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Power Sector Cost-Benefit Analysis Design Principles

GUIDANCE FOR MCC ECONOMIC ANALYSIS OF POWER SECTOR PROJECTS

BRIAN EPLEY, FRANCIS MULANGU, AND DERICK BOWEN

BASED ON Brandon Tracy (2013), *“Guidance for MCC Economic Analysis of Power Sector”*

MCC | 1099 14th Street NW Suite 700, Washington DC 2005

Table of Contents

Tables and Figures

List of Abbreviations

AC	Alternating Current
BTU	British Thermal Unit
CBA	Cost-Benefit Analysis
CDF	Consumer Damage Function
CES	Constant Elasticity of Substitution
CRT	Cost-Reflective Tariff
CV	Contingent Valuation
DC	Direct Current
Dx	Distribution
END	Energy Not Delivered
ENS	Energy Not Supplied
Gx	Generation
LOEE	Loss of Energy Delivered in Expectation
MW	Megawatt
O&M	Operations and Maintenance
PIR	Policy and Institutional Reform
rWTP	Revealed Willingness to Pay
sWTP	Stated Willingness to Pay
Tx	Transmission
VOLL	Value of Lost Load
V	Volts
VA	Volt-Amperes
VAh	Volt-Ampere-hours
WTP	Willingness to Pay
WTA	Willingness to Accept
Wh	Watt-hours
Wp	Watts-peak

I. Introduction

The purpose of this document is to establish guidance on the principles to be used for MCC's economic analysis of public investments and interventions in the power sector. It will serve as a "living" resource that can be updated as necessary and as evidence and methods evolve. It presents benefits and costs commonly employed in economic analysis across investments in the power sector, issues affecting the economic analysis, and the key technical information, data, and other needs for a full cost-benefit analysis (CBA). It also includes guidance on estimating the number of beneficiaries from power sector investments. This guidance was partially adapted from MCC's previous power sector guidance[1] and is designed to be consistent with the principles of MCC's general Guidelines for Cost-Benefit Analysis.[2]

MCC has invested extensively in the power sectors of its compact countries (See ANNEX I for a compilation). Among other possibilities, the scope of MCC's support could include any of the following: generation investments, network reinforcement, extension, or rehabilitation (e.g., transmission, and distribution), commercial practices of utilities (e.g., improvements in metering/billing/collections, IT systems, management services contractors), and policy or regulatory reform (e.g., facilitating independent power production, achieving full cost recovery, establishing an independent regulator to set performance standards and tariffs, and policies to balance the energy mix) for systems of any scale. Because Electricity provision exhibits some characteristics of a natural monopoly, and coordination failures can result in under-provision of heavy infrastructure such as an electric grid; public investment, regulation, and even state-owned operators are typical in the sector.

MCC invests in the power sector where limitations in the provision of power have been identified as a binding constraint to economic growth. There are several main types of electricity constraints: (i) a shortfall in the supply of power (generation) or the supply of power reaching consumers (transmission), (ii) low levels of access to power (distribution), (iii) a low level of reliability in the supply of power (insufficient operating reserve or poor grid management), and (iv) institutional barriers in the regulation or management of electric utilities ((e.g., related to billings and collections, or regulation and planning that may lead to a high cost of power over time). The purpose of electrical power is to do useful work, so while there may be many root causes of these problems (with only the most likely listed here), any of these factors could result in an uncompetitive industry and exports sector, a stunted structural transformation, and negative externalities in health, education, and the environment.

Power sector projects can be classified as being either on-grid or off-grid, and as addressing electricity supply or demand ("load"). On-grid projects may be further subdivided into (i) *generation* (Gx) – infrastructure that produces electricity – (ii) *transmission* (Tx) – infrastructure that moves electricity from generation to demand centers – and (iii) *distribution* (Dx) – infrastructure that delivers electricity to consumers.

MCC also engages on policy and institutional reform (PIR) as related to their power sector investments. Policy-reform includes the policies, organizations, informal norms, incentives, and relevant laws

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[1] Brandon Tracy (2013), *"Guidance for MCC Economic Analysis of Power Sector Projects"*

[2] Some important areas of overlap include such issues as: (i) defining the counterfactual (i.e., without-project) scenario; (ii) assumptions around dealing with maintenance and operations; (iii) the treatment of uncertainty, and (iv) the inclusion of induced benefits that might be important and empirically justified. Document is available at: https://www.mcc.gov/resources/doc/cost-benefit-analysis-guidelines

pertaining to the sector and the entities operating within it. Governance structures are essential determinants of sector performance[3], as are formal and informal institutions that can either impede or facilitate the furtherance of sector performance. Because the prerogatives of the national government and ministries can affect PIR in the sector, in some cases reform may even need to extend beyond the power sector[4] to be effective. The governing structure of the sector will define how the power sector policies and laws are housed, such as being located within one agency or many ministries.

Table 1 presents a taxonomy for power sector projects used in this report. Activities of a project can be categorized within the conceptual areas of the taxonomy so that subsequent analysis can benefit from past experiences and best practices in the area.

While regulation of the power sector can also be discussed within the same taxonomy, questions of regulatory quality can add further complexity. For example, the location of the regulatory body is less important than the degree of regulatory independence, and the governing structure (i.e., whether the sector is a vertically integrated monopoly owned by the government, or an unbundled value chain with an independent regulator) is thought to impact the effectiveness of sector regulation. Sector policymaking is generally recommended to be defined in an agency separate from the regulating agency, otherwise multiple interests and conflicting policies may lead to a poorly functioning power sector.

Table 1: The Power Sector taxonomy with examples of each project type.

<table>
<tr><th colspan="6">Governing Structure & Institutions</th></tr>
<tr><td rowspan="6">• Establishment or support of Independent Regulator
• Unbundling
• IPP or Dispatch framework
• Utility governance, ownership, or other institutional reforms</td><th colspan="5">Power Sector Policy</th></tr>
<tr><td rowspan="5">Support implementation of policies set by governance institutions, e.g.,
• Tariff Policy
• Differentiation Policy
• Electricity Rationing Policy
• Licensing
• Utility management reform</td><td colspan="2"></td><th>On-Grid</th><th>Off-Grid</th></tr>
<tr><th rowspan="3">Supply</th><th>Gx</th><td>• Increased Generation</td><td rowspan="3">• Isolated Generation & Mini-grids (e.g., solar, wind, small scale hydro)
• Off-grid systems (e.g., solar home systems, solar lanterns)</td></tr>
<tr><th>Tx</th><td>• Transmission system extension/rehabilitation
• Inter-regional transmission networks</td></tr>
<tr><th>Dx</th><td>• Urban/Rural Distribution Extensions</td></tr>
<tr><th>Demand</th><td colspan="2">• Appliance efficiency standards
• Subsidies and incentives for energy-efficient products
• Connection incentive programs</td><td>• Connection Incentive Programs</td></tr>
</table>

[3] Sector performance may include numerous categories of impacts, but MCC has developed common indicators for the sector that can serve as a useful starting point. The MCC common indicators for the power sector are available here: https://www.mcc.gov/resources/doc/guidance-on-common-indicators#power

[4] For example, a power sector project may need to work with the national environmental agency to reform how the country handles externalities that impact the power sector, such as in Malawi I's Environment and Natural Resources Project, or externalities the power sector may impose on the rest of the economy. Moreover, for some countries, sectors that are linked to the power sector would be regulated as part of the sector, while other countries may define the power sector more narrowly. Countries rich with hydrocarbons and/or minerals often combine the power sector with the extractives sector as such combinations are viewed as facilitating related policy design and regulation.

II. Economics of Power Networks

A. Brief Introduction to Power Economics

The purpose of this section is to provide a basic introduction to the principles underlying power sector markets that may be novel for readers coming to the sector for the first time. All technical terms are included in a glossary (ANNEX II) for ease of reference. Advanced readers may wish to skip the next two sections and continue to Section II.C instead.

The economics of the power sector result from the physical properties of the system. Power systems exhibit both economies of scale and density[5], implying that the system is a natural monopoly in the transmission and distribution subsectors. Other functions[6] of the power market may be left to competitive forces. Moreover, power cannot be stored within the system without specialized infrastructure, so any significant excess supply or demand at any point in time and at each location on the grid must be avoided. Together, these issues require the system to be actively coordinated, a role typically assigned to the transmission system operator (also referred to as the "system operator").

An electrical grid is a quantity-rationed, rather than priced-rationed, market. Managed power markets exist, typically at the wholesale level or within wholesale power pools, but the purpose of the market is mainly to provide information to the system operator for determining the "merit order" in which power is to be "dispatched"[7] from generation assets rather than to set price equal to the marginal consumer benefit. In most electricity systems, consumers are charged a tariff for each unit (usually expressed as kWh) of electricity they consume at the retail level each month, so that monthly consumption is a natural level of granularity for the sector. Bills may or may not also include fixed tariffs intended to cover the fixed costs to the utility of providing service, and tariffs for the monopoly segments of supply are typically set by government or quasi-government regulatory agencies. Because of the ways in which consumers use and pay for electricity, they may not be fully aware of the marginal benefits and costs of their own consumption, a fact that has implications for the economic valuation of power sector projects by worsening the problem of hypothetical bias in willingness to pay ("WTP") surveys.[8]

The system operator monitors technical performance of the system and dispatches generation as needed based on forecast demand and real time supply and demand conditions. If generation is insufficient to meet demand in the short term, load centers[9] must be temporarily disconnected from the system, resulting in localized blackouts (load shedding), although active demand-side management may reduce the frequency and risk of such occurrences. Even in liberalized markets, where market signals can at least

[5] Markets that exhibit economies of density benefit from cost savings resulting from spatial proximity of suppliers.

[6] For example, if generation plants are smaller than the minimum efficient scale of the system, then a well-functioning market in the generation subsector is possible. In more advanced systems, the same may be true for wholesale and retail supply, dispatch, and market operations.

[7] The dispatch merit order will be discussed later in this section.

[8] Note that, among other issues, the relative power consumption of various appliances is not understood or internalized by the consumer. However, a reasonable hypothesis is that consumers might respond to monthly price signals (billing) through trial and error. If so, this process would tend to equalize the benefits of marginal consumption and the tariff over time.

[9] In power systems, the terms "demand" and "load" are used interchangeably, despite being distinct concepts. Load refers to the work done by power delivered or consumed so that load should only be used to mean met, rather than unmet, demand and generally includes system losses.

guide new investments in generation capacity, the utility must still actively plan for new transmission lines and distribution assets to deliver power to consumers.

B. Concepts Affecting the Technical Performance of the Investment

The purpose of this section is to introduce the reader to engineering-level principles that may have an impact on the selection, due diligence, or cost-benefit analysis of projects in the power sector. This section may help the economist to better understand technical reports by providing an overview of key concepts and terminology for an economist approaching the power sector for the first time with little or no background. For ease of reference, ANNEX II.A provides a glossary of key power sector terms and concepts that may be a more convenient reference. Advanced readers may wish to skip ahead to Section II.C for a discussion of issues encountered in the cost-benefit analysis of the power sector.

i. ***Energy, Power and Consumption***:

Although often used interchangeably, energy and power are distinct concepts. Power is the flow concept associated with the stock of energy. The net injection of power—that is, generation minus consumption—into the grid at each system node (or "bus") must sum to the total system (technical) losses. That is; the grid itself can neither store a stock of energy, nor is there a stock of energy stored within the grid to draw upon without specialized infrastructure built for the purpose.[10] The system must therefore always be operated such that supply is equal to, or slightly above, demand, or else the grid will become unstable, potentially resulting in a cascading failure. In a well-functioning system, the system operator will reserve additional supply (operating reserves) so that system failure has a low probability. Most fluctuations in demand are predictable on a daily or seasonal basis, so that generation assets can be dispatched to meet the anticipated load. Since there are more consumers on a large grid, demand will be more (statistically) predictable and so such grids will generally be more stable compared to small, isolated grids such as micro- or mini-grids.

Power consumption and its associated benefits are also flow variables. However, hourly and daily variations in demand for power can be very large as households deal with changing ambient light conditions or prepare for meals and businesses open or close. Therefore, it is common to average power supply and demand over a defined period, resulting in a measure of energy over time, or average power, e.g., MWh per year. [11]

ii. ***Generation Capacity and Availability***:

Energy produced is the product of capacity, i.e., power, and utilization rate over time. [12] A capacity factor is the ratio of the total energy produced by a single power plant relative to the potential energy the asset could produce if continuously operated at maximum capacity over the same time interval. The capacity

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[10] We are discounting technologies, such as batteries or "pumped-hydro" generation, which are specifically designed to store energy as well as so-called "reactive" power that is stored on the grid in relatively small quantities.

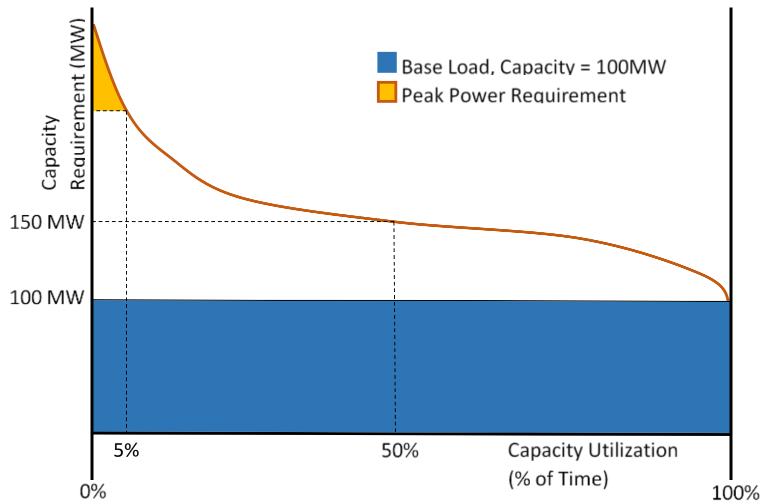
[11] Watt (W) are units of power; so that a watt-hour (Wh) is a unit of energy (1 W consumed or produced over an hour). Technically equivalent, a volt-ampere-hour (VAh) is a unit of energy used for quantifying battery capacity.

[12] I.e., total hours the generation asset is utilized in a year, divided by the hours in a year (8760).

factor is not only determined by technical considerations, but also economic issues: how often does the system operator dispatch power from this asset?

Table 1 shows a hypothetical load duration curve. The load duration curve shows power demand (MW) during every hour of a given period, ranked from highest to lowest. The purpose of the load duration curve is to relate the capacity required to meet the highest hours of demand (peak load) to the amount of time that capacity will be required. The area under the load duration curve is equal to the total energy needed to meet demand over the time interval. The base load capacity of the hypothetical system is 100 MW; this is the minimum capacity needed at all times to meet demand. Moving from right to left along this diagram, the system operator is dispatching more generation assets to meet higher levels of demand that occur at less frequent intervals.

Figure 1: Hypothetical Load Duration Curve



In conjunction with dispatch curve (discussed in more detail below), the load duration curve can be used to predict the capacity utilization of generation power plants. For example, the diagram in Figure 1 predicts that the generation asset which supplies the 151st MW of power in this hypothetical system will be utilized approximately 50% of the time, conditional on the asset's availability. Leaving aside issues of availability, this would imply that the asset has a capacity factor of 0.5. Similarly, power will be dispatched to meet peak demand (indicated by yellow area above 225 MW) about 5% of the time.

A related concept is the demand factor, which measures the actual demand over an interval of time, relative to the maximum demand in that same interval. The demand factor is higher when demand is more uniform or less "peaked." For example, the hypothetical example shown in the figure, with a peak demand of 300 MW and demand that averages a little more than 150 MW, the system demand factor is a little more than 50%.

Depending on the type of analysis, more nuanced considerations may also need to be included in the CBA model. One such consideration is the asset's availability, which indicates what percent of time, over a given period, the asset is available for production (availability factor). Due to issues such as breakdowns and maintenance, all generation assets have availability factors less than one. The capacity factor can never exceed the availability factor in practice since a power plant is not using its full capacity when it is not available. Availability is primarily a technical characteristic of the power plant (e.g., a solar panel is not available for production at night, wind power is only available when wind speed is high enough) or with a specific installation (e.g., a hydroelectric power plant that only operates during the rainy season or a pumped storage hydro plant that has finite production capacity during a given day). Improper operations and maintenance (O&M) can reduce an asset's availability factor over time.

iii. ***Transformers and Voltage***:

Electrical energy can either be delivered in the form of constant voltage (DC) power, or as sinusoidally varying (AC) power. In either case, power delivered on an instantaneous basis is given by the voltage times the current at that moment. High voltage is critical to the economic justification of transmission lines, as higher voltages can dramatically reduce losses (discussed in the next section) in the system.[13] AC systems are common in grid-applications, since voltage transformers – which function to "step-up" (or "step-down") voltage, usually at substations – do not function in DC power systems, but these systems require the grid to be synchronized over the network to within fairly narrow (+/- 5%) tolerances. DC power systems are relatively rare in grid-scale applications, although these do have niche application for transporting high voltage energy over large distances, since DC systems do not need to be synchronized with the grid.

iv. ***Planned (load shedding) and Unplanned (blackouts) Outages***:

When demand begins to outstrip supply, the system operator can remove blocks of consumers from the grid,[14] resulting in loss of electricity for customers in those blocks; this is called load shedding (or "rolling blackouts"). Load shedding is a type of planned outage that results from system planners allowing demand growth to exceed supply growth until load shedding is required to maintain stability in the network. Planned outages can also occur during maintenance cycles but are not discussed here as these are not expected to impact the economic analysis.

v. ***System Reliability and Ancillary Services***:

As discussed in the introduction, in any power system, supply must always equal the load on the system, or the system may become unstable. Reliability refers to the probability of the system performing its function adequately under the intended operating conditions.[15] Ancillary services are the group of services that are necessary to maintain reliability and guarantee delivery of electric power in an electric grid.

There are several types of ancillary services, such as operating reserves, frequency regulation, scheduling, and dispatch. Operating reserves are the most encountered ancillary services, these are the power supply that can be brought online quickly to maintain system performance.[16] Other types of ancillary services, such as scheduling or dispatch, can also serve important roles in the proper functioning of the grid.

The purpose of operating reserves is to replace generation facilities when those facilities need to be taken off-line, as for example may happen due to an accident or emergency maintenance; contingencies which may be more common if the infrastructure is failing from age or poor O&M. The main types of operating reserve are distinguished primarily by how quickly they can be brough online; frequency reserves can be

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[13] Because instantaneous power is alternating in an AC system, average power delivered over time is equal to the root-mean-square of the instantaneous power delivered adding a conversion factor of between peak power (in Volt-Amperes, VA) and average power (in Watts, W) of approximately 0.7.

[14] For example, blocks of demand can be removed at the distribution substation level by flipping a switch that shuts off part of the network, or, in systems that actively manage demand, consumers can be offered incentive payments to voluntarily remove themselves from the grid.

[15] See Prada (1999).

[16] A (non-exhaustive) list of ancillary services includes: Scheduling, System Control and Dispatch Service; Reactive Supply and Voltage Control; Regulation and Frequency Response; Energy Imbalance Service; Operating Spinning Reserve and Operating Supplemental reserve.

brought online almost instantly, spinning reserves within a few minutes, and replacement reserves within tens of minutes or longer. Most power generation technologies have a finite "ramping time" before they can generate at full capacity so that these technologies are not suitable to fill in the gap in time after a generator goes down. If generation does not fill this gap, the resulting supply-load mismatch may result in unplanned outages, or voltage collapse and a cascading system failure.

Spinning reserves are supply[17] that can be ramped up quickly to fill in the gap until cheaper sources of power provided by the replacement reserves can take over. Replacement reserves, as the name implies, replace the lost source of supply, and may use standard technologies. Recommended best practice is that the supply of both types of reserve should be sufficient to cover eventualities involving the failure of the largest generation facility during peak times; therefore, the practice is to plan for reserve capacity equal to the largest generation plant, plus some fraction of peak load.

Systems with large renewable supplies should plan for greater reserve capacity because of the intermittent nature of most sources of renewable power. The cost of the expanded reserve capacity is an additional burden that renewable technologies impose on the grid.

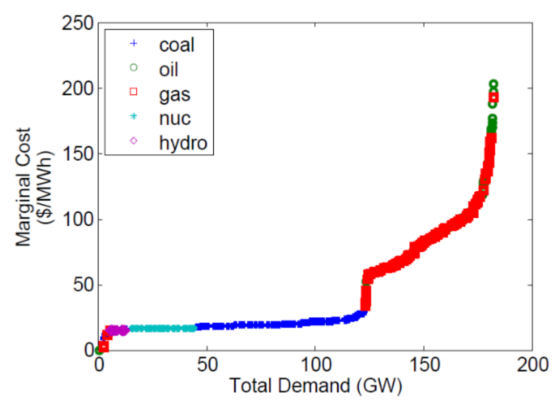
C. Concepts affecting the Economic Valuation of the Investment

i. ***Merit Order, Dispatch and Marginal Generation***:

The merit order is a ranking of energy sources by order of increasing price, although other factors such as security and pollution may also be considered. To minimize production costs and maintain balance in the system, the system operator will dispatch power according to the dispatch merit order, so that the utility is utilizing the cheapest energy first.

A dispatch curve (Figure 2 shows an example of a dispatch curve using US data[18]) is used to illustrate the merit order as demand increases. The dispatch curve relates the variable cost of operating each generation power plant to the level of demand at which the power plant is dispatched. The variable cost of the generation asset is the opportunity cost of meeting that demand on the margin, assuming that the system operator is indeed dispatching power according to the least-cost merit order ranking.[19] Generation assets on the left side of the dispatch curve are the first assets to be dispatched. The last power plant to be dispatched in this way is referred to as the marginal generation. The

Figure 2: Example of a dispatch curve.



[17] Technologies which might be used for spinning reserves include simple-cycle natural gas, heavy fuel oil, hydropower and, recently, battery technologies. Combined cycle gas facilities do not generally ramp up quickly enough to be useful as spinning reserves.

[18] Curtesy of Eric Hittinger (*DevTech Systems, Inc.*), MCC Power Training Program, 2016

[19] In systems in which MCC may invest, this assumption may no longer be appropriate. For example, if the system operator is the vertically integrated utility, then it is possible that the system operator will prefer to dispatch power from the generation assets owned by the utility, regardless of relative cost of privately-owned generation.

variable cost of the marginal generation is the system marginal cost, so that the dispatch curve is the short-run supply curve.[20]

ii. ***Load Shedding***:

The economic benefit of reduced load shedding is increased electricity consumption for affected consumers. Therefore, economic analysis of power sector investments that are expected to relieve load shedding should only attribute benefits to reduced load shedding if total consumption in the system increases. The common solution to load shedding is to increase generation capacity or reduce transmission bottlenecks, and the benefits of such an increase in capacity are captured when the new power is valued at its cheapest substitute, or "coping cost"[21]; otherwise including benefits attributable to reduced load shedding could result in double counting.

However, if load shedding is unanticipated or sufficiently large, consumption may be taking place at a lower marginal economic benefit[22], so that a reduction in load shedding can imply higher willingness to pay for marginal electricity consumption than implied by energy substitutes alone.[23,24] In a typical project, benefits from reduced load shedding in excess of coping costs are expected to be negligible, but the benefits associated with reducing *unplanned* – or *unannounced* – outages can be much larger than *planned* outages, as an unexpected loss of power can disrupt economic activities or cause property damage. Valuing reductions in unplanned outages is the subject of the section on system reliability.

iii. ***System and Technical Losses***:

Total system losses are classified into technical losses and non-technical (or commercial) losses. A reasonable benchmark for a well-functioning utility in a developing country is for total system losses to be around 10-12%.[25] These losses can occur within either the transmission or distribution systems. Technical losses are attributable to energy consumed (i.e., lost) by the physical assets of the network. Technical losses are inevitable in any electrical system, however, in a well-functioning system such as in the US losses average around 5% of the energy transmitted and distributed through the network.[26] Technical losses exceeding this level occur in less developed systems and stem from malfunctioning or inappropriate equipment, or inappropriate use of existing equipment. Inappropriate equipment may include outdated materials with properties that result in losses that are higher than losses that would result from a failure to utilize more modern materials, assets sized for one application but used beyond their rated capacities (e.g., excessive load on transmission lines), assets that have not been maintained, or assets appropriate for base load power but not for intermittent power sources (e.g., wind).

Technical losses inevitably result in heat which can damage equipment in extreme situations or over prolonged periods. Most equipment will have finite heat tolerance that limits the device's engineering capacity rating. For this reason, each system component can sustain no more than some maximum level

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[20] Setting aside availability

[21] Questions regarding coping costs should be included in a well-designed revealed willingness-to-pay survey.

[22] For example, because household tasks must be completed late at night when power is available.

[23] As discussed in the WTP section (Section V.A), one complication is that the cost of near substitutes only captures a financial WTP which underestimates economic WTP.

[24] Energy substitutes are discussed in more detail below.

[25] See Kojima & Trimble (2016) or Jimenez, Serebrisky, & Mercado (2014).

