventional fuel sources such as regular diesel and gasoline. Second, we will consider the estimation of greenhouse gas emission reductions from the conversion of natural gas that would otherwise have been flared. Third, we will examine projects involving the introduction of advanced clean-burning diesel engines that require a low-sulfur fuel such as FTD.

Table 14. Decision Table for CNG and Hybrid Vehichles in India and Ukraine

Vehicle Type	CNG Vehicles			Hybrid Vehicles		
	Model Project Technology	**Available Technology Options for Model Counterfactual**	**Conventional Technology Options Included in Model Counterfactual**	**Model Project Technology**	**Available Technology Options for Model Counterfactual**	**Conventional Technology Options Included in Model Counterfactual**
Passenger Cars	CNG	Gasoline Diesel LPG	Gasoline Diesel	Gasoline/Electric	Gasoline Diesel CNG LPG	Gasoline Diesel
Transit Buses	CNG	Diesel LPG	Diesel	Diesel/Electric	Diesel CNG LPG	Diesel

Estimating Emission Reductions From Fuel Replacement Projects. Although FTD is significantly lower in terms of sulfur and aromatics contents, the main properties of FTD are similar to those of conventional diesel. FTD does not exhibit any advantages over regular diesel in terms of greenhouse gas emission reductions. As a result, fuel replacement projects introducing FTD instead of conventional diesel will not be eligible for greenhouse gas emission reduction credits and should not be included in the technology matrix.

As a replacement fuel, FTD would only offer opportunities for greenhouse gas emission reductions if it were used in projects that encourage the use of diesel rather than gasoline. Diesel engines are much more fuel-efficient than gasoline engines, thus reducing greenhouse gases per unit distance traveled. To the extent that FTD reduces non-greenhouse gas emissions, its development could encourage the use of diesel vehicles *vis a vis* gasoline vehicles. However, such vehicle replacement projects are not likely to qualify as additional under a flexible, market-based carbon offset program. Traditionally, FTD and other low-emissions fuels have been introduced in response to strengthened air quality regulations that limit the emissions of toxins from vehicles and fuels. Similarly, tax and other excise incentives have spurred the deployment of such fuels. As the emissions benefits of FTD in terms of local air pollutants are much more pronounced than are the projected greenhouse gas emissions benefits, it is likely that FTD will continue to be used mostly as a blend or substitute for adjusting conventional diesel to match strengthened air quality regulations. If this is the case, projects utilizing FTD will by definition not be able to qualify as additional under a flexible, market-based carbon offset program, because these projects would be undertaken regardless of the availability of emission reduction credits. Hence it will not be necessary to develop an emissions benchmark or model counterfactual for this type of GTL project.

Estimating Emission Reductions From Recovering Flared Natural Gas. Vented or flared gas is usually the associated gas produced from oil fields where natural gas pipelines and processing infrastructure are not available. Worldwide, about 5 percent of total natural gas production is flared. Thus, significant opportunities exist for reducing the release of carbon dioxide through the recovery and use of gas that would otherwise have been flared.

Unlike the previously discussed transportation technologies, the procedure for estimating carbon dioxide emission reductions from a flared gas project does not require the use of a benchmark. Rather, the metered amount of gas recovered from the oil and/or natural gas field will provide the needed carbon dioxide emission reduction estimate. As metering will be undertaken on a project-by-project basis there will be no need for an emissions benchmark.

Estimating Emission Reductions From Advanced Fuel-Efficient Diesel Engines. The introduction and development of low-sulfur FT diesel has facilitated the development of a new type of clean-burning and fuel-efficient engine that operates exclusively on low-sulfur diesel. New compression ignition (CI) engines are in development to meet the increasing dual challenges of greater fuel efficiency and reduced emissions of environmental pollutants. These low-emissions diesel engines will enable diesel vehicles to take advantage of their inherent 40, percent increase in fuel efficiency they have over gasoline engines.

The diesel engine has undergone significant improvements in recent years with the addition of the common rail direct-injection technology and turbo-charging. However, conventional diesel engines are beginning to reach their performance limit, and are in any event surrounded by health issues resulting from high emissions of particulate matter (PM), oxides of nitrogen (NOx), and oxides of sulfur (SOx). Installation of catalytic converters on these vehicles can reduce hydrocarbon and CO emissions; however, they are ineffective in reducing aromatics and NOx. Catalytic converters that could reduce NOx cannot be used at present because the high sulfur levels (300 ppm) in the currently available fuels rapidly poisons the catalyst of these antipollution devices. If these pollutants could be eliminated, diesels could be made to operate as cleanly as gasoline or compressed natural gas engines, without penalizing efficiency.

In response to the problems with current diesel engines, the compression-ignition, direct-injection (CIDI) engine has been developed. CIDI engines can achieve a 35 percent improvement in gasoline-equivalent fuel economy relative to conventional gasoline vehicles and are expected to show significant emissions improvements. These engines, however, require the use of a low-sulfur diesel fuel in order to operate properly. As FTD has a high cetane number and contains virtually no sulfur and aromatics, it provides an excellent fuel for CIDI engines with significant potential for lowering NOx and PM emissions. Indeed engines that are designed or modified to use and exploit the truly unique properties of FTD have higher efficiencies and lower emissions of air toxins than engines that operate on “cleaner" diesel.

However, these advanced technologies require further research and development and are not expected to be widely available for the market place until after 2010.[75] As these advanced diesel engines are not yet on the market, there will be no opportunities for developing flexible, market-based carbon offset projects utilizing this technology in the near future. Consequently, we propose that no emissions benchmarks should be developed for this type of project at this point in time. The technology matrix will be updated regularly, preferably every five years. Thus, there is no reason to include a technology in the matrix which is still in the early development stages and which will only be available commercially in the long-term. Once the clean-burning engines have advanced beyond the early development stage, they may be included in the matrix. But for the present, an emissions benchmark need not and should not be developed for CIDI projects. Similarly, the development of a model counterfactual for clean-burning diesel engine projects will not be necessary.

Summary. GTL technology provides three potential methods for reducing greenhouse gases, including; (1) a cleaner burning diesel that will facilitate fuel replacement, (2) a means for converting natural gas that would otherwise have been flared, and (3) a low-sulfur fuel that allows for the development of advanced, fuel-efficient compression-ignition diesel engines. However, at this time, none of these potential emission reduction methods require the development of an emissions benchmark. Fuel replacement projects are not likely to qualify as additional under flexible, market-based carbon offset programs because traditionally such projects are developed in response to local air quality regulations. Flared natural gas projects do not require the development of an emissions

[75] Wang, Michael Q., GREET 1.5 - Transportation Fuel Cycle Model. Volume 1: Methodology, Development, Use, and Results. Argonne National Laboratory, Argonne, IL, August 1999.

benchmark because the metered amount of emissions from the flared gas will provide a direct estimate of the greenhouse gas reductions. Finally, advanced clean-burning diesel-engines have not yet reached a level of maturation sufficient to warrant benchmark development.

Coalbed Methane Recovery

Background

In the United States, interest in the recovery of coalbed methane has grown largely out of the need to reduce methane concentrations in the mine atmosphere. When present in air in concentrations of 5 to 15 percent, methane becomes explosive. U.S. coal mine regulations thus require that methane concentrations be kept well below 5 percent. Most mine operators can accomplish through the mine ventilation system, by ensuring that a quantity of air sufficient to dilute the methane reaches the mine working areas. The mine air is vented to the surface; no attempt is made to recover the methane because it is present in such dilute amounts.

However, at gassy mines utilizing the longwall method (a high-production method that liberates more methane per unit of time than other methods), it is often necessary to supplement the mine ventilation system with a drilling program designed to drain methane from the seam before, during, and after mining. Vertical wells are drilled from the surface through the seam in advance of mining. After mining has past through these wells, they may still be used to drain methane from the abandoned gob area behind the working longwall face. In some cases horizontal wells, drilled from within the mine, are also used to drain methane from a longwall panel prior to the mining of the panel. By reducing the amount of methane present in the seam, vertical and horizontal drilling reduce the quantity of air that must be handled by the mine ventilation system; this in turn reduces the amount of power required to run the mine fans, and it reduces airborne dust problems.

In the past, the methane drained from the seam via vertical and horizontal drillholes was simply vented to the atmosphere. Mine operators viewed the methane as an obstacle to mining, rather than a potentially valuable commodity in and of itself. More recently, however, with environmental concerns about methane emissions rising, and the growing recognition of the value of the methane, efforts to recover the methane have grown. Wells drilled in advance of mining often produce pipeline-quality gas, that can be gathered and sold to gas transmission companies if a transmission line passes near the mine. Alternatively, the gas can be used on-site, or it can be used to generate electricity either for on-site use or for sale to the grid. The methane produced from gob wells is mixed with mine air and thus is generally not pipeline-quality; however, this gas can still sometimes be used for electricity generation.

Thus, in the United States, efforts to recover methane have evolved, almost as an afterthought, from efforts to remove it from the mines. In other countries, however, interest in coalbed methane recovery is growing because it is seen as a means of recovering a potentially valuable, indigenous source of energy. This is the case in India, where conventional natural gas reserves are limited and insufficient to meet India's growing demand. Initial indications are that India's deeper coal reserves contain large amounts of methane. The Government of India's current (Ninth) 5-Year Plan explicitly lists increased coalbed methane exploration as a key goal for the near-term future.

In India, coalbed methane is seen less as an obstacle to mining and more as a potentially valuable resource. At present, approximately 75 percent of India's coal is mined by surface operations; methane is not a problem at these operations. Furthermore, India's underground mines tend to operate at relatively shallow depths, where methane concentrations tend to be low. Given India's interest in coalbed methane as a potentially large, valuable resource, and the current circumstances surrounding the country's mining industry, it is quite possible that, in India, coalbed methane recovery efforts may proceed independently of, or at least far in advance of, mining. This same possibility may exist in some other developing countries. This has implications for the determination of emission reduction credits under a flexible, market-based carbon offset program. One of the main ways in which coalbed methane recovery reduces emissions in the U.S. is by reducing the amount of methane vented to the atmosphere by coal mines. However, if India and other countries pursue coalbed methane recovery operations independently of mining operations, emissions from coal mines will remain unaffected by the recovery efforts or, at best, mine emissions will not be affected for many years hence (until mining begins in the deeper seams previously exploited for methane). However, by recovering a relatively clean-burning fossil fuel, coalbed methane recovery operations may reduce the need for coal at Indian power plants, and in this way reduce emissions. In other words, the primary impact of coalbed methane recovery efforts in India (and other countries) may be its indirect impact on carbon dioxide emissions from coal, rather than any direct effect on methane emissions themselves.

