UZBEKISTAN: INNOVATIVE CARBON RESOURCE APPLICATION FOR ENERGY TRANSITION

CREDITING PROGRAM DESIGN DOCUMENT (C-PDD)

Version 5.00

Facility: Transformative Carbon Asset Facility (TCAF)
Country/region: Uzbekistan
Sector: Energy
Type of credits: Results Based Climate Finance Verified Emission Reductions (RBCF-VERs)
Program Counterpart: Ministry of Economy and Finance of the Republic of Uzbekistan
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Acronyms and abbreviations

BUR-Biennial Update Report

CDM- Clean Development Mechanism

CMRU- Cabinet of Ministers of Republic of Uzbekistan

CPDD-Crediting Program Design Document

CPI- Consumer Price Index

DPO- Development Policy Operation

ERPA- Emission Reductions Payment Agreement

EBRD- European Bank for Reconstruction and Development

GoU- Government of Uzbekistan

GHG – Greenhouse Gases

GDP-Gross Domestic Product

HCA- Host Country Agreement

HPP- Hydro Power Plant

IEA- International Energy Agency

IMF- International Monetary Fund

INDC- Intended Nationally Determined Contributions

IPCC-Intergovernmental Panel On Climate Change

MOEF- Ministry of Economy and Finance

MOE- Ministry of Energy MOPA-Mitigation Outcomes Purchase Agreement

MRV- Monitoring, Reporting and Verification

NDC- Nationally Determined Contributions

PA- Paris Agreement

PASA- Program Advisory Service and Analytics

RBCF- Results Based Climate Finance

SD-Sustainable Development

TCAF- Transformative Carbon Asset Facility

TPP- Thermal Power Plant

UNFCCC- United Nations Framework Convention on Climate Change

UzS- Uzbek Sum

WB- World Bank

EXECUTIVE SUMMARY

Uzbekistan is a lower-middle-income, mineral rich, landlocked country. With 35.2 million population as of June 2022[1], it is the most populous of Central Asian countries. It has maintained high and stable economic growth over the past two decades. Since 2016, Uzbekistan has accelerated policy reforms towards a market-based system and opening of the country towards economic partnerships in the region. Uzbekistan ranks among top 25 countries[2] with highest fossil fuel subsidies. Domestic natural gas prices are underpriced standing at about half of its prevailing cost, entailing significant subsidies across the economy. Similarly, the electricity tariffs stand at around 70% of its cost. Reforming the tariff system and phasing out subsidies on gas and power to enable cost recovery, will reduce country's heavy reliance on gas and in the overall energy intensity of its economy. Removal of fossil fuel subsidies will also make investment in renewable energy generation more attractive.

Although Uzbekistan is a small contributor to global GHG emissions (accounts for just 0.34% [3]of global GHG emissions), it has demonstrated increased commitment to climate initiatives. Uzbekistan is a Party to the Paris Agreement (PA) and submitted its first Intended Nationally Determined Contribution (INDC) in 2017. A revised Nationally Determined Contribution (NDC), submitted in 2021, increased the target of reducing CO_2 emissions per unit of GDP by 35% below 2010 levels by 2030 (against the previous target of 10% reduction).

To support of the implementation of the obligations under the Paris Agreement, in December 2022, the Presidential Decree #436 of Uzbekistan "On Measures to Improve the Effectiveness of Reforms Aimed at the Transition of the Republic of Uzbekistan to a "Green" Economy by 2030". The main goal of this decree is to integrate the principles of a "green" economy into the ongoing structural reforms to achieve sustainable economic progress, contributing to social development, reducing greenhouse gas emissions, and ensuring environmental sustainability.

The proposed Uzbekistan-Innovative Climate and Carbon Finance for Energy Reform Program will support the implementation of the next phase of more ambitious energy reforms undertaken by the Government of Uzbekistan (GoU) and thereby the transformation of Uzbekistan's energy sector into an efficient and low-carbon sector. Emission reductions will be generated due to the change in end-user energy demand resulting from the increase in electricity and natural gas tariffs.

The program will use the "Methodology and Model for ex-post quantification of CO_2 emissions impact of end-user energy pricing" for quantifying the GHG emission impact of energy pricing policies and subsidy reduction. The methodology is intended for annual ex-post MRV of pricing policy that impact end-user energy demand of electricity and natural gas.

The Ministry of Economy and Finance (MoEF) will serve as the lead institution taking the responsibilities of (i) coordinating body of the program, (ii) signatory of the term sheets (later agreements on ERPA, MOPA and HCA) and (ii) decision maker on international transfer of carbon emissions, and (iii) focal point on conducting measurements and reporting of carbon emissions along

[1] https://stat.uz/en/official-statistics/demography
[2] https://www.iea.org/data-and-statistics/charts/value-of-fossil-fuel-subsidies-by-fuel-in-the-top-25-countries-2020
[3] https://edgar.jrc.ec.europa.eu/report_2021?vis=ghgtot#emissions_table

with Agency for Hydrometerological services under the Ministry of Natural Resources. MoEF will be supported by inter-ministerial working group consisting of representatives of relevant ministries and agencies to ensure effective implementation of the program.

The Crediting Program Design Document (CPDD) prepared for the program provides a background on host country's GHG emission trends and climate strategy, as well as explains the overall crediting program proposed, determination of baseline, the methodology applied for the estimation of emission reductions, and the institutional arrangement for implementation and monitoring of emission reductions.

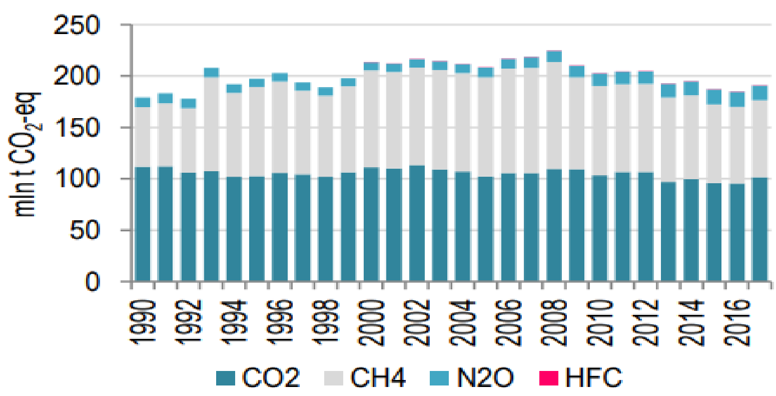
1. CLIMATE POLICY CONTEXT

1.1 Country's GHG emissions profile

Energy use in Uzbekistan is largely based on fossil fuels, even though the country has significant renewable energy potential in solar and wind. Natural gas makes up to 83% of total primary energy consumption and more than 80% of the electricity mix[4]. Uzbekistan remains one of the most energy intensive economies in Europe and Central Asia region with GDP energy intensity about 50% higher than neighboring Kazakhstan, and around three times that of Turkey[5].

According to the First Biennial Update Report (BUR) of the Republic of Uzbekistan, total GHG emissions in 2017 were 189.2 $MtCO_2e$, excluding CO_2 removals in Forestry and Land Use Sectors, totaling 0.3% of global GHG emissions. Over the period 1990–2017, GHG emissions increased by 6.7%. The emissions are dominated by the energy sector, which accounted for 76.3% of total national GHG emissions for 2017.

Figure 1. Total GHG emissions trend in Uzbekistan for the period of 1990-2017



Source: First Biennial Update Report of the Republic of Uzbekistan, 2021

The decreasing emissions trends observed in the recent years are associated with the implementation of measures taken under various government strategies and programs aimed at improving energy efficiency, energy and fuel saving in the energy sector, industry, residential sector, in transport, as well as the introduction of new energy saving technologies. Nevertheless, the demand for electricity is

[4] https://www.iea.org/reports/uzbekistan-2022
[5] https://www.iea.org/reports/uzbekistan-2022

expected to grow from 61.2 TWh to over 100.0 TWh by 2030[6] and decoupling electricity production from GHG emissions is imperative for Uzbekistan in order to pursue a low-carbon growth pathway. The First Biennial Report of Uzbekistan forecasts increase in total GHG emissions relative to 2017 as follows:

Table 1.Forecast of GHG emissions by sector, MtCO2e

Scenarios, sectors	2017	2020	2025	2030
Inertial				
Energy	145.0	159.4	182.7	207.1
Industrial processes and product use	8.5	8.9	9.6	10.4
Agriculture, forestry and other types of land use*	33.7	36.6	42.0	48.4
Waste	2.7	2.7	3.0	3.6
Amount excluding forestry and other types of land use	189.8	207.5	237.4	269.6

Source: First Biennial Update Report of the Republic of Uzbekistan, 2021

1.2 Country's climate policies, NDC and participation in international carbon markets

Uzbekistan is a Party to United Nations Framework Convention on Climate Change (UNFCCC) and ratified the Kyoto Protocol and gained carbon market experience at the international level through participation in Clean Development Mechanism. In 2018, GoU ratified the Paris Agreement and submitted its updated NDC taking up more ambitious target of reducing GHG emissions per unit of GDP by 35% by 2030 from 2010 the levels. The NDC also targets increasing the share of renewable energy sources to 25% of the total electricity generation and doubling the energy efficiency indicator to the 2018 level. Achievement of these goals is envisaged with the support of international organizations and financial institutions, access to advanced energy-saving and environmentally sound technologies, and climate finance resources.

To support the implementation of the obligations under Paris Agreement, a Presidential Decree No. 436 "On Measures to Improve the Efficiency of Reforms Aimed to the Transition of the Republic of Uzbekistan to a "Green" Economy by 2030" was approved by the President of Uzbekistan on 2nd December 2022. The main goal of this decree is to integrate the principles of a "green" economy into the ongoing structural reforms to achieve sustainable economic progress, contributing to social development, reducing GHG emissions, and ensuring environmental sustainability. Among others, the decree defined the following implementation targets for achievement by 2030:

a) Reduction of specific greenhouse gas emissions per unit of gross domestic product by 35 percent from the 2010 level;
b) Increasing the production capacity of renewable energy sources up to 15 GW and bringing their share in the total volume of electricity production to more than 30 percent;
c) Increasing energy efficiency in industry by at least 20 percent;
d) Reduction of energy intensity per unit of gross domestic product by 30 percent, including through the expansion of the use of renewable energy sources;

[6] https://www.worldbank.org/en/news/press-release/2021/06/25/uzbekistan-to-reform-and-green-its-electricity-sector-with-world-bank-support#:~:text=In%20Uzbekistan%2C%20electricity%20demand%20is,past%20their%20useful%20economic%20life.

The GoU, with support from the EBRD, has also developed a Carbon Neutrality Action Plan[7] for the electricity sector, pledging carbon-free power by 2050. In pursuit of this goal, Uzbekistan will further prioritize the development of renewable and low-carbon technologies and ensure the development of its power sector is in line with the Paris Agreement. By engaging in this policy crediting program, Uzbekistan has indicated its interest in participating in carbon markets post 2020 using the cooperative approaches provided in Article 6 of Paris Agreement.

The following decrees and legislation are relevant in the context of implementation of the NDC:

- Presidential Decree No. 436 “On Measures to Improve the Efficiency of Reforms Aimed to the Transition of the Republic of Uzbekistan to a “Green” Economy by 2030”[8]
- Strategy for the transition of the Republic of Uzbekistan to a Green economy in the period of 2019-2030 (2019)[9];
- The Law of the Republic of Uzbekistan "On Use of Renewable Energy Sources" (2019)[10];
- Presidential Decree "On Approval of the Concept of Environmental Protection of the Republic of Uzbekistan until 2030" (2019)[11];
- Ministerial Decree "On Measures for Implementation of National Sustainable Development Goals and Targets for the period until 2030" (2018)[12];
- Strategy on Solid Waste Management (2019)[13]

2. SECTOR DESCRIPTION

2.1 Sector context and practices

The Administration of the President, Cabinet of Ministers, and Ministry of Energy (MoE) are the main government institutions in the energy sector, while individual subsectors are controlled by several state-owned enterprises. The MoE is the central executive authority responsible for implementing state policy and the various regulations, orders and decrees issued by the government for the energy sector. The MoE is also responsible for regulating the production, transmission, distribution and consumption of electric and thermal energy and coal, as well as the production, processing, transportation, distribution, sale and use of oil and gas, and their products.

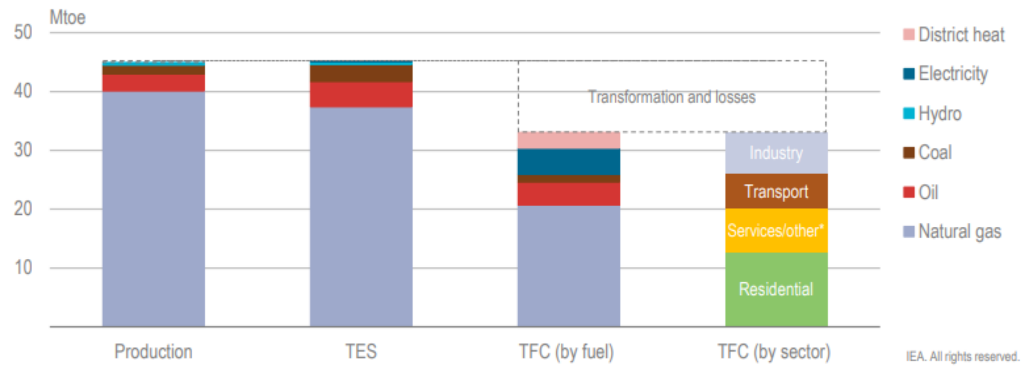
In 2019, the energy market of Uzbekistan was unbundled into three parts: generation, transmission, and distribution, a similar decision was taken with regard to the state-owned oil and gas company. The Interdepartmental Tariff Commission (ITC) under the Cabinet of Ministers of the Republic of Uzbekistan (CMRU) is in charge of energy tariff setting role in Uzbekistan.

Generation mix: Uzbekistan has 100% rate of electrification in the country. Its estimated generating capacity is 16.5 GW, with Thermal Power Plants (TPPs) making up 86% or 14.2 GW, and Hydropower Plants (HPPs) making up the remaining 12% or 2.0 GW (only 200MW of solar energy is currently

[7] https://minenergy.uz/en/lists/view/131
[8] https://www.norma.uz/novoe_v_zakonodatelstve/kak_uzbekistan_pereydet_na_zelenuyu_ekonomiku
[9] https://leap.unep.org/countries/uz/national-legislation/strategy-transition-republic-uzbekistan-green-economy-period-2019
[10] https://www.fao.org/faolex/results/details/en/c/LEX-FAOC188462
[11] https://cis-legislation.com/document.fwx?rgn=120270
[12] https://uzbekistan.un.org/en/157674-national-sustainable-development-goals-and-targets-republic-uzbekistan
[13] https://leap.unep.org/countries/uz/national-legislation/solid-waste-management-strategy-period-2019-2028

installed). Most of the electricity infrastructure has been in service beyond its useful lifetime, including 66% of the transmission and 62% of the distribution networks, 74% of substations, and more than 50% of transformer stations. Domestic energy production in Uzbekistan is dominated by the extraction of gas, amounting to over 90% of the total energy production of 45 Mtoe in 2020. Oil production represents only 6% and coal production is minor with only 3% of the total.

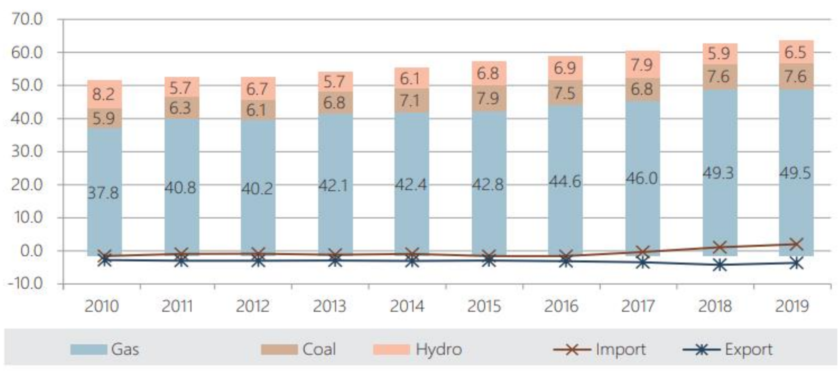
Figure 2. Overview of Uzbekistan's energy system by fuel and sector, 2020



* Includes commercial and public services, agriculture and forestry. Note: Bunker fuels of around 0.1 Mtoe are not included in TES. Source: IEA (2022), World Energy Statistics and Balances (database), https://www.iea.org/data-and-statistics.

Current power demand: Electricity demand in Uzbekistan is set to roughly double by 2030[14] which will require the commissioning of new TPPs with a total capacity of 7.9 GW over the next ten years. The need for electricity reform is recognized in Uzbekistan's "Green economy transition strategy for 2019-2030" and the "Security of electricity supply concept for 2020-2030".