[26] See https://www.eia.gov/electricity/state/ for the performance characteristics of the US grid.

of technical losses before damage becomes catastrophic. High voltage transmission lines, which may sag and fail, can be especially susceptible on hot days.[27] While there is no theoretical maximum level for system technical losses, in practice technical losses exceeding 20% are an indication of problems with the status or operation of system equipment.[28]

If there is no excess demand in the system,[29] then reducing technical losses results in slightly less dispatched power to meet load. Assuming that load is being met, the benefit should therefore be valued at the system marginal cost (usually equal to the variable cost of the marginal generation as discussed above). In practice, since the system marginal cost changes over time, a time-averaged version of the system marginal cost derived from the dispatch curve would be appropriate in this context. If there is a supply constraint, such that load is not being met (load shedding), the opportunity cost of technical losses is especially high: In this case, the benefit of reduced losses is the area under the demand curve,[30] since the cost of delivery has already been counted in the counterfactual.

iv. ***Non-technical (commercial) Losses*:**

Non-technical losses aggregate any loss associated with lack of revenue collection for consumed energy, typically resulting from theft, or inability to pay, or inability to collect revenue from certain classes of consumers (sometimes referred to as "collections losses"), such as government entities. Most Losses occur at the distribution (low voltage) level. Pilferage from the transmission (high voltage) level would be very dangerous so that commercial losses at the transmission level can typically be assumed to be quite small. Some relatively large institutional consumers, such as the government, may be responsible for large arrears, although these also will usually accrue at the distribution level.

Technical losses can be distinguished from non-technical losses using simple equipment, although identifying the source of pilferage may be more difficult. However, many power systems in MCC partner countries lack such equipment as well as the managerial capacity to track down the source of these losses, leading to situations in which commercial losses are misattributed as technical losses. Since power associated with commercial losses is consumed by end-users, commercial losses should be valued as consumption—to first order,[31] payment of tariffs is merely a transfer from paying consumers to non-

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[27] When the environment is adding heat to equipment, the system must generally be operated at a lower capacity. The Northeast Blackout of 2003 was caused by a transmission line overheating due a software glitch.

[28] If 20% of power is being lost as heat, then it is likely that some component of the system is running close to or above its designated heat-tolerance limit.

[29] As the power sector is a quantity-rationed market, it must be either demand-constrained ($D < S$) or supply-constrained ($S < D$). However, note that a country that has an identified binding constraint in the power sector is less likely to have an excess demand for power.

[30] In situations where the behavioral response can be ignored – for example, when the change in available supply is small compared to current consumption – the area under the demand curve is approximately equal to the willingness-to-pay. This assumption is likely to hold when the only change is a reduction in technical losses.

[31] Throughout the text, "first order" refers to the linearized dynamics of the system, in this example, relative to changes in price. This terminology has its origin in the Taylor Series expansion so that second order is the quadratic term, third order cubic, and so on. The unstated assumption is that corrections from higher-order terms should be "small" in a well-defined sense.

paying consumers[32]—so correct attribution of system losses as either technical or commercial losses can impact the economic analysis. Note that the counterfactual for reducing commercial losses involves a utility that is starved of funds. Such a utility must either receive funds from another source or must eventually disinvest in either maintenance or system expansion, resulting in deteriorating service provision. The economist should work with sector experts to identify evidence for the 'current behavior' of the utility and policy makers to determine the exact form for the counterfactual to take.

v. ***Cost-Reflective Tariff*:**

The opportunity cost for delivering power is a complex problem which may involve significant detective work on the part of the economist. Electrical power systems are integrated value chains for the delivery of power services to customers, which tend to exhibit significant increasing returns to scale technology.[33] Because the average cost of delivering power declines as the quantity of delivered energy increases, the average system cost tends to be bounded above the marginal cost, i.e., a policy of setting price equal to the marginal cost would require significant subsidies to implement sustainably.

To incorporate funding needed for the relatively large, fixed costs necessary to achieve assumed levels of service delivery, economists and policymakers use the concept of a cost-reflective tariff ("CRT"), which is not necessarily equal to the statutory tariff actually paid by consumers. Instead, consumers that pay the statutory tariff for power are beneficiaries of a transfer payment from the utility—and ultimately from taxpayers—in an amount equal to the difference. A too-low (high) statutory tariff implies over- (under-) consumption and therefore a dead-weight loss, which can be valued using standard methods from welfare theory. The economic analysis of underpricing is discussed in more detail in Section II.D.

vi. ***Value of System Reliability and Consumer Damage Function*:**

The valuation of ancillary services, such as reserve margin or spinning reserves, is not straightforward. Improvements in reliability must be understood in terms of insurance or option values that can be much larger than the value of the energy itself. As Prada (1999) observes:

> *The valuation of capacity reserves is less straightforward than the valuation of energy… spare capacity is not a consumable good as is electric energy… capacity reserves [provide] a hedge against the contingency of not having enough generation available to meet demand.*

A determination of the consumer costs associated with supply interruptions can be estimated using a Consumer Damage Function (CDF), which is an estimate of the insurance value to consumers of improved

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[32] There are several contingent benefits which can also be attributed to reductions in commercial losses. Since commercial losses directly impact the utility's financial health, over time reduced commercial losses may impact system stability and expansion, by facilitating investment from the utility. Also, non-paying consumers are likely to overconsume power relative to paying consumers, so that they are consuming at a lower marginal benefit; this implies that there is a reduction in deadweight loss associated with the reduction of commercial losses.

[33] For the purposes of this note, increasing returns technology is functionally identical to a system having a declining average cost curve at the scale of interest, where the scale of interest is the maximum load on the network. Primarily this is a consequence of the need for transmission and distribution infrastructure to deliver power. In large power systems, the minimum efficient scale for generation is typically many times larger than the capacity of a single generator; for example, the largest power generator in the world is the Three Gorges Dam in China, with a capacity of 22.5 GW, or about 2% of the total capacity of China's grid (estimated at about 1,250 GW in 2013, the first year of operation).

reliability. The CDF is a function of both frequency and duration of interruptions that consumers experience that can be measured, for example, using common indices of system reliability such as SAIDI and SAIFI. Unfortunately, sufficient outage data needed to estimate a CDF from first principles are unlikely to be available in developing country contexts, so that this guidance recommends fitting the shape of the CDF using available data from the US and the magnitude of the CDF using several questions added[34] to an otherwise standard willingness-to-pay study. Section II.D further discusses the use of Consumer Damage Functions to value system reliability. ANNEX IV provides additional details for estimating the CDF in a developing country context.

D. Approaches to Benefits Valuations

As in other sectors, the economic analysis of the power sector depends on the methods used for the economic valuation of the technical performance of the system. For the valuation of social or economic benefits not directly tied to the technical performance of power systems, the reader should refer to other guidance documents.

The valuation should be equal to the true social opportunity cost associated with the constraint that the project is intended to relieve. When investments in the power sector are made, regardless of whether these investments are in the generation (Gx), transmission (Tx), or distribution (Dx) subsectors, the result of the investment is to increase the supply of power in the system (Gx) or to deliver power that is otherwise being produced (Tx or Dx) to new and existing consumers. Reform activities, discussed in more detail in Section III, can accomplish similar goals by helping the utility to use existing assets more effectively.

Figure 3: Simplified theory of change for power sector projects. *Adapted from MCC's Common Indicators, 2016*.

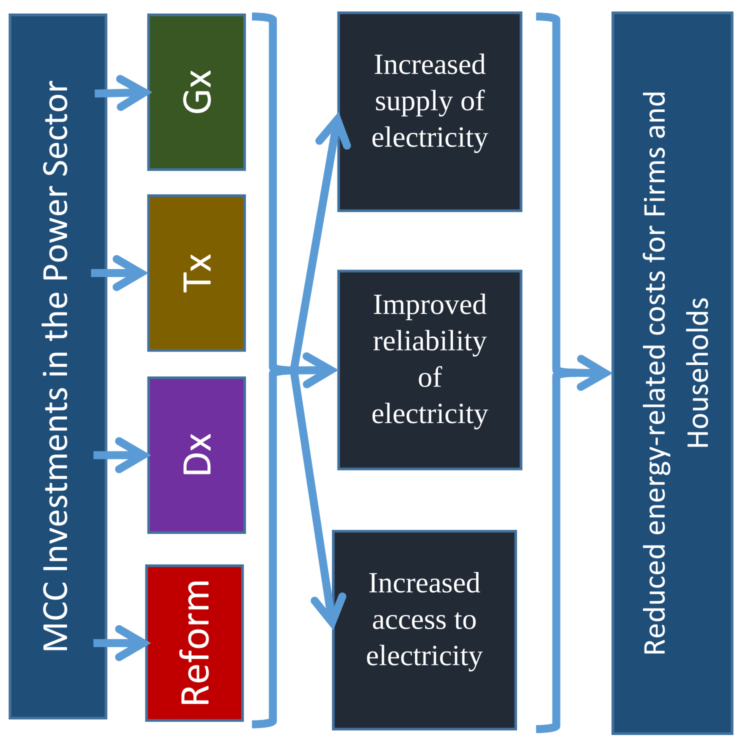

Figure 3 illustrates a simplified theory of change for power sector investments. Regardless of the nature of the investment, the result is generically (i) more power supplied to existing consumers, (ii) improved reliability of the power supply for existing consumers (for reasons discussed in Section II.A), or (iii) access to electricity for new consumers. As the basic use of electricity is to provide power to do useful work, the benefits that are ultimately derived from improved electricity provision must either (i) lower the economic cost of accomplishing work that would

[34] For example, a willingness to pay survey can include questions such as the timing, duration, and damages associated with the ***most recent*** unanticipated outage. Then the economist can deflate these self-reported damages using the CDF shape factors in the ANNEX and compute a simple average.

Table 2: Summary of Common Benefits and Costs by Project Type.[35] *Source: MCC Staff*

	Benefits					
Investment	Energy Substitution	Supply-side Cost Reductions	Increased Value-Added	Reduced Dead-Weight Loss	Reliability	Education, Health, & Environment
Generation	Y	Y	I		I	I
Transmission	Y	I			I	I
Distribution	Y		I		I	I
Sector Reform	Y		I	I	I	I
Demand-Side Management	Y		I	Y	I	I
Appliance Subsidies	Y		Y			I
Mini grids (Gx or Dx)	Y		Y			Y

	Costs					
Investment	Physical Assets	Consulting Services	Contingent Costs	Connection Fees	Consumer Costs	User Assets
Generation	Y	Y	I			
Transmission	Y	Y	I			
Distribution	Y	Y		Y		I
Sector Reform	I	Y				
Demand-Side Management		Y			I	Y
Appliances	Y	Y			Y	Y
Mini grids (Gx or Dx)	Y	Y		Y	Y	Y

"Y": Default is to always include
"I": Default is to provide argument for inclusion or exclusion
" ": Default is to exclude

otherwise be completed using other means (e.g., lighting), or (ii) allowing new forms of useful work (e.g., new "productive uses"). The former case is by far the more common category for conducting an economic analysis of the power sector.

Assessments of opportunity costs in the power sector are somewhat complicated by the managed nature of the market. Power is a quantity rationed market in which prices rarely reflect the true opportunity cost of production. Since the sector requires active management and planning, the economist must first determine whether the sector is demand or supply constrained; the determination of which can affect either the identification of the counterfactual—and hence the technical benefits—or the valuation of those benefits. Table 2 summarizes common benefits and costs in power sector projects, with each benefit or cost category in this table further explained in the subsections that follow. A typical project will include several of these benefit or cost categories, and this table is not intended to be comprehensive

[35] Refer to the text of this section (Section II.D) for the explanations of these table entries.

i. ***Energy Substitution*:**

The most common benefit stream in the power sector arises from substituting lower cost electricity for higher cost energy sources. To some extent this may be due to price reductions, but often it is due to the cost savings associated with substituting for diesel or gas generators, candles or kerosene lamps, or other more costly forms of energy. The economic benefits of the substitution of electricity for other energy sources are typically valued using the consumer's revealed willingness to pay (WTP) for the closest substitute. Methods for elicitation of WTP will be discussed in the following sections.

While the calculation of this benefit stream is straightforward, defining the approach to estimating a consumer's WTP can be difficult, as can be determining the full cost-reflective tariff (i.e., economic opportunity cost of electricity) that should be used in place of the price of electricity. For example, in a scenario where supply is constrained and the investment is only partially expected to relieve the constraint, a project may target the substitution of electricity-based lighting for the previously used kerosene lamps at the household level. The benefit stream would value the electricity-based lighting at the household's WTP for lighting, in this case determined by the observed costs of kerosene lighting. The benefit stream would then be the area between the demand curve (based on WTP estimates) and the cost-reflective tariff, for each unit of energy or lighting consumed. This approach is valid when the increment in electricity consumption is small compared to total consumption, so that the shape of the demand curve can be ignored.

ii. ***Supply-side Cost Reductions*:**

The electrical power market is a quantity-rationed, rather than price-rationed, market. That is, price is essentially fixed in this market, so the system operator must adjust quantity supplied to balance supply and demand. The market clears at a quantity equal to the lesser of the quantity supplied or demanded. This leads to two cases: If available ("dispatchable") supply exceeds demand, then the system is "demand-constrained"; otherwise, the system is "supply-constrained." For completeness, both cases are discussed below, although the supply-constrained case should be more typical for MCC countries that have an identified binding constraint in the power sector.

Demand-constrained case: A well-functioning electricity market will have sufficient reserves (i.e., supply) to meet most contingencies and so will be devoid of excess, or unmet, demand. In this case, investments in the power sector may result in the reduction of the economic cost of electricity, and subsequently, its market price. In this case, the benefits of the investment can be calculated using a standard consumer surplus approach with an appropriate demand curve.[36] For example, if an investment in new sub-stations greatly reduces transmission losses, the utility may be able to lower electricity tariffs. Independent of whether this price decrease results in increased consumption of electricity, a consumer surplus[37] analysis can be used to determine the benefits of the project to the consumer. Cost-reflective tariffs should be

[36] For small changes in prices, standard Marshallian demand can be assumed. However, for large changes in price, (Slutsky) substitution effects must be considered. Additional context regarding appropriate demand curves is discussed in Section IV.A.

[37] Methods to elicit WTP will naturally yield the Hicksian compensated and equivalent variation measures of consumer benefit. However, if the income elasticity is not too large, standard consumer surplus will be a reasonable approximation. See Willig (1976). These issues are discussed in further detail in ANNEX III.

used for this analysis,[38] as any difference between the cost-reflective level and actual tariffs reflects a transfer payment to or from consumers (to first order). Alternatively, if the market price does not change as a result of the reduction of the economic cost of electricity—as noted elsewhere, prices in the electricity sector are not generally set in the marketplace, although there may be market-based systems to inform prices and markets for close substitutes—the benefit can be estimated as the incremental cost savings per unit of technical performance. For example, returning to the substation example above, if the utility does not change the statutory tariff—implying that there is zero demand response to the cost saving investment—then the benefit of the investment is the variable cost of marginal generation since it does not need to be dispatched in this case.

Supply-constrained case: If, on the other hand, the electricity market is not a well-functioning market (hence, supply-constrained), as often the case in most MCC compact countries, then the benefits of reduced economic cost of production must come in the form of reduced deadweight loss as discussed below and, if applicable, increased consumer surplus through increased supply delivered to consumers.

Operational efficiency improvements can be valued in a similar manner as above for the supply- or demand-constrained cases, as appropriate. Such improvements can be associated with reduced operating costs for the utility. In theory, the reduced operating costs would lower the true cost-reflective tariff to the point where the decrease in revenue would equal the increased saving from the efficiency improvements. One important example of such benefits is the improvement in the efficiency of dispatch, a type of ancillary service that can be valued as the difference between the counterfactual and with-project marginal cost of dispatch. In practice, such efficiency improvements can be calculated from technical studies. This benefit stream can be captured through either approach, as the situation allows.[39]

iii. ***Increased Value-Added*:**

A reduction in the cost of energy will often result in production efficiency improvements for affected businesses, resulting in an increase in the difference between the value of a firm's inputs and its outputs, or value-added. For example, targeted investments may attempt to increase value-added, which may generate employment or put upward pressure on wages. Analogously, investments may reduce costs for households, increasing disposable income in much the same way as the situation discussed above in the energy substitution section. Many demand-side investments target cost reductions, and thus fall into this category. When projects include a power sector investment, the analysis may be conducted at a high level of cost aggregation, leaving the costs of the energy inputs hidden. In such cases the project may be viewed as one that is not a power sector project. However, if the level of analysis permits the analysis of input costs, the analysis would follow in the same fashion as the Energy Substitution analysis. For example, if an agriculture investment targets higher value-added products through irrigation, and if the irrigation system includes an isolated solar system, the analysis could be conducted using data that postulate expected costs and benefits based on similar irrigations projects. In this case, no specific consideration would be required regarding the power sector aspect of the project. However, if the analysis aims to provide detailed costs and benefits of the project, and it aims to elaborate the rationale for selecting a

[38] If the level of the cost-reflective tariff is not known, this guidance recommends funding a cost-of-service study as soon as possible during Compact development to provide this information.

[39] For example, as an expected result of reduced losses in the transmission system. For the Malawi transmission project these benefits were valued at the assumed operations and maintenance costs for a hydroelectric power plant, as actual operating and maintenance data were not available.

solar pump over a diesel pump or grid extension, then the project could be additionally viewed as one in the power sector. The net benefits leading to the selection of the solar pump over the diesel pump may stem from identical benefits provided by the equivalent systems, but with the solar pump incurring lower costs than the diesel system.

As such, care should be taken to exclude demand multiplier effects, defined as the effects on other output markets from higher incomes of producers enjoying access to improved power supply. Moreover, any assumed increases in productivity, profits, or labor market incomes resulting from increased investment in the economy would require careful empirical justification and calibration in the specific context, for example such a justification was used in the analysis of the Ghana II compact using cross-country data on disruptions to the electricity supply and GDP growth. For the treatment of other induced benefits, the economist should follow the related guidance.

Increasing value-added is an alternative to the consumer surplus approach for valuation of benefits, the two approaches will yield similar estimates for profit maximizing firms and including both measures for the same beneficiaries will result in double-counting, especially if demand multiplier effects are present in the model. A value-added approach is most suitable for valuing so-called “productive uses” of electricity.

iv. ***Reduced Deadweight Losses (DWL):***

When tariffs are set below the cost recovery level of service delivery, it follows those consumers are being subsidized in some way, resulting in the marginal benefit of consumption exceeding cost. To first order, such subsidies are transfer payments from the utility to customers[40] and so do not represent an economic cost. However, there are second order benefits from reducing these subsidies.[41] Affected consumers will tend to overconsume electricity by an approximate amount equal to $\varepsilon(CRT - t)$, where t is the effective tariff, CRT is the cost-reflective tariff and ε is the price elasticity of demand. The approximate deadweight loss implied by underpricing of electricity is then,

$$DWL\ per\ consumer = \frac{1}{2}\varepsilon(CRT - t)^2. \tag{1}$$

Which assumes a linear demand response over the relevant price discrepancy range. An exact expression for the DWL requires that the economist assume a shape for the demand curve but is an otherwise straightforward calculation.

A special case is when there is electricity pilferage (i.e., commercial losses). Non-paying customers are also likely to over-consume electricity, with the implicit subsidy falling on the utility and paying customers, implying that reducing commercial losses can result in decreased deadweight loss. If the (direct) consumer cost of pilfered electricity is assumed to be zero, then the approximate deadweight loss is equal to:

[40] Note that a budget neutral tariff restructuring would not change the cost-reflective tariff, by construction. If offsetting social benefits of cross-subsidizing consumer groups are thought to exist within the context of the program, these benefits would likely have to fall into one of the alternative categories listed in this section (for example, as benefits related to education, health, or environmental externalities among other possibilities). However, the change in deadweight loss would still be an economic cost of such a strategy.

[41] First order and second order refer to the Taylor series approximation. For benefits which are not “small” in the sense of convergence of the Taylor expansion, second order benefits could be larger than first order benefits.

$$DWL\ per\ consumer = \frac{1}{2}\varepsilon CRT^2 \qquad (2)$$

Deadweight loss is a lower bound on the potential benefits of improved collections[42] if such revenue shortfalls so implied results in suboptimal operations and maintenance, or if such shortfall undermine the credibility of the utility as an off-taker for independent power producers. While the relationship between the utility's financial health and its maintenance and investment decisions need not be simple, the implied liabilities which are likely to result from the shortfall will tend to accumulate over time.

v. ***Reduction of Supply Disruptions or Improvements in Supply Reliability*:**

If a utility provides unstable or intermittent power, then consumers may experience additional costs because of the disruptions even if total consumption and prices are not affected. In the extreme case, equipment tied to the grid may experience damage. In these cases, value determined by energy substitution alone may not capture the benefits from improved system stability. Anticipated load-shedding is the simplest case of a supply disruption.

Traditionally, valuation of system reliability has proceeded by first estimating the energy that does not reach customers that would otherwise be delivered. This approach can be separated into two components: reduced number of disruptions events and reductions in "Loss of Energy Delivered in Expectation" (LOEE). The resulting measure is referred to as Energy Not Supplied (ENS or Energy Not Delivered, END) and is typically estimated as the difference between average consumption and actual consumption that has been constrained by the supply disruption. END is valued by the Value of Lost Load ("VOLL"),[43] which is much larger than standard WTP measures.[44] This methodology, while standard for regulators, is not acceptable[45] for a rigorous cost-benefit analysis. First, VOLL has rarely been measured, values typically used having been sourced from a single 40-year-old study in Finland (Kariuki and Allen (1996)). Second, the poorly defined counterfactual from which END is defined is suitable to estimate an upper bound but will tend to overestimate consumer benefits; Kariuki and Allen (1996) suggest that overestimating benefits using END and VOLL is an attractive feature of this methodology for regulators.

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[42] Recall that a system funded partly or wholly through explicit subsidies would not necessarily be inefficient in the sense discussed in this section, as the subsidies should be counted in the calculation of the cost-reflective tariff, although, as noted, subsidies will tend to result in deadweight loss through over-consumption.

[43] See, for example, Prada (1999) for a good introduction to the technical and economic issues related to the benefits of system stability. This guidance does not, however, recommend the approach to the economic valuation advocated in this report which fails to account for the inframarginal nature of lost energy delivered when disruptions are unanticipated.

[44] See, for example, Schroder and Kuckshinrichs (2015).

[45] As noted by Kariuki and Allan (1996), VOLL has numerous fatal flaws from an economic analysis perspective. First, VOLL was first estimated from a single 1977 Finnish study that was indexed to inflation in 1989 and has otherwise been left unchanged. Second, after more than 40 years of use, numerous technical flaws with the measure have been identified and have yet to be incorporated into the methodology or standard estimates.

In particular, (i) there is no theoretical or functional relationship between ENS and VOLL so that VOLL cannot be a measure of the value of reductions to ENS; (ii) VOLL is affected by local context, including issues related to climactic conditions, load mix, availability of alternative energy sources, and customer harms; and finally (iii) VOLL is impacted by factors relating to the time and circumstances of the counterfactual consumption, such as duration of the interruption, whether or not the disruption was anticipated by consumers, and the time of year.

A better approach to valuation of system reliability is to estimate a customer damage function ("CDF") that can be estimated, in principle, from customer's self-reported damage resulting from outages, the data for which can be collected within a standard willingness to pay study. Note that VOLL is not related to the CDF but should be roughly similar in magnitude to the maximum of the CDF if measured in identical contexts.

The losses for the system are then the sum over the losses for all customers, and the economic cost of outages over the course of a year would be the result over all outages in that year. Such "outage studies" have been conducted in several developed countries, although unfortunately, few have been conducted in developing country contexts (ANNEX IV.B discusses an approach to estimating the CDF without data from an outage study by supplementing a WTP study with several short reliability questions). Following Sullivan and Keane (1995), the basic form for a single customer's CDF is:

$$Loss = f\{interruption\ attributes, customer\ charateristics, environment\} \qquad (3)$$

Where,

- *Interruption attributes* are factors such as duration of the interruption, time of day, week, or season, and whether the outage was anticipated.
- *Customer characteristics* are factors such as, type of customer, size of the business, hours of operation, presence of interruption-sensitive equipment, and presence of back-up equipment.
- *Environment* includes factors such as climate and weather.

As defined here, the CDF embodies the benefits of improved system reliability *in addition to* the benefits of consuming more electricity. This means that great care must be taken when estimating the CDF to avoid double-counting in the form of customers simply consuming more electricity. For the specific case of reductions in load-shedding, the primary benefit of which is that customers may consume more power, the loss function is generally expected to be small and can likely be ignored without affecting the integrity of the CBA. Approaches to estimating a CDF will be discussed in the next section, and in ANNEX IV.B.

For a system with sufficient reserve capacity, the opportunity cost of a supply disruption is related to the marginal cost of the marginal reserve generator. The economic analysis of investments to limit supply disruptions, however, are related to the willingness or obligation of the system operator to hold supply in reserve to insure against such disruptions. An independent system operator seeking to maximize the public good would invest in reserve capacity or ancillary services if the social cost of supply disruptions prevented are greater than the opportunity cost of maintaining the incremental reserve capacity. As discussed in the previous section, the social cost of supply disruptions can be encoded in the Consumer Damage Function (CDF).

As a result of the non-determinant, stochastic nature of supply disruptions, the benefits of reducing these disruptions are best captured by the insurance or option value benefit to consumers and the utility[46] of increased reliability. When estimating this benefit, great care needs to be taken not to double count

[46] If the utility is forced to shed load because of poor reliability, then it suffers from lost sales.

consumer coping costs.[47] As discussed in Section II.C, the opportunity cost of this type of supply disruption is far greater than the marginal cost of foregone consumption, especially when the disruption is unanticipated and short duration. A more economic perspective is that the cost of investing in marginal reliability improvements should be balanced by the benefits, for both consumers and the utility, to system reliability.