However, in developing the technology matrix it is necessary to consider both possible types of coalbed methane recovery projects: those carried out independently as well as those undertaken as a concomitant to mining. The latter type are at least a possibility in India's deeper underground mines, and may become more likely in the future as India depletes its shallower reserves. In fact India's current 5-Year plan sets out the country's goal to extend detailed exploration efforts to deeper (300- to 600-meter) reserves. Since the technology matrix must accommodate future projects as well as those planned for the present, it should incorporate the full range of potential coalbed methane recovery projects, including both independent and mining-associated projects. Furthermore, the matrix should accommodate projects that recover methane for electricity generation, as well as those involving sale of the recovered methane to natural gas pipelines.

Development of the Model Counterfactual

From an emission reduction standpoint, the basic difference between a methane recovery project designed in part to drain methane in advance of mining, and one carried out independently of mining activities, is that the former will reduce methane emissions during subsequent mining of the seam. The latter may or may not reduce methane emissions at some future point in time, depending on whether or not the seam from which the methane is recovered is eventually mined. However, since any future mining activity is not associated with the methane recovery project, may not occur until long after the recovery project is completed, and is speculative, the emission reduction estimate for the project should be limited to the reductions resulting from the displacement of other fuels with natural gas. In the following subsections we will consider first the estimation of methane emission reductions resulting from a mining-associated project; then we will consider the estimation of carbon dioxide emission reductions for both types of projects.

Estimating Methane Emission Reductions. The procedure for estimating the methane reductions resulting from a mining-associated project is unusual, in that it does not require a benchmark. Essentially, the metered amount of methane recovered from pre-mining and post-mining wells will provide an estimate of the methane reductions. This estimate may have to be adjusted downward in the case of vertical wells, because such wells may capture methane from coal seams and other strata lying above the strata affected by mining. The methane from such above-lying strata would not have been disturbed by mining, and hence should not be included in the estimate of the reduction in methane emissions from the mine.[76] However, estimating the additional methane recovered from above-lying strata is an issue of project metering and monitoring; it is not a benchmark issue. Quite simply, there is no need to develop a benchmark to estimate the *methane* reductions resulting from a coalbed methane recovery project; these reductions can simply be metered. The issue of defining the counterfactual is thus moot.

Estimating Carbon Dioxide Emission Reductions. However, estimating any *carbon dioxide* emission reductions resulting from a coalbed methane recovery project does require the development of a model counterfactual, and a benchmark. If the recovered gas is used rather than flared, a coalbed methane project may reduce carbon dioxide emissions as well as methane emissions. Specifically, the recovered gas may displace a higher-emitting fossil fuel. This is true regardless of whether the project is associated with a mine, or carried out independently of mining; hence the distinction between these two types of projects need no longer be retained as we shift our focus from methane to carbon dioxide. However, the specific use to which the methane is put is important; methane used on-site to generate electricity may displace a different mix of fuels than methane sold to a natural gas pipeline. Therefore, separate model counterfactuals will be developed for each of these two primary applications.

<u>Methane Recovery Projects for On-Site Electricity Generation.</u> Typically, on-site electricity generation projects will tend to be small. One possible exception to this general rule would be the use of recovered methane as a supplemental fuel at a large, coal-fired mine mouth power plant. In such a case, the methane recovery project would reduce carbon dioxide emissions by reducing the amount of coal required by the mine mouth plant. Projects involving the substitution of coal with coalbed methane at minemouth power plants should be evaluated using the project-specific approach rather than the technology matrix. For such projects, it should be possible to develop a much more accurate baseline using detailed data on the affected minemouth plants, rather than a sectoral average benchmark.

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[76] One potential way to estimate the methane recovered from the above-lying strata would be to drill the wells to a point just above the zone expected to be affected by mining, and then halt drilling and take measurements of the amount of methane being recovered. Once the wells stop producing methane, or reach a more or less constant level of methane production, they can be extended through the mining zone. The difference between the wells' new production levels and the old, stable levels would then provide an estimate of the amount of methane emissions reduced by the wells.

Thus for technology matrix development purposes, we will limit our considerations to projects involving the application of small gas turbine generating units. As we have seen already in the case of wind turbines and fuel cells, defining a single, discrete project as the model counterfactual for such small-capacity projects is a difficult and potentially unrealistic goal. As in these other cases, capital would probably be freed up if the model project were to be foregone; however, it is not at all clear that this freed-up capital would be used to undertake another single, discrete power generation project. In fact, in the case of a coalbed methane recovery project, there is a significant possibility that the capital would be plowed back into the mining operation rather than used to build new generating capacity. The application of the freed-up capital to either the coal sector or the power generation sector may depend, ultimately, on the identity(ies) of the project developers: coal companies (either private or State-owned) may be less likely to pursue another power generation project than utilities or independent power producers.

However, the application of the freed-up capital to the power sector is certainly a possibility. Furthermore, at least in the case of Ukraine, foregoing the model project would necessitate increasing the generation from other existing generating units, in order to make up the loss.[77] As in the case of wind turbine technology, we will again make the admittedly uncertain assumption that the freed-up capital would be disbursed to support a wide variety of new capacity projects in the power sector. Again, in the case of India, these projects will be represented with a composite emissions rate equivalent to the average emissions rate of all new capacity recently built by Indian utilities. In Ukraine, the benchmark will represent the composite average emissions rate of all existing capacity since, in this country, available capital is more likely to be spent on refurbishing existing plants than on building new capacity.

<u>Recovery Projects to Produce Methane for Sale to Natural Gas Pipelines.</u> It is very unclear whether projects involving the sale or transfer of the recovered methane to a natural gas pipeline will in fact reduce carbon dioxide emissions. For one, the capital freed up by foregoing such projects is more likely to be applied to the coal or natural gas sectors than to the power sector. For example, the capital might be used to increase production of natural gas from conventional sources, or it might be used to increase coal production. In the first case, the coalbed methane would in effect be replaced by conventional natural gas, with no net change in emissions. Another possibility is that the capital would be invested in a project to convert the coalbed methane into electricity on-site; in this case the model project might actually generate less carbon dioxide emission reductions than the model counterfactual.

Besides these uncertainties surrounding the model counterfactual, the ultimate use of the methane supplied to the pipeline is highly uncertain. For example, in India 42 percent of natural gas is used in the production of fertilizer.[78] Gas used in the fertilizer manufacturing process is not combusted and

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[77] The situation is less clear in India. Due to the existence of a significant electricity supply-demand gap in many parts of that country, the power generated from coalbed methane might simply be added to the existing power supply in order to help close the gap. Rather than displacing existing generating sources, the project would in this case simply increase the amount of power available.

[78] Council of Scientific and Industrial Research, "Coal Gasification for Sustainable Development of Energy Sector in India," 1999-2000.

hence not emitted in the form of carbon dioxide; thus coalbed methane utilized for this purpose will not displace an emitting energy source. *If* a portion of the recovered coalbed methane is used for power generation, it *may* displace other, higher-emitting fuels (primarily coal). However, given the electricity supply-demand imbalance in India, it is entirely possible that the coalbed methane would be used to increase generation rather than displace other generation sources.

In short, there is too much uncertainty surrounding the question of whether or not the recovered gas would reduce emissions to warrant the development of a carbon dioxide benchmark for these types of projects. If a particular methane recovery project is associated with an active mine, the project may still receive credit for reducing the mine's methane emissions. Furthermore, the project developers are always free to fall back on the project-specific approach to demonstrate their claim to carbon dioxide emission reductions. In some circumstances it may be possible to show that the recovered coalbed methane will displace higher-emitting fuels using a project-specific analysis. In any event, the project-specific approach is more appropriate to coalbed methane recovery projects involving the transfer of the recovered methane to natural gas pipelines, because of the high degree of uncertainty surrounding the model counterfactual and the ultimate uses of the recovered gas.

Summary

Our conclusions concerning coalbed methane recovery projects can be summarized as follows:

- A benchmark (and a model counterfactual) is not required to estimate the methane emission reductions resulting from these projects. If a particular coalbed methane recovery project is undertaken in association with a mining operation, the resulting methane emission reductions can be estimated on the basis of measurements of the quantity of methane recovered. If a project is undertaken independently of mining, it will not reduce methane emissions (unless and until the seam is mined).

- The model counterfactual for estimating the carbon dioxide emission reductions resulting from a coalbed methane recovery project depends on the uses to which the methane is put:

    - If the recovered gas is used to generate electricity on-site, either for on-site use or for sale to the grid, the composite approach used to define the model counterfactual and benchmark for other small-scale power generation projects (e.g., wind turbine projects) should be applied. Specifically, for India the counterfactual should represent a composite of all recently-built capacity, with a benchmark equal to the average heat rate for this new capacity. For Ukraine, the model counterfactual should be a composite of all existing capacity, with a benchmark equal to the average emissions rate for the Ukrainian electricity sector.

    - A benchmark cannot be supplied for coalbed methane recovery projects involving the transfer of the recovered gas to a natural gas pipeline, due to the high degree of uncertainty surrounding the nature of the model counterfactual, and the ultimate uses of the recovered gas, for such projects. However, project developers may use the project-specific approach to demonstrate their claim to carbon dioxide emissions resulting from such projects.