Figure 3. Electricity production, imports and exports dynamic- 2010-2019 TWh



Source: Ministry of Energy of the Republic of Uzbekistan (MoE), 2021

During 2010–2019, electricity production grew by 22.4%[15], which was comparable with the 21.1% population growth rate for the same period. Industrial, agricultural sector and households were the main electricity consumers during the 2010-2019 period, accounting for 26.2%, 23.2% and 20.8% of total net supply, respectively.

[14] https://www.iea.org/reports/uzbekistan-energy-profile/energy-security
[15] In-Depth Review of the Energy Efficiency Policy of the Republic of Uzbekistan | 2022

2.2 Drivers and barriers

The energy sector of Uzbekistan has developed within a monopoly structure. While this structure served its purpose early in the development of the sector, the energy sector is increasingly facing development challenges, including (i) weak financial performance of the sector; (ii) heavy reliance on public funding for investments; (iii) poor and unreliable energy supply; (iv) high losses and prevailing inefficiencies; (v) heavy dependence on fossil fuels; and (vi) limited private sector involvement. The GoU has focused its reforms in the following four areas:

1. Energy sector restructuring and enhanced regulation;
2. Improve the financial sustainability of the sector;
3. Decarbonization of the energy sector;
4. Improving demand side energy efficiency.

The tariff adjustment policy which this crediting program seeks to support is an integral part of the overall energy sector reform and contributes to strengthening the sector financial sustainability and improving demand-side energy efficiency.

2.3 Sector BAU analysis

Tariffs: As of January 1, 2019, Uzbekistan had no officially disclosed methodology on tariff formulation for calculating end-use tariffs for natural gas transmission and distribution. In practice, all tariffs in the natural gas sector are calculated by the MoEF using the cost-plus method.

For electricity generation, distribution and transmission, tariffs are set based on the Decree of the CMRU on the Measures to Further Improve the Tariff Policy in the Power Sector No. 310 dated 13.04.2019, using the cost-plus method. The current tariff methodology does not include any incentives for regulated companies to optimize costs and their own consumption. At the same time, the tariff for the final consumer is formed through adding up the weighted average generation, transmission, distribution, and supply costs. During 2000–2018 there were 10 consumer categories for electricity tariff, with almost similar rate. Starting from 2018, the country decreased the number of categories and set tariffs for four main categories of consumers, but the tariff for commercial consumers was 30% to 50% higher than for residential consumers. Tariff reforms paused in 2020-2021 due to the impacts of COVID-19 with the latest tariff adjustment being implemented in 2022.

Figure 4. Electricity tariffs (as of January 1, 2021)

Group	Category	Tariff options	Tariffs (with VAT)
I	Commercial consumers (with a connected capacity of 750 kVA and above)	Flat-rate tariff for budgetary organisations and particular categories financed by the state budget	450 UZS/kWh (0.04 USD/kWh)
		Time-of-use tariff for all other consumers	Half peak 9:00–17:00 450 UZS/kWh (0.04 USD/kWh) Peak 6:00–9:00 and 17:00–22:00 675 UZS/kWh (0.06 USD/kWh) Night 22:00–6:00 300 UZS/kWh (0.03 USD/kWh)
II	Other commercial consumers	Flat-rate tariff	450 UZS/kWh (0.04 USD/kWh)
III	Residential consumers	50% of the flat-rate tariff for consumers with electric stoves	147.5 UZS/kWh (0.015 USD/kWh)
		Flat-rate tariff for remaining consumers	295 UZS/kWh (0.03 USD/kWh)
IV	Tariff for group I and II consumers, for heating, hot water supply and cooking	Flat-rate tariff	450 UZS/kWh (0.04 USD/kWh)

Source: Energy Charter Secretariat, 2021, based on the Rules of Electricity Use, enacted by the CMRU Decree No. 22 dated 12.01.2018 and CMRU Decree No. 633 dated 30.07.2019

3. PROGRAM DESCRIPTION

3.1 Description and scope of the activity

The proposed program will support the implementation of the next phase of more ambitious energy reforms through mobilizing climate finance payments for results-based emission reductions to carry on the highest priority reform needs. Emission reductions will be generated due to the change in end-user energy demand resulting from the gradual adjustment in electricity and natural gas tariffs. Initial modeling results indicate that the historical and forecasted tariff adjustments would generate 86.7 $MtCO_2e$ over the 2021-2027 period. The emission reductions resulting from changes in electricity and gas tariffs will be quantified through an Energy Policy MRV Model, which is discussed further in the section “Methodological Approaches and Assumptions”.

The program will also support the GoU in reviewing and improving its current monitoring, reporting and verification (MRV) system for NDC implementation and GHG emissions, thus setting the stage for GoU to leverage additional climate finance to support ambition-raising for the country’s NDC.

Overall, the proposed program will support the GoU’s clean energy transition initiatives and advance the reform agenda to the next stage, thereby helping the sector move to a more sustainable and low carbon path.

3.2 Measures and technologies selected

The energy subsidy reform aims to correct negative carbon pricing and supports necessary structural changes required to transition to an efficient and low-carbon economy. No technology is involved in the program.

3.3 How this is aligned and supports national/regional climate change policy objectives

The proposed program is fully aligned with climate change and sector policies that Uzbekistan has underpinned in the recently adopted Presidential Decree on “Measures to improve the effectiveness of reforms aimed at transition of the Republic of Uzbekistan to a “green” economy by 2030” as well as the objectives set in the NDC. Specifically, the program will contribute to the following objectives of the decree:

a) Reduction of specific GHG emissions per unit of gross domestic product by 35 percent from the 2010 level;
b) Increasing energy efficiency in industry by at least 20 percent;
c) Reduction of energy intensity per unit of gross domestic product by 30 percent, including through the expansion of the use of renewable energy sources;

In addition, the Technical Assistance provided through the program will be focused on strengthening the institutional capacity, including building the technical capacity of the government and promoting stakeholder engagement and participation in the climate change planning and decision making. Furthermore, the program will also support developing a robust MRV system for GHG inventories and tracking the NDC progress. This will enable Uzbekistan to accurately measure and report its GHG emissions and progree towards its climate target.

3.4 Supporting domestic policies and incentives

Removing fossil fuel subsidies and addressing price distortion will pave the way for the long-term financial sustainability for the energy sector including allocating funds for development of renewable energy technologies. It will also support removing negative carbon pricing and therefore supporting implicit domestic carbon pricing.

3.5 How the activity contributes to sustainable development

The subsidy reform will reduce GHG emissions and enable long-term financial sustainability for the energy sector which will foster development of renewable energy technologies. The increased participation of solar and wind in power generation will promote Uzbekistan’s adoption of clean technologies and use of sustainable energy sources and reduce their dependance on fossil fuels.

3.6 What co-benefits the program supports achieving and their significance

The sustainable development co-benefits of the proposed program are mapped to the following SDG goals:

Goal 7- Affordable and Clean Energy- to ensure access to affordable, reliable, sustainable and modern energy for all;

The energy sector reform proposed by the program will reduce the fossil fuel subsidies and will promote investment in more efficient infrastructure, and clean energy technologies. The program will also help improve the reliability of the grid and thus provide a more secure electricity supply to the country’s nation.

Goal 9 – Industry, Innovation and Infrastructure – to build resilient infrastructure, promote inclusive and sustainable industrialization and foster innovation;

The energy sector reform and related tariff increase undertaken under the program will trigger upgrade of existing inefficient infrastructure and technology, industrial processes and will encourage adoption of energy efficiency measures, environmentally sound technologies and develop a reliable, sustainable, and resilient infrastructure.

Goal 12- Responsible Consumption and Production- to ensure sustainable consumption and productions patterns, including material consumption and resource husbandry; and

The proposed energy sector reform will help rationalize inefficient fossil fuel subsidies which will free up funds to promote investments for deployment of renewable energy sources and achieve sustainable management and efficient use of natural resources. It is also anticipated that tariff reform will also result in shift of behavioral changes and encourage more sustainable use of energy in the demand side.

Goal 13- Climate Action- take urgent action to combat climate change and its impacts. The goals of the proposed program are aligned with the objective of the government with regard to achieving low-carbon development and integrating climate change measures into national policies, strategies and planning. The program will build and enhance the human, institutional and technical capacity of the country on climate mitigations actions and access to climate finance and promote low carbon growth. The program will result in other social co-benefits such as job creation, improvement of local environmental quality due to reduced use of fossil fuels, strengthening of the country's national capacity etc.

4. INTERACTION WITH OTHER POLICY AND FINANCING INSTRUMENTS

4.1 How the activity interacts with other existing domestic/international mechanisms

The proposed program will support and complement Uzbekistan's planned next phase of energy reforms. The World Bank's series of Development Policy Operations (DPOs) and Support for Preparation of Energy Sector Strategy Programmatic Advisory Services and Analytics (Energy PASA) has been central to provide extensive support to above-mentioned reform.

4.2 How the activity interacts with and supports implementation of country NDC and what are the implications

The energy sector plays a key role in achieving the NDC objectives of GoU since it accounts for more than 76% of the total emissions[16] in the country. Incentives to enhance the energy efficiency in the economy, through proposed subsidy reforms, would contribute to climate change mitigation targets. A more cost-reflective electricity and gas tariffs will not only incentivize energy conservation behaviors from end users, but also create a level playing field for renewable energy sources to be further scaled up, leading to further reductions in GHG emissions. In particular, the proposed Program will contribute to the following overarching NDC goals: (i) halve the energy intensity of GDP; and (ii) increase the share of renewable energy in generation capacity from around 1% in 2020 to 30% by 2030. Furthermore, a Measurement, Reporting, and Verification system for the energy sector to be established through the proposed Program, would be a critical architecture for the country to eventually roll-out Article 6 transactions under the Paris Agreement. The emission reductions

[16] https://www.energycharter.org/what-we-do/energy-efficiency/energy-efficiency-country-reviews/in-depth-review-of-energy-efficiency-policies-and-programmes/in-depth-review-of-the-energy-efficiency-policy-of-the-republic-of-uzbekistan-2022/

achieved as a result of implementation of proposed program will be counted towards Uzbekistan's NDC.

5. PROGRAM FINANCING AND BUDGET

According to the 2022 preliminary financial statements based on local generally accepted accounting principles (GAAP), the electricity sector suffered a financial loss of around UZS 800 billion, while the gas sector suffered a loss of around UZS 3,500 billion, combined this is nearly US$ 376 million. The TCAF payments would not cover these losses and that is not TCAF's intention. Instead, TCAF's $45 million in results-based payments will help support the key areas of reform outlined in the next section, along with the necessary social/income impact mitigation measures.

6. ROLE OF CLIMATE FINANCE

6.1 Role of TCAF and the climate finance

The climate finance payments would broadly support the following key areas of the reform:

Table 2. Energy Sector Reform Program

	Key areas
1.	Establishment of Energy Sector Regulator
2.	Establishment of UzPowerTrade (Central buyer)
3.	Incremental social assistance to protect the poor from energy tariff reforms: a) Top up social assistance to protect the poor from tariff adjustments b) Implementation of renewable energy generation equipment for houses/buildings c) Improving energy efficiency and heating in houses/buildings
4.	Communication campaigns to accompany energy tariff reforms: d) Development and implementation of effective tariff policy and pricing e) Providing communication campaigns
5.	a) Establishment of Monitoring, Reporting and Verification system based on requirements of UNFCCC b) GHG inventory c) National registry
6.	Capacity building of central Ministries and Agencies (Ministry of Economy and Finance, Ministry of Energy, Agency of Hydrometeorological Service) and management of regional government bodies in line of tariff reforms
7.	Establishment of National Designated Authority (Program Implementation Unit) under MoEF according to Article 6 of Paris Agreement: d) Establishing the rules for carbon trading; e) Program review and approval process f) Preparation of national legislative base g) Development of national criteria for program approval

6.2 Role of other sources of finance including GCF

Currently there are no other sources of finance identified in the program.

6.3 Complementarity between different financing sources

N/A

7. PATHWAY FOR ACHIEVING AND VERIFYING THE PROGRAM OBJECTIVES

7.1 Contribution/Role of different players - government agencies, private sector, financial institutions (commercial and multilateral), NGOs/civil society

- The Ministry of Economy and Finance will serve as coordinating body of the policy crediting program, also responsible government body for signing program related documents (term sheets, agreements on ERPA, MOPA and HCA) as well as deciding international transfer of carbon emissions;
- Governmental Working Group consisting of representatives from relevant ministries and agencies will serve as the implementing body of the program to facilitate multi-stakeholder collaboration;
- The Ministry of Investment, Industry and Trade will serve as the central agency for coordination with local stakeholders and with other development partners;
- The Ministry of Economy and Finance together with UzHydromet Agency under the Ministry of Natural Resources, the government agency coordinating NDC and reporting requirement under Paris Agreement, will be the lead agencies responsible for assessing, quantifying, and verifying the expected results of the operation, including potential GHG emission reductions.
- Uzbekistan National Statistical Agency will serve as the main source of data that will be used for the program.

7.2 Describe any program targets/ success indicators

Progress will be monitored using the following indicators:

- Reduced GHG emissions in $MtCO_2e$, which will be verified annually by an independent third party and will be based on the outputs of the MRV model.
- Results-Based Climate Finance payments per ton of verified emission reductions, which will be made annually based on the verified GHG emissions mentioned above.
- Cost recovery tariff trajectory established and implemented over time, which will be based on the actual tariffs as published by the GoU and which will be used in the above-mentioned MRV model.

7.3 How the sustainability of the program will be ensured

Strong cooperation between different agencies such as ministries, regulators, utilities is important for ensuring the sustainability of ongoing and envisaged reforms. Thus, enhancing coordination between different stakeholders and partners is crucial for the success of reforms. To this end, the GoU will prioritize the following actions, among others: (1) developing and implementing capacity building and training programs for key ministries, regulators, and sector companies; and (2) establishing an effective platform for sector planning and coordinating the activities of different stakeholders and development partners in the energy sector.

8. METHODOLOGICAL APPROACHES AND ASSUMPTIONS

8.1 Overview of the methodological approach

Uzbekistan: Innovative Carbon Resource Application For Energy Transition will apply the "Methodology and model for ex-post quantification of CO_2 emissions impact of end-user energy pricing". The methodological and modeling approach that will be used to quantify emission reductions from energy pricing policy reform is designed to examine the effects of *tariff reform* on end-user energy demand. It helps model the emission reductions that can be achieved through the adoption of energy pricing policies by comparing emissions from the observed scenario ("with policy" scenario) with the counterfactual baseline scenario ("without policy" scenario). The "without policy" scenario is generated to simulate what would have happened in the absence of energy pricing policies.

The model evaluates the change in end-user demand for electricity and natural gas caused by the differences in end-user tariffs between the two scenarios. For each defined time period, all of the power generating units explicitly impact the marginal cost of each technology. The model also has units sorted from high to low in terms of their marginal cost of operation. Renewable energy to be added in the future is included in the model in terms of generation mix to meet the energy demand. However, the model does not include emission reductions from additional renewable to avoid double-counting in case the government of Uzbekistan decides to develop a stand-alone renewable energy crediting program.

The MRV model enables the impacts of various policy changes to be simulated without the use of more complex models

The following steps shall be repeated annually to develop an ex-post trajectory of the emission impact of the tariff increases for electricity and natural gas to the end-user.

1. Collect energy sales and pricing data to the end-user, differentiated by energy type (electricity, natural gas), by final consumption user group; residential and nonresidential--including commercial, industrial, and others--and for each tariff layer within each group.
2. Calibrate the methodology for the electricity sector and develop a CO2e emission inventory of the power generation system. The objective of this step is to establish the Withpolicy activity and emissions from all included sources.
3. Calculate CO2e emission modeled impact as the difference between the emission levels obtained from the With policy and Without policy scenarios.

Impact channels considered for the program:

The following five impact channels were identified for developing the counterfactual *Without policy* scenario that determines that CO_2 emission impact of the energy pricing policy and are monitored as per monitoring plan.

1. Short-term behavioral changes in the consumption of that energy
2. Longer-term investment and other decisions that additionally modify processes and the efficiency of appliances and equipment used.
3. Decisions to partially or fully substitute an energy source with an alternative.
4. Spending freed-up resources (caused by subsidy reduction) on other options that reduce future energy costs or improve sustainability.
5. Any change in the electricity demand can impact how the distinct generating units are dispatched, modifying their specific emissions intensity. These factors are taken into account.

Determining the CO_2e emissions reduction caused by implementing the tariff reform:

The scenario calculations are performed by the model on the following basis:

First, the Withpolicy scenario is established based on ex-post data on energy consumption and prices for electricity and natural gas. Then the model analyzes the change in end-user demand for each type of energy based on differences in end-user energy prices caused by the policy package that is being evaluated in this analysis. For this, the counterfactual Withoutpolicy scenario pricing is established and agreed upon, and the demand adjustment is determined by analyzing the price effect by employing the most rigorous possible of the methodologies laid-out in the section "Measuring price effect for demand adjustment".