On the other hand, in the context of supply-constrained systems such as in many MCC countries with energy infrastructure constraints, disruptions in supply will often be balanced through load-shedding. If load-shedding is anticipated, much of the foregone consumption will be shifted to different times, if possible, or will likely be close to the marginal consumption. For unanticipated disruptions in which reserve capacity cannot be dispatched, foregone consumption will likely occur at a higher marginal benefit (the foregone consumption is inframarginal). For this reason, the CDF for anticipated load-shedding will be close to the value of marginal consumption, while the CDF for an unanticipated disruption may be much higher.

For example, household production could suffer if appliances must be run during the early morning or late at nights, to avoid outages. Likewise, businesses may be forced to pay idle employees while equipment is not operating. These costs cannot be easily captured by standard methods[48] which rely on direct or indirect market transactions.

While outage studies in the US and other developed countries have been used to estimate CDFs, there have been few, if any, studies attempting to measure the CDF in developing country contexts where the presumption[49] is that these benefits will not be as high.

If the economist attempts to measure the CDF by, for example, utilizing a stated-WTP approach, the approach needs to be tailored to the specific factor influencing the relative social cost of power interruptions; for example, an interruption which is announced several days in advance will likely be less costly than an interruption which is completely unannounced. Table 3 lists some common factors influencing the social cost of an interruption.

Table 3: Factors Influencing Social Cost of Power Supply Interruptions

Technical Factors	Load-side Factors	Socioeconomic Factors
• Duration • Region • Frequency • Time of Day • Seasonality	• Type of Customer • Number of Customers Affected • Customer's dependence on electricity	• Disruption of Social and Cultural Events • Impacts on Marginalized or Vulnerable Groups

[47] See Section II.C for a discussion of coping costs. Coping strategies for supply disruptions may include technologies such as batteries and capacitor banks. These strategies are unlikely to fully offset the costs of a supply disruption, but may mitigate some of the worst effects, such as equipment damage.

[48] The market for power stability may be missing or incomplete. However, expenditures on batteries, flywheels or other power storage technologies may be interpreted as revealed-WTP to transact this market—these technologies insure the consumer against certain types of shocks to system stability. Therefore, to avoid double-counting, great care should be taken before utilizing non-standard methods (e.g., stated-WTP) for this type of benefit.

[49] For two reasons, (1) the opportunity cost of worker's time is lower in developing country contexts, and (2) the value of capital-at-risk is lower as well. Capital-at-risk is expected to be lower both because the capital depth is less and because surviving firms have likely adapted to the poor quality of electricity supply.

• Advanced Warning • Accustomed level of Supply Security	• Degree to which manufacturing process steps can be substituted with human effort • Existence of Standby Power

Source: adapted from Schroder and Kuckshinrichs (2015).

Generally, cost-benefit analysis of improvements to system reliability will focus only on the technical attributes of the interruptions themselves. Moreover, over the course of a CBA's time horizon, which is likely to be at least 20 years and perhaps longer, the impact from the customer characteristics and weather, as well as time of day, week, and season will be averaged over. Such factors will therefore generally result in multiplicative factors that are unique to, but constant, for a given system. Recognizing that the customer losses that result from a momentary outage (e.g., equipment damage) and prolonged outages (e.g., wages for idle workers or product spoilage) are different, this guidance recommends further simplifying the CDF by assuming that these two factors are additively separatable. Therefore, if f is the frequency of outages and d is the duration of each outage, we can write the CDF for the system as:

$$Loss\left(f_{i,c}, d_{i,c}\right) = \sum_{i \in \{\,outages\}} \sum_{c \in \{consumers\}} \left\{ \begin{pmatrix} Fixed \\ Costs \\ per\ i \end{pmatrix} f_c + \begin{pmatrix} Ave.Cost \\ per\ unit \\ time \end{pmatrix} d_{i,c} \right\} \tag{4}$$

For households, the willingness to pay for counterfactual electricity consumption (i.e., without interruptions) should be a good approximation[50] for the average cost per unit time if consumers anticipate the outages and the outages are not unusually long. For this reason, the economist may wish to further simplify the model for the household CDF in terms of the frequency of outages keeping constant the duration per outage, thus leading to a CDF that is proportional to f, or equivalently, the CDF can be rearranged as a function of total duration only. This assumption is useful as it allows the economist to estimate the benefits of system reliability using standard survey approaches (such as revealed and stated preference methodologies) by triangulating the benefits[51] to reliability. This approach was used by both MCC and also the World Bank[52] to estimate benefits of system reliability in Nepal which suffered at the time of the analysis from frequent, long-duration, but widely anticipated outages[53] in the form of load-shedding.

The methodology outlined above will tend to underestimate the loss function for firms, since firms are more susceptible to incurring additional costs as a result of unexpected outages than households, in the

[50] As discussed in Section II.B "*System Reliability and Ancillary Services*", consumers may be forced to consume electricity at a lower marginal benefit, but the difference with the counterfactual case will typically be small.

[51] The basic approach is to take the revealed preference results as the willingness-to-pay given the status quo of system reliability. Stated preference techniques can then be used to identify the benefits of a 50% reduction in outages and 100% reduction in outages. The benefit of system reliability is the excess of the stated preference at 100% reduction over what would have been expected given the 50% reduction, i.e.

$$WTP_{Reliabilty} = WTP_{S,100\%} - 2\left(WTP_{S,50\%} - WTP_{Revealed}\right) - WTP_{Revealed}$$

This benefit would then apply proportionately to the reduction in the frequency or total duration of the outages. Note that the result should always be weakly positive, within the margin of error.

[52] See Alberini, Steinbuks, and Timilsina (2020)

[53] Note that the assumptions outlined here for the CDF would, under these conditions, predict a relatively small value for the loss function. This is consistent with the findings of both studies.

form of lost production, employee overhead costs, and damage to equipment. Furthermore, the magnitude of these costs will tend to scale with the size of the firm, with a high degree of heterogeneity between industries. Only when an economy has fully adjusted to the equilibrium of poor electrical system reliability, that is, after susceptible firms have been driven out of the market, is the household approximation valid for estimating the firms' CDF. This presents a challenge for the economist, given the scarcity of high-quality outage studies in developing countries.

ANNEX IV.B presents the recommended approach for projects in which large benefits are expected from improved system stability. Sullivan et al. (2009) aggregate 24 outage studies in the US to estimate the loss function for US firms and households under a wide variety of variables. The guidance recommends using these data but deflating the terms using survey data collected in the country of interest.

vii. ***Health and Education Externalities*:**

When an investment is expected to reduce household health expenditures, reduce lost income due to health issues, or increase wages through greater education attainment, related benefit streams are typically included in the analysis. As investments in the power sector typically do not focus on health and education outcomes directly, including related benefit streams can lead to concerns of plausibility and double counting. The economist should use discretion when deciding to include benefit streams which are expected to be small, or which rely on a thin basis for evidence. While health and education benefit streams likely exist for many investments, including power sector investments, problems associated with estimating very small benefits over very long timeframes may motivate their exclusion, although exceptions do exist, such as power needed to support a cold chain for vaccine distribution. Regardless, the economist's default assumption should be that these benefits should not be included unless presented in the theory of change and supported by evidence. For example, rural electrification projects often target the reduction of indoor air pollution and the provision of lighting for education purposes, in which case health and education benefits are possible. Generation and transmission investments are much less likely to significantly alter consumer access to electricity may therefore exclude health and education externalities as relatively small compared to the consumer surplus. The valuation of health and education benefits should be consistent with MCC guidance for these sectors, respectively. For all models, the economist preparing the analysis must defend the choice to include or exclude these benefit streams.

viii. ***Environmental Externalities*:**

When power sector investments are partly or in whole motivated by concern for environmental impacts, the economist should consider the inclusion of environmental externalities in the analysis, although the economist should follow MCC's guidelines for the economic analysis of environmental externalities whenever the cost-benefit analysis includes these issues. Environmental externalities may be more complex to analyze than health and education externalities; environmental damage may include non-use values and many forms of pollution may seep across national borders. It is somewhat controversial to treat non-use benefits as economic benefits at all[54], but additionally MCC's mandate focusing on economic growth creates a strong bias against application of non-use values, which have no impact on incomes, in the economic analysis. This guidance therefore recommends excluding non-use values as benefits of MCC investments in nearly all circumstances. However, note that "non-use" is not equivalent to "non-market":

[54] See, for example, Diamond and Hausman (1994).

non-market ecosystem services such as flood mitigation, water filtration, and air pollution mitigation (including greenhouse gases) are all standard economic benefit streams. Pollution externalities which are localized should be included in the economic analysis regardless of whether they are positive or negative, though MCC environmental guidelines should restrict the degree to which MCC investments will cause significant or localized pollution. In some projects, renewable energy solutions may displace pollution compared to the counterfactual of more polluting technologies. Reduced pollution externalities of this type will tend to be non-local; in the counterfactual, polluted water may flow into neighboring countries or carbon pollution will diffuse across the entire atmosphere. However, note again that the economist should follow MCC's guidance on the treatment of environmental externalities in CBA[55] when determining how and when to include environmental externalities in the analysis.

ix. ***Contingent Benefits (i.e., complementary investments)*:**

The power sector is a networked system with and integrated value chain and strong complementarity between generation, transmission, and distribution subsystems. Often, it is not possible to attribute any benefits to a project without consideration of secondary investments which are complements for that investment in the other subsystems, even when these investments are not funded by MCC. When benefits that require secondary investments are included in the economic analysis, costs for the secondary investment must also be included. In a highly integrated value chain such as the power sector, the analysis needs to include all incremental costs incurred along the value chain to compare with incremental benefits. For example, an investment that increases transmission line capacity may be expected to result in the construction of generation capacity that would not have been expected otherwise, as failure to expand generation capacity would result in underutilized capacity in the transmission line. In such a case, the economic analysis should include the benefits associated with the increased provision of power and any costs related to the secondary investment. The analysis does not require specific knowledge of the investment pipeline, although this will tend to improve the precision of the analysis, but only an estimate of the timing and cost of the incremental capacity (including both capital and marginal costs). Benefits from complementary investments should be included only to the extent that power could not have been dispatched on the existing transmission system and the costs of secondary investments included only to the extent that these assets would not have been built in the counterfactual. For example, if the investment is modeled as increasing the capacity factor of marginal generation assets, then only new generation which would require the higher capacity factor in order to be economical should be included as secondary investments in the analysis. In all other cases, the secondary investment will be expected to occur without the project and should therefore be considered sunk for the purposes of the analysis, although the marginal costs associated with operating these assets should nevertheless be included.

Project costs typically pose a lesser burden on the economist, as the project costs are normally provided by infrastructure specialists.[56] In most cases, consumer costs such as household connections and battery replacement are dwarfed by the project investments in physical assets. Some examples of typical benefit and cost streams are described below. Even though these examples are grouped as 'benefits' and 'costs,' some benefits may occur as reduced costs and some costs may occur as reduced benefits.

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[55] At the time of this writing, MCC's guidelines on environmental externalities in CBA were still under development.
[56] See ESMAP (2007) for examples of project costs and benefits for small and medium projects, on- and off-grid, for renewables and fossil fuels.

E. Cost Streams

i. ***Physical Assets:***

Most project costs fall into the category of physical assets, including new assets and rehabilitation of existing assets. Some examples are small-scale hydroelectric generation, transmission lines, sub-stations, and household distribution connections. Complementary investments can also be included in this category, which might include irrigation pumps when part of a solar irrigation system or bio-digesters to be used with gas generators. However, referencing costs found in other project studies may not include all necessary costs. For example, the cost for a solar home system may not include the required hardware for mounting, labor for installation, or wiring the system to the household's electric circuit, even though these costs should be accounted for in the CBA.

ii. ***Cost-Reflective Tariff:***

The cost-reflective tariff (CRT) is set so that it is equal to the opportunity cost of electricity service delivery. Under ideal circumstances, the Long-Run Marginal Cost (LRMC) would be the theoretically correct concept for the cost-reflective tariff for this reason. Unfortunately, LRMC is only well defined and estimable under a set of unrealistic assumptions. The economist must therefore make several assumptions about the actual costs to the utility, weighing issues such as bloated payrolls, deferred maintenance, uncollected bills, and imports/exports to define a business-as-usual scenario. The utility's actual expenditures—as determined from financial or audit reports—can be used to estimate an average cost of service, which when supplemented with an estimate of the levelized costs of system expansion plans (or shortfalls) can be used to estimate a CRT. In practice, the economist should work with sector experts to determine the CRT, and the economist should focus instead on how the investments could result in marginal changes to the CRT. Section III.C discusses the CRT in more detail.

iii. ***Consumer Costs:***

While MCC does typically funds public goods, private consumer costs should also be included in the economic analysis to account for the total social opportunity cost of consumption. Some private consumer costs may be also subsidized as a part of the investment package, although if private consumer costs are being subsidized using MCC funds, a market failure should be identified.

Consumer costs can vary greatly from project to project, including connection fees, off-grid system maintenance, battery replacement, household wiring, and certain household appliances, such as light bulbs. A household may require light bulbs once electrified, and the choice of light bulb purchased can drive both electricity consumption and replacement frequency. Subsidies should be removed from the analysis as these represent transfers from taxpayers to consumers. However, economies of scale need to be considered when accounting for subsidized consumer costs; for example, bulk purchase arrangements can represent true cost savings. Battery costs for electricity storage can vary greatly depending on size, age, and usage behavior. Wiring costs for newly electrified households should be included; determining which of these household costs to include can be determined from the program logic. For example, if the project is grid expansion to low-income communities, household costs would include a minimal amount of internal wiring and a few light bulbs. If a demand side management project subsidized large appliances, household costs may represent a large portion of the total project costs.

Connection fees are the charges levied by utilities to establish the connection from the grid to the household or firm; such fees may or may not represent the true cost of connecting to the grid. Defining connection fees to include in an economic analysis can be difficult for many reasons. One reason is that electricity utilities often offer heavy subsidies for household connections, so that the cost faced by the household underestimates the true (i.e., financial) cost of the connection. Or the utility may choose to incorporate connection fees into its tariffs, allowing a household to connect to the grid without paying a connection fee. Commercial and industrial consumers are typically charged numerous fees as part of the connection service, perhaps incorporating the length of the connection required; the expected capacity required by the firm; or additional required assets, such as a dedicated sub-station for a large consumer. Estimating connection fees may not be necessary for generation, transmission, or off-grid investments, but estimating the true economic cost of connection will probably be necessary for projects that target grid expansion for reasons that are analogous to the use of cost-reflective tariff in the consumer surplus model. When connections fees are included in a cost-reflective tariff, the connection fee will not need to be included as a separate cost. For this reason, the economist should take note of the precise definition of the cost-reflective tariff to avoid double-counting of costs. Household wiring costs (discussed above) should also be included to the extent their costs are not included in the cost-reflective tariff.

iv. ***Consulting Services:***

Many investments will include costs associated with consulting services. Some examples include studies to estimate cost-reflective tariffs, utility benchmarking studies to be used in conjunction with training/capacity building programs, studies assessing the opportunities related to demand side management, load flow analysis to assist with the optimization of potential assets, and utility business process reengineering.

v. ***Contingent Costs:***

As discussed above in the contingent benefits section, when benefits from secondary investments are to be included in the economic analysis, costs associated with the secondary investment should also be included. The costs associated with a secondary investment may include costs that are not included in the reported financial cost of the secondary investment. For example, if an investment increases transmission line capacity, and if this investment results in the construction of a fossil fuel power plant that would not have been constructed without the increased capacity, the economic analysis should include the costs associated with the fossil fuel power plant, including pollution externalities, along with the benefits of the increased provision of power. The treatment of pollution, especially greenhouse gases, requires special care in the economic analysis of MCC investments, due to internal guidance regarding the scope of the analysis; decisions to include or exclude pollution externalities should be discussed at the EA team level, if not with a wider audience.

vi. ***Subsidies for Fuel and Electricity***:

Many power sector investments will be made in electricity markets that are subsidized. Care should be given to estimating the costs of electricity substitutes, as petroleum product prices may include taxes or subsidies. For this reason, the world price is often used in the analysis instead. As a detailed economic analysis should capture the full costs of electricity, careful analysis may be required to account for existing (and changes to) subsidy policy to establish the cost-reflective tariff to be used in the economic analysis; similar care should be given to tax policies on electricity substitutes. For some analyses where data is limited and tariff subsidies are changing (and may be expected to continue changing), the best approach may be to assume a cost-reflective tariff and to conduct the analysis as if the economic cost of electricity were known.[57] Care should be given when considering the timing of changes that may affect the cost-reflective tariff. Utilities with a high cost of electricity typically strive to lower costs (e.g., via lower-cost generation or reduced technical losses), but they may perform economic and financial analyses using cost-reflective tariffs that incorporate future, expected lower costs, thus artificially altering, and hiding the actual situation of the utility. Consumers may also resist tariff raises, creating a political coalition for the status quo.

The standard benefits and costs can be placed into the power sector taxonomy, as shown in Table 4, creating a quick reference of costs and benefits for projects in the given cell of the taxonomy (note that costs vary greatly for different projects and are loosely aggregated in the table).

Table 4: Taxonomy of Standard Benefit and Cost Streams in Power Sector Projects

<table>
<tr><td colspan="5">Governance Structure</td></tr>
<tr><td rowspan="4">Benefits:
• Increased Private Investment
• Reduced Deadweight Loss
• Reduced Subsidies
Costs:
• Consulting Services</td><td colspan="4">Power Sector</td></tr>
<tr><td rowspan="3">Benefits:
• Cost Reductions
• Price Reductions
• Improved Financial Sustainability
• Improved Physical Sustainability
Costs:
• Physical Assets
• Consulting Services</td><td></td><td>On-Grid</td><td>Off-Grid</td></tr>
<tr><td>Supply</td><td>Benefits:
• Energy Substitution
• Increased Value-added
• Price Reduction
• Efficiency Gains
• Health & Education
Costs:
• Physical Assets
• Connection Fees
• Consulting Services</td><td>Benefits:
• Energy Substitution
• Increased Value-added
• Price Reduction
• Efficiency Gains
• Health & Education
Costs:
• Physical Assets
• Connection Fees
• Consulting Services</td></tr>
<tr><td>Demand</td><td>Benefits:
• Price Reduction
• Energy Substitution
• Increased Value-added
• Health & Education
Costs:
• Physical Assets
• Consumer Costs
• Consulting Services</td><td>Benefits:
• Price Reduction
• Energy Substitution
• Increased Value-added
• Health & Education
Costs:
• Physical Assets
• Consumer Costs
• Consulting Services</td></tr>
</table>

III. Power Sector Institutions and Policies

Power sector investments often include a sector reform component, where funds are spent to alter structures, policies, or behaviors within the sector with the objective of restoring or establishing a conducive environment for effective and sustainable sector growth. Where practical, the costs and benefits of policy and institutional reform (PIR) of the sector should be quantified separately from those of infrastructure. Benefits of reform will tend to accrue across the sector, rather than for a single asset, although it is also possible that reforms may support an infrastructure investment by enhancing asset

[57] Feasibility studies conducted during Compact development will often provide an estimated cost-reflective tariff; assumptions made before this data is available can be updated after the data becomes available. Infrastructure specialists and previous studies can assist the process of defining an acceptable cost-reflective tariff assumption.

governance in some way. In either case, modeling PIR requires assuming "business-as-usual"[58] maintenance, operations, financial viability, performance, and service levels for the counterfactual case and for institutions not directly affected by the reform. Then sector or asset governance should be modeled, as applicable, given the program logic, evidence available, and context. Common PIR benefit streams include: (i) more sustained service-level improvements for the MCC assets and, if applicable, the sector as a whole; (ii) reduced cost-reflective tariffs or deadweight loss from over-consumption; (iii) reduced replacement or rehabilitation costs in the future, for MCC assets and, if applicable, to the sector as a whole; (iv) sector expansion (often captured by increased power supply) and the associated economic and social costs and benefits of this expansion; and (v) improved sector technical efficiency (often captured by reduced expenditure on subsidies).

A. Reform Taxonomy

Power sector reform projects can be grouped into three types of projects, based on their direct beneficiaries. These include projects that improve sector governance, strengthen the regulatory role, and improve utility financial solvency. The nature of interventions may be grouped into PIR and non-PIR as defined in the EA PIR guidelines.[59] The difference between PIR and non-PIR is that PIRs aim to change the "rules of the game" amongst or within institutions or create new institutions while changing the allocation of existing roles and responsibilities. Within the PIR class of interventions, there are laws, regulations, policies, changes of institutional structures, and trainings to support the newly created institutions (i.e., Type II training in this taxonomy). The only interventions that do not constitute PIR under this taxonomy are the types of trainings that enhance the capacity of an institution to perform a role it has already been tasked to perform[60] (i.e., Type I training).

Table 5 lays out the taxonomy of soft interventions (i.e., interventions that do not invest in physical infrastructure), including PIR interventions, along with examples of each within the power sector.

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[58] The details of the business-as-usual assumption are discussed in MCC's CBA guidelines available here: https://www.mcc.gov/resources/doc/cost-benefit-analysis-guidelines

[59] The Economic Analysis guidelines for Policy and Institutional Reform was not a public document at the time publication but may be available upon request.

[60] Therefore, these interventions do not alter the "rules of the game" under which the current policy and institutional framework operates. As such, these should be understood as a standard non-PIR investment in capital, that happens to focus on human capital, rather than physical capital or infrastructure.

Table 5: Taxonomy of non-physical infrastructure interventions in the Power Sector, including PIR. *Source: MCC Staff*

			Soft Interventions		
			Improve Sector Governance	*Strengthen the Regulatory Role*	*Improve Utility Financial Solvency*
PIR[61]	Policies[62]		• Unbundle Gx, Tx, and/or Dx functions of a vertically integrated utility • Develop and operationalize of a gender integration plan	Tariff reform and review	• Service and management contracts • Corporatization • Wholesale/Retail markets
	Laws [63]		Improve the legal and sectoral framework	Improve the legal and sectoral framework	Changes in the structure of ownership, including public private partnerships to full privatization
	Regulations [64]		Develop new regulatory frameworks in established or emerging subsectors.	• Develop and implement a new organizational structure and technical assistance to administrative staff • Develop a multi-year communications plan to support monitoring, enforcement, and transparency • Develop and implement regulations[65]	
	Institutions	Structure	• Develop, implement, and monitor an integrated sector investment planning framework • Develop a "one-stop shop" • Develop an IPP/PSP procurement framework to allow streamlining of the procurement process for IPPs and other potential private sector actors in transmission or distribution	• Conduct a grid audit, an assessment of licensee conformity to norms and standards, and evaluations of regulatory effectiveness • Develop a monitoring and enforcement strategy with identification of interventions available to the regulator	• Incentivizing increased utility performance • Advancing environmental and social management
		Training, Type II[66]	• Develop and implement a long-term for private participation providing operations and maintenance services • Monitoring and assessments of implementation of the strategic action plan		
Training, Type I[67]			Training and technical assistance to the rural electrification agency		Reinforcing management of the transmission and distribution networks

[61] Changing the "rules of the game" amongst the institutions, thus creating new institutions, and changing the allocation of existing roles and responsibilities.

[62] A policy outlines what a government ministry hopes to achieve and the methods and principles it will use to achieve them. It states the goals of the ministry. A policy document is not a law, but it will often identify new laws needed to achieve its goals.

[63] Laws set out standards, procedures and principles that must be followed. If a law is not followed, those responsible for breaking them can be prosecuted in court.

[64] Rules for practical everyday tasks aimed at supporting the roles of technical actors.

[65] E.g., licenses, operational and safety standards, asset management requirements, standard procurement document or other related contracts, power purchase agreements, etc.

[66] Granting new capacity to an institution to perform a new role it is newly tasked to perform because of PIR interventions.

[67] Enhancing the capacity of an institution perform a role it is already tasked to perform.

The typical recipient of aid that seeks to improve sector governance is the Ministry of Energy, although the ultimate beneficiaries remain electricity consumers. Projects may include activities that seek to change the structure of the sector; notably, through an update of the legal and sectoral framework, the unbundling of the utility, the creation of a generation/transmission/distribution system operator, the re-definition of distribution perimeters, and the clarification of private and public ownership of assets. Auxiliary activities may also include the creation of conveniences such as an online "one-stop shop" to reduce the cost of doing business in the electricity sector, strengthening the Ministry of Energy's capacity to plan, monitor, and evaluate investments in the sector.

Regulatory Strengthening projects support the energy sector regulator's role in promoting the financial solvency of electricity sector companies and protecting consumer interests as it pertains to the price, quality, and access of electricity service. Natural monopolies, such as exist in the power sector, require robust regulation to reach economic efficiency. Through its rules, the regulator ensures that the benefits of power sector infrastructure assets are sustainably and cost-effectively passed on to consumers, ideally, by setting tariff rates equal to a cost-reflective level for the utility given expected system expansions and below heterogeneous end users' willingness to pay. Depending on the intensity of the intervention, the activities of this group may seek to improve regulatory governance through the development of a new organizational structure, a strategic plan, financial autonomy strategy, a communications plan, improved IT systems, a grid audit, ensuring licensee compliance with technical norms and standards, stepping up an independent regulator, and a monitoring and enforcement strategy. It may also improve regulatory substance through the development of a cost of service and/or tariff reform, the regulator's application of the new tariff regime, and various other regulations formulated to promote the rational development of the supply of electricity. At the end, these interventions should strengthen the regulator's capacity to execute its stated mandate of improving conditions of financial viability, protecting consumer rights, promoting competition, and encouraging private sector participation.