Energy-Plex

Background

The concept of the energy-plex forms the core of "Vision 21," NETL's program for developing clean energy plants for the twenty-first century. Essentially, an energy-plex is conceived of as an advanced, ultra-high efficiency, fully-integrated energy production facility capable of producing multiple energy products (e.g., electricity, steam, liquid transportation fuels, chemicals, hydrogen, etc.) from a variety of fuel inputs. As such, it would stand in contrast to today's power plants, which are typically designed to utilize one type of fuel and to generate one product (electricity). Two additional features further distinguish the energy-plex from current plants. First, it would be designed to maximize efficiency, by maximizing the utilization of the various fuel inputs. The ultimate goal would be to use as much of the energy in the fuels as possible. And second, it would be designed to dramatically reduce or eliminate the various environmental impacts associated with energy production. For example, the energy-plex design would include an option for capturing and storing its own carbon dioxide emissions, thus eliminating the facility's greenhouse gas emissions. Other pollutants might be converted into marketable co-products.

The energy-plex would utilize advanced technologies such as IGCC, fuel cell/turbine hybrids, indirect liquefaction. These technologies would be developed as modular components to the energy-plex, which could be combined in a variety of ways to meet site-specific market requirements. For example, one energy-plex might be designed to produce electricity for the grid as well as steam for a nearby industrial complex, a second might produce coal gas and high-value chemicals, while a third might be a combination power plant/coal liquefaction facility, producing electricity and transportation fuels. By utilizing advanced technologies for the individual modules, this flexibility could be achieved in a manner compatible with high operating efficiencies and low emissions. The goal would be to achieve overall thermal efficiencies of 85 to 90 percent (as compared with the 33 to 35 percent efficiencies currently be attained by conventional coal-fired power plants).

Baseline Development

Rather than attempting the full-scale development of quantitative benchmarks for energy-plex projects, we instead propose a more modest effort at this point in time. Specifically, we propose to consider, in broad outline, a potential benchmark development approach geared to this highly complex set of technologies. This proposal is, we believe, in keeping with the level of maturation of the energy-plex concept. Most of the other technologies considered in this report have been developed well beyond the initial concept phase. In many cases they have been tested at the pilot or demonstration scale, if not at the commercial scale. The energy-plex concept, on the other hand, is a very advanced idea that remains at this point in the initial "drawingboard" stage. In fact, the current energy-plex research and development schedule calls for the completion of a virtual (i.e., computer-simulated) demonstration by 2015.[79] An actual pilot or demonstration plant would presumably be built at some point after 2015.

Technology matrix benchmarks should not be developed fifteen or more years in advance of any project likely to require the benchmarks. The basic approach to benchmark development involves the selection of a group of actual facilities (e.g., power plants), the average emissions rate of which becomes the basis for the benchmark. If an attempt were to be made to select such a benchmark group for the energy-plex concept at this point in time, it is likely that many of the facilities chosen for inclusion in the group would no longer exist by the time the concept has matured. Changes and advances in existing commercial technologies would most likely necessitate the selection of a completely different benchmark group by 2015. In short, any benchmarks developed now would not be utilized until at least 2015, at which point they would be obsolete.

Furthermore, it is very difficult to develop even reasonably accurate benchmarks for a technology concept that is not, as yet, fully defined or refined. The energy-plex concept involves the integration of a significant number of core technologies that are themselves advanced and non-commercial at this point in time. Some of these technologies may prove themselves to be adaptable to a commercial energy-plex project, while others may not. On the other hand, other technologies that may not be considered to be likely candidates for energy-plex modules at this point in time may, over the course of the next fifteen years, evolve to the point where they will prove highly adaptable to the energy-plex concept. In short, the energy-plex concept is likely to change or evolve significantly as it is developed. Any benchmark based on the current concept is likely to become increasingly obsolete as that concept evolves.

The energy-plex concept thus serves as an example of an additional technology that nonetheless need not, and should not, be included in the technology matrix *at this point in time.* It is preferable to focus the resources available for benchmark development on technologies that might be utilized under a flexible, market-based carbon offset program in the near-term future. Specifically, efforts should be focused on non-commercial technologies that have reached the demonstration stage, or at least the pilot stage, of development.

A Possible Approach to Future Benchmark Development. This being said, there may well be a need for benchmarks for energy-plex projects fifteen or twenty years from now, as the concept matures and reaches the pilot or demonstration stage. How might a benchmark be developed for the energy-plex concept? This concept embodies not a specific technology per se, but rather represents an integrated system of advanced technologies. Clearly the approach to developing a benchmark for such a complex system must differ from that used for the technologies considered thus far.

On the one hand, there is an argument to be made that the energy-plex system of technologies is simply too complex, and too flexible, for inclusion in the technology matrix. Given that each

[79] U.S. Dept of Energy's National Energy Technology Laboratory, *Vision 21 Program Plan, Clean Energy Plants for the 21st Century.*

individual energy-plex may differ significantly from all other energy-plexes in terms of its products, fuel inputs, technologies employed, and even industrial affiliations (electricity, chemicals, petroleum refining, etc.), there seems to be little of the commonality required for the development of a generic benchmark. Rather if each energy-plex is potentially uncommon if not unique in its fundamental characteristics, then the project-specific approach would appear to be more appropriate than the technology matrix as the baseline development technique.

The project-specific approach is in fact a very reasonable option for the energy-plex concept, and should be given careful consideration as the concept matures and moves closer to deployment. However, the technology matrix approach may also be worthy of consideration, if it can be tailored to provide a set of benchmarks rather than a single benchmark. Although it is true that each individual energy-plex may differ from all others, all energy-plexes will share the same set of components. In fact, one of the goals of the Vision 21 program is to modularize the various component technologies of the energy-plex. The modular technologies would be generic, enabling them to be utilized in any number of different system configurations. Thus, while the systems comprising energy-plexes will differ, the system *components* will be similar.

Therefore it may be possible to analyze an energy-plex system using the technology matrix approach, by breaking the system down into its individual components and assigning a separate benchmark to each component. Under this approach, benchmarks would be developed not for the energy-plex per se, but rather for the modular technologies comprising the energy-plex. There would, for example, be a benchmark for the chemical production module of the energy-plex, the indirect liquefaction module, etc. In fact, some of the benchmarks required for energy-plexes may already be addressed in other sections of this report. For example, IGCC technology is considered to be a prime candidate for adaptation to the energy-plex concept; a benchmark for IGCC power plants is developed in the next chapter.

Using this "component analysis" approach, each module of a particular energy-plex would be analyzed separately. A benchmark would be assigned to the module, and used to develop an emissions baseline for the module. That baseline would be compared to the module's actual emissions to determine the module's emission reductions. Finally, the emission reductions would be summed across all modules to yield the overall reduction estimate for the energy-plex.

Ultimately, the applicability of the technology matrix to the energy-plex concept, using the component analysis approach, will depend on the direction concept development takes and the ability of the technology matrix to capture the complexities of the fully-developed system. If, for example, some of the system components are not modularized but remain highly dependent on site-specific conditions, the technology matrix approach will probably not work. However, this does not mean that energy-plex developers will not be able to take advantage of the emission reduction credits anticipated to be offered under a market-based carbon offset program. As in other cases in which the technology matrix is not applicable, the developers will always have the opportunity to fall back on the project-specific approach. The project-specific approach remains in all cases the default approach; the technology matrix approach is offered as a *possible* alternative, in some cases, to reduce transaction costs.

Concluding Remarks

This completes the development of the qualitative baselines for the ten selected technologies, in India and Ukraine. Again, the results of the analyses documented in the preceding sections are presented in Table 5, at the beginning of this chapter. Having completed the qualitative baseline development, we now turn to the next step in the development of the technology matrix: quantifying the benchmarks.

4. DATA ANALYSIS AND BENCHMARK DEVELOPMENT

Introduction and Summary of Results

In the preceding chapter the model counterfactuals for the ten selected technologies, in India and Ukraine, were defined in a qualitative manner. It remains only to quantify these counterfactuals, by estimating the emission rate (or heat rate) benchmarks for each counterfactual. To accomplish this goal, data were collected from both government and non-government sources in India and Ukraine. These data were assessed as to their quality and applicability to the task at hand. Then, the applicable data were analyzed. Subsets of the databases that meet the criteria necessary for benchmark development were identified and selected for further analysis. For example, since the model counterfactual for supercritical coal technology in India is a new coal-fired steam turbine power plant (see Table 5 in the preceding chapter), the available power plant data for India were reviewed in an effort to identify recently-built coal-fired power plants.

The selected subsets of data were then subjected to closer scrutiny. In some cases, data were rejected because they are "outliers," or because they appear to be erroneous or suspect in some way. Finally, the remaining "clean" data were used to compute the benchmarks. In general, the benchmark was computed as the average emission rate (or heat rate) for the facilities or vehicles included in the cleaned data subset.

The resulting benchmarks are presented in Table 15. This table *is* the technology matrix for the ten selected technologies in India and Ukraine. The matrix indicates whether or not each technology qualifies as additional: qualifying technologies are shown without shading; non-qualifying technology/country combinations are indicated with light shading. Also, the matrix provides a numeric benchmark for each technology/country combination. Note that benchmarks are provided for both qualifying and non-qualifying technologies. Again, projects utilizing a non-qualifying technology are *not* automatically disqualified from receiving emission reduction credits. Rather, the project-specific approach may be used to demonstrate the additionality of these projects. If such a demonstration is forthcoming, the project developers may use the benchmarks provided in Table 15 to quantify their emission baselines. Projects using technologies identified as additional in Table 15 automatically qualify for emission reduction credits; again, the developers of qualifying technologies may use the benchmarks specified in Table 15 to estimate their emission baselines. Note, however, that *all* projects—whether employing qualifying or non-qualifying technologies--must still meet the basic criteria outlined in Tables 6 and 13 of Chapter 3 in order to utilize the technology matrix. Essentially, these criteria limit use of the technology matrix to projects involving the development of *new* capacity geared to meet *new* demand.