Establishing CO_2e emissions from Withpolicy operation

Based on the end-user, final demand data collected, CO_2e emission levels under the *Withpolicy* operation[17] are determined using Equation 7-8 and applying country-specific emissions factors per fuel and sector or technology when these are available or from the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, tables 2.2 to 2.10 for stationary sources.

Establishing CO_2e emissions from counterfactual Withoutpolicy operation

The CO_2e emissions levels under the counterfactual *Withoutpolicy* operation are determined with the end-user energy prices that could be expected. Using the results of these analyses, the inventory method is then used in all cases to evaluate the CO_2e emissions under this counterfactual *Withoutpolicy* operation applying equations 9-10.

8.2 GHG covered

CO_2 emissions from electricity generation in fossil fuel powered plants and CO_2 emissions from natural gas consumption. Transport and heating sector emissions are excluded.

8.3 Boundary

The program boundary encompasses greenhouse gas emissions resulting from the consumption of electricity and natural gas by end-users in Uzbekistan. It is important to acknowledge that the definition of the Withpolicy and Withoutpolicy scenarios may not capture all changes in GHG emissions, including upstream emissions. These additional emissions have the potential to significantly expand the analytical boundary of the program. The applied methodology is specifically designed to quantify the impact of the energy pricing policy on CO2e emissions through nine distinct channels. However, in the case of Uzbekistan's program, only five impact channels are considered applicable to the final consumption of energy. Any potential effects beyond these channels are regarded as leakage and are not accounted for.

Source	GHG	Included	Justification/explanation
Emissions from electricity generation in fossil fuel fired power plants	CO2	Yes	Main emission source
	CH4	No	Minor emission source
	N2O	No	Minor emission source
Emissions from end user natural gas consumption	CO2	Yes	Main emission source
	CH4	No	Minor emission source
	N2O	No	Minor emission source

[17] Note that the 'with-policy' scenario represents the actual and observable conditions.

8.4 Baseline setting

A baseline is set by considering business-as-usual, historical trends and the expected trajectory of emissions in the scenario where the policies would have not been implemented and selecting the one that represents the country's own effort to achieve the NDC. The difference between the "With Policy" and baseline scenario ("Without Policy") determines the impact of the policy on emission reductions.

Two baseline options were explored to examine the expected emission trajectory, i.e., under business-as-usual scenario and under NDC-implied scenario. The two baseline options were then compared with the policy scenario and the differences in emissions were calculated. Whichever baseline option is more ambitious in the policy effort and generates more conservative ER results is proposed as the TCAF crediting baseline.

Table 3: Overview of Scenarios (including policy and two baseline scenarios)

Scenario	Description	Justification
Policy scenario (actual)	Historical nominal electricity and natural gas tariffs from 2017-2022 Projected tariff increases used from 2023 onwards. All years converted to constant 2021 UzS	The policy goal is well defined with a clear timeline for implementation. The policy implementation result from 2017-2021 can already be observed, proving the government policy implementation has been on track with multilateral organization's technical assistance program's support to manage the distributional impact and public communication campaign to win the broad political support. The government's policy goal to reach cost recovery by 2026 is considered realistic. Social barriers can hinder implementing energy tariff reforms because of a lack of awareness and understanding, affordability concerns, political opposition, perception of unfairness, and distributional impact. These factors can make it difficult to gain public support and political will for reforms, leading to resistance to change and a status quo bias. As a result, the government struggles to enact meaningful tariff reforms that could address energy affordability, sustainability, and equity issues. The program supports to manage the distributional impact and public communication campaign the

Scenario	Description	Justification
		government overcomes the social barriers and gains broad political support. Additionally, the program will support building the institutional capacity required to implement new tariff structures and effectively implement tariff reforms.
Baseline scenario 1: Business-as-usual baseline (tariff would be adjusted according to CPI)	Historic nominal tariff to 2016. Electricity tariff increases in 2017-2019, mirrors the inflation rate. From 2020 and 2022 the rate is maintained at nominal 2019 rates to manage the negative impacts of the COVID-19 pandemic. From 2023 onwards, mirrors the inflation rate.	Uzbekistan experienced quite high inflation rate of 10.4% during 2012-2016. To keep up the tariff with the high inflation rate would be the course of action that the government will most likely adopt without consideration of Uzbekistan's own effort in the NDC.
Baseline Scenario 2: NDC-implied baseline (tariff would be adjusted following historical trend – 5-year average)	Calculate historical average nominal monthly price increase 2012 to 2016 and subtract inflation to get price increase delta. Add this delta to CPI from 2017 to 2019. Due to Covid, 2020 to 2022 at nominal December 2019 rates (covid impact) Add this delta to CPI from 2023 onwards until cost recovery tariff is reached, then apply the cost recovery tariff. Tariffs then increase with inflation (CPI) only. All years use constant 2021 UzS.	As the tariff increases to a level that causes more political sensitivity, the government needs to make extra effort than under BAU scenario to manage the distributional impact and public awareness campaign to chart the reform carefully. GoU published its first NDC, the same year as the start of the proposed policy crediting program. This is the scenario that reflects the country's own effort in implementing its NDC.

8.5 TCAF crediting baseline:

Comparing these two baseline options, the tariff following historical trend based on 5-year average increase rate is proposed to be the TCAF crediting baseline for its conservativeness and reflecting more ambitious policy actions.

8.6 Source of Key Data:

Official economic and energy data published by Uzbekistan National Statistics Agency and other government agencies have been used where available. The model uses data provided by the MoEF, specifically, energy balance data, i.e., generation and consumption, from 2012 to 2021. Energy prices are officially published final energy price by year in local currency (UzS). Historical electricity tariff and natural gas tariff are based on the task team's inputs.

Key economic indicators (up to 2021) such as GDP, GDP growth, inflation rate are based on the World Bank database and International Monetary Fund (IMF) World Economic Outlook. The historical currency exchange rate is based on public online sources. Specific data at the power plant level is based on the Platts database, WB Least Cost Planning Model, etc. The data has been cross-checked where multiple resources were available.

8.7 Role of targets

N/A

8.8 Environmental integrity

As per the methodology and model, additionality of emission reductions as a result of policy reform is assessed by developing two scenarios – an ex-post, results-based With policy scenario based on historical data and a Without policy counterfactual calculated scenario – where the only difference between the two is the change in fuel prices and subsidies due to implementing the specific policy or measure. Thus, all the other activities that change the emissions and are outside of the scope of the policy or measure being evaluated are included in the With policy measured scenario and directly transferred to the Without policy counterfactual scenario. Uzbekistan's NDC does not specify an unconditional target, however, the program will credit against a crediting threshold (or "TCAF baseline") that is well below the BAU emissions trajectory for its conservativeness and reflecting more ambitious policy actions.

8.9 Double counting

As required by Article 6 of Paris Agreement, the GoU will create and maintain a registry for the purpose of tracking and shall ensure that such registry records, including through unique identifiers, as applicable, authorization, first transfer, transfer, acquisition, use towards NDCs, authorization for use towards other international mitigation purposes, and voluntary cancellation (including for overall mitigation in global emissions, if applicable), and shall have accounts as necessary.

8.10 Leakage

There will always be changes in GHG emissions that are not captured by the definition of the With policy and Without policy scenarios and will be treated as leakage. These include changes in upstream GHG emissions that could be caused by the change in demand for these fuels (such as methane leakage) and scope three indirect emissions generated in the value chain, and other impact channels that cannot be adequately quantified. These are treated as leakage and held constant between the two scenarios.

8.11 Competitiveness, if relevant.

N/A

9. CREDITING PERIOD

9.1 Life of the program

The lifetime of the program is from January 2021 to December 2030 to coincide with the NDC implementation period.

9.2 Duration of the program

The crediting period of the program is from 2021 up to 2027.

9.3 Start date

The start date and date after which TCAF will credit emission reductions is January 1, 2021

9.4 End date

The program will end when the full contract volumes have been delivered, but no later than December 31, 2027.

10. MRV ARRANGEMENTS

10.1 Parameters to be monitored

The following five types of data will be monitored and collected ex-post.

1. Macroeconomic variables and forecasts.

Macroeconomic variables and forecasts will be obtained from consistent sources, such as GDP, population, consumer price index (CPI), exchange rates, and the mass and trade value of fuel imports (or exports) of different commodity codes[18], used to establish the actual value of fuels and their internal-market subsidy levels. To develop local elasticities, data will be used for 30 most recent years, and then data is required for each historic year in the modeling period, updated yearly.

Table 4. Macroeconomic data

Data	Unit:
Population	million people
Urbanization	%
Household electrification of urban and rural households	%
Ave. Household size (urban and rural)	people/HH
GDP	LCU million
GDP contribution by sector	LCU million
CPI	
Exchange Rate	LCU/US$
Income per capita	LCU/yr
Mass and trade value of energy imports and exports	
By commodity code	
270119	kg and US$
271019	kg and US$
271121	kg and US$
270900	kg and US$
Heating and cooling degree days	deg-day

[18] Typically, commodity codes, 270119, 271019, 271121, 270900

2. End-user demand for energy (Final Energy Consumption) by sector and by fuel type.

Consistent monitoring and collection of data will be done on the end-user demand for energy (Final Energy Consumption) by sector[19] and by fuel type and in different tariff brackets. Data for 30 most recent years is used to develop local elasticities, and then data is required for each historic year in the modeling period, updated yearly.

Table 5. End-user energy demand data

Annual system level data required[20]	Unit:	historical data for ex-post	forecast data for ex-ante
Price (and tariff) data			
By economic sector and tariff group:			
Electricity	*UZS/MWh*	[Annual]	[Annual_Est]
Natural Gas	*UZS/MJ*	[Annual]	[Annual_Est]
Consumption data			
By economic sector and tariff group:			
Electricity consumption	MWh	[Annual]	[Annual_Est]
Natural Gas Consumption	MJ	[Annual]	[Annual_Est]

3. Current operation of the electricity-supply system for all sectors and client classes.

To capture any changes in electricity demand, data to be collected on the real operation of all the generating units involved, including any constraints historically or currently placed on their operation. The database shall be developed at the generating unit level and include all electricity-generating units. The list of data required for the inventory is provided below and further specified in the excel document "MRV data requirements".

1. Plant information
2. Unit Characteristics
3. Capacity and generation
4. Fuel consumption and efficiency
5. Non-fuel, generation process emissions
6. Energy Efficiency improvement costs
7. Investment costs-for new and planned plants only
8. Operating costs-for all plants
9. Electricity prices
10. Electricity demand, imports and exports
11. Annual load duration curve based on hourly data, including exports

[19] Residential, Commercial, Public Services, Industry, Agriculture, Forestry, and Fishing
[20] If the model is using one elasticity number for all sectors, an annual consumption-weighted average end-user price is needed for each energy source, across all tariff groups and sectors. If the model is using a different elasticity number for each sector, an annual consumption-weighted average end-user price is needed for each energy source, across all tariff groups for each sector.

4. Documentation of the policy change being analyzed

Documentation that quantifies the change in tariff increase policy, through **Error! Reference source not found.** that clearly illustrates what can be expected to have happened if the current policy had not been enacted.

Table 6. Policies evaluated in the program

Policies
Tariff increases for electricity to the end-user
Tariff increases for natural gas sold to the end-user

5. Plausibility of indicators

As part of this program, Sustainable Development (SD) co-benefits will also be monitored. Table 15 of Annex 2 lists the indicators to be monitored. Plausibility indicators are not needed to determine GHG emissions reductions but to validate that the policy change has, in fact, affected the real economy. Renewable and energy efficiency indicators in the SD co-benefits are selected as plausibility indicators and are specified in the Table 15.

Detailed list of parameters that should be monitored ex-post and those that are fixed ex-ante are provided in the Annex 2 of the CPDD and will be recorded in a separate document "MRV data requirements".

10.2 Data needs

Data is required for each year from the initial year in the model up to the most recent year . Each year, the database will have to be updated with consistent data, preferably from the same sources, which is an important consideration when initially selecting the sources to be used.

10.3 Data sources

Local data from Uzbekistan National Statistical Agency shall be used whenever possible for fuel energy content, specific gravity, specific emissions, etc. All data shall be consistent with the 2019 Refinement to the 2006 IPCC guidelines for national greenhouse gas inventories (see https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html). However, if not available, the data can be collected from reliable sources such as IEA and the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

10.4 Data collection procedures

All required data will be collected by MoEF and recorded in electronic format. The archived data will be stored for 2 years after the end of the crediting period.

10.5 QA/QC procedures

To the extent possible, national data from statistical agency will be used for the calculations of emission reductions. The data will be cross-checked and signed off by MoEF.

10.6 Monitoring and reporting frequency

The frequency of data to be collected will depend on the type of the data. The details of monitoring frequency are provided in excel document "MRV data requirement".

10.7 Monitoring of indicators for measuring progress made/success of the program implementation

Progress will be monitored using the following indicators:

- Reduced GHG emissions in MtCO2e, which will be verified annually by an independent third party and will be based on the outputs of the MRV model.
- Results-Based Climate Finance payments per ton of verified emission reductions, which will be made annually based on the verified GHG emissions mentioned above.
- Cost recovery tariff trajectory established and implemented over time, which will be based on the actual tariffs as published by the GoU and which will be used in the above-mentioned MRV model.

10.8 Domestic registry needs and arrangements

The Government of Uzbekistan has indicated that the designated body for Article 6 implementation will be part of the MoEF supported by interdepartmental council consisting of representatives from different relevant ministries and agencies. The government is currently collaborating with several development agencies in development of register to record emission data reported from installations, development of transaction registry which will record and track carbon units for the market mechanisms, including emission allowances and carbon credits.

10.9 Ex-post monitoring and verification arrangements

All data to be collected and recorded is provided in the excel document "MRV data requirement" which will serve as a source of data for the estimation of emission reductions achieved by the program. All required data will be collected by MoEF and recorded in electronic format. Based on the data collected and recorded, selected Independent Reviewer will verify the emission reductions achieved by the program.

11. EMISSION REDUCTION CALCULATIONS

11.1 Baseline emissions

NDC-implied baseline based on five-year historic average increase rate for the tariff was chosen as the TCAF crediting baseline. Ex-ante emission reduction estimate is the difference of the emissions under with-policy scenario and the emission under TCAF crediting baseline.

Tariff under Policy Scenario. Since 2017 which is the start year of the new tariff adjustment being accelerated, the tariff for both electricity and natural gas has been increasing steadily. The tariff was frozen in 2020 and 2021 to manage the covid impact. The last tariff adjustment was done in 2022 and is projected to reach cost recovery in 2026 according to the following schedule.

Table 7. Projected tariff increase during 2022-2030 under policy scenario

	2022	2023	2024	2025	2026	2027	2028	2029	2030
Electricity	35.3%	26.0%	9.8%	6.9%	5.0%	5.0%	5.0%	5.0%	5.0%
Gas	42.2%	29.7%	9.8%	6.9%	5.0%	5.0%	5.0%	5.0%	5.0%
CPI	11.4%	11.2%	9.8%	6.9%	5.0%	5.0%	5.0%	5.0%	5.0%

Table 8. Nominal electricity and natural gas tariff under policy scenario

	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Electricity	UzS/kWh	176.9	231.2	342.9	414.5	415.6	492.4	728.8	888.6	959.9	1036.8	1119.9
Natural Gas	UzS/MJ	7.5	9.7	15.0	15.6	15.9	16.2	27.5	37.4	40.4	43.6	47.1

Note: Data beyond 2022 (included) are based on government projections.

Tariff under baseline scenario (5-year historic average increase rate)

To set a baseline reflecting country's own effort, historic average annual increase rate is calculated based on the nominal tariff of electricity and natural gas aggregated by the residential, non-residential and industry sector over 2012-2016. The increase rate is 16.6% for electricity (all sectors) and 26.6%, 21.3%, and 21.3% for natural gas in the residential, non-residential, and industry sectors, respectively. After deducting the average annual inflation rate of 10.4 %, the real increase rate is 6.2% for electricity (all sectors) and 16.2%, 10.9%, and 10.9% for natural gas in the residential, non-residential and industry sectors, respectively. This increase rate will be applied to the observed inflation rate from 2017-2019 and the projected inflation rate from 2022-2030 and produce a series of nominal increase rate. The nominal increase rate schedule will be applied to the observed tariff in 2016 to produce the tariff for 2017 in the baseline scenario. The following table summarizes the CPI and nominal increase rate for the tariff under crediting baseline over the crediting period.