Utility Strengthening projects are expected to improve the utility's governance, commercial, financial, operational, and environmental performance. Activities under this class of project may include incentives to improve key performance indicators, development of a GIS database of the network, and provision of technical assistance to develop the utility's capacity to manage the network. Additional activities may include technical assistance to the utility to manage assets, procurement, accounting, and financial management performance.

This guidance recommends that the economist be as specific as possible when defining PIR benefit streams and to focus on observable consequences of the intervention which may include, for example, achieving revenue targets, reducing technical or non-technical losses, or expanding supply on the grid.[68] To the extent possible, the economist should only consider benefit streams listed in Table 4, focusing on similar strategies to quantify and monetize these benefits as would be done for an investment in physical infrastructure. Some interventions will be more challenging to quantify, for example, for a project aiming to improve revenue collection or reduce financial leakage from the utility, a change in the cost-reflective tariff, even if the statutory tariff remains unchanged, or a reduction in deadweight loss, would both potentially be appropriate benefit streams.

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[68] See Bacon (2018) for a recent review of the evidence around economic benefits of policy and institutional reform investments.

B. Key Concepts

Studies of the impact of sector reform in the literature are limited by the focus on select indicators, the choice of which is constrained by data availability (see Bacon (2018)). Additionally, cross-country studies may lack external validity when applied to countries in which MCC is likely to invest; a cross-country regression, for instance, can estimate the marginal effect of reform on the average country in the sample. A country with an electricity infrastructure constraint is less likely to be average in this sense because an economic constraint implies the existence of a perverse political economic equilibrium that is less likely to admit reform than a typical unconstrained economy. This guidance therefore recommends the use of literature evidence only in the event when primary data at the country level are not available. If cross-country data must be used, the economist should ground the analysis in measurable quantities that can be tracked in the M&E plan, as well as minimize bias by aggregating the results of as many empirical studies as possible.

The sector reform programs in Senegal II and Burkina Faso II Compacts[69] focused on improving revenues and lowering costs for the utilities, thereby bringing statutory tariffs more in line with the cost-reflective tariff and ensuring the sustainability of the sector and MCC's investment in physical infrastructure. Cost recovery can result from technical, administrative, and managerial changes within the utility. However, it should not be viewed as providing an all-encompassing approach to PIR—for example, improvements to planning and private sector participation may nevertheless cause prices to rise in the short run. [70]

The cost-reflective tariff (CRT) is an estimate capturing the social opportunity cost of consumption that should include recovery of current costs, cost of system expansions, and the financial sustainability of the sector. Cost-recovery also includes identifying a tariff schedule for individual consumer classes. Generally, charging consumer classes with different tariff rates involves deviating from the principle that prices should reflect the social opportunity cost of service delivery, i.e., the system marginal cost, but could also reflect to an extent the costs that different consumer classes impose on the system. For this reason and to capture the costs of investments in new capacity, this guidance recommends conceptualizing the cost-reflective tariff as an approximation to the sector's long-run marginal cost (LRMC).

Differentiated tariffs for consumer classes can nevertheless be justified if the consumer class imposes differentiated opportunity costs on the system, as well as other non-economic justifications such as equity. If this is the case, the economist should also ensure that the proposed tariffs structure improves revenue generation for covering current costs and system expansions, although tariffs should be expected to deviate from the fully cost-reflective level in general.

C. Cost-Reflective Tariffs

The opportunity cost for delivering power is a complex problem which may involve significant detective work on the part of the sector experts with support from the economist. Electrical power systems are integrated value chains for the delivery of power services to customers. As a general matter, power systems exhibit significant increasing returns to scale technology[71] from the perspective of the production

[69] A case study of the Burkina Faso II Compact is included in ANNEX II.D.

[70] In some cases, causing the phenomenon of "rate shock" which can undermine further reform efforts.

[71] For the purposes of this guidance, increasing returns technology is functionally identical to a system having a declining average cost curve at the scale of interest, where the scale of interest is the maximum load on the network.

function of a unified value-chain. Because the average cost of delivering power is declining in the quantity of power delivered, the average system cost tends to be bounded above the short-run marginal cost; a policy of setting price equal to the marginal cost would require significant subsidies to implement sustainably.

To incorporate the need to account for funding for the relatively large, fixed costs necessary to achieve assumed levels of service delivery, economists and policymakers use the concept of a cost-reflective tariff. It should be noted that the statutory tariff paid by consumers is not typically equal to the cost-reflective tariff. Instead, consumers that pay the statutory tariff for power are beneficiaries of a transfer payment from the utility—and ultimately from taxpayers—in an amount equal to the difference. As discussed regarding commercial losses, this transfer payment does not represent an economic benefit to first order; however, a too-low (high) statutory tariff implies over- (under-) consumption and therefore a deadweight loss, which can be valued using standard methods from welfare theory.

Under ideal circumstances, the Long-Run Marginal Cost (LRMC) would be the theoretically correct concept for the cost-reflective tariff for this reason, but the LRMC is difficult to estimate. The economist must therefore make several assumptions about the actual costs to utility, weighing issues such as bloated payrolls, deferred maintenance, uncollected bills, and imports/exports to define a business-as-usual scenario. The utility's actual expenditures—as determined from financial or audit reports—can be used to estimate an average cost of service, which, when supplemented with an estimate of the levelized costs of system expansion plans, (or shortfalls) can be used to estimate a cost-reflective tariff.

Because of these issues, the LRMC is difficult to define and impractical for the economist to attempt to estimate. This guidance recommends either a "rate of return" or "cash needs" approach to calculating the CRT, although the economist should work with sector experts to determine the level of the CRT.[72] Hence, the two recommended approaches utilize different strategies to approximate the LRMC as the average cost of current level of service, supplemented by an estimate of the levelized incremental cost of system expansions. Roughly, CRT takes the form:

$$Cost\ Reflective\ Tariff\ (CRT)\ at\ t = \frac{MRC_t}{C_t} +\ LCIP_t + LRAIC_t \qquad (5)$$

Primarily this is a consequence of the need for transmission and distribution infrastructure to deliver power. In large power systems, the minimum efficient scale for generation is typically many times larger than the capacity of a single generator; for example, the largest power generator in the world is the Three Gorges Dam in China, with a capacity of 22.5 GW, or about 2% of the total capacity of China's grid (estimated at about 1,250 GW in 2013, the first year of operation).

[72] For example, see Lazar et al. (2020).

Where MRC_t is minimum revenue needed to cover current costs;[73] $LCIP_t$ is the levelized cost of the generation investment plans,[74] $LRAIC_t$ is the long-run average incremental cost of new transmission and distribution infrastructure, and C_t is the electricity consumed.

MRC_t is the backward-looking business-as-usual cost of service provision under the condition that the utility does not expand capacity. This includes the costs of the utility's payroll and other business expenses, generation and fuel costs, and debt service and other transfer payments.[75] The economist and sector experts must determine the MRC formula used by the regulator and how it is used to inform CRT.

When forecasting the MRC over the investment horizon, the utility's investment plans must be factored into the estimate: Capital, operational and maintenance on new generation, transmission and distribution investments must be counted so long as these expenditures are necessary to achieve the supply forecast for the network used in the analysis. If the system is not investing in these new assets, then the system is falling short of the supply forecast, due to shortfalls in capacity installation or system degradation.

For relatively dysfunctional systems in which MCC might invest, a business-as-usual scenario for the MRC can be constructed by summing all revenue sources and transfers to the utility as discussed above to determine the base case which can be used to construct a forecast from the underlying trends in these component measures. However, if this is done for a utility that does not cover all the costs of maintenance, then the business-as-usual scenario also implies that any new investments are likely to degrade to some system average well below ideal.

$LCIP_t$ is a rolling estimate of the levelized cost of electricity ($LCOE$) concept, common in power sector applications. $LCOE$ is the price per unit of electricity that the utility would need to compensate a risk-neutral owner of a generation facility so that the owner is just indifferent about entering the market. As such, this concept is primarily suited to estimating the cost of expanding generation. A more thorough approach would require the more sophisticated "rate of return" or "cash needs" approaches to calculate the change in system costs, including new transmission and distribution expansions.

A reform will affect CRT through one or more of its determinants discussed from equation (5), including the sub-components of the various variables in equation (6). The task of the economist will mainly consist of (i) identifying the determinants of CRT and MRC for the country they are working on, (ii) identifying the sub-component(s) of CRT through which the reform will affect CRT, (iii) determine the magnitude of the

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[73] See Huenteler et al. (2017) for a discussion of the quasi-fiscal deficit, a concept related to the implicit subsidies in the sector. In brief, the quasi-fiscal deficit is a measure of the contingent liabilities incurred from underpricing of electricity; that is, it is the difference between actual revenue (charged and collected) and the revenue required to cover full costs of service provision and depreciation. The QFD takes the reduced form:

$$QFD = Cost\ of\ Underpricing\ of\ Electricity + Cost\ of\ Nonpayment\ of\ Bills + Cost\ of\ Excessive\ Line\ Losses + Overstaffing$$

[74] If the utility does not publish an investment plan, then the economist should work with sector experts to determine what is reasonable.

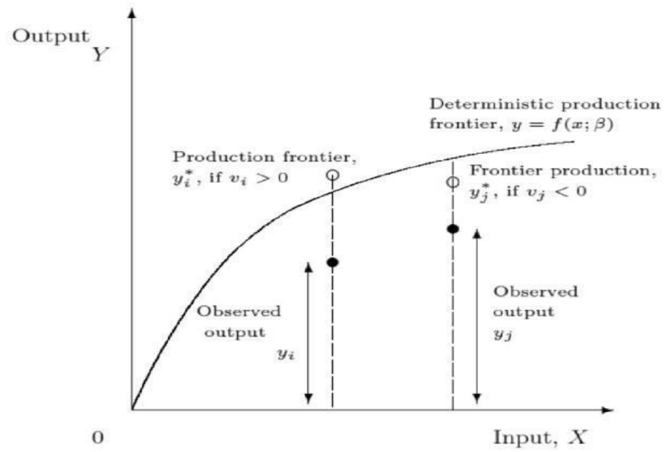
[75] Transfer payments such as these capture the implicit cost of underpricing electricity. For example, costs may be associated with renting emergency power generation units because of poor planning. The implicit cost of non-payment, for example, including payment arears by government agencies and state-owned companies is that these costs must be borne by paying consumers or taxpayers.

impact of the reform on the CRT sub-component, and (iv) work backward to identify the resulting impacts on the CRT.

D. *Efficiency*

Some PIR investment may seek to improve efficiency of the utility. Such investment may include trainings, adoption of improved technology, improvement of processes, or structural and institutional reorganization. To estimate the impact of PIR investment on efficiency, the economist will first need to estimate the current efficiency level of the utility. The two most used methods to estimate the efficiency in the literature are data envelopment analysis[76] ("DEA") and stochastic frontier analysis[77] ("SFA"). DEA is a non-parametric approach that uses linear programming to identify the efficient frontier, while SFA is a parametric approach that hypothesizes a functional form and uses the data to econometrically estimate the parameters of that function. Both methods measure efficiency as the distance between observed and maximum possible (frontier) outcomes, but the key advantage of SFA is that, unlike DEA, it can separate random noise in the error terms from the efficiency score. A graphical depiction of this concept is shown in Figure 4.

Figure 4: Stochastic frontier used in Stochastic Frontier Analysis (SFA). *From Maruyama et al. (2018).*



Conceptually, the stochastic frontier production function[78] is defined as:

$$y_i = f(x_i; \beta)\exp\,(v_i - u_i) \qquad (6)$$

Where y_i is the possible production for utility i, $f(x_i; \beta)$ is an adequate function of input x and parameters β, v_i is a random error with zero mean, associated with random factors that are not under the utility's control, and u_i is a non-negative random variable associated with factors that prevent utility i from being efficient. The parameters of this model can then feed into the utilities value-added to estimate the social benefits of the efficiency improvement.

[76] See Charnes et al. (1978).
[77] See Aigner et al., 1977 (1977); Meussen and van den Broeck, (1977); Battese and Corra, (1977).
[78] To empirically estimate the efficiency, the analyst can use the Stata command "frontier" for cross sectional data from a number of utility firms or "xtfrontier" for panel data to estimate the production function and later use post-estimation command "predict efficiency, te" to estimate technical efficiency of the utility. Key data the economist will need can be obtained from the utility include value added (this could be the quantity of energy produced or revenue), number of workers, operation cost, and value of assets of the different production units over a period of time.

E. Recommended CBA Approach

While the economist can use one of the key concepts above to estimate the impact of a particular PIR activity, this guidance recommends a single project-level ERR for all stand-alone PIR activities. This is for two reasons: First, dependencies between separate PIR activities are common in practice, sometimes in ways that are not anticipated. Second, there can be several potential measurable outcomes from each intervention which may overlap for two or more activities. PIRs interventions usually stem from a sector wide gap analysis that attempts to diagnose the power sector's institutional shortcomings relative to a standard benchmark, such as a regional average. After the diagnostic phase, the elaboration of a roadmap will follow. A roadmap often consists of the following methodological steps:

- Determination of long-term **strategic objectives** for the electricity sector.
- Identification of **action levers** to progress towards the achievement of objectives.
- Construction of **scenarios** for a given period based on action levers.
- **Modeling the technical and financial performance** of the sector, based on identified scenarios.
- Selection of the preferred scenario and development potentially embodied in an existing **sector roadmap or action plan** for its implementation.

One key tool that a Roadmap exercise develops is the technical and financial model of the sector. The model presents annual projections of key indicators such as cost of service, supply forecast, subsidy needs, investment needs, and share of cost of service per components of the power sector value chain across several policy options, including the base case. A case study of this approach for Burkina Faso is included in ANNEX II.D. Using roadmap results as the basis for the PIR CBA has the benefit of ensuring strong buy-in from the sector leads.

PIR interventions carry with them more uncertainties than infrastructure investments so that CBA results will be more uncertain. Therefore, this guidance recommends that the economist integrate Monte Carlo simulations (MCS) into the main body of the analysis to identify key risk factors and assumptions during design. For this application of Monte Carlo Analysis, knowledge of the precise form of parameter distributions is not necessary, since the goal is to highlight risk factors, rather than to calculate a precise distribution of the ERR. The mean ERR should be the key indicator that the economist will use to inform PIR project design and report to management, but the economist can also leverage the MCS to estimate the probabilities that the ERR is above 10%, giving project team and management a better understanding of the underlying risk.

IV. Evidence in the Economic Analysis of Power Sector Investments

MCC investments are described by a program logic, which enumerates the project inputs, outputs, and outcomes through a causal-linked chain; the verbal argument accompanying the program logic and describing how the investment is expected to lead to economic growth is known as the investment's theory of change. Economic analysis of power sector investments should follow MCC's guidelines for cost-benefit analysis, although supplemental these guidelines with other standard approaches is acceptable where gaps exist.[79] For all practical purposes, demand for electricity is derived demand: it is never consumed directly. This characteristic allows the demand for electricity to always be considered as an

[79] See Zerbe et al. (2010) for a discussion of principles and standards in benefit-cost analysis. See Asian Development Bank (2013) for guidance on the analysis of large-scale energy generation and transmission projects.

input to a production function.[80] As such, the most prominent benefit stream in most analyses will result from (i) the cost reductions afforded by substitution of electricity for a more costly input; (ii) the cost reductions afforded from operating the electrical system more efficiently; and/or (iii) the ability to consume more of the input. Additional benefit streams may exist according to the design of the investment, depending upon the context and degree to which excess demand for power constrains investment and production in the economy in question.

A. Market Demand

While not technically true for the general case[81], consumers' willingness to pay are assumed to aggregate straightforwardly to produce a standard market demand curve.[82] Therefore, as an intermediate good, electricity demand can be inferred from the ordered prices and quantities of its close substitutes,[83] so that a price elasticity can be deduced. The income elasticity of demand can likewise be inferred from the behavior of a cross-section of consumers at various income levels. Unfortunately, employing such an approach leads to a financial WTP[84] rather than the economic WTP. This will result in an underestimate of the WTP, as non-monetized consumption will be excluded. For example, economic WTP incorporates the value of time spent collecting and burning firewood for cooking purposes, while financial willingness-to-pay would not, as no money was used to purchase the fuel. Estimates of WTP can vary greatly and their underlying assumptions can be challenged.[85] While Stated Preference techniques could in theory mitigate this problem, such an approach is not recommended for the reasons discussed in the previous section.

Problems can arise in the power sector due to the derived demand nature of electricity consumption. The starting point for the analysis should consider that the household or firm is demanding energy for use in its production function; the energy consumed is typically destined to various final demands. Problems can arise when one source of energy substitutes another. In some cases, analysis will be easier when final demand is differentiated into different components; other times the analysis is simplified by considering aggregated energy consumption.

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[80] At the household level 'utility function' could be used in place of 'production function' without loss of meaning: 'production function' is used for both households and firms.

[81] Because of substitution effects, only when consumers' preferences are quasi-linear do individual demands sum simply to give the correct market demand curve. In the general case,

$$WTP \leq C \leq \Delta CS(\boldsymbol{p^0}, \boldsymbol{p^1}) \leq E \leq WTA$$

Where $\Delta CS(\boldsymbol{p^0}, \boldsymbol{p^1})$ is the consumer's surplus of the market demand when prices change from $\boldsymbol{p^0} \rightarrow \boldsymbol{p^1}$; C, E are the compensating and equivalent variation, defined by: $C = y - e(\boldsymbol{p}^1, u^0)$ and $E = e(\boldsymbol{p}^0, u^0) - y$, respectively.

[82] Consumer demand curves are discussed later in this section.

[83] That is, goods which generate close substitute flows of services—such as light and cooking heat.

[84] Financial WTP should not be confused with ability-to-pay (ATP), usually defined as a fixed percentage of consumers' budget allocation to electricity and its near substitutes. Ability-to-pay is not relevant to the economic analysis of an investment, although it may be a consideration in a practical tariff setting process.

[85] See (World Bank, 2008) for an example of an estimated WTP that can be challenged. The approach to calculate WTP assumes that the operating costs of the equivalent of 4 kerosene lamps and some other small appliances will be replaced by electricity. The report assumes that these marginal household connections will consume 125 kWh per month. A simple estimation of electricity consumption for such a household results in consumption of less than 25 kWh per month, which results in a much higher WTP. Further reading reveals that the report assumes the household consumes at the average consumption rate of Dar-es-Salaam, which includes commercial consumption. Basic calculations using data presented in the report reveal a WTP of $0.75 per kWh.

An example of analysis based on multiple final demands would be one considering a household that cooks with charcoal and uses kerosene for lighting. If the investment expects the household to adopt electricity for lighting but not for cooking, the analysis should be based on light consumption, not energy consumption. Care must be taken to identify what is being demanded (i.e., consumed) and to convert the energy inputs into consistent units associated with the final demand.

Consider the case of lighting as the "consumption" good. While not normally accounted for in the literature, lighting is also an input to household production with a derived demand curve; it is a strong complement for some household activities, such as reading. This has potentially important implications because lighting generally involves lumpy production technologies (i.e., candles or lightbulbs). Lumens are the most common unit of measure used for lighting; a common candle will produce almost 15 lumens, while a 60W incandescent bulb produces approximately 800 lumens; or nearly 60 candles worth. If, for example 100 lumens is sufficient brightness for casual reading[86], then the last 700 lumens of light are being consumed at much lower marginal benefit than the first 100 lumens. This implies that the demand curve for lighting is more convex than implied by the demand for lumens at low lighting levels.

The above example demonstrates that energy substitution patterns can be complex. Regardless, the economist should base the analysis on the substitution of electricity for its closest substitutes within the applicable context: that is, kerosene or candle use corrected for lumens of lighting demanded, valued at the different costs for each energy source.[87] As the energy consumed for a given amount of light is much higher from kerosene than from electricity, such an analysis could lead to unexpected results: if this analysis were conducted on a 'quantity of energy' basis, the lower cost energy source would be consumed less than the higher cost energy source.

An example of analysis based on a single final demand would be an analysis that considers the benefits to a firm that switches from producing its own diesel-based electricity to consuming lower cost, grid-supplied electricity. In this example, the analysis is best conducted on the firm's aggregate electricity consumption, unless other energy-related substitutions are expected.[88]

Energy substitution will be more prevalent for populations that do not currently consume grid-electricity, so that the lumens-accounting discussed above generally needs only be considered in off-grid, or mini-grid and grid-extension projects.

i. ***WTP by Consumer class:***

Economists should disaggregate projected valuations and demand by residential, commercial, and industrial, and/or other consumer groups, and possibly by region. Typically, lower household incomes have lower demand for electricity than higher income households, although on the margin where they consume, their WTP for substitute energy sources may reflect a higher marginal willingness to pay due to the convex shape of the demand curve. The consumer's ability to pay – i.e., the affordability of energy-related expenditures for specific consumer classes – is, like the WTP, often discussed in the context of

[86] 10 foot-candles, or equivalently, about 100 lumens from a source 1 foot away, is a common assumption for comfortable reading.

[87] See Mills (2003) for an analysis of lighting quality and energy consumption for different lighting sources.

[88] While uncommon, if substantial shifts from one fuel to another are expected, some investments may require additional analysis to account for the effects of energy substitution. For example, given new access to electricity, a firm may switch from a process utilizing heating fuels, such as wood or oil, to electricity.

tariff setting, and is typically related to the consumer's WTP, although as noted above care needs to be taken regarding goods like firewood whose cost to the consumer may not be financial. While it is possible that an analysis would indicate that electrification investments should start in the rural regions and progress towards the urban regions, such an analysis probably missed higher costs and losses associated with the more distant investment locations. Collaboration with infrastructure specialists should help to ensure that the economic analysis is conducted on a feasible project.

ii. ***Demand Curves and Elasticities***:

Building on the willingness to pay discussion, care should be exercised in estimating electricity demand curves for use in WTP calculations. The most common functional forms applied in the literature are linear, constant elasticity of substitution (CES), log-linear and semi-log.

Economic theory typically assumes that the demand curve is strictly convex,[89] so that a non-linear demand curve should be used where possible.[90] Most common convex functional forms, such as CES family of demand curves, imply non-satiation of demand at low prices – an unlikely outcome.[91] Regardless of this theoretical inconsistency, however, in most economic applications, with prices bound well above zero, this issue is unlikely to have a substantial effect on the estimated willingness to pay.

When estimating the effects of small price changes on currently electrified consumers, a linear demand curve can locally approximate the actual, non-linear curve. This approach has the advantage of being robust to the "true" form of underlying preferences. On the other hand, for modelling effects of electrification on currently non-electrified consumers or the effects of large price changes on currently electrified consumers, assuming a linear demand curve is likely to substantially overstate project benefits.

On balance, log-linear demand should be considered the default functional form in most applications in which prices or consumption are likely to change substantially for a typical project beneficiary. Assume a demand curve of the form,

$$Ln(q) = \alpha + \beta p \tag{7}$$

The price semi-elasticity of demand is then,

$$\beta = \frac{[\ln(q_1) - \ln(q_0)]}{(p_1 - p_0)} \tag{8}$$

Thus, benefits from incremental consumption are,

[89] This is a consequence of locally non-satiated preferences. However, since electricity is an intermediate good providing lighting, cooking or similar services, points of satiation should be expected (i.e., too much light or too much cooking can reduce welfare).
[90] See World Bank (2008, pp. 39-52) and (2008, pp. 131-139) for a discussion on different approaches to World Bank project analysis, including a critique of the application of linear demand curves to off-grid electrification projects. Table H.3 shows that applying a linear demand curve can overstate consumer surplus versus a log-linear demand curve by up to eight times in extreme cases.
[91] See Choynowski (2002)for an exposition of a log-linear demand curve for electricity that incorporates demand satiation while arguing against the commonly used constant elasticity of substitution demand curve. This approach is applied in Asian Development Bank (2013).

$$\int_{q0}^{q1} pdq = q_1\left(p_1 - \frac{1}{\beta}\right) - q_0(p_0 - \frac{1}{\beta}) \tag{9}$$

While benefits from counterfactual consumption are,

$$q_0(p_0) \tag{10}$$

Where q_0 and q_1 are with and without project consumption and p_0 and p_1 are the price of energy with and without the project, respectively.