If a project meets these criteria, the project developers would first use the matrix to demonstrate the additionality of their project. Quite simply, if the project utilizes technology identified as additional in Table 15, the developers need only provide evidence of their use of this technology in order to automatically qualify for emission reduction credits. Then, using the appropriate benchmark from Table 15, the developers would compute the annual emissions baseline for their project. The

Table 15. The Technology Matrix for Ten Selected Technologies in India and Ukraine

Technology	Application/Gas	Country	
		India	Ukraine
Supercritical Coal	All	10.211 MMBtus/MWh	DNA
IGCC	All	10.211 MMBtus/MWh	DNA
Natural Gas Combined Cycle	All	DNA	DNA
Wind Turbine	Off-grid	DNA	DNA
	On-grid	DNA	DNA
Solid Oxide Fuel Cells	Commercial cogeneration	DNA	DNA
	Low-cost fuel	DNA	DNA
	Distributed generation	**UPS**	**UPS**
CNG Vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Hybrid (gasoline/electricity) vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Gas-to-Liquids	All	**BNP**	**BNP**
Coalbed Methane Recovery	Methane	**BNR**	**BNR**
	CO_2/Onsite electricity generation	DNA	DNA
	Transfer of gas to pipeline	**UPS**	**UPS**
Energy-Plex	All	**BNP**	**BNP**

DNA: Data Not Available; may become available for subsequent version of this draft report.
UPS: Benchmark Not Provided, use Project-Specific Approach
BNR: Benchmark Not Required
BNP: Benchmark Not Provided

algorithms to be used to convert the benchmarks to an emissions baseline estimate are simple and straightforward; these algorithms are specified in the following sections of this chapter. Finally, the actual project emissions, in each year, would be subtracted from the corresponding annual emissions baseline, to yield the estimated emission reductions. The project developers would be awarded annual emission reduction credits equal to these estimated reductions.

Note that in some cases separate benchmarks are provided for different applications of the same technology. For example, two benchmarks are provided for wind turbines—one for on-grid and one for off-grid applications. Separate benchmarks are required whenever the model counterfactual differs for different technology applications. Note, further, that benchmarks are deliberately withheld for some technologies/technology applications. In some cases (e.g., distributed generation applications for solid oxide fuel cells), benchmarks are not provided because the project-specific approach is preferred for baseline estimation. In other cases (e.g., energy-plex) benchmarks are not provided because the technology has not yet reached a sufficient level of maturation; benchmarks may be provided for these technologies in future versions of the technology matrix. Finally, in the case of methane emissions for coalbed methane recovery technology, benchmarks are not provided because they are not necessary; methane emission reductions can be measured directly for projects using this technology.

Finally, note that the benchmarks have not been computed for many of the technology/country combinations, because the data required to compute the benchmarks were not available in time for this draft report. Data collection is proceeding in both Ukraine and India, and we plan to add new benchmarks to Table 15 in later versions of this report.

Once again we wish to emphasize that the technology matrix presented in Table 15 was developed for illustrative purposes. It is *not* intended to represent the final, definitive technology matrix for the selected technologies in India and Ukraine. On the contrary, it is offered as a starting point, for further discussion, debate, and development of the technology matrix concept.

The remainder of this chapter presents our analyses of the data obtained for the electricity and transportation sectors in India and Ukraine. For each country and technology group, it includes a basic description of each database used, a general analysis of the available data, a discussion of the procedures used to develop the benchmarks, and a presentation of the benchmark results. It also includes a description of the procedures required to derive the project emission baselines from the benchmarks, a description of recommended procedures for updating the benchmarks, and a discussion of data deficiencies and options for addressing these deficiencies.

At this point, available data are limited to the power sector in India. We do expect to receive data on the power and transportation sectors in Ukraine in the near future. We are also working to obtain data on the transportation sector in India. As these data are received, new sections covering these sectors will be added to the chapter.

Electricity Generation Technologies

India

Data Description. Two separate databases were obtained on Indian power plants. The first of these was the Utility Data Institute (UDI) database. UDI is a private company that gathers and disseminates data on power plants around the world. NETL is a subscriber to UDI's global database.

The UDI database for India is believed to cover most if not all power plants providing electricity to the grid. Both operating and planned units are included in the database. For each generating unit, the UDI database provides data on a variety of items, including the following:

- Utility, power plant, and unit name or identifier
- Unit location (city and State)
- Operating status (planned, under construction, operating, etc.)
- Prime mover
- Nameplate capacity
- Year the unit was commissioned
- Primary fuel type
- Alternate fuel type.

In the case of India, missing data is rare for the above items.

The UDI database provides a good basic description of the population of Indian power plants. As such, it has proven quite useful to this project. However, the database does not include any data on power plant efficiency or heat rates. Furthermore, it does not include any data on the two items that could be used to compute heat rates: fuel consumption and net generation. Since estimation of the benchmarks requires heat rate data, the UDI database was not sufficient in and of itself for our purposes.

Therefore, the UDI database was supplemented with a second database. This second database was originally developed in support of a U.S. Environmental Protection Agency (EPA) study of the benchmarking approach to analysis of CDM projects under the Kyoto Protocol. The data were actually obtained by the former director of Coal India, who now is employed (in India) by an EPA contractor. The data were gathered in an informal manner, through the personal contacts developed by the former director when he was employed by Coal India.

This second database, which we will refer to as the EPA database, does not cover the entire population of generating units. Furthermore, the database provides data at the power plant rather than the unit level,[80] and it is limited to coal-fired plants. And the informal data gathering technique utilized clearly falls short of a statistical sampling approach. Nonetheless, the EPA database provides excellent coverage of India's coal-fired power plants. In fact, the EPA database covers 88 percent of the 59,000 MWs of operating coal-fired capacity included in the UDI database.

Furthermore, the EPA database provides a time series of fuel consumption and net generation data for each generating unit. Specific items provided by the EPA database include the following:

- Power plant name
- Number of generating units and unit capacities
- Location (State)
- Prime mover
- Year commissioned (the database actually provides a range of years, defining the time period over which each unit was commissioned)
- Average calorific value of the coal consumed (Kcal/kg)
- Coal consumption (in million metric tons)
- Net generation.

The coal consumption and net generation data are provided on an annual basis for the period 1990-99. For many plants this time series is incomplete; however, all of the plants include coal consumption and net generation data for at least several years in the 1990-99 time frame.

Using the coal consumption and net generation data, in conjunction with the calorific content data, it is possible to compute annual heat rates for each power plant. However, one serious drawback of the database is that it provides only a single calorific value for each power plant. The heat content of coal can vary significantly from year to year, and even from shipment to shipment. The annual heat rates will not capture this variation. However, it is hoped that the calorific values at least represent reasonably accurate averages for the time periods covered. Given the lack of a time series of calorific

[80] It appears that data for the National Thermal Power Corporation—India's large Federal utility—are not broken out separately by power plant within each State. However, data from India's various State-run utilities are broken out by power plant.

values, our benchmarks will be computed based on the overall average heat rate for each power plant, rather than the annual heat rates.

General Data Analysis. Before proceeding to the computation of the benchmarks, it will prove useful to compile some general statistics from the UDI and EPA databases. First, Table 16 presents a breakdown of India's operating units, by energy or fuel type. As can be seen, India has a total of nearly 100,000 MWs of capacity. Of this total, 60 percent is coal-fired. While coal is clearly dominant, this still leaves a significant amount of capacity, comprising primarily hydropower (23 percent). It is important to keep in mind that the EPA database covers only the 60 percent of capacity that is coal-fired.

Table 17 provides a breakdown of India's planned generating units, by energy/fuel type. Note, first, that India has plans to add a total of 113,000 MWs. This would more than double the country's existing capacity of 98,000 MWs. This enormous planned growth reflects both India's need to close the current electricity supply-demand gap, and to keep pace with the country's rapid population and economic growth. The extent to which India will be successful in bringing these plans to fruition is unclear; the capacity actually under construction at present is presumably more certain than the capacity that is merely planned at present.

Table 17 also indicates that coal-fired capacity will continue to play the dominant role in India's generation mix for the foreseeable future. However, the plans indicate that India is attempting to reduce its reliance on coal, by increasing its utilization of oil, nuclear and other energy sources (including renewables such as wind, solar, and biomass). Note, furthermore, that hydro capacity actually under construction is nearly three times larger than coal capacity builds. Nonetheless, despite the apparent future shifts towards other energy sources revealed by Table 17, coal will remain dominant.

Tables 18 and 19 provide a more detailed, State-by-State breakdown of the information shown in Tables 16 and 17. Table 18 shows a considerable degree of regional heterogeneity in India's generation mix. Although coal is the dominant fuel choice in most States as in the country as a whole, some of the smaller States—e.g., Andaman and Nicobar Islands, Arunachal Pradesh, Goa, and Himachal Pradesh--are coal-free. And there are even a few larger States—particularly Karnataka, Kerala, and Rajasthan—where other energy sources (mainly hydro) are more important than coal. On the other hand, coal comprises over 80 percent of total capacity in the States of Bihar, Madhya Pradesh, and West Bengal.

Note, however, that in two of these States—Madhya Pradesh and West Bengal—coal is much less dominant in the future plans (Table 19). Coal nonetheless remains a key future generation source for these and many other Indian States. Note, however, the importance of other energy sources in the plans for some States such as Assam (natural gas and hydro), Gurjarat (hydro and other), Kerala (oil), Uttar Pradesh (hydro), and Rajasthan (nuclear). Again, the extent to which this planned capacity will actually be built is unclear, but in these and other States India is at least hoping to reduce its dependence on coal.

Analysis of Data Availability. Tables 16 through 19 present an overall picture of the electricity generation mix in India. Table 20, on the other hand, focuses more specifically on the issue of data coverage for generating emission benchmarks. This table combines data from the UDI database with the EPA data, to indicate how well the latter covers the population. The table shows the number and capacity of coal-fired units commissioned in the years 1990-94 (the first set of columns) and 1996-00 (the second set of columns). It will be recalled that in many cases the model counterfactual for the generating technologies was defined as a new unit or plant; therefore the benchmarks are to be based primarily on data for newer units.