Table 9. Historic nominal tariff (2011-2016) and the average annual increase rate

	Residential	Non-residential	Industry		Residential	Non-residential	Industry
	Electricity (UzS/kWh)				*Natural Gas (UzS/thcm)*		
2011	62.83	78.58	78.58		79,003	93,150	93,150
2012	73.22	91.52	91.52		126,352	113,000	113,000
2013	84.15	105.12	105.12		156,976	139,835	139,835
2014	98.83	123.41	123.41		188,007	165,960	165,960
2015	115.90	144.67	144.67		219,652	193,895	193,895
2016	135.45	169.36	169.36		256,696	244,974	244,974
Annual increase rate	16.6%	16.6%	16.6%		26.6%	21.3%	21.3%
Nominal average annual inflation 2011 - 2016				10.40%			
Real increase rate	6.2%	6.2%	6.2%		16.2%	10.9%	10.9%

11.2 Program emissions

The MRV tool would model the electricity and natural gas consumption reduced at the end-user level in response to the tariff according to the price elasticity and resulted in different emission trajectories. The following tables show the final energy consumption and emissions at both policy scenario and crediting baseline scenario.

Table 10. Energy consumption under policy scenario and without policy scenario

Final Energy Consumption		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
By Fuel															
Sale of electricity	GWh	46,188	48,456	50,000	52,782	53,126	55,038	57,955	61,143	64,544	68,135	71,926	75,928	80,153	84,612
Electricity	ktoe	3,971	4,166	4,299	4,538	4,568	4,732	4,983	5,257	5,550	5,859	6,185	6,529	6,892	7,275
Natural Gas	ktoe	13,401	13,899	13,965	15,754	16,761	17,364	18,285	19,290	20,364	21,497	22,693	23,955	25,288	26,695
Sum	ktoe	**17,372**	**18,065**	**18,264**	**20,293**	**21,329**	**22,097**	**23,268**	**24,548**	**25,914**	**27,355**	**28,877**	**30,484**	**32,180**	**33,970**
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
By sector															
Residential	ktoe	8,613	9,300	9,324	11,005	11,119	11,519	12,129	12,797	13,508	14,260	15,053	15,891	16,775	17,708
Nonresidential	ktoe	8,759	8,765	8,940	9,288	10,210	10,578	11,139	11,751	12,405	13,095	13,824	14,593	15,405	16,262
Sum		**17,372**	**18,065**	**18,264**	**20,293**	**21,329**	**22,097**	**23,268**	**24,548**	**25,914**	**27,355**	**28,877**	**30,484**	**32,180**	**33,970**

Final Energy Consumption		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
By Fuel												
Sale of electricity	GWh	45,053	47,553	51,925	56,285	56,781	61,934	74,825	81,430	83,995	87,135	90,390
Electricity	ktoe	3,874	4,089	4,465	4,840	4,882	5,325	6,434	7,002	7,222	7,492	7,772
Natural Gas	ktoe	13,201	13,589	13,965	15,541	16,598	17,236	19,726	21,317	22,075	22,928	23,896
Sum	ktoe	**17,074**	**17,678**	**18,430**	**20,380**	**21,480**	**22,562**	**26,160**	**28,318**	**29,297**	**30,420**	**31,668**
By sector												
Residential	ktoe	8,465	8,836	8,726	10,250	10,357	10,730	12,609	13,958	14,407	14,922	15,537
Nonresidential	ktoe	8,609	8,842	9,704	10,130	11,124	11,831	13,550	14,361	14,891	15,498	16,130
Sum		**17,074**	**17,678**	**18,430**	**20,380**	**21,480**	**22,562**	**26,160**	**28,318**	**29,297**	**30,420**	**31,668**

Table 11. Power sector generation mix under policy scenario and without policy scenario

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generation												
Coal	*GWh*	11,464	11,464	10,631	1,478	0	0	0	0	0	0	0
Hydro	*GWh*	3,165	3,165	3,165	3,583	3,583	3,692	3,692	3,692	4,940	4,940	4,940
Pumped Storage	*GWh*	0	0	0	0	0	0	0	0	0	0	0
Natural Gas	*GWh*	31,161	32,857	32,754	46,111	47,690	47,834	46,315	43,156	39,789	41,010	43,722
LNG	*GWh*	0	0	0	0	0	0	0	0	0	0	0
Oil	*GWh*	44	133	444	295	964	1,041	1,041	955	1,174	1,174	1,174
Solar PV	*GWh*	0	0	0	0	0	1,253	1,253	7,515	7,515	10,647	10,647
Solar CSP	*GWh*	0	0	0	0	0	0	0	0	0	0	0
Wind	*GWh*	0	0	0	0	0	0	4,469	4,469	8,937	8,937	10,278
Imports	*GWh*	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324	13,324
Other	*GWh*	0	0	0	0	0	0	0	0	0	0	0
Total	*GWh*	**59,158**	**60,943**	**60,318**	**64,790**	**65,560**	**67,143**	**70,092**	**73,110**	**75,679**	**80,031**	**84,084**

		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Generation												
Coal	GWh	11,463.9	11,463.9	11,322.4	3,182.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	GWh	3,165.3	3,165.3	3,165.3	3,582.7	3,582.7	3,691.6	3,691.6	3,691.6	4,940.1	4,940.1	4,940.1
Pumped Storage	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	GWh	29,706.7	31,721.4	34,383.9	48,705.4	52,200.5	56,246.4	66,718.0	67,414.2	62,595.1	63,326.0	65,307.1
LNG	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil	GWh	44.4	133.2	444.1	295.2	963.6	1,040.7	1,040.7	954.8	1,173.8	1,173.8	1,173.8
Solar PV	GWh	0.0	0.0	0.0	0.0	0.0	1,252.5	1,252.5	7,515.2	7,515.2	10,646.6	10,646.6
Solar CSP	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wind	GWh	0.0	0.0	0.0	0.0	0.0	0.0	4,468.6	4,468.6	8,937.1	8,937.1	10,277.7
Imports	GWh	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0	13,324.0
Other	GWh	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	GWh	**57,704**	**59,808**	**62,640**	**69,090**	**70,071**	**75,555**	**90,495**	**97,368**	**98,485**	**102,348**	**105,669**

11.3 Leakage

Upstream GHG emissions that could be caused by the change in demand for these fuels are treated as leakage and held constant between the two scenarios.

11.4 Total emission reductions

Table 12. Emission Reductions under the two scenarios

Scenarios	Units	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
with policy	Mt CO2	56.3	58.1	55.9	56.9	61.9	63.4	60.3	57.0	58.4	61.8	65.7	655.7
w/o policy	Mt CO2	55.19	56.90	57.44	59.04	63.61	67.44	76.16	75.82	75.28	76.57	80.22	743.67
Difference	Mt CO2	-1.08	-1.23	1.53	2.09	1.72	4.03	15.88	18.84	16.89	14.76	14.53	88.0

The estimated emission reductions from the program are 88 million tCO_2 over the period of 2017-2027. The results for each scenario are presented in the table below.

Table 13. Estimated emission reductions per baseline scenarios

Scenario	Estimated ERs 2021-2027 (MtCO2e)	Estimated average annual ER (MtCO2e)
Baseline Scenario 1: NDC-implied baseline (tariff would be adjusted following historical trend – 5yr average)	86.7	12.4
Baseline scenario 2: Business as usual baseline (tariff would been adjusted according to CPI)	161	23

12. ENVIRONMENTAL AND SOCIAL SAFEGUARDS

12.1 Domestic compliance requirements

The proposed program will not support or design any kind of physical intervention or civil work and thus does not require an environmental impact assessment.

The potential social risks and impacts mainly relate to impacts of changes to tariffs. Whilst the increase in tariffs will be differentiated for residential versus other end users even marginal and gradual increases may likely disproportionately impact vulnerable and poor households and require support from social safety nets. The program will co-ordinate and co-operate with agencies providing social safety nets, including through the World Bank's ongoing subsidy reform dialogues on strengthening the social assistance delivery systems.

13. STAKEHOLDER CONSULTATION

13.1 How stakeholders were identified and consultation process

In addition, citizen engagement activity will continue as part of the program and overall World Bank engagement with the GoU. As part of this work, a communication plan accompanying the subsidy reforms will be implemented. Key stakeholders and potentially impacted households will be identified as part of the distributional impact assessment with recommendations on potential mitigation measures. A communications campaign will also be designed to inform stakeholders on the reforms and accompanying social impact mitigation measures.

14. INSTITUTIONAL ARRANGEMENTS

The MoEF is the lead institution for the preparation and implementation of the policy crediting program. MoEF is an authorized National Body for Article 6 of Paris Agreement and will also coordinate and support on aspects related to program linkages with the NDC and issue the Letter of Approval ensuring that the program supports sustainable development in the country.

The Government Working Group formed to support the program consisting of members of relevant ministries and agencies will support the MoEF the with implementation of the program and ensure it is aligned with the transition to "green" economy, Climate Strategy and Action Plans.

The Ministry of Energy will be responsible for implementing priority reforms under this operation as well as key actions and measures for utilizing TCAF funds.

MoEF, supported by UzHydromet Agency will be the lead agency responsible for assessing, quantifying, and verifying the expected results of the operation, including potential GHG emission reductions.

15. HOST COUNTRY APPROVAL PROCEDURES

15.1 What approvals are needed

The proposed program is Results Based Climate Finance operation and will adhere to the requirements established by TCAF contributors and agreed upon by the host country. The host country shall issue a Letter of Approval confirming it:

- Approves the specified program in accordance with the Host Country Agreement between Host Country and the International Bank for Reconstruction and Development, as Trustee of the TCAF.
- The Program (i) promotes sustainable development and environmental integrity in Uzbekistan and (ii) relates and contributes to the implementation of its nationally determined contribution.

15.2 Who is responsible for what approval

Ministry of Economy and Finance as a National Body for Article 6 will issue the Letter of Approval authorizing the program and potential transfer of emission reductions.

16. VALIDATION & VERIFICATION OF THE CREDITING PROGRAM

16.1 Describe the proposed process for validation and verification of emission reductions

Validation and verification of the proposed program will be undertaken by Independent Reviewers selected by the World Bank following TCAF Result Based Climate Finance Validation and Verification Protocol.

17. RISKS AND MITIGATION MEASURES

Policy reversal risk: The risk for tariff reform reversal is moderate as Uzbekistan has been implementing a strong, sustained, and systematic reform program over the past several years. Uzbekistan's energy reform program is now entering the next phase. The policy reforms supported through this operation tackle several fundamental issues such as gradual removal of ineffective subsidies, energy sector market, regulatory and institutional measures, financial sustainability of the companies, among others. Understanding associated risks that may arise during the reform implementation period, the GoU has prepared and is committed to apply certain mitigation measures to ensure the sustainability of the sector reform agenda and successful implementation of the proposed operation.

Political and governance risk: GoU and sector stakeholders' support for the sector reforms continues to be strong, recent measures such as market design, establishment of new sector players (regulator, market operator) and subsidy reforms are complex and may generate public discussion and debate. GoU has demonstrated commitment to further pursue sector financial sustainability initiatives including gradual tariff increase to cost recovery level, while protecting the energy poor. Authorities are also aware of the above-mentioned risks and have taken a number of initial measures to mitigate them. They have also started practicing communication campaigns to explain the need for the proposed reforms and collect citizens' feedback. The World Bank, as a lead partner for the GoU, will continue to support the design and implementation of the reform program through the energy transition in a coherent manner. In this regard, the World Bank's active role in design and implementation of the GoU's Electricity Sector Reform Implementation Plan (ESRIP) will be instrumental to strengthen the sector policies and strategies. On the proposed subsidy reforms, the prevailing electricity and gas tariffs are still below cost recovery level. As part of the ongoing dialogue, the World Bank will continue to support the GoU in broader electricity sector reforms, including on cost recovery initiatives through implementing the new methodologies and undertaking tariff adjustments on a regular basis to be accompanied by social mitigation measures to protects the vulnerable people as well as sound communication campaigns. In this regard, the proposed operation will benefit from the ongoing comprehensive reform program and World Bank support to the GoU.

ANNEX 1. CONTACT DETAILS

National entity responsible for the activity

Name: Ministry of Economy and Finance
Address: 45A, Islam Karimov street, Tashkent, 100003, Uzbekistan
Phone: +99871 207-71-73
Fax: +99871 232-63-72
E-mail: info@mineconomy.uz

Buyer details

Name: International Bank for Reconstruction and Development,
as Trustee for the Transformative Carbon Asset Facility
Address: 1818 H street NW, Washington DC, 20433
Phone: 202-473-0000
Email: tcaf@worldbank.org

ANNEX 2: SUPPORTING DOCUMENTATION FOR ABOVE SECTIONS

Table 14. Indicators to monitor transformational change

Criteria	Description	Proposed indicator to monitor the transformational impact
Size		
	Based on high-level assumptions, the program is expected to generate 86.7 million tons of emission reductions over the period (2021-2027), it demonstrated that the energy subsidy reform has substantial mitigation impact.	Total emission reductions during the TCAF crediting period 2021-2027
Sustainability		
Technology	The energy subsidy reform aims to correct negative carbon pricing and supports necessary structural changes required to transition to an efficient and low-carbon economy. Uzbekistan also has an ambitious renewable energy development goal of generating 10 GW by 2030, which seeks to accelerate a move toward sustainable energy technologies.	Increase of installed capacity of renewable energy measured by GW. This is a plausibility indicator to proof that emission reduction is indeed happening in the sector, as a results of the comprehensive sector reform including subsidy reduction measures.
Policy	The Government of Uzbekistan is undertaking holistic policy reforms which seek to ensure a competitive and financially sustainable energy sector as well as offer protection to vulnerable groups in the face of rising tariffs. The World Bank's Energy GP is collaborating with other GPs (social protection, poverty reduction) to support the government in establishing such social protection projects as well as carrying out campaigns that communicate the importance of upcoming changes to citizens. Additionally, activities that are planned to be implemented under the TCAF program will help identify the technical and financial barriers, develop the much-needed capacity in relevant institutions, including increasing the number of relevant staff and improving their expertise in leading country's climate policy mandate as well as strengthening the inter-ministerial coordination.	Number of the beneficiaries covered by the social protection project and number of new positions created for leading the sustainable development policies of the country.
Financing	The subsidy reform will reduce the financial burden on the public budget and pave the way for the long-term financial	Government subsidy spending on the industrial and commercial segment of electricity and natural gas.

Criteria	Description	Proposed indicator to monitor the transformational impact
	sustainability for the energy sector including allocating funds for development of renewable energy technologies.	Total investment on renewables in the electricity mix.
Leverage		
	Along with the subsidy reform, GoU also embarked on unbundling the power sector as a significant step towards the creation of a more competitive electricity market. To encourage private sector participation in the country, the government has approved a PPP law in 2019 and established a PPP agency under the Ministry of Finance which has been working ambitiously to promote PPPs in Uzbekistan. Almost 70-80 percent of potential PPPs today are in the energy sector including 5,000 MW of solar power to be developed by 2030. The RBCF payments provided by TCAF will reduce the costs related to implementation of the tariff reform and as such it may encourage the country to pursue increased ambitions with regards to its mitigation targets. Also, successful implementation of this program will create a demonstration effect which the government may potentially replicate in other sectors of the economy. In addition, this collaborative government-driven program will strengthen technical and institutional capacities at the national and sectoral level, integrating mitigation and adaptation in the planning processes and strengthen domestic capacities in long term policy planning and programming and required MRV capacity.	Millions of US$ of private sector financing that has been leveraged in low carbon technology investment (renewable energy and energy efficiency). This is a plausibility indicator to proof that emission reduction is indeed happening in the sector, as a results of the comprehensive sector reform including subsidy reduction measures Robust MRV system developed and implemented. Designated National Authority established for implementation of Article 6 of the Paris Agreement
Carbon pricing		
	Uzbekistan will be removing negative carbon pricing and therefore supporting implicit domestic carbon pricing. By crediting emission reductions from this policy action, TCAF will directly support implicit domestic carbon pricing. Additionally, the proposed program is first of its kind transaction that Uzbekistan is implementing outside	Impact on Article 6: ITMOs transacted through Article 6.2. Carbon price signal: $/ton of ITMO

Criteria	Description	Proposed indicator to monitor the transformational impact
	compliance-based carbon market where the price of emission credits is not established by supply and demand but rather through the costs of the program. As such, the price setting exercise for this program will provide the relevant stakeholders with practical insights on prices of different carbon units and the costs of mitigations actions provided in the NDC.	