A problematic approach to defining benefits for a given investment is to assume a causal relationship between demand for electricity and national production, which results in specifying an assumed increase in output for a given increase in input. While there are numerous studies that try to identify casual relationships between energy, electricity, and growth, the general premise for such studies is not well-grounded in economic theory and econometric practice.[92]

iii. ***Forecasting Suppressed Demand***:

Caution is often needed when discussing or interpreting electricity demand, typically referred to as "load."[93] Proposed investments often target underserved areas, typically with low electrification rates, and demand in such areas may not support the full costs of these extensions. Reported maximum load on a given network can only indicate demand served by installed capacity and not subject to transmission and distribution bottlenecks, as the system will collapse if load exceeds installed capacity. However, demand based on installed capacity can be exceeded by including adjustments made for load shedding and off-grid/self-generation. For example, if installed capacity is 1000 MW and the system is experiencing 100 MW of load shedding, the utility may report that system demand is 1100 MW. Continuing this example, if a nearby mine produces 20 MW of electricity from diesel generators, the utility may indicate that demand is 1120 MW, as this much demand is observed, even if the utility cannot supply it. To further complicate the use of "demand," electricity utilities often produce demand forecasts, which can incorporate assumptions of varying degrees of plausibility into demand projections. Such demand forecasts are often of little value for the economic analysis of proposed investments, unless the system is relatively close to equilibrium;[94] many MCC investments will be too small to significantly alter the demand balance. Also problematic is the consideration of suppressed demand, which captures the expected increase in demand by existing consumers on a given system if supply were unconstrained. Distinguishing between excess demand (i.e., expected electricity demand from new connections) and suppressed demand is not always necessary, but it can be important for some analyses, and it can be quite important

[92] See Tracy (2011, pp. 14-17) for a discussion on some of these problems and see Tracy (2011, pp. 59-61) for empirical results indicating changes in Granger causal relationships for Brazil, which are used to caution against the present use of Granger causality in energy economics. See Bruns et al. (2013) for a meta-analysis of the Granger causality literature on energy and output, whose results highlight the lack of consensus on any findings.

[93] Load, as an engineering concept, conflates issues in production of electricity services, such as losses, with quantity of electricity demanded while ignoring price sensitivity of quantity demanded implicit in the economic notion of demand.

[94] 'Equilibrium' for a well-functioning national system includes sufficient excess supply so that demand factors (i.e., the ratio of maximum-to-maximum possible load, a measure of the "peak-ness" of the load profile) are around 50 percent, which is very uncommon in MCC partner countries.

for determining beneficiaries of a given investment. If an analysis considers suppressed and excess demand, a standard assumption should be that suppressed demand is to be relieved before any additional load is placed on the system through new connections.

To forecast suppressed electricity demand, it is necessary to first estimate both the income and price elasticities of energy demand, including demand for all close substitutes. An appropriate tool for estimating these parameters is the Deaton and Muellbauer (1980) almost ideal demand system (AIDS). The AIDS model has proven to be popular as it possesses key properties such that: perfect aggregation over consumers, axioms of choice, homogeneity, and symmetry. Since its inception, the AIDS model has arguably become the most widely used approach for modeling consumption behavior for grouped commodities.

The demand for electric power from all sources is derived; electricity is not consumed per se, but rather the services that it makes available through the use of electricity consuming machinery and appliances.[95] To consume electricity, natural gas, gasoline, or coal directly would be unpleasant at best and fatal at worst. Expenditures on energy sources such as electricity, kerosene, candles, and others can be captured in surveys. These expenditure figures can be used to estimate price and income elasticities using the AIDS model.[96]

In practice, demand systems in the AIDS model are typically specified with expenditure shares as the dependent variables. A household's expenditure share for energy source *i* is defined as:

$$\omega_i = \frac{p_i q_i}{m} \tag{11}$$

Where p_i is the price paid for energy source i, q_i is the quantity of energy source i purchased, and m is the total expenditure on all energy sources in the demand system, so that ω_i are the expenditure shares. Thus,

$$\sum_{i=1}^{K} \omega_i = 1 \tag{12}$$

Where K is the number of energy sources in the system.

Once the expenditure shares, $\omega_{i,}$ are calculated, the demand system can be estimated[97]. The relevant electricity price is the actual tariff rate in units of currency per kWh as charged by the utility for the consumer class in question.[98] Current and historical tariff schedules are generally available from the utility company. Income growth can be forecast from expected GDP growth. These forecasted income and price/tariff changes can then be used along with the estimated elasticities to forecast electricity demand.

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[95] Note also that these household and business not connected to the grid may need time to purchase and install these assets, so that uptake of electricity to new areas is likely to be lower than implied by willingness and ability to pay, alone.

[96] As discussed elsewhere, these surveys may also be used to estimate willingness to pay.

[97] E.g., using the STATA® command "quaids". The post estimation command "estat" can be used to derive both the income and price elasticities μ_i and ϵ_{ij}.

[98] For cost-benefit analysis, the economist should use cost-reflective tariffs to reflect the opportunity cost of service delivery and ignore the redistribution of costs and benefits arising from underpayment. However, when forecasting demand, the issue is what the consumer is paying so that the statutory tariff is applicable.

Data required for the demand estimates exercise are common and can easily be found in household surveys. Prices and quantities for energy substitutes may not be included in most household surveys, but prices can be determined in the due diligence process through a simple market-sounding exercise—excluding fuel, the prices of electricity and other energy sources are not volatile. Fuel prices are set on international markets—usually with some local markup—and can be approximated using international oil prices if the country's energy mix is dominated by petroleum-based fuels.

A similar analysis can be done for firms using Enterprise Surveys. Unlike households, the sources of energy available to firms are typically limited to on-grid electricity and petrol generators.

B. Forecasting Supply and Demand Balance

As noted in the introduction, supply and demand must always exactly balance at every point in the network. Moreover, since prices are not set in the market, a system operator is responsible for maintaining this balance by dispatching supply as necessary to meet fluctuations in demand. However, the economist does not need to model the system's balance at a higher frequency than the CBA (i.e., yearly, or at most monthly, for certain issues such as seasonality). The economist should work with sector experts on issues requiring modeling system balance with higher than yearly frequency that might arise—for example, from changes to the dispatch and merit order that could reduce costs to the utility.

i. ***Power Absorption Study***:

Depending on the investment under analysis, the CBA model may include supply and demand components that will be used to show benefits of increased supply over the baseline case. In a typical project of this nature, the economic model should attempt to capture the supply-demand balance. For a project that plans an increase in supply, perhaps through reduced transmission losses or increased generation, existing and expected demand should be included in the model, along with an indication of excess supply or demand. Excess supply can typically be allocated to new connections, while excess demand, or load shedding, can be captured and compared to the baseline scenario.[99]

Demand is given by addition of new sources of demand plus the growth of existing sources of demand, the growth of which is assumed to be mediated by price and income changes. Although this may be estimated in a number of ways, the recommended model of demand growth for households is:

$$D_t = D_{t-1}(1 + \mu g_t)\left(\frac{\Delta P_t}{\Delta CPI_t}\right)^{\varepsilon} + \Delta N_t d_t \tag{13}$$

Here, D_t is the demand forecast, given the change in the previous tariff, P_t, (in period t). Other parameters are the growth rate of income, g_t, the price and income elasticities (ε, μ respecitively) and the number of new connections N_t consuming d_t on average. Extending this model for industrial and institutional consumers is straightforward.

***Estimating* Elasticities:** Income elasticities can be estimated on a macroeconomic scale by regressing income growth on aggregate consumption, although each consumer class should ideally be estimated based on own income growth if such data is available. The IMF provides independent forecasts for the

[99] The Malawi economic model indicates that load shedding in year 20 is expected to be higher in the with-project scenario than in the without-project scenario. This is an important and perverse result of the assumption that the electricity utility increases connections in response to excess supply and on an ongoing basis.

near-to-midterm growth rates and inflation of most countries. Since MCC works in many agriculturally intensive economies, failing to adjust raw growth projections for non-agricultural and, especially, industrial growth can result in significant errors. Therefore, consumption forecasts should always be broken down by consumer class to the extent feasible. In data poor environments this analysis may not be feasible, in which case this guidance recommends a value taken from the literature, such as Wilson, Jones, and Audinet (2011).

Price elasticities are more difficult. Relying on strong assumptions of substitutability, price elasticities can be estimated in principle by comparing household or business consumption of close electricity substitutes at various price points; unfortunately, this approach requires the use of high-quality customer usage data that may not be available, so a standard value for the price elasticity is often assumed instead.[100] An alternative would be to estimate the elasticity from changes in the tariff rate. Unfortunately, however, tariffs change infrequently, and consumer response could occur with a significant lag; identification would likely pose a significant challenge.

Building on the supply-demand balance, the economic model can incorporate expected changes to transmission losses due to system demand. Under normal conditions where available supply is at least ten percent greater than demand, technical transmission losses can be assumed to reflect normal technical losses. Technical losses increase considerably as demand approaches maximum throughput capacity.[101] If the economic analysis addresses an investment in an environment with considerable load shedding, care should be taken to include or exclude these increases in losses, as appropriate, in the baseline and with-project scenarios.[102]

ii. ***Supply Forecast***:

The economic return of a transmission or distribution investment will generally be sensitive to the forecast electricity supply (generation and imports) available to the network. However, in underdeveloped networks, delays in adding new generation capacity are common, so care should be taken in aggregating information on expected generation investments to forecast generation capacity.

There is no universally applicable strategy for forecasting generation capacity under these conditions. However, new investments in generation assets, especially for larger more impactful assets, require significant lead-times to complete so that a "business-as-usual" case is likely to be a good assumption, even for as much as a decade or more into the future. For this reason, simply extrapolating current trends can produce a reasonable estimate, even if, for example, the project is expected to accelerate new IPP development.

If the power system is sufficiently large, the lumpiness of generation investment can be ignored. In these cases, extrapolating the current growth rate of generation capacity into the future is a reasonable approach. But for the case of a power system in which incremental capacity of new generation assets is relatively large compared to the system the economist should consider the actual pipeline of new generation investments. The stated commercial operation date (COD) of these assets is unlikely to reflect

[100] A value around $\varepsilon = -0.5$ is typical.
[101] Technical losses occur in both transmission and distribution systems as heat that can cause system damage.
[102] See the Malawi economic model for an example of the treatment of increasing transmission losses in a load shedding environment.

the actual COD but given the stated COD and the stage of project completion (i.e., licensing, financial close, construction), an adjustment can be made for the historical pattern of delays in the system to generate a rough forecast of the actual COD.

The economist should also assess the status and reliability of current and planned import and export agreements. The publicly stated start and end dates for import/export agreements, and the price of electricity purchased, may differ substantially from MCC's forecast in some contexts.

Likewise, the stated retirement date for generation plants may differ from MCC's expectation. Where appropriate, the certainty of the projected year online and retirement date can be coded by supply source.

C. Load Flow Analysis

The cost-benefit analysis of transmission infrastructure can be very complex. Program logics for transmission investments might include i) facilitating the efficient dispatch of current generation capacity, ii) the servicing of demand, especially peak demand, and iii) providing off-take capacity for new investments in generation capacity. In each case, the economic benefit of the transmission line is directly related to the incremental power flow that the transmission line facilitates[103]. Unfortunately, determining the incremental power flow is a difficult engineering problem beyond the scope of the economic analysis.

A Load Flow (or "Power Flow") Analysis is an engineering assessment of the steady-state power flow in an electrical network. The load flow is calculated for a range of scenarios[104] that may differ in terms of (i) the period studied, (ii) the expected level of demand in the system, and (iii) new generation that comes online during the period in question. Since the steady state power flow through the network has such a large effect on the economic analysis, this guidance recommends that the economist work with the project engineers to develop scenarios for the load flow model that are most relevant to the economic analysis. ANNEX II.B discusses some of the key considerations for the economist in the development of the load flow model.

V. Crosscutting Issues in Economic Analysis at MCC

A. Revealed and Stated Willingness to Pay

In many economic applications, researchers must identify parameters of agent preferences. In broad terms, such studies are designed to elicit or infer a willingness-to-pay (WTP) for goods or willingness-to-accept (WTA) harms within a well-defined context or application. While the methods used to obtain this information vary widely, all methods fall into two distinct categories: 1) estimates derived indirectly from revealed behavior (revealed preference techniques) or, 2) estimates derived directly from participant statements (stated preference techniques). The WTP estimates that result when these methods are used are the revealed-WTP (rWTP) and stated-WTP (sWTP), respectively. In practice, rWTP data often need to be gathered from surveys just as for sWTP data, somewhat blurring the practical distinction between the two methodologies.[105]

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[103] Note that valuation of increased throughput capacity will depend on the specific program logic of the investment.
[104] Since load flow studies are expensive in terms of both computation and money, it is not generally practical to conduct a load flow analysis for every scenario. Therefore, the economist must work with the sector experts to prioritize the scenarios that are most relevant to the analysis.
[105] Since the economist may be required to design or adapt surveys to collect revealed preference data, the opportunity cost of including stated preference modules in the survey may be low.

Using revealed preference methods to estimate a rWTP is the recommended approach for valuing benefits in the electricity sector. While sWTP estimates derived from stated preference methods are not necessarily less accurate, these methods suffer from poor reliability, less credibility among economists, and may be subject to numerous biases if survey instruments are not designed correctly to avoid these issues. As discussed below, sWTP may nevertheless have a niche role to play in the economic analysis. ANNEX III discusses the controversy around the use of stated preference methods in economics as well as practical guidance on proper design of sWTP survey instruments.

i. ***Revealed-WTP:***

Revealed-WTP studies in the power sector rely on the assumption that power is an intermediate good. This is assumed to be straightforward for firms whose energy consumption is driven by profit maximization, and hence by the relative tradeoffs between cost and productivity. Households are not profit-maximizing, but energy is still an input into household production, specifically of light, cooking heat or similar energy-intensive applications. Therefore, consumer expenditures on lighting or cooking services, such as candles, kerosene lamps or woodstoves, are treated as close substitutes for expenditures on electricity, with higher costs per unit of benefit (i.e., lumens of light or BTU of heat). For this reason, rWTP generally captures[106] the energy substitution benefit discussed elsewhere, although some cautionary notes are discussed below.

Revealed Preference methods are limited by the assumption that market prices represent the true opportunity cost of energy substitution and the reliance on market data or consumers' self-reported consumption expenditures. rWTP must often be inferred from surveys of (self-reported) consumption of energy substitutes (i.e., number of candles purchased per month, or number of gallons of diesel used, among others) and ownership of energy-producing assets (i.e., maintenance and depreciation of generators or solar panels). Using self-reported consumption worsens the precision of the WTP estimate and may increase the bias as well.[107] Moreover, assumptions must be made regarding the likelihood that consumers will substitute for cheaper electricity. This adds an element of model uncertainty to the rWTP estimate. However, these issues do not justify the use of sWTP.

ii. ***Stated-WTP:***

Relying on stated preference techniques to derive a sWTP estimate is not recommended, for reasons noted above. However, stated preference methods do have a potential role in the economic analysis in certain situations, especially for goods that are not traded in markets,[108] making these methods especially important for valuing public or environmental goods.[109] When the good in question is not traded in a

[106] Exceptions include services, such as television, which require electricity. On the other hand, cost savings for batteries or third-party charging services for cellphones can be understood as less common, but standard, examples of energy substitution.
[107] For example, if respondents are more likely to recall times of especially heavy consumption.
[108] These "non-market" values may result from externalities; non-zero "non-use" values; or missing, incomplete or thin markets.
[109] Two common methods of eliciting stated preferences are Choice Experiments (CE) and Contingent Valuation (CV). Not discussed further here, choice experiments are a quasi-experimental approach to eliciting preferences by preparing a set of choices for respondents in an experiment-like setting. CE is generally the most expensive approach for eliciting information and depending on whether the choices made by respondents are binding or not, the approach may still be subject to criticisms of hypothetical bias that affect CV approaches (see ANNEX III).

market, or the market price does not accurately reflect value, sWTP can be used in place of rWTP. Regardless, stated preference techniques should be used only when there is a clear justification and then only with great care to minimize bias. For cases when the economist believes SP techniques are necessary, this guidance lays out best practices for minimizing potential biases in ANNEX III.

In the power sector, community-level damages to livelihoods or the environment are several potential examples of externalities in which stated preference methods might be useful. Other applications might include incomplete markets, such as the market for power quality, whose value may only be imperfectly captured through revealed preference methods. However, revealed- and stated-preference techniques can be usefully combined[110] to produce improved estimates if care is taken not to double-count benefits.

The use of stated preference methods for economic valuation is controversial[111]; issues of credibility, reliability and precision may result from poorly designed survey methodologies. Nevertheless, errors arising from these sources can be greatly reduced, although not eliminated, with carefully designed surveys.[112] These methods require the economist to clearly identify respondents' incentives to respond truthfully and to carefully align the response with the informational requirements of the survey.[113] Of particular interest is the cheap talk approach of Cummings and Taylor (1999), which can significantly reduce hypothetical bias in CV studies by drawing respondents' attention to their incentive to respond truthfully.[114]

iii. ***Choosing a methodology:***

The economist should first determine data needs, which may vary greatly from project-to-project. Because prices are not necessarily set to match demand in the power sector, WTP is a necessary input in most, if not all, economic analyses of the power sector.[115] However, WTP studies are common and require significant expenditure of time and effort. So, the economist should first ascertain if there has been a relevant WTP study conducted in the country before deciding that a new WTP study is necessary to support the economic analysis. Factors to consider when determining whether a WTP study may be relevant include i) whether the study was recent, ii) whether the study focuses on consumers similar to the intended project beneficiaries, iii) the impartiality and quality of the third-party study, and iv) coordination with other donor organizations and consistency with Monitoring and Evaluation at MCC (such as the M&E plan, and planned data collection related to the evaluation or special studies). If a third party WTP study is not available, or the quality of such existing studies is insufficient, the economist will need to plan for a WTP during the program design process. Stated preference methodologies require a

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[110] For example, see Adamowicz et al. (1994).
[111] See Diamond & Hausman (1994) for the critical exposition and Hanemann (1994) for the response.
[112] Arrow et al. (1993) provides a useful "gold standard" of best practices in CV. Carson & Hanemann (2005) and Mitchell & Carson (2013) provide useful manuals, while Hanemann & Kanninen (1996) discusses statistical analysis of CV data.
[113] See Carson et al. (1996), Carson et al. (1997) and Carson et al. (1998)
[114] For example, a cheap-talk script could point out that if the respondent's WTP is high, the government will be more likely to make investments and increase the tariff, while if the respondent's WTP is low, the government will be less likely to either make the investment or raise the tariff. The key is to draw the respondent's attention to idea that their response has a non-zero chance of altering an outcome that will impact their household or business so that it is in their interest to be as honest as possible. A sample cheap talk script can be found in ANNEX II.B.
[115] This is the result the sector's natural monopoly characteristics and heavy government involvement in tariffs setting. See Section III.C. for a discussion about cost-reflective tariffs.

modest increase in the time required to design, test, and conduct each interview compared to revealed preference methods, but these incremental costs are balanced by the benefit of providing additional data for the analysis.

B. Other Issues

i. ***Central and Peripheral Investments:***

Electrical power systems exhibit strong complementarities between system components, especially but not exclusively for the transmission system; for example, transmission and distribution systems require that sufficient generation capacity exists to facilitate the flow of incremental energy, and vice-versa. MCC's planned transmission investment in Nepal is an example of a central ("trunk" or "backbone") component for Nepal's electric grid: once completed, the asset is expected to impact the flow of electricity throughout the system even for components that are geographically quite distant. On the other hand, the distribution system of Kathmandu in Nepal – an important but peripheral component of Nepal's network – is also being upgraded. While Kathmandu is the most important load center in Nepal, the city can, in principle, be isolated from the rest of the grid with little or no impact on the rest of the system. System costs and benefits are the incremental costs and benefits which accrue only in the with-project case, but not directly or exclusively because of the investment; these are a particular and important class of contingent costs/benefits. In the example of the backbone transmission line in Nepal, imports and exports across pre-existing border crossings are expected to improve because of the investment even though these cross-border lines are not directly connected to it.

When systemic costs or benefits are possible, the economist must first determine whether the investment is a peripheral component or a central component of the system. A central component of the power system may require that the economist conduct a detailed accounting of the likely systemic impacts of the investment on the entire portfolio of potential investments and the efficient operation of existing assets. For example, a central transmission line may impact transmission losses across the network while encouraging new potential IPP investors to enter the market.

System costs and benefits can greatly exceed the benefits of the isolated investment. One way around this problem—which may also simplify accounting—is to include the increment of systemic costs and benefits in the cost-reflective tariff calculation discussed in Section III.C.

ii. ***Seasonality***:

The availability and cost of generation from a given source, as well as electricity demand may vary substantially by season. For example, the availability of a hydroelectric power plant depends on seasonal rainfall in interaction with the plant's reservoir size. Likewise, the availability and cost of a biomass plant's fuel source can depend substantially on seasonal factors. Moreover, the availability and cost of imported generation can depend on seasonal factors affecting electricity demand and the availability and cost of renewable energy in the origin country. For this reason, it may be necessary to model available generation and generation costs on a seasonal or monthly basis for electric power systems for which sources of supply sensitive to seasonal factors either make up a large share of available generation or are a target of the MCC investment under analysis.

For cases where bottlenecks in transmission, distribution or electricity demand constrain the consumption of available energy during one season but not during another, it may be necessary to model the entire system on a seasonal basis to accurately estimate economic benefits and perform sensitivity analysis, although the CBA would still be conducted using the annualized data. An investment to relieve a transmission or distribution constraint, for example, would increase consumption during the season with excess generation, but not during the season when generation is constrained. Generation costs would also likely be lower in the season with excess generation due to non-use of the most expensive sources in the merit dispatch order but would rise as the constraint is relaxed.

Similarly, domestic and export electricity demand may also vary substantially by season in some contexts. This problem can be dealt with in the same manner as seasonal supply constraints, by conducting the analysis on a seasonal basis.

iii. ***Sensitivity Analysis***:

Sensitivity analysis of the power sector should not typically be different than for other sectors, although the strong complementarity between the system elements can in principle complicate the analysis. For example, in cases where bottlenecks in transmission, distribution or electricity demand constrain consumption of available energy (excess generation capacity), analysis of sensitivity to the constraining factor or adjustment of this factor may need to account for the mechanical relationship between higher consumption and higher average cost of generation. Higher average cost results from use of more expensive supply sources that are lower in the merit order dispatch to accurately reflect the sensitivity of the economic return.[116] The economist should be aware of the potential of such countervailing tendencies when conducting the sensitivity analysis.

VI. Identifying Beneficiaries for Power Sector Investments

MCC's Beneficiary Analysis Guidance and Cost Benefit Analysis Guidelines [117]should be applied to determining the number and value of benefits for power sector investments. Most investments in the power sector can be considered targeted investments, rather than regional or national investments. This narrower focus stems from the common scope of the investment focus, which often targets only those connected to the grid or targets provision of electricity to new consumers. Depending on the scale of the investment, the targeted population may cover much or little of the geographic area of the country. When investments specifically target productive uses of electricity, the benefit-cost analysis may use an 'increased incomes' approach, and the estimated value of benefits may stem from increases in income. Accordingly, beneficiaries would likely include employees of those firms and all household members associated with those employees. Benefits from many investments will result from reduced costs to firms and households, and the estimated benefits will stem from consumer surplus calculations. When an investment reduces the costs of energy to a household, all members of the household are counted as beneficiaries. When investments lower the costs of energy to firms, the beneficiaries may or may not include firm employees.

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[116] In the analysis of MCC's investment of Nepal's backbone transmission line – an investment whose motivation includes the facilitation of imports from India – the analysis found that the ERR was too sensitive to the border price of electricity. However, at a certain point, high border prices would likely cause less power to be traded, reducing the expenditure on exports and moderating the effect.

[117] MCC's Beneficiary Analysis Guidelines is available to internal users, but not available publicly. MCC's CBA Guidelines is available at https://www.mcc.gov/resources/doc/cost-benefit-analysis-guidelines

For example, consider a Compact that plans to increase electricity supply on a grid experiencing excess demand, but not substantially beyond the assumed suppressed demand. Benefits accrue to firms with existing connections due to increased consumption of grid-supplied electricity, valued at the estimated WTP. How each firm would react to the assumed cost reduction is unknown. High unemployment leads to the expectation that wages would not increase without increases in labor productivity. Labor productivity increases may result from increases in capital productivity, but this is expected to result from the employment of new capital. New capital could reduce the need for labor. Related assumptions should be made only for targeted investments where extensive data has been collected on a specific sector, leading to a reasonable understanding of the expected adjustments. Thus, for the case of firms with existing grid connections, no assumption is made that firms' employees benefit from the Compact. When the results of the model indicate expected new commercial and industrial connections resulting from the Compact, the expected employees associated with these firms are included as beneficiaries even if the expected wages are not above the outside options for these employees. In lieu of more specific data, when estimating the beneficiaries of new firm connections, the average employment of existing firms can be used as the expected size of new firms, and the average number of household members can be used to determine the assumed size of the employee's household. Care should be taken not to double count households that also benefitted from other aspects of the investment.

Investments in the power sector, unless specifically targeted to poorer households, typically favor the wealthier households. This outcome stems from the path dependence of historical grid expansion on income: those firms and households that could afford to pay were connected, while those that could not afford to pay were not connected.[118] Furthermore, electrification efforts can lead to perverse outcomes within the household unit: under some circumstances, women do not benefit or can even be penalized due to electrification.[119]

Such dynamics, even when included within the program logic, are unlikely to belong in the economic logic or, specifically, the cost-benefit analysis. Regardless, the consumer surplus approach to cost-benefit analysis recommended in this guidance captures many benefits to households outside of the direct effects on energy usage – a reduction in the time needed to collect firewood being only one example. Even when the economic analysis does not explicitly attempt to quantify these benefits, the evaluation can be used to address these more difficult to quantify hypotheses.

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[118] See World Bank (2008, pp. 19-28) for a discussion regarding the beneficiaries of electrification. Bernard (2010) reviews and questions the results highlighted in World Bank (2008), noting that many household changes were not included in these analyses that would plausibly affect the outcomes. See Louw et al. (2008) for an analysis conducted in South Africa on residential demand for electricity, which finds electricity demand is income inelastic, at least among the low-income households in their sample. Dinkelman (2011) finds that rural electrification in South Africa increases participation in the labor force for men and women, but with women earning a lower wage than prior to electrification. See van de Walle et al. (2013) for a recent assessment of the long-term impacts of rural electrification on schooling, consumption, and labor supply in India.