Table 16. Operating Generating Units in India

Fuel/Energy Type	Capacity (MW)	Percent Of Capacity
Coal	59,093	60.1
Gas	6,935	7.1
Hydro	22,341	22.7
Nuclear	2,140	2.2
Oil	2,919	3.0
Other	4,818	4.9
Total	98,246	100.0

Table 17. Planned Generating Units in India

Fuel/Energy Type	Planned (MW)	Under Construction (MW)	Total (MW)	Percent
Hydro	11,673	17,115	28,788	25.5
Nuclear	4,940	1,940	6,880	6.1
Coal	41,755	6,086	47,841	42.3
Gas	5,060	469	5,529	4.9
Oil	6,722	1,421	8,143	7.2
Other	12,334	3,454	15,788	14.0
Total	82,484	30,485	112,969	100.0

Table 18. India's Operating Generating Units by Fuel Type and State

State	Fuel/Energy	Capacity (MW)	Percent
Andaman and Nicobar Islands	Oil	15	100.0
Andhra Pradesh	Gas	533	6.1
	Hydro	2729	31.3
	Oil	133	1.5
	Coal	5101	58.5
	Other	218	2.5
Arunachal Pradesh	Hydro	3	100.0
Assam	Gas	391	32.9
	Hydro	379	31.9
	Oil	138	11.6
	Coal	240	20.2
	Other	41	3.5
Bihar	Hydro	191	4.6
	Coal	3870	93.8
	Other	65	1.6
Goa	Oil	3	100.0
Gurjarat	Gas	2173	23.0
	Hydro	552	5.9
	Oil	171	1.8
	Coal	4447	47.2
	Nuclear	440	4.7
	Other	1636	17.4
Haryana	Gas	40	4.4
	Hydro	126	14.0
	Oil	55	6.1
	Coal	680	75.5
Himachal Pradesh	Gas	60	5.9
	Hydro	963	94.1
Jammu & Kashmir	Hydro	1316	88.7
	Oil	143	9.6
	Coal	24	1.6
	Other	5	0.3
Karnataka	Hydro	2651	65.6
	Oil	326	8.1
	Coal	1050	26.0
	Other	11	0.3
Kerala	Gas	230	10.7
	Hydro	1717	80.2
	Oil	122	5.7
	Other	73	3.4

Table 18. India's Operating Generating Units by Fuel Type and State (Continued)

State	Fuel/Energy	Capacity (MW)	Percent
Madhya Pradesh	Hydro	720	8.4
	Oil	16	0.2
	Coal	7802	91.3
	Other	10	0.1
Maharashta	Gas	1511	12.0
	Hydro	1742	13.8
	Oil	403	3.2
	Coal	7491	59.2
	Nuclear	320	2.5
	Other	1181	9.3
Manipur	Hydro	108	100.0
Meghalaya	Hydro	186	100.0
Nagaland	Hydro	4	100.0
New Delhi	Oil	13	100.0
Orissa	Hydro	1170	28.8
	Oil	30	0.7
	Coal	2869	70.5
	Other	0	0.0
Punjab	Hydro	705	29.2
	Coal	1700	70.4
	Other	0	0.4
Rajasthan	Gas	335	6.9
	Hydro	3016	65.4
	Oil	6	0.3
	Coal	890	18.4
	Nuclear	440	9.0
	Other	0	0.0
Sikkim	Hydro	16	100.0
Tamil Nadu	Gas	94	1.1
	Hydro	2091	24.8
	Oil	325	3.8
	Coal	4953	58.8
	Nuclear	470	5.6
	Other	495	5.9
Tripura	Hydro	15	8.2
	Gas	168	91.8
Uttar Pradesh	Gas	1064	7.9
	Hydro	1619	12.0
	Oil	121	0.9

Table 18. India's Operating Generating Units by Fuel Type and State (Continued)

State	Fuel/Energy Type	Capacity (MW)	Percent of State Total
Uttar Pradesh (cont.)	Coal	9661	71.6
	Nuclear	470	3.5
	Other	550	4.1
West Bengal	Hydro	172	2.5
	Oil	206	2.9
	Coal	6408	92
	Other	164	2.4
No State Name Given	Gas	336	10.2
	Hydro	150	4.6
	Oil	621	18.9
	Coal	1907	57.9
	Other	278	8.4

Table 19. India's Planned Units by Fuel Type and State

State	Fuel/Energy Type	Capacity (MW)	Percent by State
Andaman and Nicobar Islands	Hydro	6	19.4
	Oil	25	80.6
Andhra Pradesh	Gas	306	4.0
	Hydro	992	12.8
	Oil	1360	17.6
	Coal	4365	56.6
	Other	691	9.0
Arunachal Pradesh	Gas	48	3.3
	Hydro	1416	96.7
Assam	Gas	620	57.8
	Hydro	453	42.2
Bihar	Gas	340	5.4
	Hydro	216	3.5
	Coal	5561	89.2
	Other	120	1.9
Goa	Other	48	100.0
Gurjarat	Gas	201	3.7
	Hydro	1594	29.1
	Oil	170	3.1
	Coal	1120	20.5
	Other	2369	43.4
Haryana	Gas	318	18.7
	Oil	300	17.7
	Coal	920	54.2
	Other	160	9.4
Himachal Pradesh	Hydro	5207	100.0
Jammu & Kashmir	Hydro	990	100.0
Karnataka	Hydro	1915	17.8
	Oil	658	6.1
	Coal	4735	44.0
	Nuclear	1410	13.1
	Other	2035	18.9
Kerala	Hydro	452	10.1
	Oil	2718	61.0
	Coal	1000	22.4
	Other	288	6.5
Madhya Pradesh	Hydro	2030	26.2
	Oil	460	5.9
	Coal	4432	57.2

Table 19. India's Planned Units by Fuel Type and State (Continued)

State	Fuel/Energy Type	Capacity (MW)	Percent by State
Madhya Pradesh (cont.)	Other	829	10.7
Maharashta	Gas	1894	15.7
	Hydro	2618	21.8
	Coal	4422	36.8
	Nuclear	1000	8.3
	Other	2099	17.4
Manipur	Hydro	1590	100.0
Mizoram	Hydro	370	100.0
Nagaland	Hydro	99	100.0
Orissa	Hydro	1724	22.9
	Coal	5800	77.1
	Other	70	0.92
Punjab	Hydro	600	20.8
	Oil	859	29.8
	Coal	1420	49.3
Rajasthan	Oil	50	1.1
	Coal	1250	26.2
	Nuclear	2470	51.7
	Other	1004	21.0
Sikkim	Hydro	570	100.0
Tamil Nadu	Gas	242	1.5
	Hydro	183	1.1
	Oil	573	3.5
	Coal	8051	49.6
	Nuclear	2000	12.3
	Other	5186	31.9
Tripura	Hydro	1	100.0
Uttar Pradesh	Gas	600	6.8
	Hydro	3800	43.0
	Oil	967	11.0
	Coal	3110	35.2
	Other	356	4.0
West Bengal	Hydro	1803	52.4
	Coal	1630	47.4
	Other	8	0.2
No State Name Given	Gas	960	55.1
	Hydro	159	9.1
	Oil	3	0.2
	Coal	25	1.4
	Other	595	34.2

For coal-fired units commissioned in both the 1990-94 and 1995-00 time periods, Table 20 presents the total capacities from the UDI and the EPA databases. In addition, the EPA capacity totals are presented as a percentage of the UDI totals. These percentages in effect indicate the size of our sample relative to the population. In a couple of cases the percentages are larger than 100, indicating discrepancies between the UDI and EPA databases; however, for the most part the percentages fall in the 0 to 100 range. It should be noted that the EPA database provides only a range of years for each plant, rather than the precise year of commissioning for each unit. Therefore, for some plants that straddle the 1990-94 or 1995-00 time periods, judgment was required to assign individual units to a time period.

Table 20 indicates that, in general, the EPA database provides good coverage of recently-opened coal-fired power plants. The database provides data on 46 percent of Indian coal-fired units opened between 1995 and 2000, and 68 percent of units opened between 1990 and 1994. Coverage is more than adequate not only at the national level, but for most States as well. Even for the 1995-00 time period, where coverage is somewhat weaker, data are available for 25 percent or more of the capacity in most States. There are, however, a few States for which data are lacking; namely Karnataka, Punjab, Uttar Pradesh, and Madhya Pradesh. Of these, Karnataka relies primarily on hydropower, not coal. However, coal is dominant in the other three States.

But with the exception of these few States, the EPA database provides more than adequate coverage of India's newer coal-fired power plants. Based on the data presented in Table 20, a sufficient sample could be obtained even if the sample was to be limited to plants opened in the last five years. Although the inclusion of plants opened in the 1990-94 time period would help to increase the sample size, it might also skew the resulting benchmark. Therefore, it was decided that only plants opened in the last five years would be considered as a basis for benchmarking.

Developing the Benchmark. It will be recalled, from the preceding chapter, that two of the power generation technologies require benchmarks representing the average or typical heat rates for newly-built, subcritical steam turbine units utilizing pulverized coal as the primary fuel. These two technologies are supercritical steam and IGCC. The EPA database provides the necessary data to support benchmark development for these two technologies.

However, the EPA database will not support the development of benchmarks for the three remaining power generation technologies. The model counterfactual for natural gas combined cycle technology was defined as a gas-fired steam turbine plant; since the EPA database covers only coal-fired plants a benchmark for this counterfactual could not be developed. The counterfactuals for wind turbine and fuel cell technologies include diesel generators and composites representing a mix of newly-built generating capacity. Again, diesel units are not included in the database, nor does the database provide the breadth of coverage necessary to the development of a composite benchmark that must reflect a mix of energy/fuel types.

Table 20. Recently-Built Coal-Fired Power Plants in the EPA and UDI Databases

State	1990 – 1994				1995 – 2000			
	Number of Units in UDI Database	Capacity of Units in UDI Database (MW)	Capacity of Units in EPA Database (MW)	Percent of Total Capacity Covered by EPA Database	Number of Units in UDI Database	Number of Units in UDI Database	Capacity of Units in EPA Database (MW)	Percent of Total Capacity Covered by EPA Database
Andhra Pradesh	5	1088	420	38.6	5	775	210	27.1
Tamil Nadu	8	1680	420	25.0	7	1501	420	28.0
Karnataka	1	210	210	100.0	4	645	0	0.0
Orissa	1	120	0	0.0	4	1420	1420	100.0
Rajasthan	0	0	210	N/A	2	500	420	84.0
West Bengal	7	1766	1255	71.1	10	1815	1130	62.3
Bihar	4	840	630	75.0	7	1148	420	54.9
Gujarat	7	820	330	40.2	6	747	630	84.3
Punjab	2	420	420	100.0	2	420	0	0.0
Uttar Pradesh	5	1240	1370	110.5	7	1170	0	0.0
Maharashta	3	1210	710	58.7	6	1450	920	103.4
Madhya Pradesh	3	630	840	133.3	3	565	0	0.0
Total	46	10024	6815	68.0	63	12156	5570	45.8

It will be recalled that the possibility of a few regional variants to the basic model counterfactual for supercritical steam and IGCC was raised. Specifically, for the States of Assam and Kerala, gas-fired or oil-fired plants may represent a better choice for the counterfactual than the standard coal-fired plant. However, once again the limitations of the EPA database do not allow the development of alternatives to coal-fired benchmarks. Therefore we will limit our focus to the development of the standard country-wide benchmarks for supercritical steam and IGCC; regional variants to these standards will not be developed as a part of this report.