Table 15. Indicator for monitoring Sustainable Development Co-Benefits

Proposed sustainable Development co-benefit	(a) Indicator and (b) measurement units
Co-benefit 1: Social	a. Job creation in energy efficiency and renewable energy sectors b. Number of green jobs created
Co-benefit 2: Environmental	a. Improved air quality due to reduced use of fossil fuels and sustainable use of natural resources b. Amount of fossil-fuel subsidies (production and consumption) per unit of GDP or change in the level of GHG emissions from energy sector
Co-benefit 3: Economic	a. More efficient consumption and production patterns; Access to clean energy investments and payments for emission reductions b. Annual energy consumption per capita; Share of production of renewable energy resources; Improved energy efficiency and increase of share of renewable energy are selected as plausibility indicators.
Co-benefit 4: Institutional	a. Capacity building, international cooperation, integrated decision-making, institutional and legislative changes b. International cooperation agreements signed, legislation passed

Table 16. Electricity system-level data

Electricity System-level data (Electricity Imports, Exports and Generation - transformation from other energy sources)			
Annual system level data required	**Unit:**	**historical data for ex-post**	**forecast data for ex-ante**
Total System Generation	*MWh*	[Annual]	[Annual_Est]
Hourly generation (raw data for load-duration analysis)	*MWh*	[Hourly]	[Hourly_Est]
System T&D Loss Rate	*%*	[Annual]	[Annual_Est]

Electricity System-level data (Electricity Imports, Exports and Generation - transformation from other energy sources)			
Annual system level data required	**Unit:**	**historical data for ex-post**	**forecast data for ex-ante**
Off-Grid Capacity	*MW*	[Annual]	[Annual_Est] with specific data from known planned plants and assumption-driven estimate for other plants /years
Off-Grid Generation	*MWh*	[Annual]	[Annual_Est] with specific data from known planned plants and assumption-driven estimate for other plants /years
Imported Electricity			
Imported Energy	*MWh*	[Annual]	[Annual_Est]
Imported Capacity	*MW*	[Annual]	[Annual_Est]
Exported Electricity			
Exported Energy	*MWh*	[Annual]	[Annual_Est]
Exported Capacity	*MW*	[Annual]	[Annual_Est]
Electricity price	*UZS/MWh*	[Annual] with cells to capture tariffs by customer group/sector as appropriate	[Annual_Est] with cells to capture tariffs by customer group/sector as appropriate
Natural Gas Price - Delivered	*UZS/MJ*	[Annual]	[Annual_Est]
Electricity production, tier 1 or tier 2 inventory data			
Total Electricity generated	*MWh*	[Annual]	
Natural Gas Consumed	*MJ*	[Annual]	
Fuel Oil Consumed (by oil grade if appropriate)	*MJ*	[Annual]	
Coal Consumed	*MJ*	[Annual]	
Carbon Emissions per period from Natural Gas	*tonne CO2*	[Annual_Calc]	
Carbon Emissions per period fromFuel Oil	*tonne CO2*	[Annual_Calc]	
Carbon Emissions per period from Coal	*tonne CO2*	[Annual_Calc]	

Table 17. Electricity generating units data

Data required for each generating unit	Unit:	historical data for ex-post	forecast data for ex-ante
Unit name	*Text*	[Descriptive]	[Descriptive] for known planned plants only
Unit ID number	*Number*	[Descriptive]	[Descriptive] for known planned plants only
Ownership		[Descriptive]	[Descriptive] for known planned plants only
Transmission Zone name or number	Text	[Descriptive]	[Descriptive] for known planned plants only
Unit maximum capacity	*MW*	[Descriptive]	[Descriptive] for known planned plants or [Descriptive_w/Default] based on studies and projections
Online Date	*Year*	[Descriptive]	[Descriptive]
Retirement Date	*Year*	[Descriptive] when known, or [Descriptive_w/Default] based on expected life	[Descriptive_w/Default] based on expected life
Emission Controls	*Name of controls (e.g., SCR, FGD, scrubber)*	[Descriptive_w/Default]	[Descriptive_w/Default]
Unit fuel type	*Fuel (e.g., NG, oil, solar PV, solar thermal, hydro)*	[Descriptive]	[Descriptive]
Fuel source	*Source (e.g., pipeline, rail shipments)*	[Descriptive_w/Default]	[Descriptive_w/Default]
Variable O&M Costs	*UZS/MWh*	[Annual_w/Default]	[Annual_Est_w/Default]
Fixed O&M Costs	*UZS/MW-year*	[Annual_w/Default]	[Annual_Est_w/Default]
Expected Annual Capacity Factor	*%*	[Annual_w/Default]	[Annual_Est_w/Default]
Expected Annual Availability or	*%*	[Annual_w/Default]	[Annual_Est_w/Default]

Data required for each generating unit	Unit:	historical data for ex-post	forecast data for ex-ante
Forced Outage Rate			
Annual Capital Requirements (if additional from FOM)	*UZS/MW-year*	[Annual_w/Default]	[Annual_Est_w/Default]
Ramp Rate	*MW/hr*	[Annual_w/Default]	[Annual_Est_w/Default]
Minimum Runtime	*hrs*	[Annual_w/Default]	[Annual_Est_w/Default]
Minimum Off Time	*hrs*	[Annual_w/Default]	[Annual_Est_w/Default]
Maximum run time or other operating constraints	*hrs*	[Annual_w/Default]	[Annual_Est_w/Default]
Data required for each generating unit on sub-annual basis (By Hour, by Day, by Month, or Season). At a minimum, annual data			
Generation	*MWh*	[Subannual]	
Capacity Factor	*%*	[Subannual_Calc]	
Fuel or Heat Input	*MJ*	[Subannual]	
Heat Rate	*MJ/MWh*	[Subannual]	
CO2 Emission Rate from energy	*tonne CO2/MWh*	[Subannual_Calc]	
CO2 Emission Rate - non-energy sources	*tonne CO2/MWh*	[Subannual]	
Carbon Emissions per period from energy	*tonne CO2*	[Subannual_Calc] with degradation factor	
Carbon Emissions per period: non-energy sources	*tonne CO2*	[Subannual_Calc] with degradation factor	

Table 18. Total final consumption data

Annual system level data required	Unit:	historical data for ex-post	forecast data for ex-ante
Residential			
Electricity	*MWh*	[Annual]	[Annual_Est]
Natural Gas	*MJ*	[Annual]	[Annual_Est]
Industry			
Electricity	*MWh*	[Annual]	[Annual_Est]
Natural Gas	*MJ*	[Annual]	[Annual_Est]
Commercial and Public Services			
Electricity	*MWh*	[Annual]	[Annual_Est]
Natural Gas	*MJ*	[Annual]	[Annual_Est]
Other (Agricultural, Forestry, Fishing, Non-specified)			
Electricity	*MWh*	[Annual]	[Annual_Est]
Natural Gas	*MJ*	[Annual]	[Annual_Est]

Table 19. End-user energy pricing data

Annual system level data required	Unit:	historical data for ex-post	forecast data for ex-ante
Residential			
Electricity	*UZS/MWh*	[Annual]	[Annual_Est]
Natural Gas	*UZS/MJ*	[Annual]	[Annual_Est]
Industry			
Electricity	*UZS/MWh*	[Annual]	[Annual_Est]
Natural Gas	*UZS/MJ*	[Annual]	[Annual_Est]
Commercial and Public Services			
Electricity	*UZS/MWh*	[Annual]	[Annual_Est]
Natural Gas	*UZS/MJ*	[Annual]	[Annual_Est]
Other (Agricultural, Forestry, Fishing, Non-specified)			
Electricity	*UZS/MWh*	[Annual]	[Annual_Est]
Natural Gas	*UZS/MJ*	[Annual]	[Annual_Est]

Table 20. Econometric data

Econometric Data to define country-specific elasticities	Unit:	historical data for ex-post
Population	million people	30 year's annual data. Cite source
Urbanization	%	30 year's annual data. Cite source
Household electrification of urban and rural households	%	30 year's annual data. Cite source
Ave. Household size (urban and rural)	people/HH	30 year's annual data. Cite source
GDP (in UZS)	US$ million	30 year's annual data. Cite source
Exchange rate	UZS/USD	
Deflator to USD(2010)		
Income per capita (in constant USD)	US$/yr	30 year's annual data. Cite source
Electricity price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Heat price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Coal price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Natural Gas price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Gasoline price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Diesel price (current LCU and constant USD)	US$/MJ	30 year's annual data. Cite source
Other Oil Products (by oil grade if appropriate)	US$/MJ	30 year's annual data. Cite source
Renewable (by type if appropriate)	US$/MJ	30 year's annual data. Cite source
Electricity total consumption	MWh	30 year's annual data. Cite source
Heat total consumption	MJ	30 year's annual data. Cite source
Coal total consumption	MJ	30 year's annual data. Cite source
Natural Gas total consumption	MJ	30 year's annual data. Cite source
Gasoline total consumption	MJ	30 year's annual data. Cite source
Gasoline total consumption	MJ	30 year's annual data. Cite source
Diesel total consumption	MJ	30 year's annual data. Cite source
Other Oil Products (by oil grade if appropriate)	MJ	30 year's annual data. Cite source
Heating and cooling degree days		
Heating degree-days	deg-day	30 year's annual data. Cite source
Cooling degree-days	deg-day	30 year's annual data. Cite source

ANNEX 3. MRV METHODOLOGY

Ex-post quantification of CO_2e emission impact of end-user energy pricing: a methodology and model

Background and context

Climate change threatens to push millions of people into poverty and undo hard-won development gains, particularly in the most vulnerable countries suffering adverse effects from climate change. The challenge of reaching the Paris Agreement targets is massive – and must be faced globally. As stated in countries' nationally determined contributions (NDCs), current national ambitions are insufficient to achieve the needed reduction in GHG emissions fully and must be raised. Increased international mitigation cooperation is necessary to overcome this challenge. International carbon crediting – through climate finance and carbon markets – can play a pivotal role in achieving transformative and cost-efficient global emission reductions. While international carbon markets developed under the Kyoto Protocol catalyzed some $400 billion in investments, in many cases with support from climate finance, the cost of implementing the Paris Agreement goals will run into trillions of dollars. Moving from project-based and programmatic crediting approaches to scaled-up approaches is essential for both results-based climate finance (RBCF) and international carbon market mechanisms.

One of the mechanisms that have been set up to provide opportunities for developing countries to address climate change is the Transformative Carbon Asset Facility (TCAF). Going beyond project-based mitigation opportunities, TCAF uses innovative carbon accounting methodologies to attribute emission reductions to scaled-up crediting interventions (i.e., policy-based, sectoral, and jurisdictional approaches). TCAF delivers climate finance based on verified emission reductions through a results-based payment approach and offers a carbon market component that pays for internationally transferred mitigation outcomes (ITMOs).

Within TCAF, this is the first methodology that seeks to quantify the mitigation impact of energy pricing and subsidy reform based on ex-post modeling rather than ex-ante projection. It uses an evidence-based approach to Measure, Record, and Verify (MRV) the GHG emissions generated by the crediting intervention. This is compared to a reasonable conservative estimation of what emissions would have resulted if the policy-based, sectoral or jurisdictional approach had not been implemented. This methodology and accompanying model have been developed for this purpose.
It is the critical technical foundation for claiming emission reductions and disbursing results-based climate finance under TCAF and in the future under pillar 3 of CERF.

Introduction

This paper describes a methodology for quantifying the GHG emission impact of energy pricing policies and subsidy reduction. The methodology is primarily designed to be used for a results-based evaluation (ex-post) of policy impact on an annual basis. Throughout a measurement period, it evaluates the emissions reductions that can be attributed to the increase in energy prices caused by specific policies and measures over and above the reductions caused by other mitigation activities that have taken place independently.

Most energy consumers are economically rational in that an increase in energy prices will lead to a possible reduction in demand or a switch to a lower-cost but less convenient energy source. Over the short term, they can modify behavior by, for example, changing the setting on a thermostat to reduce the heating or cooling load or using an appliance or machinery for less time or in another more energy-efficient way. Over the longer term, higher energy costs can cause them to change processes or invest in more energy-efficient equipment, leading to a more significant reduction in consumption.

In electricity generation, a change in the variable cost of generation (including the cost of fuels used) can modify how generating plants are dispatched, changing the amount of electricity produced from each fuel type, and if the electricity tariff is defined on a cost-plus basis, modifying the cost of electricity to the end user.

Strategies toward market-based fuel pricing and cost-recovery tariffs for electricity and other energy sources are often adopted to improve economic performance and rationalize energy consumption. When these lead to a reduction in fossil fuel usage (or a reduction in the consumption of electricity generated from fossil fuels), mitigation of GHG emissions--characterized in terms of tonnes of Carbon Dioxide equivalent (CO2e) can result. Table 1 gives examples of policies that can be evaluated using this methodology and model.

Table 1 – Examples of policies that can be evaluated

Policies
Carbon Pricing
Reduction of fossil fuel subsidies to end-users
Tariff increases for electricity to the end-user
Price increases for fossil fuels sold to the end-user
Reduction in subsidies for fossil fuels used in electricity generation
Price increases for fossil fuels used in electricity generation

Policy crediting can theoretically include non-pricing policies affecting power generation, some of which can be analyzed with this model. However, it is TCAF's deliberate choice not to include non-pricing policies[1] as we would like a simplified methodology for the users and third-party validators to understand and evaluate it easily. Thus this methodology description clarifies how the applicable policies are limited to price-based policies.

The objectives of this methodology are very specific and different from other analytical work. This methodology is exclusively for TCAF MRV-based, ex-post crediting of emissions reductions due to pricing policies that affect end-user energy demand of electricity and natural gas. It is not meant to create another dispatch model or energy system optimization, even though the changing dispatch order might be the interim result for ER quantification.

A results-based, ex-post analysis is very different from traditional modeling in that the results of applying the policy action in a preceding year can be measured on the ground and are compared to a counterfactual scenario of what could reasonably be expected to have happened if the policy measures had not been enacted. The results of the policy action are found by comparing the outcomes of these two scenarios.

If, for example, the policy action has the result of reducing energy demand, this is reflected in the counterfactual *Withoutpolicy* scenario by increasing energy demand above that which can be measured on the ground; it does not modify the (measured) *Withpolicy* scenario.
The modeling also includes forward-looking ex-ante analysis to aid decision-makers by evaluating the expected outcome of future actions and policies. For this, the calculation is different. The results of future actions are applied to the *Withpolicy* scenario in coming years and not involved (or applied differently) to the counterfactual *Withoutpolicy* scenario. The expected outcome of the future policy action is again found by comparing the two scenarios.

The methodology attempts to balance the trade-off between the broad coverage of the applicable policies for crediting and the implication of the time required for the counterpart and the third-party validators to understand and evaluate the methodology.

The methodology is built upon the Morocco energy policy MRV tool, which has been peer-reviewed and approved. The methodology has included quantifying policy impacts from end-user fuel pricing.

Applicability of the model and methodology

The methodology is applicable in all countries where the energy system responds to changes in energy prices. The methodology does not apply in cases where its price does not directly influence the energy demand.

At the point of final consumption (the end-user)

For energy supplied to the final consumer, the methodology and model evaluate the price-demand relationship for any price change caused by a specific policy or measure to estimate the energy demand that would have occurred had that policy or measure not been enacted.

The methodology and accompanying model are set up to calculate CO_2e emissions reductions (ERs) from changes in the end-user demand for any of the following energy sources:

- Electricity
- Natural Gas
- Coal
- Fuel Oil
- LPG

In any of the following sectors of the economy:

- Power sector
- Residential
- Commercial and public services
- Industry
- Agriculture/Forestry/Fishing

The methodology and accompanying model are not currently set up to calculate ERs from changes in the demand for diesel, gasoline, or other fuels in the transport sector or from district heating. However, these would be simple to add.

Most end-users will react to the price elasticity of demand for the energies they are currently using. Typically, long-run price elasticities imply a more significant change than short-run because the end-user can react in more ways by adopting more efficient equipment, appliances, or production methods, for example. Where data is available and substantiated by plausibility indicators, a mixture of short-run and long-run demand elasticities can be used. When not, the short-run offers a more conservative approach.

The analysis will often run only on a sub-set of energy sources and sectors where data provides clear evidence supporting a price difference between the measured *Withpolicy* scenario and what can reasonably be expected to have happened without the policy implementation. In some cases, constraints on fuel availability (including the impact of possible fuel shortages or fuel smuggling) may limit the possibility of switching between the current and a different, lower-cost, but less convenient energy source.

For electricity generation

Of the five energy sources available to the end-user in the model, only electricity changes in demand can modify the emissions factor. Here, the methodology and model apply additional steps to dynamically evaluate the specific emissions based on an economic dispatch of power plants that varies according to the annual and seasonal demand for electricity.

If the power sector dynamically optimizes the tariffs to the end-users to cover the cost of generation, changes in energy costs to the power sector can modify its specific GHG emissions (g/kWh) of electricity because such changes can also modify how generating plants are dispatched[21]. However, in practice, efficient dispatch is not always achieved due to various technical, political, and economic factors. Electricity dispatch is also subject to operational constraints, including environmental/emission control regulations, availability of generating units and fuel resources, transmission limit, etc.

If electricity dispatch does not react directly to changing fuel costs, then the impact of changes in the cost of fuel for generation should be excluded from the calculation by using the same fuel costs for generation in both scenarios.

For example, in many countries, the electricity tariffs to the final consumer (end-user) in the residential, industrial, nonresidential, and/or services sectors are fixed by the government for a certain period. While these may vary from time to time, the tariff increases may be defined based on macroeconomic or political considerations and not only on recovering the generation cost (including fuel costs). In these and other similar cases, this section of the methodology would not apply. In all cases, the methodology will evaluate the change in end-user demand for electricity (final consumption) caused by the policy action that modified end-user prices and dispatched the generating plants to produce the demanded electricity in both the *Withpolicy* and *Withoutpolicy* scenarios.