[119] See Clancy et al. (2011) for a discussion of gender issues related to electrification.

ANNEX I. Investments in the Power Sector

A. Brief Introduction to Project Types and Taxonomy

i. Reform of Sector Governance

Reform of Regulators and Regulatory Frameworks: Investments in the power sector may target reform, or the creation, of an independent regulator, or the reform of regulatory frameworks within the relevant ministries. It is quite common that an independent regulator is independent in name only. Investments in such a reform may target the creation of an accountable entity that is mostly independent of government influence. Conversely, reforms targeted to relevant ministries might focus on the creation or implementation of regulatory frameworks that insulate key decision makers from political interference. In this example, the reform would assist the government entity to reduce political influence, aligning its focus on concerns within the power sector.

Reform of the legal status, board structure, or financial autonomy of the utility: Investments in the sector may also involve a change in the degree to which a state-owned electricity utility is required to meet commercial performance criteria, reduce or cease any dependence on state funds to cover operating losses; and/or the degree of professionalism and political independence of the utility's board of directors.

ii. Support for Implementation of Sector Policies

Implementation of Cost-Reflective Tariffs: Many partner countries will not have cost-reflective tariffs in place due to the strong political incentive to subsidize electricity tariffs. While often politically rewarding, such policies usually lead to underinvestment by the utility. Utilities that are not permitted to charge cost-reflective tariffs typically operate at a loss and are thus not considered to be credible off-takers. Such insolvent entities are not able to pay private power suppliers on a regular basis, which in turn, can limit investment in generation. Investments in this area could include funding cost-of-service studies and the development of financial models for the utility to be used to develop and maintain cost-reflective tariff estimations. Any potential investment should consider political incentives and influences that may affect the sustainability of proposed changes.

Tariff Differentiation Policies: As not all power consumers are alike, most utilities apply different tariffs to different classes of consumers (e.g., residential, commercial, and industrial). Questions that economists and policymakers or regulators must ask include: How should these different tariffs be defined? Should tariffs vary by region? Should tariffs vary by time of use? How frequently should these tariffs change? What is the right fee to charge an industry for potential demand? Answering such questions can also help define concerns related to low-income subsidies, as a cross-consumer subsidy scheme can be implemented to encourage connection and use by households in the lower income deciles. An absorption study can help determine whether peak pricing can reduce system strain during peak hours and allow the utility to manage its energy portfolio more efficiently. In addition, the question of cross-subsidization of different consumer classes should be addressed.

Development of Electricity Rationing Policy: Independent of the utility's ability to meet demand for electricity, a transparent electricity rationing policy should be in place to avoid problems related to load shedding. Regarding electricity rationing policies, "very few, if any, countries plan how they would deal with rationing should it become necessary. ‘Planning’ for a crisis is more often than not perceived as politically incorrect. As a consequence, when a shortage episode happens, there are no consistent procedures, regulations, incentives, and political consensus on how the crisis should be managed” (Maurer, Pereira, & Rosenblatt, 2005). Research considering possible responses to electricity shortages has produced recommendations of international best practice; investments in this area could fund the needed studies to develop and implement such a policy.

iii. Increasing On-Grid Supply[120]

Increased Generation Capacity*:* Investments in this area could include new generation capacity (e.g., a new power plant[121]) or increased capacity through refurbishment of existing equipment (e.g., increasing head-pond capacity, weed/sediment removal, generator replacement/expansion).

Transmission System Extension/Rehabilitation*:* The transmission systems in many partner countries exhibit high losses and frequent failures. Failures may result from assets that have outlived their useful operation, such as wooden electricity poles that have rotted to the point of collapse or inoperable mechanical switches due to lack of maintenance. Total system losses indicate the percent of energy that is not billed, in relation to the total energy produced. Investments in this area could include refurbishment or replacement of existing assets (e.g., transmission lines, sub-stations, SCADA - supervisory control and data acquisition).

Urban/Rural Distribution Extensions*:* As electrification rates are low in many partner countries, common country goals include extending grid coverage. Typically, grid extension projects are extensive (i.e., extending grid coverage to locations not yet connected) and occur in rural areas, rather than intensive (increasing the connection rate in areas with existing access to electricity), occurring more frequently in urban areas. Aside from the physical expansion to the distribution network, grid expansion projects need to consider the social and economic situation of households and businesses that have yet to connect; individual decisions to connect to the grid are not always straightforward.

iv. Reducing on-Grid Demand[122]

Appliance Efficiency Standards*:* Implementing efficiency standards for appliances can reduce demand on the grid, allowing the power sector time to adjust to growing demand. Investments in this area could help the country’s power sector develop appropriate policies to implement appliance efficiency standards.

Subsidies for energy-efficient products*:* Like appliance efficiency standards, governments may choose the policy of subsidizing energy-efficient products with the intention of rapidly reducing electricity demand or slowing electricity demand growth. Energy-efficient product subsidies can be used to target products that

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[120] Many on-grid supply investments that include multiple projects and/or activities should be modeled as one investment, due to the interrelations and dependencies of the network. For example, the Malawi Compact’s Power Sector Program, which consists of three projects, is modeled as one.

[121] The MCC generally sees non-renewable power plants as an area for private sector investment; some renewable power plants may be considered for MCC investments, due to the lack of private sector interest.

[122] See CPUC (2002) for a guide, from the perspective of the public electricity utility, detailing demand-side management options and analysis, including conservation, load management, fuel substitution, load building, and self-generation. Please note the correction memo CPUC (2007), if using this reference.

are contributing to peak demand and to encourage consumers to implement technologies that have very short payback periods, but otherwise are not being implemented.[123]

v. Increasing off-Grid Supply[124]

Isolated Generation (e.g., solar, small-scale hydro, wind, biogas and diesel)*:* Off-grid and mini-grid supply installations can be the preferred investment to increase access to electricity when extending grid access is not cost effective, typically due to required long transmission or distribution distances or difficult terrain. Isolated systems may generate and distribute electricity, or they may target energy-intensive applications directly, thereby reducing demand for electricity or other electricity substitutes. Examples of energy-intense applications may include hot water heating and cooking heat sources. Common off-grid supply examples include solar systems for rural households and public institutions, solar ovens, and isolated pumping systems for irrigation.[125] Investments in isolated solar generation are generally not limited in scale, ranging from household systems through community-wide mini-grid systems.

Mini-grid Refurbishment and Expansion*:* Due to the small scale of these systems, small grids often face more acute difficulties balancing supply and demand across the network. Demand is inherently less predictable when fewer consumers are connected to the grid, leading to technical losses and system degradation. These problems are often exacerbated by poorly functioning institutional arrangements and a lack of local technical capacity for operating the grid effectively. Investments could include reforming the system operations, new generation grid extensions or battery systems to help shift supply to serve peak demand.

vi. Increasing off-Grid Demand[126]

Connection Incentive Programs: Outreach programs are sometimes needed to explain the potential benefits of connecting to an isolated system. Investments can fund education programs that help potential customers understand the benefits of electricity over inferior energy sources (e.g., use of wood, which is costly to collect and often results in deforestation); programs can also prepare customers to manage financial and social aspects of electricity connections and consumption.

Demand Management**:** Peak/Off-peak tariff structures can reduce demand at peak times while increasing demand off-peak. Similarly, tariffs can be structured to better reflect seasonal variations in supply. Such demand-smoothing policies can help reduce system disruption and premature asset depreciation. Other policies to increase investment in productive uses of excess supply, such as powered ropeways or agri-processing, can also help small grids to balance supply and demand.

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[123] See Limaye, Sarkar & Singh (2009) for an evaluation of international energy efficiency efforts related to subsidized purchase of CFLs. The estimated customer savings are more than 20 times the cost of the $2 million, illustrative program (p. ES-7). Also, see the website and publications of the National Association of State Energy Offices for examples of state and federal appropriations used to reduce energy costs in the U.S.: www.naseo.org

[124] See Barnes & Floor (1996) for an introduction to some of the history and challenges associated with rural electrification in developing countries.

[125] See Burneya et al. (2010a) and Burneya et al. (2010b) for a benefit-cost analysis of solar powered irrigation systems implemented to replace diesel irrigation pumps in the Sudano-Sahel region. See Martin et al. (2011) for a technical presentation of energy and costs options for pumped irrigation.

[126] See Winkler et al. (2002) for a benefit-cost analysis of various low-income housing improvements related to energy efficiency; discussion of required government policies to address households' ability to pay is included.

Table 6 applies the taxonomy to previous MCC investments in the power sector; some MCC projects and activities contain multiple elements in the taxonomy and are listed more than once. This table can be updated periodically to guide readers to internal documentation of similar projects that were included in previous Compacts.

Table 6: Taxonomy of Past MCC Compacts in the Power Sector

<table>
<tr><td colspan="6">Governance Structure</td></tr>
<tr><td rowspan="6">Malawi I:
• IPP framework
• Unbundling
Senegal II:
• Reform sector institutions (utility, regulator, and ministry)</td><td colspan="5">Power Sector</td></tr>
<tr><td rowspan="5">Malawi I:
• Utility strengthening
Mongolia I:
• Wind Subsidies
Ghana II:
• Utility Financial Strengthening
Benin II:
• Tariff Policy
• Utility strengthening
Senegal II:
• Utility strengthening</td><td colspan="2"></td><td>On-Grid</td><td>Off-Grid</td></tr>
<tr><td rowspan="3">Supply</td><td>Gx</td><td>Indonesia I: Large Renewables
Liberia: Hydro. Rehab
Benin II: Solar PV;</td><td rowspan="3">El Salvador I:
• Solar home systems
Tanzania:
• Kigoma Solar
Indonesia I:
• Small Renewables (solar and biogas/biomass)
Malawi I: Solar irrigation grant
Ghana:
• Rural Electrification
Benin II:
• Off-grid solutions (solar home systems, mini-grids)</td></tr>
<tr><td>Tx</td><td>Tanzania: Zanzibar Connector
Malawi I: Tx extensions; Environmental management
Nepal: Tx Backbone and Power Trade
Senegal: Dakar Tx Strengthening</td></tr>
<tr><td>Dx</td><td>El Salvador I: Rural Dx Extensions
Mongolia I: Network Upgrades
Tanzania: Distribution Rehab and Extensions
Ghana II: Distribution Rehab and Extensions
Benin II: Network Reinforcements
Senegal II: Network Extensions & Upgrades</td></tr>
<tr><td>Demand</td><td colspan="3">Mongolia I: Energy Efficiency
Ghana II: Energy Efficiency
Senegal II: Encourage electricity adoption & productive uses in Rural/Periurban areas</td></tr>
</table>

B. MCC Investments in the Power Sector

This section presents an overview of existing Compacts with projects and activities in the power sector. Some of MCC's experience in the power sector includes projects or activities in Georgia, Mongolia, Indonesia, Ghana, El Salvador, Tanzania, Malawi, and Liberia. Several other power sector projects in Senegal, Nepal, and Burkina Faso are currently awaiting entry-into-force, as of the time of this writing. The Georgia Compact included funds for the rehabilitation of a natural gas pipeline and storage facility as part of a larger $314 million project. The Mongolia Compact included $47 million for consumer subsidies for energy-efficient products, subsidies for wind generation, a transmission substation upgrade, and a public awareness campaign related to these activities. The Indonesia Compact includes $242 million for a facility to fund commercial and small-scale renewable energy investments (as well as investments in productive sustainable land use). The Ghana Compact included funding for on-grid and off-grid electrification of rural agricultural facilities. The El Salvador Compact included $33 million for on-grid network extensions and off-grid solar electrification system investments. The Tanzania Compact included $206 million for three distinct investments: a transmission system interconnector between Zanzibar and mainland Tanzania, a small hydroelectric power plant and associated distribution system, and a distribution network extension and rehabilitation activity in six regions of the country. (During Compact implementation, the hydropower activity was cancelled due to environmental concerns and replaced by an off-grid solar project in the same region of Tanzania.) The Malawi Compact includes $350 million for investments in the transmission system, rehabilitation of a hydro power plant, improvements in hydro plant availability, and power sector reform. The Liberia Compact includes a $209 million Energy Project that aims to rehabilitate the Mt. Coffee Hydropower plant and reform electricity sector institutions.

The economic analysis approaches used in the El Salvador and Tanzania Compacts are contrasted to highlight the need for guidance on economic analysis of power sector investments.[127] Some of the changes to the economic analysis for the Malawi Compact are also presented to highlight the differences in past economic analysis of power sector investments.

El Salvador: Rural Electrification Sub-Activity ($32.8 M)

According to the El Salvador Compact, signed in November 2006 for $461 million, the $32.8 million Rural Electrification Sub-Activity was part of the Community Development Activity, which was part of the Human Development Project. The Sub-Activity proposed the construction of approximately 1,500 km of new distribution lines, distribution upgrades, 46,000 household connections to the network, and 950 solar power system installations.

The economic logic of this Sub-Activity was based on the reduction of household costs associated with energy consumption. From the 2006 MCC El Salvador Investment Memorandum, 'Program Analysis, II. Project Assessments:'

> Access to electricity results in immediate and significant financial savings and increased household productivity… [H]ouseholds served by the Rural Electrification Sub-Activity will realize an estimated savings of almost USD 90 per year when served by connection to the distribution network (based on a reduction in cost from over USD 2.50/kWh to USD 0.20/kWh), and roughly USD 95 per year when served by a solar photovoltaic system (based on a reduction in cost from over USD 3/kWh to USD 0.70/kWh). These savings are equal to more than 6% of the average annual household income in the Northern Zone.

The stated approach used to estimate economic benefits for this Sub-Activity is indicated in the Investment Memorandum:

> In the without-project scenario, a household uses some combination of candles, gas or kerosene lamps and car batteries for its electricity and energy needs. Information from the 2004 household income and expenditure survey (EPHM-04) indicates that the average household without electricity spent USD 8.04 and consumed 3.13 Kilowatt-hours (kWh) per month. The latter calculation used conversion factors to convert consumption of candles, gas and batteries to

[127] For the purposes of this review, background information and CBA logic is pulled from MCC Investment Memoranda, Compacts, and initial CBA models.

Kilowatt-hour equivalents. These figures imply that average price was USD 2.57 per kWh. In the with-project scenario, prices are estimated to decline to USD 0.20 per kWh. This price decline is the driving force behind the economic returns.

Review of the benefit-cost analysis spreadsheets indicates modeling of the project similar to what is indicated in the Investment Memorandum. A consumer surplus model is employed to estimate the cost savings to households, which includes the use of a constant elasticity of substitution (CES) demand curve estimated from a household survey.

Tanzania: Energy Sector Project ($206 M)

According to the Tanzania Compact, signed in February 2008 for $698 million, the Energy Sector Project consists of three Activities: Zanzibar Interconnector Activity ($63.1 M), Malagarasi Hydropower and Kigoma Distribution Activity ($53.7 M), and Distributions System Rehabilitation and Extension Activity ($89.7 M). The Zanzibar Interconnector Activity proposed increasing the electric power supply to Zanzibar's Unguja Island by laying a 40 km, 100 MW, submarine transmission cable between Zanzibar and Dar es Salaam, installing 42 km of overhead transmission lines, and rehabilitating the main substation near Zanzibar Town. The Malagarasi Hydropower and Kigoma Distribution Activity proposed the construction of an 8 MW hydropower plant and the construction of a transmission and distribution network to serve approximately 21,000 customers.[128] The Distributions System Rehabilitation and Extension Activity proposed the rehabilitation of existing power distribution assets and the extension of the distribution network in six regions to serve approximately 215,000 customers. Capacity building and technical support for TANESCO and ZECO were also part of these Activities.

As stated in the 2007 Investment Memorandum, the description of the Zanzibar Interconnector Activity indicates that economic benefits arise from consumption of lower-cost electricity from the mainland, rather than the higher-cost electricity that could be generated on Zanzibar by diesel generators. The description of the Malagarasi Hydropower and Kigoma Distribution Activity indicates economic benefits arising from consumption of lower-cost electricity from the hydropower plant, rather than the consumption of higher-cost electricity from diesel generators. The description of the Distributions System Rehabilitation and Extension Activity does not indicate the source of economic benefits.

The Investment Memorandum further elaborates the economic benefits included in the analysis of the three Activities. Three benefit streams are common to the Activities: the assumption of increased economic activity due to the provision of electrical infrastructure, the avoided costs of operating electrical protection equipment, and improvements in education and health resulting from avoided emissions from kerosene and diesel. A fourth benefit is specific to the Zanzibar Interconnector Activity: the value of not experiencing an extended blackout due to a failure of the existing submarine cable. The Investment Memorandum indicates that consumer surplus is not included in the economic analysis.

Review of the benefit-cost analysis spreadsheets indicates modeling of the project similar to what is indicated in the Investment Memorandum. Benefits streams are included for improved health and

[128] The Malagarasi Activity was later dropped from the Compact due to environmental concerns and it is not considered in later discussions of MCC projects in this paper. As part of the Compact rescoping, the Malagarasi funds were substituted into the Kigoma Solar program.

education, improved power quality, an insurance value for the Zanzibar Interconnector Activity, and assumed increases in growth.

Malawi: Power Sector Revitalization Project ($309 M)[129]

Malawi's Compact, originally defined as one project, consists of two activities in the power sector: The Infrastructure Development Activity, with funds of $283 million, and the $26 million Power Sector Reform Activity. The Infrastructure Development Activity provides funds to rehabilitate and modernize part of the transmission grid, rehabilitate hydroelectric turbines, and increase availability of hydroelectric power plants. The Power Sector Reform Activity funds activities to strengthen the public utility and to implement regulatory reform to strengthen the power sector.

C. *Malawi Compact*

Table 7: Malawi Compact Summary

Project/Activity	Funding	Sector(s)	Description
Infrastructure Development Project	290.2	Generation Transmission Distribution	Rehabilitate, upgrade, and modernize ESCOM's generation, transmission, and distribution assets, including the refurbishment of the Nkula A hydropower plant, construction of a 400 kV transmission line, transmission and distribution upgrades, and installation of new SCADA controls
Power Sector Reform Project	29	Sector Reform	Supports the Government's policy reform agenda and builds capacity in pivotal sector institutions, including ESCOM, Malawi Energy Regulatory Authority, and the Ministry of Energy
Environmental and Natural Resources Management Project	31.5	Generation	Increases hydroelectric power plant availability by addressing the growing problems of aquatic weed infestation and excessive sedimentation in the Shire River
Costs/Benefits Included	Generation/Transmission/Distribution: Energy Substitution is included as the expected reduction in technical losses in the transmission system should result in increased supply in the supply-constrained environment, allowing consumers to substitute lower-cost electricity for other energy sources. Generation/Transmission/Distribution: Efficiency gains capture the reduced O&M of hydroelectric power plants, given the reduced technical losses in the transmission system. Generation: Energy Substitution is included by incorporating the expected increased availability of hydroelectric power plants resulting from decreased weed infestation and sedimentation. Sector Reform: Power sector reform investments are expected to contribute to the sustainability of the benefit streams from other projects and activities.		

[129] The Malawi Compact underwent changes that created three distinct projects encompassing the original Compact Project and Activities; the budget remains the same.

Costs/Benefits Excluded	Generation/Transmission/Distribution (including ENRM): Price Reductions and Increased Value-Added are not included due to the limited expected increase in the supply of electricity (3 MW). Health and Education benefits are excluded, as the increase in the consumption of electricity is expected to be absorbed by existing customers. Connection Fees are not included as no new customer connections are expected beyond the baseline scenario. User Asset costs are not included in the model as no new customer connections are expected beyond the baseline scenario.

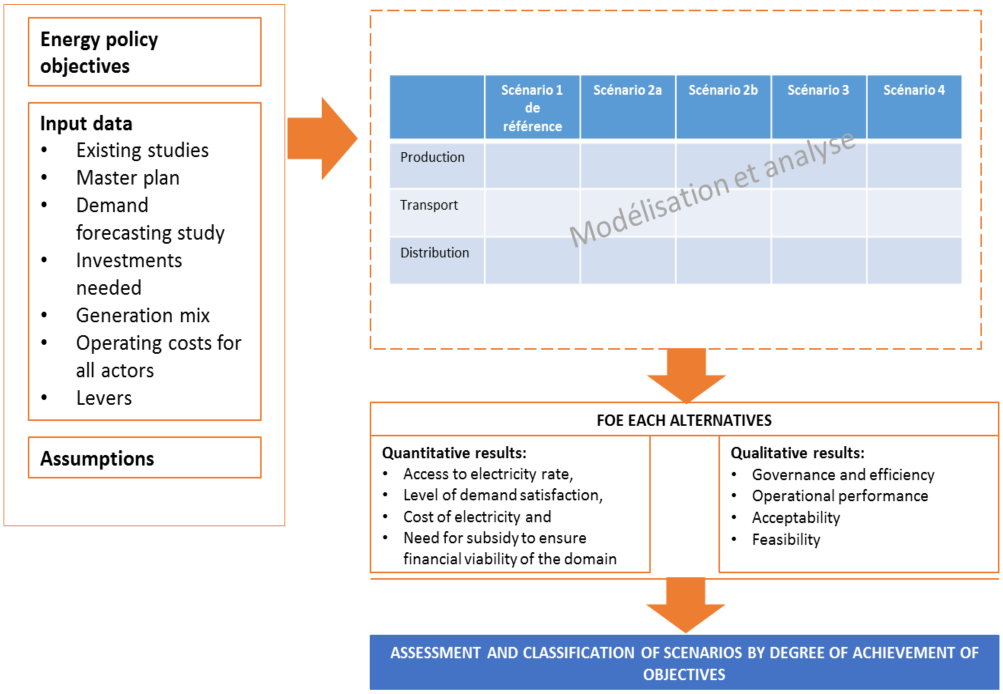
This summary table of typical costs and benefits is a table for each Compact with investments in the power sector, with an indication of the included and excluded costs and benefits.[130] Where Compact projects and activities are modeled separately, the "Costs/Benefits Included" and "Costs/Benefits Excluded" rows should be completed for each project or activity. Where multiple projects and activities are modeled jointly, these rows should describe the costs/benefits accordingly. Where costs and benefits are included or excluded beyond the standard recommendations, reasons for not following the guidance should be provided. Proper citations should guide the reader to original or supporting documentation. The first table is Table 6 for the Malawi Compact.

D. PIR Case Study, Burkina Faso II

The economist should consider using the output of the technical financial model simulations to estimate the change in consumer surplus that will results from the selected PIR options. To illustrate this, consider the case of Burkina Faso. The benefit streams of the reform project is expected to come from four sources, including (i) reduction in cost of service, (ii) increase supply as the system will create the necessary environment for independent power producers (IPP) to enter the market, (iii) increase electrification due to higher investment (both public and private), and (iv) reduction in subsidy needs since cheaper imports and solar-based IPPs will reduce cost of service and therefore reduce the need for government subsidies as Burkina power sector improves its power imports institutional capabilities. The magnitude of the change of these indicators depends on the policy reform scenario chosen out of several potential scenarios developed based on the gap analysis. Five scenarios were developed and analyzed as part of the

[130] The information provided here is meant to be condensed so as to facilitate its use as a reference tool. Indicated funding should include monitoring and administrative costs; values in US$ M.

Figure 5: CPCS/PWC technical-financial modelling structure from the Burkina Faso roadmap study.



Burkina Faso power sector roadmap study. Each of the sub-components of the scenarios are associated with a financial trajectory of the power sector developed based on the existing correlation between variables in power sector budget.

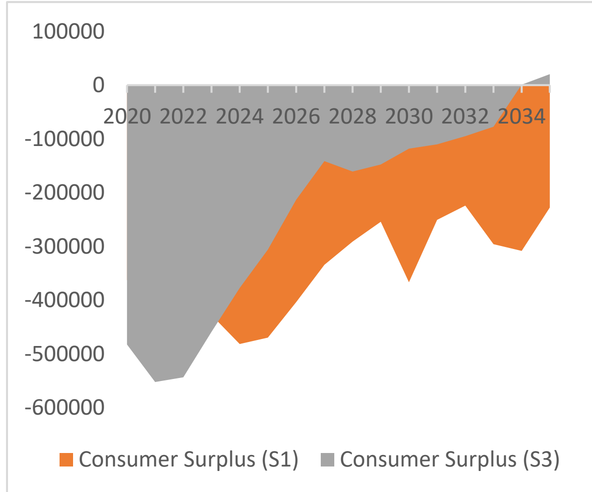
The technical-financial model developed by CPCS and PWC as part of the roadmap analysis was used to estimate the differences across the four benefit streams between what the model assumes as the base case scenario and the scenario that reflects the changes that will results from the reforms and interventions that GoBF agreed to pursue per the roadmap recommendations. Due to the interdependencies between the various activities under project 1, the country team decided to only estimate a single project level ERR to avoid any double counting errors. The process used to develop the technical financial model is illustrated in

To estimate the project's ERR, the economist compared the consumer surplus of the base case scenario to the consumer surplus of the scenario chosen by the GoBF. The consumer surplus can then be estimated using the formula:

$$CS_{it} = (WTP - CRT_{it}) * GWh_{it} - Inv_{it} - Sub_{it} \tag{14}$$

where CS_{it} stands for consumer surplus; WTP is the Willingness to Pay as captured by the WTP survey conducted in both Ouagadougou and Bobo Dioulasso; CRT_{it} is the cost reflective tariff measured in the PWC technical-financial model; and GWh_{it} is the additional supply identified in the PWC model. The consumer surplus is not generated in a vacuum, but is an outcome of investments, and the PWC model estimates both the investment and subsidy costs associated with various policy reform scenarios. Specifically, the model defines Inv_{it} as the investment required to meet the expected demand, and Sub_{it} is the subsidy requirement to ensure that the utility is financially viable. Finally, the subscript i stands for the scenario (base case vs. with reform) and t for the year, as the analysis covers the impact of the reform for the next 15 years, 2020 - 2035.