Beyond these limitations, the EPA database should provide a sufficient basis for the development of country-wide benchmarks for IGCC and supercritical steam technology. It will be recalled that, for both of these technologies, the counterfactual is defined as a *newly-built* power plant. Therefore, in defining the group of power plants that will form the basis for the benchmarks (i.e., the "benchmark group"), we limited ourselves to recently built plants—specifically, plants opened in the last five years.

The EPA database includes 3 plants commissioned entirely after 1995, along with one plant with units opened in both 1995 and 1996. In addition, the database includes three plants opened in 1995. To increase the size of the benchmark group, 1995 rather than 1996 was chosen as the cutoff year; all plants with all units opened during or after 1995 are included in the group. Plants with some units opened before and some after 1995 were excluded, due to the lack of unit-level data (there were four such plants).

Based on this temporal criterion, the power plants selected as candidates for inclusion in the benchmark group are listed in Table 21. As can be seen, there are seven such plants. Five of these seven plants have heat rates falling in the range of 9700 to 10,500 Btus per kWh. One has a heat rate of 7365 Btus/kWh, and one has a heat rate of 5611 Btus per kWh.

The latter plant (Budge-Budge) is clearly an outlier. Its estimated heat rate implies a thermal efficiency of well over 50 percent. This is unheard of for coal-fired steam turbine power plants. Clearly, the data for the Budge-Budge plant are suspect. For this reason the plant was dropped from the benchmark group.

With a heat rate of only 7365 Btus/kWh, the Suratgarh plant is also a suspect outlier. Suratgarh is the newest of the seven plants, having been commissioned in 1998. Hence there is only one year of fuel consumption/net generation data available for this plant. A review of the data for the other five plants indicates that in many cases, the first year data yields a low heat rate estimate. In fact, the estimated heat rates in the first year of operation are unusually low for four of the five power plants. Table 22 shows the calculated heat rates by year for each of the six plants (including Suratgarh). As can be seen, the Talcher and 1b Valley power plants have estimated heat rates in the 8,000 to 9,000 Btu/kWh range in their first year of operation, rising quickly to the 10,000-11,000 Btu/kWh range in the second operating year. The efficiency change between the first and second year is even more dramatic in the case of the Mejia plant (7,470 Btus/kWh, rising to 10,794 Btus/kWh). The data for the Tenughat plant are clearly erroneous, in so far as they indicate a heat rate increase from an impossibly low 4,831 Btus/kWh in the first year, to 12,119 Btus/kWh in the second year.

It is possible that India's power plants operate at high efficiencies when brand new, and then quickly drop to more expected efficiency levels by their second year of operation. However, the estimated heat rates for the first year of operation appear to be too low to support this explanation. This is certainly the case for the Tenughat plant, but even the first year heat rates for the plants in Orissa appear to be too low to be plausible.

Instead, it is suspected that the low first year heat rates are the result of a data anomaly. One plausible explanation is that the recording of fuel use lags behind actual consumption, consequently lowering the estimated heat rates in the first year of operation. The effect would be more exaggerated for some plants than for others. Specifically, plants that opened later in the year would be more heavily impacted than those opened early in the year. This theory is supported by a comparison of first year versus second year coal consumption. When first year consumption is specified as a percent of second year consumption, the results, for the four plants with questionable first-year heat rates, are as follows:

Table 21. Candidate Indian Power Plants for the Benchmark Group

State	Utility	Power Plant	Number of Units and Capacity (MW)	Total Plant Capacity (MW)	Year Commissioned	Average Heat Rate (Btus/kWh)
Orissa	NTPC	Talcher STPP	2x500	1000	1995	10,015
Orissa	Orissa Power Generation Corp.	1b Valley	2x210	420	1995	10,218
Rajasthan	Rajasthan State Electricity Corp.	Suratgarh	2x210	420	1998	7,365
West Bengal	Damodar Valley Corp.	Mejia	3x210	630	1995-96	9,745
West Bengal	CESC Ltd.	Budge-Budge	2x250	500	1997	5,611
Maharashtra	BSES Ltd.	Dahanu	2x250	500	1995	10,610
Bihar	Bihar State Electricity Board	Tenughat	2x210	420	1996	10,466

Table 22. Annual Heat Rates for Six Coal-Fired Power Plants in India

State	Utility	Power Plant	Annual Estimated Heat Rate (Btus/kWh)			
			1995-96	**1996-97**	**1997-98**	**1998-99**
Orissa	NTPC	Talcher STPP	8,730	10,155	9,662	10,529
Orissa	Orissa Power Generation Corp.	1b Valley	8,294	10,844	10,246	10,582
Rajasthan	Rajasthan State Electricity Corp.	Suratgarh	N/A	N/A	N/A	7,365
West Bengal	Damodar Valley Corp.	Mejia	N/A	7,470	10,794	15,873
Maharashtra	BSES Ltd.	Dahanu	12,442	11,105	9,935	10,072
Bihar	Bihar State Electricity Board	Tenughat	N/A	4,831	12,119	11,446

- Tenughat—19 percent
- 1b Valley—46 percent
- Mejia—47 percent
- Talcher STPP—65 percent.

Note that the plant with the lowest first year fuel consumption (19 percent relative to second year consumption) also has the lowest first year heat rate (4831 Btus/kWh). And Talcher STPP, the plant with the highest first year fuel consumption (65 percent of second year consumption), has the highest first year heat rate (8730 Btus/kWh). First year fuel consumption, measured as a percentage of second year consumption, should provide a rough indication of when a plant opened during the year; presumably, the lower the percentage, the later in the year the plant came on line. Hence the data indicate that plant's opening later in the year tend to have lower estimated first-year heat rates than those opened earlier in the year. This result is as expected if the recording of fuel use is lagging behind actual consumption.

Of course, it is difficult to know if this or some other explanation accounts for the tendency towards low first-year heat rates. What we can conclude is that the first-year data is suspect, and that, therefore, the Suratgarh power plant, with only one year of data, should be excluded from the benchmark group.

The remaining five power plants—Talcher STPP, 1b Valley, Mejia, Dahanu, and Tenughat—form the final benchmark group for supercritical and IGCC technology in India. Data on these five plants are presented in Table 23. With one exception, these plants comprise two generating units; there are a total of 11 units. Furthermore, most of the units (6) are 210 MWs in size, suggesting that they may to at least some degree utilize a standardized design.

The total capacity of the 5 plants is 2970 MWs. This represents 3.0 percent of India's total coal-fired capacity, and 24.4 percent of coal-fired capacity opened since 1995—a good-sized sample.

Two sets of heat rates are provided in Table 23—one including, and one excluding, the first year of operation for each plant.[81] Both sets of heat rates thus represent averages over a period of time ranging from two to four years. As previously discussed, annual fuel consumption and net generation data are available from the EPA database. However, the coal heat content data provided by the database are not annual. Since the latter must be used to convert the fuel consumption data from physical (weight) to energy units, and since coal heat contents typically vary widely from year-

[81] An exception was made in the case of the Dahanu power plant. Since the first-year heat rate for this plant was not suspiciously low, it was included in the computation for both sets of heat rates.

Table 23. The Benchmark Group for Supercritical Coal and IGCC Technology in India

State	Utility	Power Plant	Number of Units and Capacity (MW)	Total Plant Capacity (MW)	Year Commissioned	Average Heat Rate (Btus/kWh)	
						First-Year Excluded	Life-of-Plant
Orissa	NTPC	Talcher STPP	2x500	1000	1995	10,111	10,015
Orissa	Orissa Power Generation Corp.	1b Valley	2x210	420	1995	10,542	10,218
West Bengal	Damodar Valley Corp.	Mejia	3x210	630	1995-96	10,173	9,745
Maharashtra	BSES Ltd.	Dahanu	2x250	500	1995	10,610*	10,610
Bihar	Bihar State Electricity Board	Tenughat	2x210	420	1996	11,784	10,466
Total/Average				2,970		10,644	10,211

*Life-of-plant heat rate.

to-year and even from shipment-to-shipment, the database does not provide the data necessary to compute accurate annual heat rates.[82] Therefore, for benchmark development purposes, we must limit ourselves to the computation of an average life-of-plant heat rate (possibly excluding the first year of operation) for each plant.

Both sets of heat rates shown in Table 23 are plausible. To put these India heat rates in perspective, U.S. power plant heat rates typically fall in the range of 9,700 to 11,000 Btus/kWh (31 to 35 percent thermal efficiency). All but one of the heat rates shown in Table 23 fall within this same range. The true life-of-plant heat rates are lowest for the Mejia plant; however, Mejia's 9,745 Btus/kWh (or 35 percent thermal efficiency) is certainly reasonable for a new power plant. The first-year-excluded heat rates are highest for the Tenughat power plant, but 11,784 Btus/kWh (29 percent thermal efficiency) is also reasonable considering the poor quality (i.e., high ash content) of India's coals, and the effect that this has on heat rates. The overall average heat rates across all five power plants differ by only 433 Btus/kWh, or 4 percent.

Given that both sets of heat rates appear reasonable, it was decided that the benchmark should be based on the true life-of-plant heat rates (first-year data included). Although the cause of the lower-than-normal heat rates in the first year is unknown, a lag between the use and recording of fuel consumption appears to be the most plausible explanation. Given this explanation, it is better to include as many years of data as possible (including the first year), in order to diminish the effect of the lag on the heat rate computations.