Overall

Driven by TCAF's deliberate choice to keep the methodology simple to understand and evaluate for the users and third-party validators, the methodology, and model do not evaluate changes in upstream GHG emissions that could be caused by the change in demand for these fuels, as these could considerably widen the analytical boundary. For example, the GHG emissions implicit in the extraction of crude and processing fuel oil, the methane leakage associated with the extraction and handling of natural gas, or the manufacturing and end-of-life associated emissions for producing electricity generating and transmission equipment. These are treated as leakage and held constant between the two scenarios.

It is important to note that not all impact channels will be considered in every specific policy evaluation, and the analytical boundaries must be established accordingly. If the energy system (electricity

[21] In theory, electricity generation conforms to the principle of least-cost economic dispatch, recognizing any operational limits of generation and transmission facilities. The aim is to meet the electricity demand with the lowest operating cost of the system. Power plants with the lowest variable (marginal) costs are generally dispatched first, and plants with higher variable costs are brought on line sequentially as electricity demand increases[21]. The variable cost associated with a power unit varies based on a number of factors, such as fuel type, fuel price, generator efficiency, and age of the plant.

generation) does not respond to changes in variable cost, then this methodology cannot be used for electricity generation but could still be used for evaluating the end-user final consumption of this energy source. However, there are cases where this methodology and model cannot be used to assess all final consumption. For example, if residential electricity pricing obeys social rather than economic constraints, then in real terms, its tariff could decrease over time, while industrial energy pricing is moving towards free-market canons. In such a case, consideration could be given to defining the analytical boundary to concentrate on the industrial sector only.

Similarly this mechanism opens up the possibility of additional impact channels--such as using some of the generated funds from a tariff increase to invest in cleaner generation)

Methodology

The methodology's primary purpose is to compare an ex-post measured *Withpolicy* scenario (what happened) against a modeled counterfactual *Withoutpolicy* scenario that estimates what would have happened if the policy had not been enabled.

The type of policies that the methodology can assess include:

1. policies influencing end-user energy prices (if end-users demand is affected by energy prices)
2. policies influencing the merit order / dispatching of power generation (if the dispatch order is affected by end-user demand)
3. policies influencing variable costs in power generation (if the electricity tariff is affected by fuel costs)

The methodology delivers the modeled impact by seasonally comparing these two scenarios and determines the ER for the years where ex-post historical data is evaluated. This ER could be credited or assigned toward meeting national commitments. A secondary purpose of the methodology is to estimate ex-ante the expected ER in future years to approximate the program's value over the modeling period.

Broad steps toward calculating the CO_2e emission impact of changes in end-user energy pricing in a particular year are outlined below. As end-user energy prices increase—in real terms—users may partially compensate through behavioral changes (affecting their consumption habits) and enhanced adoption of higher efficiency appliances and equipment over the longer term. If this results in prices that are higher in the *Withpolicy* scenario than in the modeled counterfactual *Withoutpolicy* scenario, then end-user compensation may lead to lower demand for energy in the former than in the latter, resulting in an ER.

In the specific case of electricity, any policy affecting end-user demand can also affect how and when it is generated according to the generating sector's principles and operational constraints.

The following six steps should be repeated annually to develop an ex-post trajectory of the emission impact of the policies. If the analysis is to be conducted only on a subset of fuels (for example, electricity and natural gas) or only on a selection of sectors, then the information to be collected will be that related to the final consumption within the chosen sectors, except for electricity where data across all consuming sectors is required. The emissions intensity of electricity will vary at different levels of generation because the power plants are dispatched on an economic least-cost basis to seasonally supply the demand at any point in time. Thus, if this analysis were to be conducted using only part of the total load, the emissions intensity would be wrong. Calculating electricity emissions intensity based on the dispatch of generating units to supply the complete demand is essential. To this end, every year, the data relating to all electricity-generating units and the critical operational constraints affecting dispatch should be updated (see steps "b," "c," and "d" below)

a) **For policies influencing end-user energy prices**
Collect energy sales and pricing data to the end-user, differentiated as necessary by energy type (electricity, natural gas, coal, fuel oil, LPG, etc.), by final consumption user group (residential, nonresidential and commercial, industrial, and others) and for each tariff layer within each group.

b) **For policies influencing the merit order/dispatching of power generation**
Collect data on all electricity generating units/plants and other relevant parameters within the electric system including seasonality. Determine the basic principles of system dispatch, key operational constraints, and the utilization of sources other than domestic grid supply (i.e., captive, off-grid, and electricity imports).

c) **For policies influencing variable costs in power generation**
The policies also impact the cost of fuel for electricity generation and tariffs, collect fuel consumed in generation, and cost data to the electricity generating units/plants.

d) **Calibrate the methodology for the electricity sector** with the dispatch principles, key constraints, and other characteristics identified and develop a CO_2e emission inventory of the power generation system. The objective of this step is to establish the Withpolicy activity and emissions from all included sources. Develop the counterfactual Withoutpolicy "reference" conditions of what could be expected to have happened without the policy by running the methodological procedures through all "impact channels." For electricity, this includes applying the same dispatch principles and constraints/characteristics above to compute the CO_2e emission level of the Withoutpolicy operation. Calculate CO_2e emission modeled impact as the difference between the emission levels obtained from the *Withpolicy* and *Withoutpolicy* scenarios.

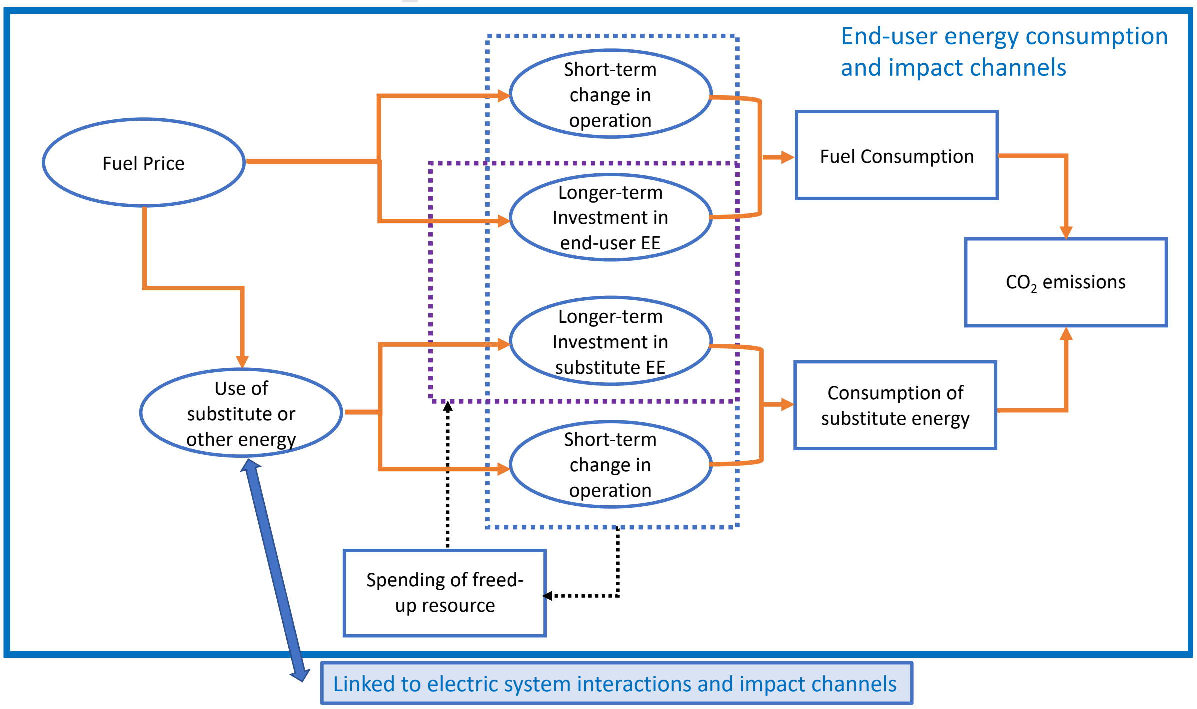
Note that this establishes evidence-based, actual levels of CO_2e emissions resulting from all determining factors (economic, political, social, demographic, etc.), including the energy pricing policy in question in the assessment year. The key objective of this methodology is to develop a counterfactual level of emissions—all other things being equal—without the adopted energy pricing policy, thereby singling out the emission impact of the policy. This implies that all other factors that caused the emission in that year (be it economic shock, diffusion of new technology, or demographic shift) are also included in the counterfactual emissions levels. It is also important to note that this does not imply that energy prices in the *Withoutpolicy* scenario are held constant. This scenario should reflect the pricing structure (and increases) that can be expected to have happened without the adoption of the pricing policy under evaluation.

Impact Channels

Although the methodology focuses only on pricing policies, two sets of impact channels are inescapably linked: those concerning end-user energy demand and those concerning electricity generation. These two figures provide a simplified schematic representation of the impact channels and the assessment boundary of this methodology. As previously stated, factors (such as import or export fuel smuggling) may increase the uncertainty associated with applying parts of the methodology.

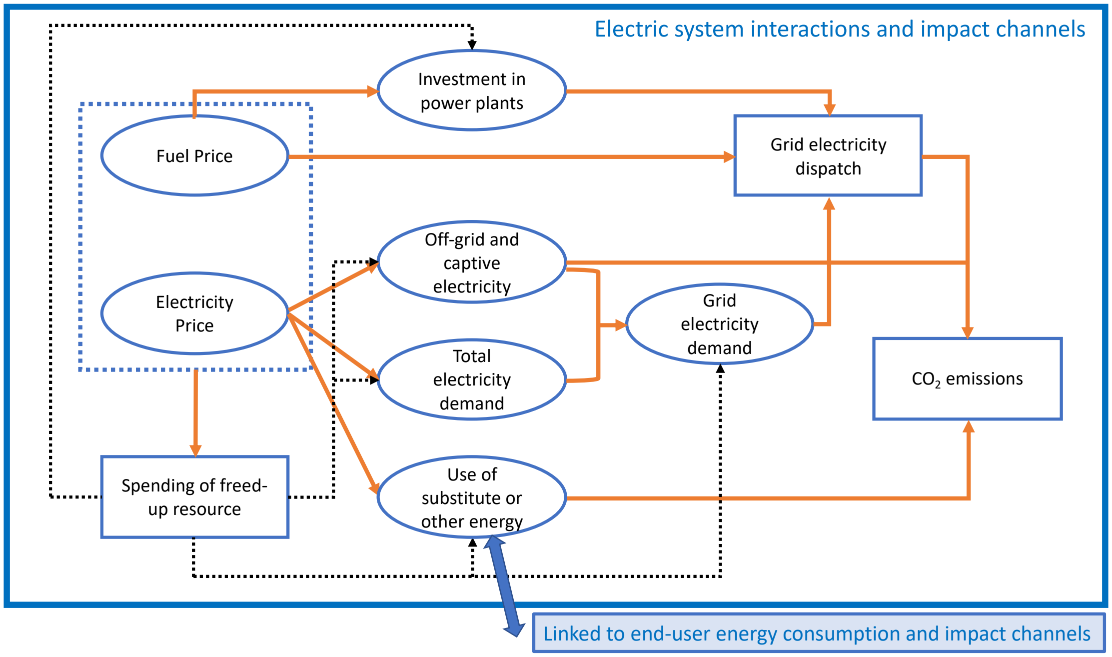
Concerning end-user energy demand

Figure 1 - Concerning end-user energy demand



Concerning electricity generation

Figure 2 - Concerning electricity generation



For the end-user, an increase in energy prices may impact the following:

1. Short-term behavioral changes in the consumption of that energy
2. Longer-term investment and other decisions that additionally modify processes and the efficiency of appliances and equipment used.
3. Decisions to partially or fully substitute an energy source with an alternative.
4. Spending freed-up resources (caused by subsidy reduction) on other options that reduce future energy costs or improve sustainability.
5. Any change in the electricity demand can impact how the distinct generating units are dispatched, modifying their specific emissions intensity.

For the power sector, an increase in energy costs may impact:

6. Changes in how grid-supplied electricity is generated caused by an increase in fuel prices to all on-grid units only (removal of subsidy to incumbents). This channel assumes grid-supplied electricity price does not change and that end-user prices of other fuels do not change
7. Change in constraints on grid-supply unit-level fuel use (leads to fuel substitution in existing plants. For example, removal of gas take or pay contracts, or additional gas availability)
8. The decision on investment and construction of new power plants and the retirement of old units
9. The operation of off-grid and captive capacity, the export or purchase of import of electricity

Chapter 1: Modelling Framework and Analytical Steps

The modeling tool is a transparent, user-friendly, Excel-based bottom-up model of intermediate complexity that sector specialists can use directly.
The basic premise of the analysis is that if end-users have higher real energy costs than they would otherwise, then they will take steps to improve efficiency and reduce their energy consumption and this change in consumption may cause a change in GHG emissions, either because less energy is consumed, or because that energy is generated and distributed with lower GHG emissions.

The analytical process is scenario-based, in which a measured *Withpolicy* scenario (what happened) is compared against a modeled counterfactual *Withoutpolicy* scenario that estimates what would have happened if the policy had not been enabled.
Broad steps toward calculating the CO_2e emission impact of changes in end-user energy pricing in a particular year are outlined below. As end-user energy prices increase—in real terms—users may partially compensate through behavioral changes (that affect their consumption habits) and, over the longer term, may additionally adopt higher efficiency appliances and equipment. An important impact of any change in the electricity demand can affect how and when it is generated in accordance with the principles and operational constraints of the generating sector.

Time period

The model is set up to conduct scenario-based analysis over 22 years. which must be divided into three parts:

- A historical period that covers from the base year in which the package of policies was first implemented up to the most recent year for which data is readily available
- A period before this base year that will serve to evaluate tendencies before the policy package was introduced
- A period into the future after the year with the most recent data to forecast the future impacts of the policy package over a crediting period.

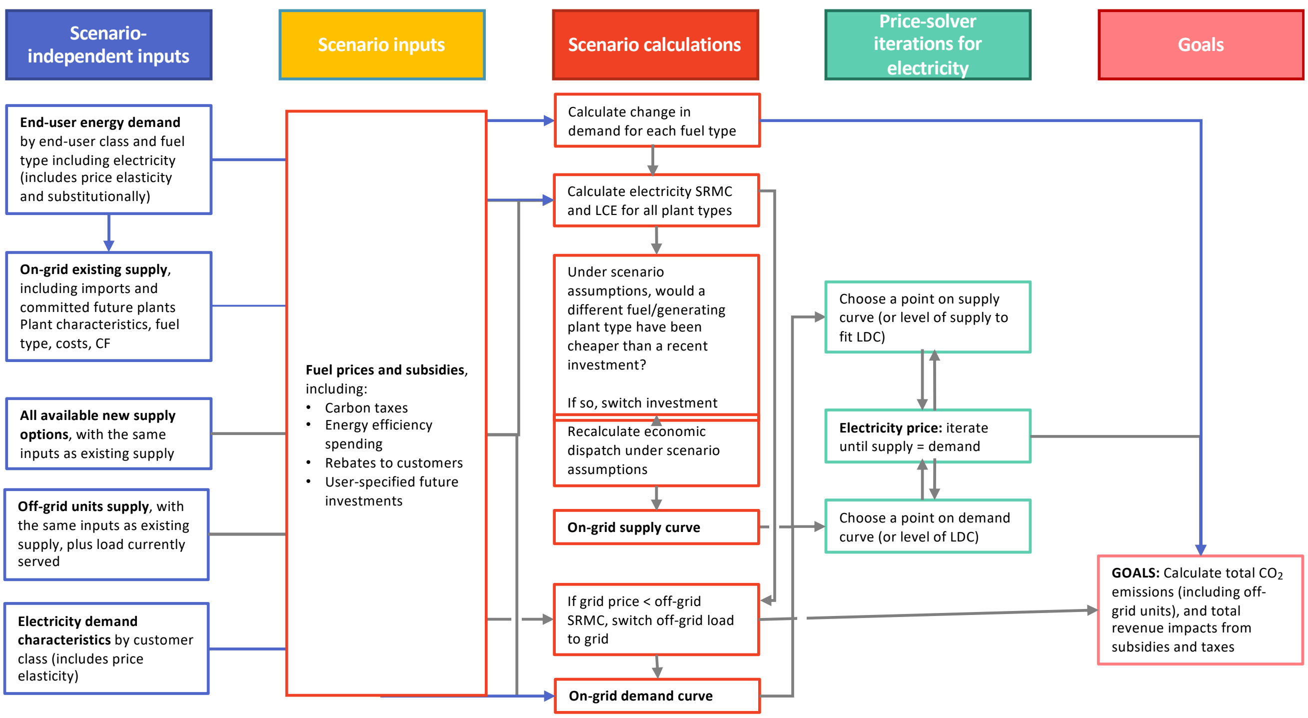
For example, if a package of policies was first implemented in 2017, the year with the most recent available data is 2020, and the proposed crediting period is through 2030, the first year of the modeling framework could be 2012. This would give a period with historical data available from 2012 to 2020 and a forecasting period through 2033. The analysis from 2017 to 2020 would be results-based (ex-post), while from 2021 to 2030 would be an ex-ante analysis evaluating the forecast future value of the policy actions.