Figure 6: Consumer surplus between the base case (S1) and the selected scenario (S3).

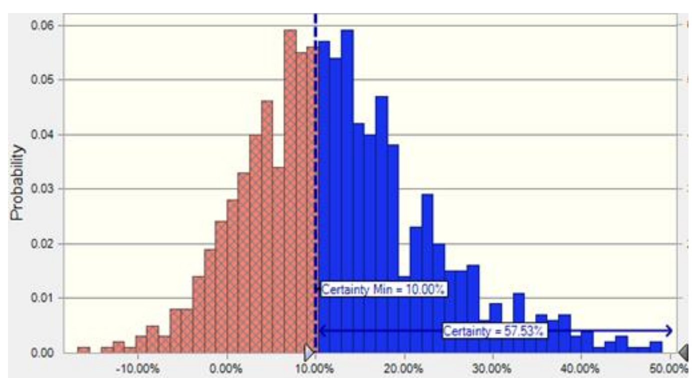


The CBA model consisted of taking the difference between consumer surplus before and after the implementation of project 1, $CBA = CS_{after\ P1} - CS_{Before\ P1}$. The difference in consumer surplus is illustrated in Figure 6 and correspond to an ERR of 11.30% with a NPV of $78.04 million. Figure 6 shows that the reforms will initially have a negative impact on consumer surplus, but the effect will become more favorable than the base case scenario after three years. Although consumer surplus is negative in both cases, the incremental benefits from project 1 become positive before year 15: thus, the roadmap to the utility financial viability is expected to be long, but with a long-term positive impact.

Given the numerous uncertainties around the model inputs, we conducted Monte Carlo simulations using 1000 trials with uncertainties around changes in cost of service, in MW supply, and in the probabilities that the reforms will materialize (see Figure 7) and found that there are 57% chances that the ERR is above 10%.

The beneficiaries of this project include all connected households in 2027, the close of the compact. We estimate that total electrification rate will increase to 35% (8.1 million people) in 2027 and the profile of project 1 beneficiaries includes 2.2 million poor, 2.5 million near-poor, and 3.4 non-poor people, if we assume the poverty distribution to remain as it is today. The present value of project 1 benefits per beneficiary is $50.76, representing 2.8% of annual consumption per household.

Figure 7: Monte Carlo Simulation for Project 1



ANNEX II. Technical Appendix

A. Glossary of Terms[131]

Term	Section & Page	Explanation
Ability-to-Pay	IV.A p.37	Ability-to-pay is often discussed in the context of tariff setting, along with the willingness-to-pay. Ability-to-pay is the characteristic of the consumer that relates the affordability of a consumers' expenditures, for example, as measured by the relative budget share on energy-related items.
AC/DC Power	II.B p.8	Alternating current (AC) and direct current (DC) are two means for delivering electrical power in an electrical power system. Alternating current refers to a current or voltage that varies sinusoidally over time, while for direct current these quantities are constant. AC systems may become unstable if not properly synchronized across the network but allow the use of transformers that can 'step up' voltage to reduce system losses as heat. DC systems do not need to be synchronized, but also cannot use transformers to step-up voltage. Hence, while AC systems are far more common in electrical grids, DC systems have a niche role in transmitting high voltages over long distances where synchronizing distant parts of the system is a constraint.
Ampere	II.B p.8	Ampere is the unit of electrical current, often referred to as an 'amp' and denoted by A.
Ancillary Services	II.B p.8	Ancillary services are the services necessary for the system operator to maintain service reliability to consumers in the operator's control area, facilitating the continuous flow of electricity that allows supply to continually meet demand.
Availability	II.B p.8	See Availability Factor.
Availability Factor	II.B p.8	The availability factor is the ratio of the amount of time that a power plant is available to produce power over a period and the amount of time in the period. By construction, the availability factor should always exceed the capacity factor.
Base Load	II.B p.8	Base load (or baseload) in an electrical grid is the minimum level of demand on an electrical grid over a period (i.e., a week or a year). Some generation power plants are specialized to deliver baseload power: these assets generally have low marginal costs of generation, but often large, fixed costs and slow ramp times.
Bus or Busbar	II.B p.8	A busbar refers to a metal strip or bar that carries current connecting components of an electrical system, especially high voltage equipment within substation switchyards. A bus can also refer, somewhat more figuratively, to a special link in a 'bus' network, of which electric power grids are but one example.
CAIDI		CAIDI stands for the Customer Average Interruption Duration Index. CAIDI is a measure of the reliability of a power system based on the average

[131] Definitions in this section have been harmonized with those found on wikipedia.org/.

		duration of outages that any given customer would experience during the period. $$CAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customer\ interruptions}$$
Capacity	II.A p.7	The capacity of an asset (e.g., a generation power plant or a transmission line) is the maximum sustained power than can be produced or transmitted by that asset. See nameplate capacity (generation) or throughput capacity (transmission).
Capacity Factor	II.B p.8	The capacity factor is the ratio of the amount of energy produced over a period and the maximum amount of power that could have been produced in that period. Generally, the maximum amount of power that could have been produced in a period is equal to the product of the nameplate capacity and the length of time of the period but may fall significantly below this level for renewable technologies that depend on the availability of natural resources such as the sun to operate at their nameplate capacity.
Coping Cost	II.C p.11	Coping costs are the costs incurred by consumers due to the consumer's attempts to avoid or reduce the impact of supply disruptions. Coping costs reveal the consumers' willingness to pay (WTP) for more, or higher quality, power, so that these are a broad conception of the revealed willingness to pay for reliable electricity. These costs should include purchases on (i) the equipment for supplying power at need (e.g., diesel gensets or solar panels); (ii) the equipment for smoothing the delivery of power (e.g., batteries or capacitors); (iii) costs of maintaining or fueling such equipment; and (iv) electricity substitutes (e.g., candles). Coping costs are the recommended approach for estimating the revealed-WTP for grid-connected consumers.
Consumer Damage Function (CDF)	II.C p.11	A consumer damage function (CDF) relates the damage incurred by electricity consumers due to an interruption to the supply of electricity. The CDF is a function of numerous factors related to the characteristics of the interruption (including season and time of day) and the consumers affected, as well as the context of the network. This guidance provides shape factors for the CDF and recommends estimating an overall scale factor for each MCC country using a short set of survey questions.
Cost-Reflective Tariff (CRT)	II.C p.11	The cost-reflective tariff is a concept for identifying the social opportunity cost of electricity consumption. Since electricity prices (tariffs) are not necessarily set in the market. As the social opportunity cost, the cost-reflective tariff should approximate the long-run marginal cost of the system, including both current costs and levelized costs of new investments.
Demand	II.A p.7	Demand is the level of desired consumption, i.e., in the standard economic sense. In quantity rationed markets, such as the electricity sector, there is an additional distinction between met and unmet demand, as the price does not self-equilibrate to match the quantities of supply and demand in the market.
Dispatch	II.A p.7	See merit order.

Dispatchable Generation	II.D p.15	Dispatchable generation refers to sources of power that can be dispatched on demand by the operators of the power grid. System operators must dispatch power to meet momentary fluctuations in demand.
Dispatch Curve	II.B p.8	See merit order. The dispatch curve relates the (system) marginal cost of dispatching generation to the load on the system.
Duration Curve	II.B p.8	A duration curve (e.g., a load duration curve, or a price duration curve) is a relationship between the magnitude of a quantity (e.g., load) and the frequency at which a system meets or exceeds that magnitude. For example, a load duration curve shows the frequency that a system meets or exceeds a given load. This allows the analyst to quickly determine the approximate frequency that a generation power plant will need to be dispatched based on its position in the merit order. This can help the analyst understand the incentives for new investments in generation.
Economies of Scale	II.A p.7	Economies of scale are the cost advantages that enterprises obtain due to their scale of operation. If the minimum of the average cost curve occurs at the scale of the market size, then the enterprise is a natural monopoly.
Economies of Density	II.A p.7	Economies of density are cost savings that result from spatial proximity of suppliers (to one another or to consumers).
Electricity	General p.4	Electricity is the phenomenon associated with the flow of electrical charge, a fundamental property of subatomic particles. It can occur either through the physical movement of electrically charged particles or, as in most practical electrical or electronic systems, through a net bias in the motion of a group of such particles due to an applied electric field.
Energy	General p.4	Energy is the property that must be transferred to an object to do work, for example, moving an object. Energy cannot be created or destroyed, but it can be stored for later use or lost to the environment, e.g., in the form of light or heat.
Grid	General p.4	An electrical grid is an interconnected network for delivering electrical power to consumers from distant producers. On-grid refers to projects or assets that are connected to a national grid, generally containing millions of individual connections. Off-grid refers to projects or assets that are not connected to the national grid, which can include smaller grids (i.e., mini- or micro-grids). Because of increasing returns to scale in the sector, smaller grids will tend to provide power at a higher cost and lower level of reliability than larger grids.
Intermittency	II.B p.8	See non-dispatchable power. Some sources of energy are not continuously available, especially for renewable sources such as wind, solar, and run-of-river hydro.
Installed Capacity		See capacity.
ITSO		ITSO stands for Independent Transmission System Operator. See transmission system operator.
kV		See volt.
kVA		See volt-ampere.
kW		See watt.
kWh		See watt-hour.

Levelized Cost of Electricity (LCOE)	III.C p.32	The Levelized Cost of Electricity is the price per unit of electricity that the utility would need to compensate a risk-neutral owner of a generation facility so that the owner is just indifferent about entering the market. It is given by: $$LCOE = \frac{discounted\ sum\ of\ lifetime\ cost}{discounted\ sum\ of\ energy} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$ WhereE_t is the energy produced, and M_t and F_t are the maintenance and fuel expenses in year t. One advantage of the LCOE concept is that there are industry standards for LCOEs of many classes of technologies currently in use.
Load	II.A p.7	Load is the power delivered to or consumed by electrical devices on the network. Load is a conceptually related to, but distinct from met demand, although the two terms are sometimes used interchangeably in power sector contexts. An important exception is that, depending on the context, power consumed by the network itself (i.e., losses) may also be identified as "load." For example, if we consider a load center in a national grid, such as a city, the transmission system operator only needs to know how much power is being drawn by the city (i.e., the load) and not the extent to which power is being lost within the city's distribution network.
Losses (Commercial)	II.C p.11	See losses (non-technical).
Losses (System)	II.C p.11	System losses are the difference between the energy produced in an electrical system and the energy consumed. System losses are equal to the sum of the technical and non-technical (i.e., commercial) losses.
Losses (Non-technical)	II.C p.11	Non-technical losses are losses associated with lack of revenue collection for consumed energy, typically resulting from theft, or inability to pay, or inability to collect revenue from certain classes of consumers (sometimes referred to as "collections losses"), such as government entities. See also losses (commercial).
Losses (Technical)	II.C p.11	Technical losses are energy wasted as heat or light due to the technical characteristics of the system. While some level of technical losses is inevitable in any electrical power system, these losses can be mitigated for any given level of power flow by reducing the current and increasing the voltage in a transmission or distribution line.
Load Shedding	II.B p.8	Load shedding is a tool for managing demand on an electrical grid. Because electrical systems must always exactly balance supply and demand on the network, system operators will sometimes need to remove customers from the grid to avoid cascading failures. Groups of consumers can be removed from the grid for this purpose using switches located at a distribution substation.
Long Run Average Incremental Cost (LRAIC)	III.C 32	The Long Run Average Incremental Cost (LRAIC) is the total cost of transmitting an incremental of additional energy divided by the total energy transmitted.

Marginal Generation	II.C p.11	Marginal generation (or the "marginal generator") is the last generation power plant to be dispatched in the merit order. Such generation is used to meet peak demand in a well-functioning system, or functions as reserve power supply in case of contingencies involving the loss production from other power plants. When new, cheaper, generation power plants are added to the electricity grid, the marginal generator is displaced by a less expensive marginal generator, hence leading to cost savings for the utility.
Merit Order	II.C p.11	The merit order is a way of ordering electric generation plants, generally in order of increasing price (i.e., an economic merit order arranges generation plants based on short-run marginal cost of production). In a liberalized power grid, the merit order is the order in which generation plants are dispatched.
MW		See watt.
Natural Monopoly	General p.4	For the purposes of this guidance, a natural monopoly is a market in which, at the scale of interest, the average cost curve is declining. The minimum efficient scale for the market, i.e., the scale at which competition becomes feasible, is the scale at which the average cost curve is minimized. Based on this broad definition, both transmission and distribution subsectors are natural monopolies (as is a vertically integrated utility that includes either or both). While an individual generation power plant can exhibit increasing returns to scale, physical limits on the size of generation plants means that these assets tend to be smaller than the minimum efficient scale, and hence the generation market is not a natural monopoly.
Nameplate Capacity		See capacity. Nameplate capacity is the maximum sustained power that can be produced by a power plant. Nameplate capacity may also be referred to as 'rated capacity' or 'nominal capacity'.
Non-dispatchable Generation		See dispatchable generation. An intermittent energy source provides non-dispatchable power: that is, energy that is not continuously available for conversion into electricity. Examples of non-dispatchable power include renewable energy sources such as wind, solar, and run-of-river hydro.
Off-grid	General p.4	See grid. Off-grid refers to projects or assets that are not connected to the national grid, e.g., isolated solar and mini-grids. Because of their limited scale and the economies of scale present in electrical systems, off-grid solutions are generally more expensive than on-grid solutions. Off-grid solutions are generally preferred only when consumers cannot be easily connected to the national grid.
On-grid	General p.4	See grid.
Operating Reserves	II.B p.8	Operating reserves are generating capacity that are readily available to the system operator to maintain supply and demand balance over short time intervals. Roughly, there are four varieties of operating reserves classified by how quickly they can be brought online; (i) frequency-response reserves are brought online automatically to regulate supply characteristics, (ii) spinning-reserves can be brought online within seconds, (iii) non-spinning or supplemental reserves can be brought online after a short-delay, and (iv) replacement (or contingency) reserves that can be brought online within

		tens of minutes if an emergency causes some generation supply to go offline. Operating reserves are examples of ancillary services.
Peak Load	II.B p.8	Peak load in an electrical grid is the maximum level of demand on an electrical grid over a period (i.e., a day, week, or year). Some generation power plants are specialized to deliver peak load power: these assets generally have higher marginal costs of generation, but lower fixed costs and rapid ramp times compared to baseload generation. For hydroelectric plants, a peaking run-of-river hydroelectric plant is a plant with enough pondage (i.e., water stored in a pond or canal) to provide several hours or days of continuous power (and thus is a hybrid between run-of-river and storage hydroelectric technologies).
Power	General p. 0	Power is the rate at which work is done to a system, or equivalently, the amount of energy transferred to the system per unit of time.
Price-rationed Market	II.A p.7	A price-rationed market is a market in which prices adjust until the quantity demanded equals the quantity supplied in equilibrium. That is, prices can adjust until the equilibrium condition is met.
Quantity-rationed Market	II.A p.7	A quantity-rationed market is a market in which prices cannot adjust to balance the quantity supplied and demanded. Quantity-rationed markets are common in utility applications where tariffs are set according to political factors. Efficiency in such markets requires institutions to set the quantity supplied in the short run and set prices to reflect costs in the long run. In the power sector, these roles are typically performed by the system operator and regulator, respectively.
Ramp Time	II.B p.8	The ramp time is a characteristic of a generation power plant, it is the time that is required for the generation power plant to 'ramp-up' to its full production capacity. Ramp time is a constraint on the efficient dispatch of power generation since supply and demand must always be in balance in an electrical power grid. The ramp time depends on the technology of the generation power plant, with coal having a very slow ramp time and hydroelectric having a relatively short ramp time. Batteries, diesel, fuel oil, and natural gas have superior ramping time performance making these technologies suitable to provide reserves and ancillary services to the grid.
Reserves		See operating reserves.
Reserve Margin		See operating reserves. The reserve margin is a regulatory concept relating the anticipated load in the system to a recommended level of operating reserves.
Retail Market	II.A p.7	A retail market for electricity involves more efficient market-based mechanisms and institutional arrangements into the sale of electricity to consumers. Due to the economies of density in the sector, such institutional arrangements may add significant complexity to the functioning of the sector. See wholesale market.
SAIDI	II.C p.11	SAIDI stands for the **System Average Interruption Duration Index**. SAIDI is a measure of the reliability of a power system based on the average duration of interruptions experienced by consumers over the period. I.e.: $$SAIDI = \frac{sum\ of\ all\ customer\ interruption\ durations}{total\ number\ of\ customers\ served}$$

SAIFI	II.C p.11	SAIFI stands for the **System Average Interruption Frequency Index**. SAIFI is a measure of the reliability of a power system based on the frequency of interruptions experienced by consumers over the period. $SAIFI = \frac{total\ number\ of\ customer\ interruptions}{total\ number\ of\ customers\ served}$
Substation		A substation is a part of an electrical grid that serves to transform the voltage in the system from a higher to lower level, or vice versa. High voltage current can be transported in electric lines much more efficiently – that is, with less loss to heat – than low voltage current.
System Operator	II.A p.7	See transmission system operator.
Throughput Capacity		Throughput capacity is the maximum sustained power that can be transmitted by the transmission infrastructure, including the transmission line, substations, and transformers.
Transformer		A transformer is an electric device that increases (‘steps up’) or decreases (‘steps down’) voltage on the electric grid, although these devices only function for alternating current (AC) systems. Transformers are critical components of electric power systems that must transport power over long distances, as losses in transmission lines can be reduced by a factor proportional to the square of the voltage. For example, a transformer that stepped-up voltage by a factor of 10 would reduce counterfactual losses in the line by a factor of 100.
Transmission System Operator (TSO)	II.A p.7	The transmission system operator (or independent system operator, ISO) is the entity that dispatches power from generation plants and transmits that power through the electrical grid to regional distribution centers. The TSO is an example of a natural monopoly.
Volt (V)	II.B p.8	The volt is the unit of electric potential and electric potential difference. See voltage.
Voltage	II.B p.8	Voltage, measured in volts, is the common term for the electrical potential difference between two points. It is the electrical energy needed to move an electric charge between two points. The voltage can be either a source of energy or energy lost. A current operating at a high voltage will lose less energy as heat compared to a counterfactual current operating at a lower voltage so that transforming a current to a higher voltage (and back to a lower voltage) is a critical component of an electric power grid. This is achieved through a transformer.
Volt-Ampere (VA)	II.B p.8	The volt-ampere is a unit of electric power; this unit is equivalent to the watt. For practical uses, volt-ampere are the units of power capacity.
Watt (W)	II.B p.8	The watt is a unit of electric power; this unit is equivalent to the volt-ampere.
Watt-hour (Wh)	II.B p.8	The watt-hour is a unit of electric energy. It is the energy that is consumed over an hour at a rate of one watt each second.
Wp		See watt. Then-p suffix is often used for intermittent generation sources to distinguish the peak output for the asset.
Wholesale Market	II.A p.7	A wholesale market for electricity involves more efficient market-based mechanisms for the sale of electricity to large-scale institutional buyers, which may include distribution utilities and industry, among others.

Work	II.A p.7	Work is the effort that needs to be expended to change an object's state, such as the force applied to an object to move it over a distance. Work is equal to the energy applied to the system to change its state. Although not mentioned in the text, the concept of work is included here to further explicate the concepts of Energy and Power.

B. Other Technical Issues

i. Supporting the development of scenarios for a Load Flow Study

Defining the Counterfactual: As noted in MCC's general guidance on CBA, the counterfactual represents the status of the system if the projects targeted for MCC investment do not take place, and always requires care to define. In the power sector context, it is important to note that the counterfactual may require separate modeling of load flows or careful calibration based upon detailed engineering input. While such work is often done by contracted firms for the investment case, the economist may need to ensure that attention to a counterfactual is included in scopes of work during the compact development process, for example, by properly defining the counterfactual load flow scenarios.

The Steady-State Flow of Power: Electricity flows through an electrical system according to Kirchhoff's Laws and Ohm's Law[132] and is also subject to real world constraints such as thermal limits of the system components, reactive power management and considerations of system stability. In a typical application, a Load Flow (LF) study will take as input a model of the network, including:

1. Network nodes or "buses"—i.e., substations—where there is a net injection[133] of power.
2. Transmission lines which connect the nodes.
3. Engineering constraints, such as thermal capacity limits, and dispatchable energy.

Although the power flow problem is non-linear, it may be possible to calculate the power flow for simple investments, such as transmission lines which are peripheral to the rest of the network. But utility-scale systems are too complex to admit a tractable closed-form solution, so that numerical methods using specialized software packages[134] are used instead.

Scenarios: To estimate the incremental power flow attributable to the transmission investment, power flow must be estimated in both the with-project and counterfactual cases, so that the economic analysis requires at least two simulation runs for each year *keeping all other parameters constant*. However, because of the need to utilize specialized software, it is prohibitively expensive to run more than a handful of scenarios: The economist must identify the most parsimonious set of relevant parameters or

[132] Kirchoff's Laws relate power flow through a network 1) currents at each node must sum to zero, and 2) voltage drops and electrical motive forces must sum to zero around each closed current loop. Ohm's Law relates voltage, current and resistance.

[133] A net injection is the difference between the electrical production and consumption of power at the node. If consumption is greater than production, as is typical for load centers, then the net injection is negative.

[134] For example, CYME Power Engineering software, ETAP and PSS/E.

sensitivities as inputs for scenario simulation runs. Best practice for the economist is to interpolate as much as possible from this relatively small set of key scenarios.[135] Some considerations include:

1. Key years for the investment lifecycle:
    a. The status of the network at time of commissioning
    b. When the asset is expected to operate at capacity
    c. Complementary investments in Generation and Transmission assets
    d. Key sector risks or delays in investment plans, or power trading agreements
2. Key sensitivities and risks for achieving expected benefits of the project:
    a. Demand forecasts (optimistic vs. pessimistic scenarios)
    b. Alternative investments packages
    c. The absorptive capacity of the distribution system
    d. Delays in achieving the generation master plan

Output: The load flow analysis should provide the following information for each scenario:

1. Energy consumption and dispatch
2. Network losses and load shedding due to network faults
3. Total energy imported and exported (if applicable)
4. Load shedding due to lack of supply and generation available but not dispatched

Limitations: When bottlenecks develop at points in the system, the benefits of relieving those constraints can be attributed to the projects that remove the constraints. In developing countries, however, the utility may not follow a rational ("least cost") system expansion plan as might typically be assumed in the Load Flow model. Hence, future scenarios modeled by the Load Flow study may include incremental power flows attributable to other complementary investments. To avoid double counting, the economist must account for future system expansions[136] and consider modeling scenarios that include deviations from the least cost system master plan.

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[135] Ignoring sensitivities, estimating the incremental power flow over a 20- or 25-year time horizon will require, at minimum, four scenarios: i) Baseline scenarios (with- and without-project), ii) Future system scenarios (with- and without-project). Each sensitivity will require 2-4 additional scenarios.

[136] As discussed in the following section on calculating the cost-reflective tariff, the system expansion plan used in the analysis should be included as a cost of delivering power of the desired load and included in the cost-reflective tariff.

ANNEX III. Stated-WTP Surveys

As noted in the main text, valuing consumption using stated willingness-to-pay methodologies is not recommended because these methods tend to be relatively unreliable. However, there are situations in which more conventional revealed willingness-to-pay results will not accurately reflect underlying valuations. There are two situations in particular that the economist should consider when determining whether the use of stated-WTP methods are necessary: 1) is there a market failure which could cause the revealed-WTP result to differ substantially from the "true" WTP? 2) is the pattern of substitutability between electricity and near substitutes difficult to predict from the pattern of consumption of near substitutes?

If the answer to either of these questions is affirmative, then the revealed-WTP result should not necessarily be assumed to be more reliable than stated-preference methods for determining the "true" valuation of consumption. If this is the case, the economist should consider using stated-WtP techniques instead. This section discusses how to apply stated preference techniques using methodologies developed to minimize the potential for bias.

A. Contingent Valuation; controversy and evidence

The Exxon-Valdez disaster marks the beginning of the controversy surrounding Contingent Valuation (CV) methods which continues to be a live debate within economics journals today. Can the implied damages from CV surveys be taken at face value when these values are so much larger—perhaps an order of magnitude—than the direct use values implied by other techniques?

Diamond and Hausman (1994) suggest that perhaps no number for nonuse values may be better than some number which may not be reliable. For example, if non-use values are used to assess benefits of an environmental protection project, there may also be a corresponding harm due to the employment loses which the project might cause. Are researchers accurately identifying the full and complete non-use values of the project? Is the proportion of accurate responses sufficient for making public policy decisions?

To make their point Diamond and Hausman break down the possible sources of error in CV studies—credibility, reliability, and precision—and they identify numerous empirical irregularities.