Thus, the benchmark for supercritical coal and IGCC technology is 10,211 Btus/kWh (10.211 MMBtus/MWh), the average life-of-plant heat rate for the five benchmark power plants listed in Table 23. A heat rate value, rather than an emissions rate value, will be used as the benchmark because this will enable a more accurate computation of baseline emissions using coal-rank specific emission factors (as explained below).

Using the Benchmark. Using the benchmark to compute annual emission baselines for an IGCC or supercritical coal project will be very simple. The equation is as follows:

$$EB_j = (10.211\ \text{MMBtus/MWh})(G_j)(EF_r)$$

where

EB_j = Emissions baseline for supercritical coal or IGCC project, in year j (tons carbon dioxide)

G_j = Net generation in year j for the project (MWh)

EF_r = Emissions factor for coal of rank r used by the project (tons CO_2/MMBtu)

[82] This is another possible explanation for the low first-year heat rates (although it is less satisfying than the explanation offered above, because it is unclear why coal quality would differ in a systemic manner in the first year of operation).

As the equation indicates, by specifying the benchmark as a heat rate rather than an emissions rate, it is possible to tailor the emissions factor (EF_r) to the rank of coal actually being used by the project. Since emissions factors for U.S. coals range from 205.3 lbs/MMBtu for bituminous coal, up to 227.4 lbs/MMBtu for anthracite, this approach should yield a modest improvement in the accuracy of the resulting baseline emission estimate.

Updating the Benchmark. Clearly, it will be necessary to select a new benchmark group of power plants on a periodic basis, to reflect changes or improvements in the operating efficiencies of new coal-fired power plants. It is believed that re-estimation once every 5 years will be sufficient to keep the benchmark up to date, since the average heat rate of new conventional steam turbine plants tends to be fairly stable over time.

The most recently-selected benchmark group should, of course, always be used as the basis for benchmarking *new* supercritical coal and IGCC projects. However, although updates will also be required for *ongoing* projects, these updates should be based on the benchmark group originally assigned to these projects. In other words, a new project should always be assigned the most recently-selected benchmark group, but once a project has been assigned a benchmark group, that assignment becomes the project's benchmark group *for the life of the project.* Here it is important to recall that the model counterfactual for supercritical coal and IGCC projects is a conventional, coal-fired, steam turbine power plant. Steam turbine power plants are long-lived facilities. It is not uncommon to find power plants that have been in operation for over 50 years in the United States, and in India the impetus for extending the life of existing plants is even greater given the electricity supply shortfalls. If we were to update the benchmark for *existing* projects every five years, based on the heat rate of recently-constructed plants, then we would in effect be assuming that the counterfactual power plant would be shut down and replaced with a new power plant every five years. Such an assumption is clearly unrealistic.

However, the heat rate of the model counterfactual power plant would clearly change over time. Heat rates naturally tend to increase with power plant age, due to wear and tear on the equipment. To combat this problem, plant operators replace worn parts and equipment on a regular, and fairly frequent, basis. Furthermore, on a less frequent basis, major overhauls are undertaken to improve plant availability and efficiency. Repowering projects, which may involve the retrofitting of new technologies to existing plants, may also be undertaken on occasion. And, as power plants reach the end of their design lives, life extension projects may be undertaken. All of these projects usually have the effect of improving efficiency, just as the passage of time has the effect of reducing efficiency.

How do we take into account the effect of time, and of efficiency improvement efforts, on the benchmark heat rates for *ongoing* supercritical coal and IGCC projects? One of the key advantages of the "benchmark group" approach is that it facilitates the process of updating the benchmark for existing power plant projects. The benchmark group of power plants provides a means of benchmarking projects, not just at project initiation, but throughout the projects' lives. By continually updating our data on the average heat rate for the five Indian power plants selected as the benchmark group, systemic changes in heat rates over time can be captured. For example, if the quality of Indian coal deteriorates, or improves, over time, this systemic change will be reflected in the average heat rate of the benchmark group. Similarly, if India undertakes widespread repowering projects involving the retrofitting of new technologies to existing plants, the resulting heat rate improvements should be captured by the benchmark group. Alternatively, if in the future India lacks the capital to retrofit new technologies, or even to keep existing plants well-maintained, the resulting deterioration in heat rates will be captured in benchmark updates, through the benchmark group approach. In short, the benchmark group provides a means of quantifying what would have happened in the absence of the project, not just at project initiation but throughout the project's life. In this way, the impact of large-scale trends on *existing* power plant heat rates will be captured in the benchmark updates, while still maintaining a certain degree of benchmark stability (as warranted by the long-lived nature of coal-fired power plants).

In effect, we are adding a third dimension to the technology matrix: time. At first, a group of benchmark power plants, such as those listed in Table 23, is selected from the population; all supercritical coal and IGCC projects initiated in the subsequent five years will use that group of plants as their benchmark throughout their lives. After 5 years has elapsed, a new benchmark group will be selected; all projects implemented in the next five years will use this new group of plants as their benchmark. Hence for any given qualifying technology and country, a series of benchmarks will be in use at any given time for new and ongoing projects; the specific benchmark used by a particular project will be determined by that project's start date.

It should be emphasized that, using this approach, the benchmark heat rate may decrease or *increase* over time, depending in part upon the vigilance of India's efforts to maintain existing power plants. If in general India fails to adequately maintain its power plants, this failure will lead to a deterioration in the plants' heat rates, and this deterioration should be reflected in the benchmark. If, on the other hand, India maintains its heat rates and even improves upon them by introducing new technologies into its existing plants, this improvement should likewise be captured in the benchmark. The goal, in all cases, is to trace the time path most likely to be followed by the model counterfactual, and in so doing to maintain a set of benchmarks that provide a realistic, credible reflection of developments in the Indian power sector.

In some cases a project may outlive the group of power plants upon which its benchmark is based. If, at some point in time, over 50 percent of the capacity forming a particular benchmark group has been retired, then it would be reasonable to conclude that the model counterfactual represented by this group has been retired. At this point in time, it would be reasonable to switch the benchmark for any projects still in existence from this old benchmark group to the group used to define the most up-to-date benchmark. The assumption underlying this benchmark switch is that the original counterfactual power plant has been retired, and replaced with a new counterfactual plant.

Data Quality. It is clear that the EPA database, used as the basis for the benchmark, is problematic and suspect in a number of respects. First, the provision of a single coal heat content value for each plant, rather than annual values, is a significant deficiency. Furthermore, some of the heat rate estimates computed using the data were unrealistically low, particularly in the first year of plant operation. This problem forced us to eliminate two of the seven potential candidates for inclusion in the benchmark group, thereby significantly reducing the size and scope of our sample. Furthermore, the first year problem, along with the lack of annual heat content averages, cannot but reduce our confidence in the accuracy of the data for the other years. Our benchmark estimate of 10.211 MMBtus/kWh may suffice for the purpose of this report—i.e., to explain the technology matrix concept and to illustrate, in broad outline, the procedure for developing the matrix. However, given both the known and potential unknown data problems, we do not believe that this benchmark meets the criteria for application to any actual flexible, market-based carbon offset projects. The data upon which it is based most first be improved upon.

But beyond the immediate data problems, it is clear that what is really required of India is not simply a better database, but rather the institutional capacity needed to support the data requirements of a flexible, market-based carbon offset program. Informally obtained, unverified, ad hoc databases cannot serve the long-term requirements of benchmarking. For one, the data collection effort must be extended to include *all* of India's power plants, or at least a statistically representative sample of all plants. Data limited to only one group of plants (e.g., coal-fired plants) will not provide sufficient coverage of all of the technologies included in the matrix. Furthermore, the needed data must be collected on a regular, periodic basis to support the benchmark updating process. And most importantly, the data must be subjected to validation and verification procedures, to ensure a reasonable degree of accuracy. In particular, safeguards and enforcement provisions will be required to prevent gaming. Given that the technology matrix approach involves the identification of specific groups of plants, and that the data from these plants will determine the awarding of credits with monetary value, strong incentives for gaming clearly exist.

To support benchmark development for the Indian power sector, either the existing data collection agency (which does collect some data, but does not collect fuel consumption statistics) must be upgraded, or a new agency must be established. This agency must be granted the regulatory authority required to collect and validate the needed data, on a regular, periodic basis. Populations will need to be identified, sampling plans devised, data survey instruments created, data processing and editing procedures established, and means for data dissemination developed. To build this institutional capacity, India and other developing countries planning to participate in a flexible, market-based international carbon offset program may require both financial and technical assistance from developed countries.

Ukraine

[The data required for this section is not yet available]

Transportation Technologies

[The data required for this section is not yet available]

Coalbed Methane

[The data required for this section is not yet available]

5. CONCLUSIONS AND RECOMMENDATIONS FOR FURTHER WORK

Summary

This report has illustrated the development of the technology matrix for ten selected technologies in India and Ukraine. For each technology/country combination, additionality (or non-additionality) was established. Then, the model counterfactual—the most likely alternative to projects utilizing the technology—was defined. Data of the type required to estimate emission rates were collected for the two countries. The available databases were analyzed, and subsets of the data that could be used to represent the model counterfactuals were selected. These data subsets were checked for outliers and suspect data. Finally, the "cleaned" data subsets were used to compute emission rate (or heat rate) benchmarks for each technology and country.

The results of this process are shown in Table 24. This table *is* the technology matrix for the ten selected technologies in India and Ukraine. The table indicates which particular technology/country combinations qualify as additional, and which are non-additional. It also provides an emissions benchmark for each combination.

Table 24 is supplemented by Tables 25 and 26, which summarize the criteria a project must meet in order to utilize the technology matrix. Table 25 covers projects in the electricity generation sector, while Table 26 applies to transportation sector projects. Essentially, projects involving the development of *new* capacity, to meet *new* demand, qualify for use of the technology matrix. On the other hand, the project-specific approach should be used to estimate the baseline for projects involving modifications to existing facilities or vehicles.