For results-based crediting, each year, new evidence-based reported data is introduced into the model (with a time lag dependent on data availability). Thus, for example, in 2023, data for 2021 may become available. This is added to the model to calculate the emissions reductions caused ex-post by the policy package for 2021. In this way, the model records the outcomes of the MRV program annually. It also recalculates the forecast period (to 2032) based on this new information. The model will output data and results over any period selected by the user within this 22-year period.

Modeling structure

Once the time period has been selected, the next step involves including historical data and calibrating the tool for the *Withpolicy* operation. Figure 3, which illustrates the modeling diagram, shows that there are two types of input data: (i) scenario-independent inputs that define the energy system within this framework, and; (ii) scenario-specific inputs that distinguish the *Withoutpolicy* from *Withpolicy* operation. For example, if an Energy Efficiency incentive is introduced as a mitigation measure to support the price reform, scenario-specific inputs should credibly distinguish whether these incentives are likely to have also existed in the *Withoutpolicy* scenario. Specific data requirements are given in a later section.

Figure 3 - Modeling Diagram



Scenario-independent inputs

The scenario-independent inputs should ideally be publicly available data so as not to limit the use of this tool to share data and findings and build consensus across different groups of stakeholders. All this data is stored on the model's "Library" page. Data that needs to be updated at a later date—via the MRV process mentioned before—has separate sheets per data type where the updated data (and its cited reference sources) can be added without disturbing the initial "Library" load. This helps to ensure data integrity and preserve a data chain of custody[22], giving a complete, fully documented step-by-step history of data and who has changed them.

Scenario specific inputs

The scenario-specific inputs are a mix of historical measured data that define the *Withpolicy* pricing drivers and data and assumptions that will be used to conservatively describe the *Withoutpolicy* pricing drivers of the analysis.

For future years, the assumptions applicable to the *Withpolicy* operation and the *Withoutpolicy* counterfactual are defined and used as the basis of ex-ante analysis.

Baseline setting

Defining and building agreement around the counterfactual *Withoutpolicy* baseline for emissions reduction (ER) crediting can be a complex process. The basis used to determine the energy pricing that is likely to have been implemented without the policy package needs to be supported by a logic that is acceptable to all stakeholders, Since the emission reduction that can be reported is the difference between the emissions in the *Withpolicy and Withoutpolicy scenarios,* setting this counterfactual has a direct impact on the ER. It is a balancing act to demonstrate that the resultant ER is sufficiently rigorous for both the donors and the host country.

There will always be changes in GHG emissions that are not captured by the definition of the Withpolicy and Withoutpolicy scenarios and will be treated as leakage. These include changes in upstream GHG emissions that could be caused by the change in demand for these fuels (such as methane leakage), the scope three indirect emissions generated in the value chain, and impact channels that cannot be adequately quantified. These are treated as leakage and held constant between the two scenarios and, therefore, are not taken into account in estimating the impact of the policy.

Additionality

GHG emissions reductions can only be counted if they are *additional*, that is to say, they would *not* have occurred in the absence of the policy or measure having been enacted. If the reductions would have happened anyway and there is no causality, they are not additional. The concept of additionality in the methodology meets TCAF core parameters.

The difficulty in determining additionality is that GHG-reducing activities occur all the time. In many client countries, the emissions intensity of the economy is continually improving because some energy efficiency activities are required by law, while others reduce emissions simply because they are profitable without any consideration of GHG emissions reductions (for example, an investment in energy-saving lighting can pay for itself through avoided energy costs.), others are due to structural social and economic changes. In

[22] A process that tracks the movement of evidence through its collection, safeguarding, and analysis lifecycle by documenting each person who handled the evidence, the date/time it was collected or transferred, and the purpose for the transfer

contrast, other technological and good-practice changes are driven by regulatory, policy, and market changes in other countries that impact suppliers and clients.

This precludes trying to evaluate a before-and-after analysis of GHG emissions reductions since, over the intervening period, many activities that change emissions intensity may have occurred that are totally outside the control of the policy or other measures being evaluated.

For the ER to be considered as caused by a specific policy that leads to an energy price increase or subsidy reform, the analysis would need to demonstrate how, without this policy, an energy price increase or subsidy reform would have occurred differently. Evaluating barriers that work against implementing the specific policies and measures can help prove their additionality. These barriers may include:

- Local practice: Lack of knowledge or practices, laws, customs, and market conditions, that have prevented a more GHG-efficient scenario from being implemented.
- Social: Pressure from society, industrial groups, and advocates against increasing energy prices and reducing subsidies.
- Financial: Implementing the specific policies and measures may require funding that would not be available without demonstrating a GHG emissions reduction. This may include an investment analysis to determine that the program is not the most financially attractive scenario.
- Institutional and political: Such as lack of institutional capacity / human capital or political support for implementing these policies and measures. This can include international commitments such as the NDCs to the Paris Agreement
- Technological: The country or sector may have a lack of access to materials, equipment, or infrastructure that was only overcome when implementing the specific policy or measure. So, if it were not to be implemented, the business-as-usual scenario would result in higher emissions.

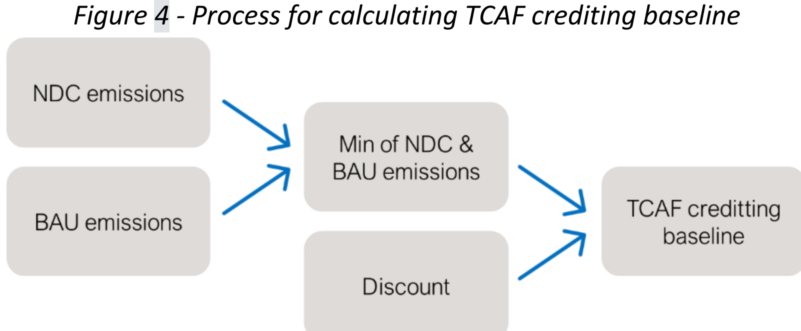
The methodology and model address these demands for additionality by developing two scenarios - an ex-post, results-based, Withproject scenario based on historical data and a Withoutproject counterfactual calculated scenario - where the only difference between the two is the change in fuel prices and subsidies due to implementing the specific policy or measure. Thus, all the other activities that change the emissions and are outside of the scope of the policy or measure being evaluated are included in the Withproject measured scenario and directly transferred to the Withoutproject counterfactual scenario.

The primary scope of the methodology is to assess the impact of fuel and electricity pricing policy. It applies to national, sub-national, and sub-sectoral policies of similar type (for example, where different electricity and fuel tariff levels are used in residential and industrial sectors and across distinct income groups) and to other policies, such as CO_2e charges across the whole economy. The methodology is primarily designed to be used for a results-based evaluation (ex-post) of policy impact on an annual basis. The time lag of the analysis (e.g., 2020 evaluation carried out in 2021 or 2022) is dependent on the availability of data. A secondary objective of the methodology is to help analyze the future (ex-ante) impacts of policies that could be implemented as part of a decision-making process. The methodology is supported by a transparent, user-friendly, Excel-based model of intermediate complexity that sector specialists can use directly. If the model is being used to determine emissions reductions for results-based crediting, several baselines may be required. The following paragraphs[23] illustrate this point with the case of TCAF crediting:

- All countries that are signatories of the Paris Agreement agreed to reduce their GHG emissions and strengthen their commitment over time. Most high-income developed countries committed to an emissions reduction target in absolute terms compared to an earlier year. Developing countries, however, are typically committed to reducing their emissions versus a business-as-usual (BAU) scenario or reducing the emissions intensity of their future growth. Most commonly, they offered in their NDCs an unconditional single-year target for 2030, which is a percentage reduction of the expected BAU emissions that they can achieve by their own means and a more ambitious target that they can achieve only with international assistance

- The emission reductions needed to meet these unconditional NDC targets will not be credited and should be part of the baseline. Additionally, since the Paris agreement anticipates that the NDCs will strengthen over time, and since emission reduction units (ERs) that have been sold cannot be applied to future more ambitious commitments, the crediting baseline should be more conservative than the unconditional NDC target to ensure a high level of environmental integrity and compensate for uncertainties in the ER determination and calculation process (see Figure 4 below). If any other project-based ERs are sold (e.g., from a project-based mechanism such as Article 6.4 under the Paris Agreement), these would have to be subtracted from the crediting emissions reductions in the scale-up crediting program. In practical terms, this means that TCAF will credit against a crediting threshold (or "TCAF baseline") that is well below the BAU emissions trajectory and typically also below the unconditional target emission trajectory (see Figure 5 below). Single-year targets will conservatively be broken down to a trajectory of annual targets, with the default being linear interpolation to the 2030 goal.

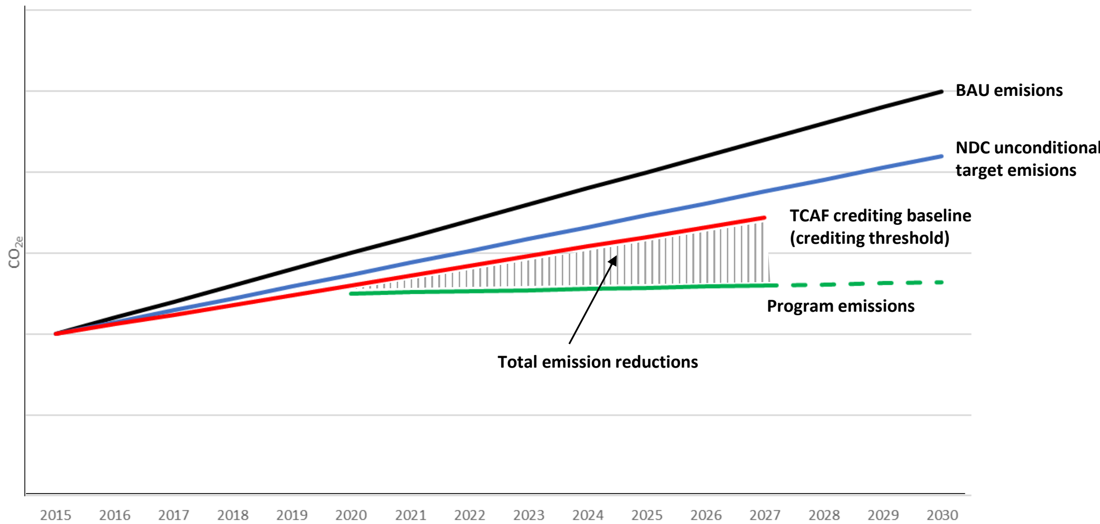
Figure 4 - Process for calculating TCAF crediting baseline



Note: BAU = business as usual; NDC = nationally determined contribution; Min = minimum

[23] Extracted from Transformative Carbon Asset Facility (TCAF). Crediting Blueprint Synthesis Report, December 2020

Figure 5 - TCAF approach to crediting baseline



Note: BAU = business as usual; NDC = nationally determined contribution

In this case, it may be necessary to define and agree on three scenarios:

- BAU emissions
- NDC unconditional emissions; and
- The crediting threshold

And calculate the emissions reduction between the *Withpolicy* scenario emissions and each of the three.

If another co-financing is involved or the policy implementation receives financial support from other sources (for example, it is included in a policy lending operation), the calculated emissions reduction would have to be attributed to the different funding sources or partners. This attribution would be processed outside the model based on the model's results.

Scenario Calculation

The scenario calculations are performed by the model on this basis.

1. First, the *Withpolicy* scenario is established based on ex-post data on energy consumption and prices. Then the model analyzes the change in end-user demand for each type of energy (fuel) based on differences in end-user energy prices caused by the policy package that is being evaluated in this analysis (for example, subsidy elimination in electricity pricing or fossil fuel prices; application of a carbon tax, etc.). For this, the counterfactual *Withoutpolicy* scenario pricing is established and agreed upon, and the demand adjustment is determined by analyzing the price effect by employing the most rigorous possible of the following approaches:

   a. *Time-series econometric analysis*
   b. *Panel econometric analysis*

c. *Adopting robust estimates from the literature*
d. *General equilibrium analysis*

2. This difference in end-user energy demand between the two scenarios can be analyzed through the different impact channels to evaluate the difference in emissions. This methodology is applicable only when the energy system responds to changes in variable cost, and this has to be confirmed. See Chapter 4: Determining the applicability of this methodology for the methodology that is used. If end-user electricity and fuel prices do respond to variable costs, then this methodology will apply. If, however, electricity generation does not respond to variable costs, then changes to the grid emissions factor due to changes in the price of fuels for generation cannot be included. This will normally result in a more conservative ER, but this has to be substantiated.

3. Before the model can produce results, it should be calibrated:

a. For the power sector (since the emissions intensity of electricity depends on the dispatch of different electricity generating units)
   - Dispatching all years
   - Comparing end-use energy usage, electricity generation, energy usage for generation by fuel, and GHG emissions to data reported on that year's operation in the most recent published data from official sources.
   - Making adjustments as necessary (including plant-level annual assumptions such as heat rate, generation, etc.) and import/export, captive generation assumptions until dispatched annual results match reported yearly results.
   - The tool is then considered calibrated for the *Withpolicy* operation for those years that have reported (historical) annual data.

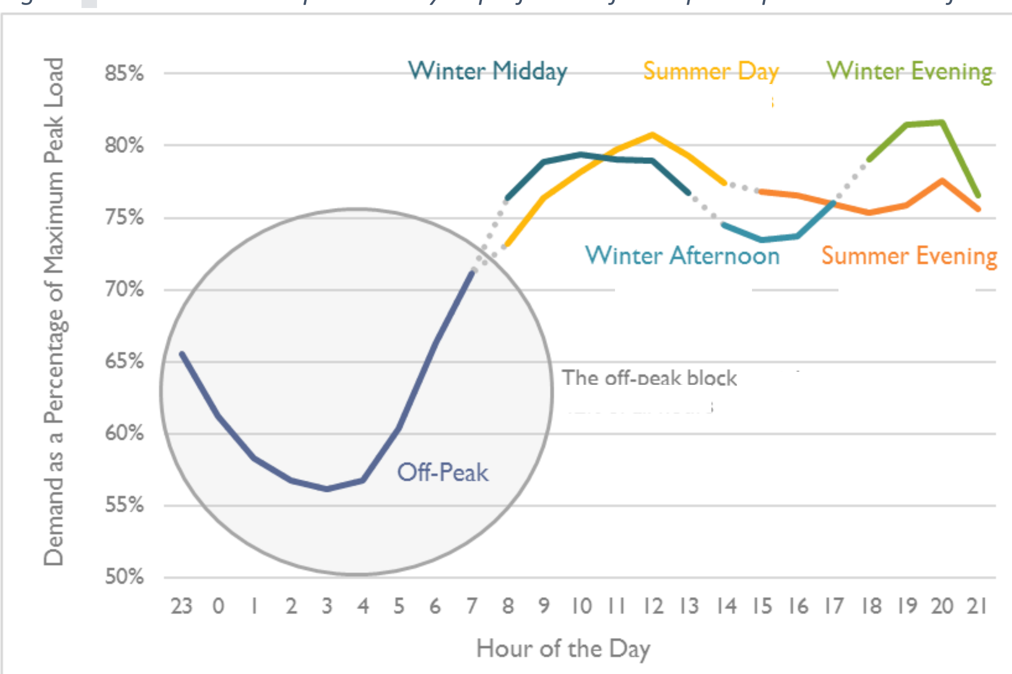
b. For Final Consumption, energy sources other than electricity:
   - Identify all supply limitations or bottlenecks that can constrain energy supply to the end-user from meeting the demand in future years in the Withoutpolicy scenario in which energy demand is likely to be higher than in the Withpolicy case

10. Then the model determines the end-user energy consumption for the *Withpolicy* and *Withoutpolicy* operations in the base year, subsequent (historical) years, and — ex-ante —future years to the end of the modeling period.
    - Any constraints on energy supply by fuel type are applied.
    - Any additional energy supply needed to meet the demand for the operation in future years is now defined. Since energy demand in the Withoutpolicy scenario is likely higher, additional capacity may be required.

11. Then for the **power sector**, the model dispatches the generating capacity for the *Withpolicy* and *Withoutpolicy* operations to evaluate how the electricity that is demanded would be generated in each of the years
    - Any constraints on electricity supply by fuel type are applied.