Low precision is due to small sample sizes and can be addressed by scaling up the sample population and will not be discussed further here. Nevertheless, precision is still a major concern because of the expense of conducting sufficiently large surveys. This is not generally a concern of market-based measures, which naturally aggregate many consumers' preferences.

The *credibility* of a survey is related to whether the respondents are answering the question posed by the researcher. As Kahneman and Knetsch (1992) observe "[t]he standard interpretation of [Contingent Valuation Method (CVM)] results is that the [Willingness-To-Pay (WTP)] for a good is a measure of the economic value associated with that good, which is fully comparable to values derived from market exchanges and on the basis of which allocative efficiency judgments can be made."

Embedding and Scope. When respondents are asked to evaluate different types or amounts of a public good, it is reasonable to expect that the demand for two goods together should not be too much less than the demand for each good purchased separately. The insensitivity of CV-derived WTP measures due to project category is known as the embedding effect. Kahneman and Knetsch (1992) argue that embedding is best explained as a “warm glow” feeling for the project type; responses are a “purchase of moral satisfaction” that are not directly comparable to market prices. Others disagree, arguing that this “warm glow” is a valid non-use value.

Embedding may be the most significant source of error in CV studies but it is closely associated with the scope effect —the insensitivity of CV studies to the scale of the project—and the two effects are difficult to separate empirically. While empirical tests for the embedding and scope effects exist, the usefulness of these tests has been called into question as they require strong assumptions of sufficiently concave or quasi-linear preferences to be valid. Furthermore, Madden (1991) argues that when public goods are demand rationed—such as in the power sector—insensitivity to scope should be expected.

Guessing. Another issue which undercuts the credibility of CV surveys is evidence that respondents are simply guessing. Some survey respondents explain their answer as expressing an attitude towards the actions of others—for example as a need to punish offenders. This last possibility can include an inordinate number of zero-values (“protest zeroes”) when the respondent does not believe the costs are being shared fairly.

Credibility problems can undermine the goal of an accurate determination of welfare loses; for example, even if “warm glow” feelings are valid non-use values, it could be double counting if the benefits of every affected individual are included, while none of the harm caused to those without the “warm glow”. However, Hanemann (1994) argues that when surveys are presented as yes/no referenda, such double counting does not occur.

The *reliability*, or bias, of a survey is the degree to which the numbers derived from the method are truly comparable between individual respondents and individual surveys. A CV survey which is not reliable may produce numbers for the WTP which differ from “true” values, determined by the respondent’s utility function. In theory, this bias can be corrected if the magnitude can be determined. However, in most practical CV applications, there is no observable behavior from which a correction term can be calibrated.

Diamond and Hausman identify three major sources of bias. First, there is hypothetical bias, which emerges because agents (presumably) have no “skin in the game” and are therefore free to answer the survey questions any way they choose without consequence. The second source of bias is interview bias, which is self-explanatory and will not be discussed further here. Respondents are sometimes known to give answers which they believe will please the interviewer. Finally, there is framing bias, in which the specific wording of survey questions or the order in which questions are asked affects the answers the respondents provide.

Hypothetical Bias. A common concern with CV studies is that the magnitude of non-use values are unreasonably large when aggregated over the population; a problem that is usually attributed to hypothetical bias. Since there are no clear consequences for their responses, respondents may be tempted to claim very high WTP, hoping that this will make the project more likely to occur. This suspicion is seemingly bolstered by the large divergence between WTP and WTA.

While such strategic behavior from respondents may be a real constraint in survey design, modern approaches utilize strategic behavior to reduce respondent hypothetical bias. For example, the cheap talk approach of Cummings and Taylor (1999) relies on explaining the strategic situation to the respondent—

the problem in this view is that the respondent may misunderstand her own incentives in the "game" she is playing. If respondents believe that there is a non-zero chance the project will be implemented as posed and the survey is designed with a single-binary-discrete-choice (SBDC) format with a take-it or leave-it offer, then the respondents will have an incentive to truthfully report their preferences. Binary-choice referenda-style questions may also be less taxing for the respondents.

Furthermore, Carson et al. (2001) point out that if WTP derived from CV overestimates the non-use value, then the same reasoning should imply that WTA[137] is too small. However, as Hanemann (1991) shows, this need not be the case when evaluating WTP for demand-rationed public goods[138], even without large income elasticities.

To keep the survey anchored in reality and less vulnerable to hypothetical bias, best practice is to present the project as a unified bundle, including the payment mechanism, making clear to respondents how their personal consumption choices could be affected if the policy goes into effect.

Table 8: Sources of error in CV studies. Adapted from Diamond and Hausman (1994).

Credibility		
Embedding/Scope Effects	Casual Cost-Benefit Analysis	Preferences over Fairness
Respondents are insensitive to project scale, or too sensitive to project category	Respondents weigh costs of the project or the benefits to others, rather than hedonistic benefit.	Respondents express desire to punish offenders or protest unfair distribution of costs.
Reliability		
Hypothetical Bias	Interviewer Bias	Framing Effects
Respondents overinflate willingness-to-pay because the results of the survey are not binding.	Respondents may wish to please the interviewer by expressing a higher value.	Respondents express lower values for willingness-to-pay when the question is asked later in the survey.

Framing Effects. Order effects can occur when stated willingness to pay depends on question ordering. It is a particular example of a framing effect in which the form of the survey itself alters the outcome. While this behavior may seem disturbing to the researcher, Carson, Flores and Hanemann (1998) show that "context independence" requires fairly strong assumptions on underlying preferences and should not be expected. When a Hicksian substitute public good is quantity or quality rationed, the "virtual price" of

[137] WTP must be less than WTA for normal goods.
[138] Compensating (C) variation bounds-from-above the willingness-to-pay (WTP) for a good, while equivalent (E) variation bounds-from-below the willingness-to-accept (WTA) payment for harm. So given an indirect utility function, $v(\cdot)$, and an amount or quality ($q^1 > q^0$) of the public good which is taken as given; then $WTP \leq C$ and $WTA \geq E$, where C and E are defined as the numbers which solve:

$$v(\mathbf{p}, q^1, y - C) = v(\mathbf{p}, q^0, y)$$
$$v(\mathbf{p}, q^1, y) = v(\mathbf{p}, q^0, y + E)$$

Hanemann shows that when the public good is a suitably strong Hicksian complement with at least one other good, then it is possible that $C \ll E$. Hence WTP may be much less than WTA even without abnormally large income effects to explain the discrepancy.

that good is falling in sequence order. In this way, if the order of questions implies quantity rationing then the result will include order effects. Studies seeking to avoid this problem should limit the survey to a single question per subsample or randomize question ordering.

Table 9: Best practices for CV studies. Adapted from Hanemann 1994.

Best Practices for CV studies

Random Probability Sampling with in-person interviews	The survey should be statistically unbiased and sufficiently large for the necessary precision. The interview should be conducted in-person to avoid biases in phone surveys.
Avoid Hypotheticals	Open-ended questions may encourage respondents to guess or to engage in "casual cost/benefit" analysis.
Referendum Framing	A single yes/no vote provides the respondent with the incentive to answer truthfully and helps to prevent hypotheticals.
Specific Payment Mechanism	A clear link should be made between the result of the referendum and the respondent's consumption choices so that the vote expresses an intention to pay.
Provide Adequate Information	Respondents must have a clear understanding of the problem.
Insulate from Larger Issues	E.g., dislike of big business
Debriefing	Is damage as bad as described? Do you think this program will work? Would you really be willing to pay higher taxes if program went through? Etc.
Use Medians	Medians are more robust if there are "protest zeroes" or very large responses.

B. Sample Cheap Talk Script

As discussed above, a single-binary-discrete-choice survey design is incentive compatible with a respondents' telling the truth about their underlying preferences. However, this fact is not obvious—either for the researchers or the respondents. Cheap talk is a concept from game theory referring to strategies which do not directly result in payoffs for participants. It has become a standard model for understanding communication in game theoretic contexts. Cummings and Taylor (1999) suggest using a "cheap talk" script to explain to respondents why they should respond truthfully. Below is an example of a cheap talk script:

> *We would like to know how much you value better quality electricity service. No one will change your electricity tariff because of what you say. However, if you value electricity enough, the*

government may decide to invest more in electricity and your tariff may have to increase to pay for the investment.

Some people overestimate the amount they are willing to pay because they are frustrated by the current situation and want the investment to happen. If many respondents provide higher estimates, then the government could set higher tariff for electricity which is beyond your ability to pay.

Likewise, some people underestimate the amount that they are willing to pay because they are concerned that they already pay too much, or they lie thinking that the government will charge them less. But if enough people respond this way, the government will think that electricity is not important to you and may not make additional investments in electricity improvement projects.

Please also be aware about your expenses on alternative energy sources, such as candles and kerosene, and how your family's budget will be affected if you no longer have to purchase so many alternatives to electricity.

You and your [community] will be at disadvantage whether you overestimate or underestimate your willingness to pay. So, please try to be honest and tell us only what you are truly able and willing to pay based on your income.

While this methodology has been shown to reduce hypothetical bias, it is limited to cases when it is in fact in the respondents' interest to respond truthfully. Unfortunately, this will not always be the case.

ANNEX IV. Two Practical Approaches for Valuing System Reliability

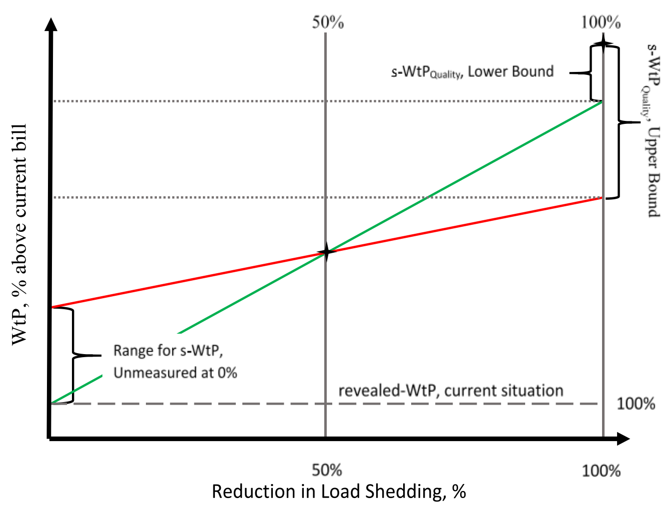
A. Using Stated-WTP to Value Reliability without Double-counting

One of the more likely applications for stated willingness-to-pay techniques at MCC is the valuation of system reliability, such as is provided by ancillary services. Low quality, low-reliability, electricity supply is a common feature in developing countries. Maintaining reliable power supply requires that some system capacity remain in reserve, which has a high opportunity cost when systems are power-infrastructure constrained.

As discussed in the main text, the benefit of improving reliability can be substantially larger than the benefit of consuming a higher quantity of electricity. When a power system is not reliable, this will lead to intermittent characteristics of the power supply that result in inframarginal losses to consumers. Consider, for example, a household chore which must be done late at night, because power is not available during the day. The fact itself of waking late at night reveals a high degree of utility for performing the task, although the consumer loss is not financial and therefore is not included in revealed preference measures. This is a challenge for the economist since the benefit derived from reliable power cannot easily be separated empirically from the benefit the consumer derives from consuming a greater quantity of power.

For reasons discussed in Section V.A, stated-preference techniques are not the recommended approach for benefits valuation, in general. Regardless, stated-preference techniques can help to value system reliability. The primary advantage of stated-preference methodologies is that surveys to collect this data can be included in the same revealed-preference willingness-to-pay surveys that are part of the recommended approach that the marginal cost of adding a stated-preference module to the WTP survey is low.[139] Thus, stated-preference techniques should be used only when benefits streams associated with reliability improvements are expected to be smaller than more direct benefits associated with increased quantity of electricity consumption, but also sufficiently large to impact the CBA.

Figure 8: Triangulating reliability benefits from stated- and revealed-WTP**.**



If the economist decides to use stated-preference techniques to value system reliability or quality, the recommended approach is to "triangulate" reliability benefits using both the revealed- and stated-WTP. Figure 8 illustrates a simple approach to triangulation. Revealed-WTP, as a lower bound[140] for stated-WTP for

[139] One important cost that the economist must consider is respondent fatigue. A stated-preference module can be cognitively burdensome: Respondents may not respond as accurately to the rest of the survey – including revealed preference modules – or may refuse to cooperate altogether if the survey becomes too long.

[140] See Section V.A. for an explanation.

counterfactual reliability, is the starting point for the analysis. The slope of the curve is closely related to the elasticity of the quantity demand curve, although care should be taken when interpreting this slope. The difference in the right-intercept (i.e., at 100% improvement) and the stated-WTP at 100% improvement is the estimate of the reliability improvement. Note that this value should always be (weakly) positive, so that negative values should be interpreted as zero. After some minor simplification, the WTP for the reliability improvement is:

$$WTP_{Reliability} = WTP_{S,100\%} + WTP_{Status\ Quo,Revealed} - 2 \cdot WTP_{S,50\%} \tag{15}$$

As demonstrated in Figure 8, this estimate gives a lower bound to the reliability benefit. This is highly recommended, as there is a risk of double-counting benefits if the economist attempts to anchor the status-quo benefit using stated-preferences, precisely because the stated-WTP should always be higher than the revealed-WTP. For this approach to work properly, the revealed-WTP should include coping cost that are incurred by the consumer, since these costs reveal the consumer's willingness to pay for the status quo level of quality. The WTP so calculated then applies to the proportional reduction in either the frequency or duration of outages, but not both simultaneously.

Hashemi (2021) discusses the use of stated WTP measures to estimate the value of system reliability in Nepal and concludes that the approach may under- or over-estimate the benefits of system reliability depending on the characteristics of the consumers on the grid. A more careful analysis could also attempt the above calculation for each consumer class to reduce this bias.

Under certain assumptions – most notably that the cost for a momentary outage is small, and that there is a stable relationship between frequency and duration of outages[141] – this style of analysis should give similar[142] results as the consumer damage function (CDF) methodology discussed in the next section without the need to conduct an expensive outage study.

B. *Estimating Reliability Benefits using Consumer Damage Functions*

The recommended methodology for valuing improvements in system reliability, as discussed in Section II.D is to use a Consumer Damage Function or CDF. The CDF encodes the losses that accrue to consumers because of an interruption to the power supply. Such interruptions result in consumer losses through various channels, including damage to equipment or appliances and lost production. Such losses are often much larger than consumers' WTP. However, if interruptions are anticipated, as might be the case for load-shedding, consumers will likely shift consumption to times when supply is available. In such cases, detailed in the previous section (ANNEX IV.A), losses from the interruption may be less than consumers' WTP.

Unfortunately, estimating a CDF is not a trivial exercise. To rigorously identify consumer losses, a survey (i.e., an "interruption" or "outage" study) needs to be conducted following actual interruption events that cover a representative sample of impacted consumers. This survey needs to then be repeated across a representative sample of interruptions. This process would be time-consuming and expensive in a developing country context, given the relative paucity of data on interruptions and often incomplete

[141] Note that both assumptions will tend to be true only when interruptions are anticipated, and consumers have already adjusted to the poor quality or low reliability of the power supply.
[142] This statement should be treated, cautiously, as an untested hypothesis, as the author is unaware of any empirical tests.

customer records. Indeed, investments in data systems, management information systems, and records management are common components of power projects. Conducting an outage study in an MCC country is not likely to be practical.

Instead, this guidance recommends utilizing high-quality data from interruption studies conducted in developed countries (Sullivan et al. (2009) provide data from 24 studies conducted in the US), and using this data to fit several "shape" parameters of a simple CDF, including; (i), the impact of momentary (zero duration) interruptions, (ii) the impact of interruption duration, (iii) season and time of day effects, (iv) industry or sector effects, and (v) other issues as appropriate. Once these shape parameters are identified, a single question or set of questions can be added to a standard WTP survey to fit the data to the country context.

The first step of the analysis is to determine the consumer damage function for a single consumer impacted by a single, representative event. For interruption, i, and the consumer impacted by the interruption, c, the losses can be written as a discrete Taylor Series approximation in the outage duration:

$$Loss_{i,c}(d) = \sum_{n\in\mathbb{N}} a_{i,c;n}\, d^n \tag{16}$$

As typical for the Taylor series approximation, the coefficients correspond to the constant loss term ($a_{0;i,c}$) that accrues regardless of the duration of the interruption, and to the derivatives of the CDF with respect to the outage duration, with higher-order terms corresponding to higher-order derivatives. Note that this formula abstracts away from issues of context, such as time of day or type of firm impacted. Table 10 shows values empirically derived from US data for the derivatives of the CDF, indicating a nearly linear relationship with a slight "S-curve" shape. Due to relatively thin data, this guidance recommends identifying the CDF only up to the linear term (i.e., first derivative term of the Taylor series), although the higher-order terms are also included below for context.

Table 10: Derivatives of the CDF with respect to duration of interruptions**.**

	1st Derivative	2nd Derivative	3rd Derivative
Medium and Large C&I	0.83	0.08	-0.05
Small C&I	1.08	0.15	-0.06
Residential	0.41	-0.01	-0.01

Losses[143] relative to momentary interruptions (at peak).
Derived from Sullivan et al. (2009, pp. xxi-xxiv).

Therefore, the CDF can be simplified into the form of Equation 3 for a single outage:

$$Loss_{i,c}(d) = a_{i,c} + b_{i,c}\, d = a_{i,c}\left(1 + \frac{b_{i,c}}{a_{i,c}}\, d\right) = a_{i,c}\left(1 + B_{i,c}\, d\right) \tag{17}$$

[143] Derivatives are defined as the average of the discrete differences of the CDF across the duration range from 0 up to 8 hours. Higher-order derivatives are the discrete differences of the next lower-order of derivatives using the same methodology.

For an interruption that does not impact consumer c, the loss for that interruption is zero. To simplify further, we can assume that there is no systematic correlation between the characteristics of the outage (i.e. frequency, duration, time of day, or time of year) and the characteristics of the consumers impacted by the typical outage. This assumption could fail if (i) there are regions that are impacted more severely because of network bottlenecks, or (ii) there is a privileged consumer class that the utility grants access to higher quality of power. This assumption allows us to sum Equation 18 across both interruptions and consumers, keeping fixed the time of day/year. This result assumes that the loss can be decomposed into a fixed component (for each outage), and a component linear in the duration of the outage.

The next step requires calculating a time-of-day and year adjustment, which can be accomplished by first summing Equation 18 for a single firm or household over the course of a year (divide by the total number of outages the firm or household experiences to obtain an average per event). Then, the daily/seasonal adjustment factor is just a weighted sum of kilowatt-hours consumed on-peak verse off-peak, with the weighting given by the relative cost for an on-peak or off-peak outage, respectively. Average kilowatt-hours can be used to determine kilowatt-hours on-peak and off-peak consumption using the demand factor (discussed in Section II.B). Using the results in Table 11, it is even possible to go one step further and calculate this adjustment using a moderately more detailed seasonal and time of day model – for example, breaking down the hours in the year by season (summer or winter) and time of day (morning/afternoon (peak)/evening). The parameters needed to calibrate the daily and/or seasonal model will be country-specific and should be agreed upon by the country team.

Table 11: Losses relative to summer afternoon peak at various times for each consumer class.

Time			**Cost Per Event Relative to Peak**		
Day	**Season**	**Time of Day**	**Medium and Large C&I**	**Small C&I**	**Residential**
Workday	Summer	Peak	1.00	1.00	1.00
Workday	Summer	Morning	0.69	0.79	1.37
Workday	Summer	Afternoon	1.00	1.00	1.00
Workday	Summer	Evening	0.79	0.45	0.89
Workday	Winter	Peak	0.79	1.35	0.63
Workday	Winter	Morning	0.55	1.06	0.86
Workday	Winter	Afternoon	0.79	1.35	0.63
Workday	Winter	Evening	0.62	0.61	0.56
Weekend/ Holiday	Summer	Peak	0.71	0.60	1.19
Weekend/ Holiday	Summer	Morning	0.49	0.48	1.62
Weekend/ Holiday	Summer	Afternoon	0.71	0.60	1.19
Weekend/ Holiday	Summer	Evening	0.56	0.27	1.05
Weekend/ Holiday	Winter	Peak	0.52	0.75	0.74
Weekend/ Holiday	Winter	Morning	0.36	0.59	1.01
Weekend/ Holiday	Winter	Afternoon	0.52	0.75	0.74
Weekend/ Holiday	Winter	Evening	0.41	0.34	0.65

Derived from Sullivan et al. (2009, pp. xxi-xxiv).

If the economist must additionally make an adjustment for the case when outages are more likely during a particular time of day or season, the extension of the procedure outlined in the previous paragraph to this case is straightforward: Simply add an outage-frequency weight for the relevant timeframe.

The final step in the analysis of system reliability is to sum the results obtained above – which apply to a single firm or household – across all firms and households affected. In general care must be taken in this step to avoid double-counting outages, which in general affect many, though not all, firms at a given time. However, the approach recommended here largely avoids this issue by first summing over losses from all the outages that affect a single firm. By construction, this approach generally[144] avoids the potential for double counting.

To adjust for the relative losses experienced firm types, the first step is to adjust for firm size. The main drivers of relative losses are: (i) the number of employees at the firm, and (ii) the firms' consumption of power. However, these two drivers tend to be correlated across firms within a given firm type, so that these drivers are expected to be nearly colinear in a regression analysis. For ease of analysis, this guidance therefore recommends using power consumption only, as unserved energy is a parameter that may be observable by the utility. Losses relative to the average firm (by firm type) are given in Table 12.

Table 12: Losses per event by firm type and size**.**

	Firm Size	
Firm Type, by Sector	**Medium and Large C&I**	**Small[145] C&I**
Agriculture	0.37	0.67
Mining	0.84	2.13
Construction	2.30	2.40
Manufacturing	1.88	1.39
Telecommunications & Utilities	0.96	1.33
Trade & Retail	0.65	0.96
Fin. Ins. & Real Estate	1.48	1.36
Services	0.70	0.76
Public Administration	0.80	0.52

Derived from Sullivan et al. (2009, pp. xxi-xxiv).

As with the case for the daily/seasonal adjustments discussed above, these factors can be used to make an adjustment for the sectoral composition of the affected economy. Most importantly, for the

[144] There is some ambiguity in these estimates regarding the definition of firms: A multi-establishment firm, for example, may be affected more than once by the same outage. Reducing this risk requires some care in defining the sum over firms, with the best approach being to include all establishments in the sum, if possible. This may be complicated if the sampling unit are firms rather than establishments.

[145] In this context, small firms should be those with consumption on the same order as (up to two or three times) a household's consumption. Note that there is a complication with the definition of small firms in this context: This data was gathered in the context of the US economy wherein a small firm may still have higher consumption than a larger firm (as measured by number of employees) in a developing country context. However, this should not be a major source of error given the coarseness of these categorizations.

developing country context, is that the agricultural sector is a relatively larger part of the makeup of a developing country economy than for a developed country, so that the sectoral adjustment will tend to lower the estimate for the losses. Note, however, that the firms of interest are those that are connected to the grid or mini-grid (i.e., only grid-connected firms and households can experience reliability issues on the grid).

Only one parameter remains for calculating the system average CDF function: An overall scale factor, given by $A_{\sigma,\omega}$ below, that embodies the loss that an average firm experiences if the interruption lasts only moments (equivalently, an outage of duration zero). This parameter is the $a_{i,c}$ parameter from equation 18, averaged over all outages, i, for the (consumption-weighted) average consumer, c, among those firms in sector, σ, of size, ω. For each firm type, the losses are:

$$Loss_{\sigma,\omega}(f,\bar{d})\ per\ outage = L_{\sigma,\omega}(\bar{d}) = C_\omega S_\omega A_{\sigma,\omega}(f + B_\omega\, f\bar{d}) \tag{18}$$

Where C_σ is the firm's average consumption[146], f is the (yearly average) frequency of outages that the firms experience, and S_ω is the daily or seasonal adjustment whose calculation is discussed above. $A_{\sigma,\omega}$ can be further simplified into a component relating only to the size of firms (i.e., small, or medium and large) according to the data available in Table 11 and Table 12, respectively. If we write $K_{\sigma,\omega}$ for the summary data in Table 12, then $A_\omega = {}^{A_{\sigma\omega}}\!/_{K_{\sigma\omega}}$ are the scale parameters that are associated with the losses from momentary interruptions for firms of size ω, taking all other parameters for their average values.

The last remaining problem, then, is to estimate the parameters A_ω. This guidance recommends estimating these parameters directly from survey data, using a short module attached to the willingness to pay survey. The recommended methodology is to determine the losses that the firm suffered in its most recent experience[147] with outages. The response to such a question will be a function of the duration of this outage, as well as the approximate time of day and season. All this supplemental data can either be collected within the survey or even noted by the enumerator through observation.

[146] For example, in units either of power (kW), or energy (kWh). The purpose of this term is to adjust for the firm's size, not the size or impact of the outage. Unserved-kWh, or END, is the unit that is in broadest usage for such purposes but note that, given that a measure of duration of outage is included in the definition of unserved kWh, these units will result in a double-counting error.

[147] Consider, for example, the question: *"In your most recent outage (at DATE and TIME, lasting for DURATION), what would you estimate to be the losses your firm experienced?"*. A better approach would be to break the question down for specific categories of losses, such as equipment damage, value of lost production, etc. Note that this is a revealed preference methodology, but stated-preference questions can also supplement the approach (i.e. *"What would you be willing to pay to avoid such an outage in the future?"*).

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