The technology matrix is designed to significantly reduce the costs associated with the evaluation of flexible, market-based carbon offset projects. It is therefore very simple to use. Project developers would first refer to Table 25 or 26 to determine whether or not their projects meet the criteria that would allow them to use the technology matrix. If a particular project meets the criteria, the developers would then refer to Table 24 to determine whether or not the project utilizes qualifying technology. If the project technology does not qualify as additional in Table 24, the developers still have the opportunity to demonstrate the project's additionality using the project-specific approach. If the project does utilize technology identified as qualifying in Table 24, it should automatically qualify for emission reduction credits under a flexible, market-based carbon offset program.

Once a project has been demonstrated to be additional, using either the technology matrix or the project-specific approach, the appropriate benchmark from the technology matrix can be used to estimate the project's emission baseline for each year the project is in operation. The project's actual emission reductions are subtracted from the emissions baseline to yield the estimated emission reductions in any given year. The developers would receive emission reduction credits equal to the estimated emission reductions.

Table 24. The Technology Matrix for Ten Selected Technologies in India and Ukraine

Technology	Application/Gas	Country	
		India	Ukraine
Supercritical Coal	All	10.211 MMBtus/MWh	DNA
IGCC	All	10.211 MMBtus/MWh	DNA
Natural Gas Combined Cycle	All	DNA	DNA
Wind Turbine	Off-grid	DNA	DNA
	On-grid	DNA	DNA
Solid Oxide Fuel Cells	Commercial cogeneration	DNA	DNA
	Low-cost fuel	DNA	DNA
	Distributed generation	**UPS**	**UPS**
CNG Vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Hybrid (gasoline/electricity) vehicles	Passenger Cars	DNA	DNA
	Transit buses	DNA	DNA
Gas-to-Liquids	All	**BNP**	**BNP**
Coalbed Methane Recovery	Methane	**BNR**	**BNR**
	CO_2/Onsite electricity generation	DNA	DNA
	Transfer of gas to pipeline	**UPS**	**UPS**
Energy-Plex	All	**BNP**	**BNP**

DNA: Data Not Available; may become available for subsequent version of this draft report.
UPS: Benchmark Not Provided, use Project-Specific Approach
BNR: Benchmark Not Required
BNP: Benchmark Not Provided

Table 25. Criteria for Selecting an Approach to Baseline Development for the Electricity Generation Sector

Project Type	Corresponding Approach	Exceptions
1. Projects involving the installation of new capacity, and utilizing advanced qualifying technologies	Modified Technology Matrix	a. Projects to be implemented in host countries without qualifying technology lists/sector benchmarks must use the project-specific approach b. Project developers *may* choose to use the project-specific approach to estimate the baseline, *if* they can demonstrate that the result is more accurate c. Projects designed to replace existing capacity rather than meet new demand should use the project-specific approach for baseline development, *if* the capacity to be replaced can be readily identified.
2. All projects utilizing conventional, non-qualifying technology	Project-specific	a. Projects involving the installation of new capacity to meet new demand should use a sectoral benchmark for baseline estimation, *unless* the project-developers choose to use the project-specific approach *and* can demonstrate that the result is more accurate.
3. Projects involving the retrofitting of advanced qualifying technologies to existing facilities, with no resulting change in capacity	Modified technology matrix to establish additionality; project-specific to estimate the baseline	None.

Table 26. Criteria for Selecting and Approach to Baseline Development for the Transportation Sector

Project Type	Corresponding Approach	Exceptions
Projects involving the use of advanced/alternative fuels and vehicles	Technology Matrix	a. Projects to be implemented in host countries without qualifying technology lists/sector benchmarks must use the project-specific approach b. Project developers may choose to use the project-specific approach to estimate the baseline, if they can demonstrate that the result is more accurate c. Projects designed to replace existing vehicles rather than meet new demand should use the project-specific approach for baseline development, if the emissions of the vehicles to be replaced are readily identifiable
All projects using conventional transportation technologies	Project-Specific	Projects involving the deployment of new vehicles to meet new demand may use the appropriate sectoral benchmark from the technology matrix for baseline estimation, unless the project-developers choose to use the project-specific approach, and can demonstrate that the result is more accurate
Projects involving the deployment of advanced conversion kits/technologies to convert conventional vehicles	Technology Matrix to establish additionality, Project-specific to estimate the baseline	None

Conclusions

The technology matrix approach offers a number of potential advantages. Like the various benchmarking approaches that have been discussed in the literature, it is designed to substantially reduce the costs of project evaluation to project developers. The technology matrix approach is in fact similar to benchmarking, but with the addition of a stringent, true test for additionality based on economic and market evaluations of project technologies. Furthermore, the focus on individual technologies rather than sectors or sub-sectors enables the tailoring of benchmarks to groups of projects characterized by similar technological characteristics. Where appropriate, separate benchmarks can even be provided for different applications of the same technology. The resulting benchmarks thus exhibit a high degree of specificity with respect to both the technological and market characteristics of individual projects. In effect, the technology matrix approach groups projects with similar technological and market characteristics *within* economic subsectors, enabling the development of a more accurate benchmark for each group.

The technology matrix approach is designed as a supplement to, rather than a substitute for, the project-specific approach. Projects that do not meet the criteria outlined in Tables 25 and 26—mainly projects involving modifications to existing facilities or vehicles—would be required to use the project-specific approach. Furthermore, projects utilizing commercial technologies would be required to use the project-specific approach to demonstrate additionality, although these projects may still use the benchmarks from the technology matrix, and thus reap at least a portion of the cost benefits offered by the matrix. But projects utilizing advanced, commercial technologies may use the technology matrix to establish both additionality and the emissions baseline, thus reaping the full cost benefits of the matrix. Because the project-specific approach remains the default, the technology matrix approach may not in and of itself eliminate any projects from participation in a flexible, market-based carbon offset program; project developers always have the opportunity to use the project-specific approach if they cannot use the technology matrix. In short, the technology matrix offers significant cost savings to many types of projects, without barring any projects from participation in a market-based carbon offset program.

We wish to emphasize, once again, that the technology matrix developed in this report, and presented in Table 24, is for illustrative purposes only. It is not intended to represent the final, definitive technology matrix for the ten selected technologies in India and Ukraine. Rather, the goal has been to highlight the main issues associated with matrix development, and to bring the strengths and limitations of the technology matrix approach into sharper focus, through the development of a concrete, illustrative example. In fact, through this approach we have been able to identify two key areas where further improvements are needed. We have touched upon both of these areas in previous chapters, but would like to return to them here.

First, as was discussed in the introduction to Chapter 3, the process of defining the model counterfactual is highly subjective, relying as it does on expert opinion and judgment. This subjectivity is largely unavoidable, if the core hypothetical issue—what would happen in the project's absence?—is to be addressed in a direct, explicit manner. However, given the subjective nature of the model counterfactuals, it is important that they be selected based on a broad consensus rather than the opinions of a few individuals. Thus, we would recommend the use of a Delphi approach to define the model counterfactuals for any future versions of the technology matrix. Specifically, panels of international experts should be brought together to define the model counterfactuals, based on consensus opinion. These panels could be organized, e.g., based on economic sector. Although using this Delphi approach the resulting model counterfactuals would remain subjective, they would reflect the consensus of a wide range of expert opinion.

Second, the data available to support baseline development is not adequate to the task, at least in the case of India. We wish to emphasize that, in our belief, this conclusion holds not only for the technology matrix approach, but for *all other* baseline development approaches that have been discussed in the literature. Although the specific data requirements will vary somewhat from one approach to another, we believe that all of the various approaches will have some basic requirements in common. For example, in the electricity generation sector, there will be a need for reliable generation and fuel consumption data, as the basis for heat rate computations. As we have seen, the heat-rate related data that we obtained for India are of questionable reliability.

Furthermore, *all* baseline development approaches will require data on a *continuing* basis, so that the emission baselines can be updated periodically. India does not at present possess the institutional capacity required to provide the needed data updates. For example, although power sector data are collected and disseminated by the Indian government on a regular basis, these data do not include a key item—fuel consumption. To meet the data needs of a flexible, market-based carbon offset program, either the existing data collection agency must be upgraded, or a new agency must be established. This agency must be granted the regulatory authority required to collect and validate the needed data, on a regular, periodic basis. Populations will need to be identified, sampling plans devised, data survey instruments created, data processing and editing procedures established, and means for data dissemination developed. To build this institutional capacity, India and other developing countries planning to participate in such flexible, market-based carbon offset programs may require both financial and technical assistance from developed countries.

Recommendations for Further Work

The development of the needed institutional capacity will likely prove to be an expensive and time-consuming, though necessary, undertaking. Because *all* of the proposed baseline development approaches, including the technology matrix, cannot be developed until a firm data foundation has been provided, institutional capacity building must have priority over the implementation of specific approaches. Therefore, we do not recommend the further development of the technology matrix presented in Table 24 until the underlying data needs have been more thoroughly addressed.

Rather than further development of the technology matrix, we recommend a shift in focus to the *marketing* of the technology matrix concept. As yet, this concept is not well known beyond NETL. It differs in certain key respects from other project evaluation approaches currently under consideration, and at a minimum it deserves a hearing in the on-going international debate concerning methodologies and protocols for flexible, market-based carbon offset programs. The marketing effort could begin with the wider dissemination of the report *Developing Emission Baselines for Market-based Mechanisms: A Case Study Approach*. This report lays the groundwork for the technology matrix approach, and is in many ways a prerequisite to the present report. In fact, it may be useful to disseminate the earlier report as the first volume of a two-volume set (with this present report serving as the second volume). In any event, dissemination of the earlier report should be followed up with the finalization and dissemination of this present report.

Because both reports are lengthy and complex, the preparation of one or more papers summarizing their key findings would be a logical next step. Relevant conferences, where these papers could be presented, should be identified. Also, one or more articles summarizing the reports might be prepared for publication in appropriate journals. NETL attendance at conferences and workshops focusing on flexible, market-based carbon offset programs should perhaps be stepped up, and full advantage should be taken of any opportunities to disseminate the reports, papers, and articles at such events. Finally, some consideration might be given to the possibility of an NETL-sponsored workshop, to explore various approaches to flexible, market-based project evaluation, including the technology matrix.