- Define the on-grid demand curve in six analytical time blocks, as shown in Figure 6. The annual hourly load-demand data is divided into six time blocks and dispatched separately in each of these on a least-cost basis to account for the differences in supply availability (particularly solar and wind).
- Any additional generating capacity needed to meet the demand for the operation in future years is now defined. Since energy demand in the *Withoutpolicy* scenario is likely higher, additional capacity may be required here.
- User input should define (exogenously) if these additional plants are likely to be constructed by the central or independent power producers
- Define the most cost-effective technology that can be added to meet the additional future demand:
    - Use LCOE to rank technologies if additional plants are likely to be constructed by the central authority
    - Use ROI to rank technologies if additional plants are likely to be constructed by independent power producers
- Under the scenario assumptions, if the SRMC of captive generation results higher than the cost of grid electricity, then shift part of the mix of captive to grid electricity.
- "Commission" the most cost-effective new plants as required to meet the forecast demand

Figure 6 - Annual load-dispatch analysis performed for all powerplants in each of 6 time-blocks



12. Evaluate the cash flow generation difference between the *Withpolicy* and *Withoutpolicy* runs to the actors involved and define to whom they may accrue. The results generated in the difference between end-user consumption or in the power sector, the dispatch of the *Withpolicy* operation

and the *Withoutpolicy* scenario, may generate a difference in free cash flow that could be positive in the *Withoutpolicy* scenario or the *Withpolicy* operation**. In either case,** this additional free cash flow could be used to improve end-user energy efficiency or energy sector operation or to fund programs that are not related to GHG emissions reductions.

- User input should define exogenously what fraction (if any) of this additional free cash flow is applied to different plausible funding streams. The User input should also define the time delay exogenously between free cash flow generation and results from the various funding streams. Note that any additional revenue stream in the *Withpolicy* operation in historical years should be substantiated with observations.
- The additional free cash flow can be assigned to other programs in three categories:

    a) Programs that do not influence energy supply or demand.

    This can be the case of funding that goes into a general government kitty and is not earmarked for a specific use. This use of financing does not affect the emissions reduction determined by this tool.

    b) Programs that influence energy supply.

    This can be the case of funding that, for example, goes into an identified earmarked fund to reduce T&D losses. This could reduce the need for generation to meet unchanged electricity demand and could be assigned exogenously.

    b. Programs that influence energy demand.

    This can be the case of funding that goes into an identified earmarked fund for end-user energy efficiency measures. This could reduce the demand for energy (and/or for electricity) and could be assigned exogenously.

If additional free cash flow is used, then this may adjust the equilibrium between the supply and demand curves.

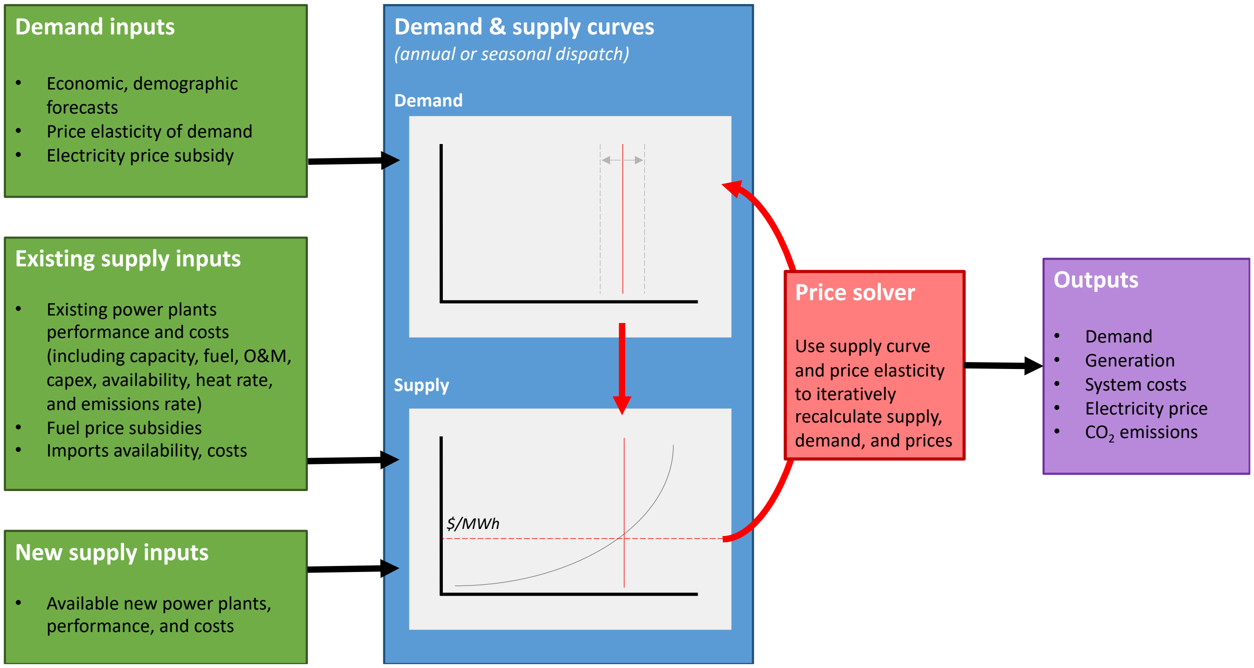
- If the revised equilibrium applies to the *Withpolicy* operation, this may require several iterations for a new equilibrium to be reached.
- If the revised equilibrium applies to the *Withoutpolicy* counterfactual scenario, this may also require several iterations for a new equilibrium to be reached.

Note that as the analysis is performed ex-post where the Withproject scenario is supported by existing data, all exogenous applications are included (positively or negatively) in the Without policy scenario

Price-solver iterations in the energy sector

The seasonal demand and supply curves for electricity are iteratively dispatched to recalculate the electricity price upon which demand is dependent.

Figure 7 - Iterative electricity price solver calculations

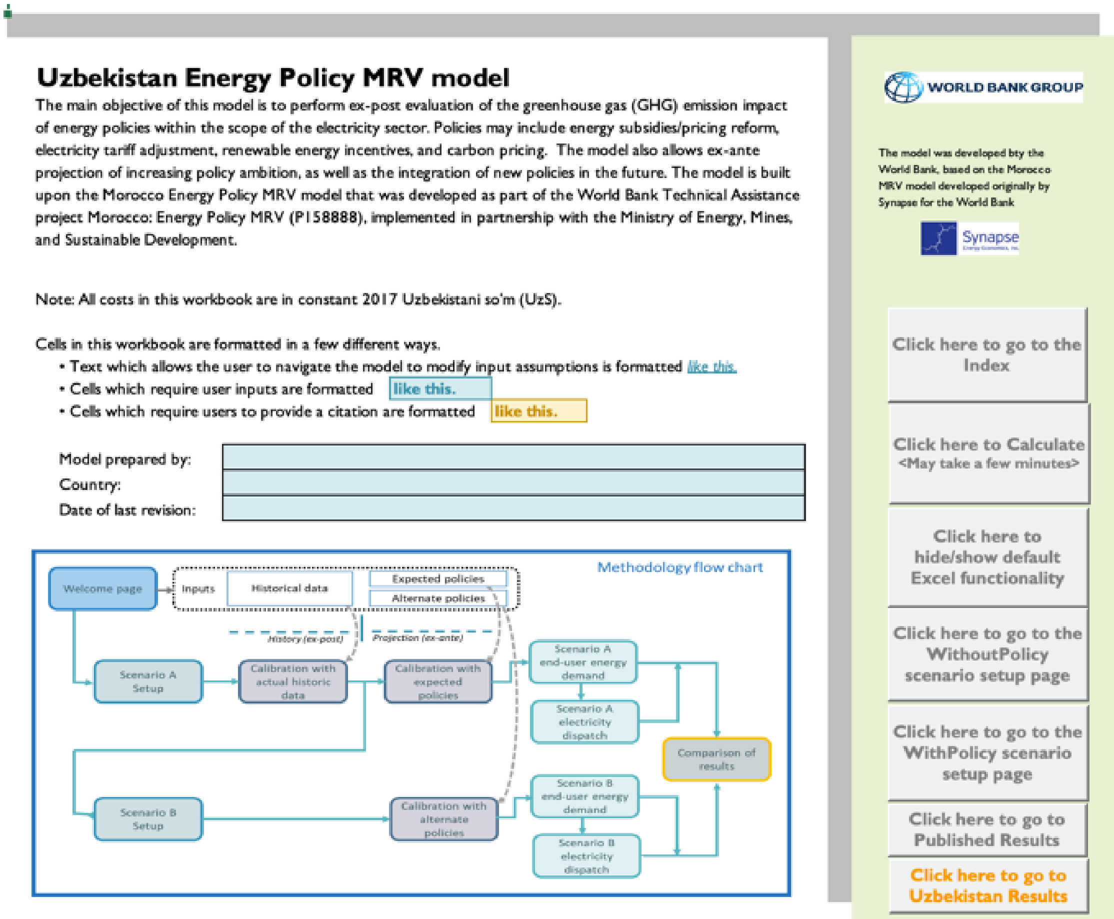


Goals

Evaluate the emissions differences between the two runs. The (ex-post) analysis based on historical data within the confines of the different baselines feeds the results-based emissions crediting. At the same time, the recalculation of the (ex-ante) forward-looking estimate reevaluates the expected total value of the program.

Chapter 1: Model Layout

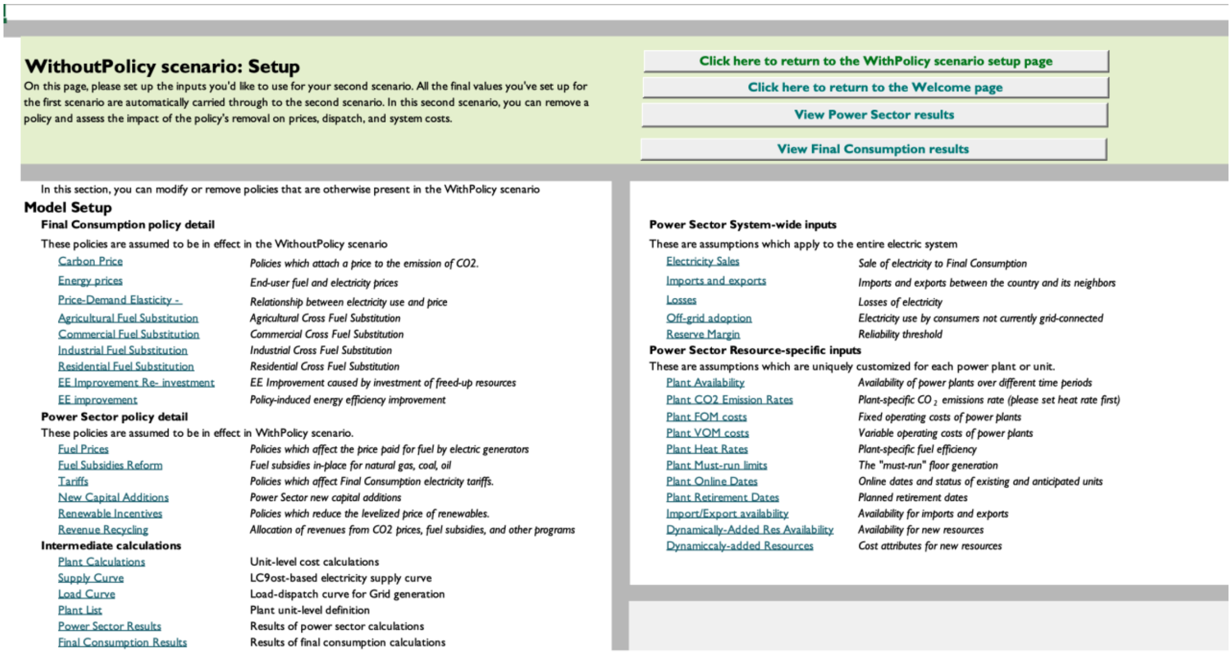
Figure 8. model's Welcome page



The model is easily customizable to specific analyses. It does not require Excel default functionality to be enabled and can be navigated using the built-in buttons and links. Its welcome page gives easy access to setting up the *Withpolicy* and *Withoutpolicy* scenarios, running the calculations, and accessing the results. It consists of one Excel workbook with 85 worksheets: Sheets with names starting with “FC” analyze end-user final energy consumption, those starting with “PS” are power-sector specific, and all the sheets that are specific to a scenario end in “1” or “2” (*Withpolicy* or *Withoutpolicy* scenario respectively).

The main navigation of the model is via the *Withpolicy* scenario setup and the *Withoutpolicy* scenario setup pages, which have links to all necessary sheets. Figure 8 illustrates the model's Welcome page, and Figure 9 shows the *Withoutpolicy* setup sheet.

Figure 9 - Withoutpolicy scenario setup page



Easy access to all sheets can be found in the INDEX sheet, indicating what sector or scenario each sheet applies to and whether the sheet contains data inputted by the user.
All the initial data is located in the 'Library' sheet, and each variable has a specific sheet to allow the user to easily update numbers from one year to the next (in accordance with their MRV program) and cite the source of the update to keep an adequate control. These specific sheets also make it easy for the end-user to use the model to evaluate the likely impact of different policy packages.
The model has results sheets and charts that the user can easily adjust to any output period (while the model calculates from 2012 to 2033, the user can select different periods (for example, 2017-2027) for the reports on the 'Publish' sheet.

Chapter 2: Impact Channels

The impact channels are crucial for developing the counterfactual *Withoutpolicy* "reference" conditions and moving from the *Withpolicy* to the *Withoutpolicy* emission levels. This methodology is designed to measure the CO_2e emission impact of the energy pricing policy through **nine distinct channels** where other possible impacts may be treated as leakage.
It is important to note that not all impact channels will be considered in every specific policy evaluation, and the analytical boundaries must be established accordingly. Also, note that a combination of impact channels may be needed to describe the modeled change.

Channels one to four focus on the final consumption of energy (by the **end-user)**:

1. Short-term behavioral changes reduce the demand for electricity and other) fuels due to an increase in prices to the end-user (this can also lead to substitution with other cheaper but less convenient energy sources/fuels)
2. Longer-term investment (with or without process changes) that improves end-user energy efficiency reduces the demand for electricity and other fuels due to an increase in prices to the end-user (this may be accompanied by behavioral changes and also may lead to substitution with other cheaper but less convenient energy sources/fuels)
3. Change in constraints on end-user fuel use or availability. This leads to fuel substitution for end-users. For example, additional natural gas availability improved distribution to some end-users
4. Investment in new off-grid generation

Channel five covers the impact of an increase in fuel prices for all on- and off-grid generating units when grid-supplied electricity price does not change and end-user prices of other fuels do not change:

5. Changes in the use of off-grid generation driven by an increase in fuel prices for all on- and off-grid generating units. This channel assumes that the grid-supplied electricity price does not change because this is covered by a different impact channel.

Channels six to nine are exclusively for looking at the impacts of price changes on grid-based electricity generation:

6. Changes in how grid-supplied electricity is generated caused by an increase in fuel prices to all on-grid units only (removal of subsidy to incumbents). This channel assumes grid-supplied electricity price does not change and that end-user prices of other fuels do not change
7. Change in constraints on grid-supply unit-level fuel use (leads to fuel substitution in existing plants. For example, removal of gas take or pay contracts, or additional gas availability)
8. Investment in new on-grid plants
9. Increase in export of electricity or decrease in import of electricity from/to the grid

As the methodology is established primarily for results-based crediting using ex-post analysis, in all cases, the *Withpolicy* activity and emissions can be measured (with a time delay dependent on data availability). The table, therefore, shows what would be expected in the counterfactual *Withoutpolicy* scenario and the expected outcome of this change. In the section on methodological steps, the calculation used for each of these impact channels is discussed.

Table 2 – Expected outcome in the counterfactual Withoutpolicy scenario[24]

#	Current system (with-policy) was affected by:	Counterfactual scenario	Counterfactual expected outcome
1	Shorter-term behavioral changes reduce the demand for electricity and other fuels due to an increase in prices to the end-user (this can also lead to substitution with other cheaper but less convenient energy sources/fuels)	Lower energy prices (electricity and fossil fuel) to the end-user. Energy demand is higher impacted by short-run eleasticities	*Off-grid* : possibly lower generation *because grid-electricity is cheaper*
			On-grid : (i) higher generation (ii) higher grid supply to end-users because of increased demand; (ii) possibly higher supply to compensate any reduction in off-grid generation
			End-user fossil fuels: increaseed consumption because of lower pricing
2	Longer-term investment (with or without process changes) that improves end-user energy efficiency reduces the demand for electricity and other fuels due to an increase in prices to the end-user (this may be accompanied by behavioral changes and also may lead to substitution with other cheaper but less convenient energy sources/fuels)	Lower energy prices (electricity and fossil fuel) to the end-user. Energy demand is higher impacted by long-run eleasticities. No specific additional investment to improve energy efficiency	*Off-grid* : possibly lower generation *because grid-electricity is cheaper*
			On-grid : (i) higher generation (ii) higher grid supply to end-users because of increased demand; (ii) possibly higher supply to compensate any reduction in off-grid generation
			End-user fossil fuels: increaseed consumption because of lower pricing
3	Change in constraints on end-user fuel use or availability. This leads to fuel substitution for end-users. For example additional natural gas availability, improved distribution to some end-users	Some fuel availability is limited to some ends-users due to the constraints that were in place	*Off-grid* : may increase generation
			On-grid : may increase demand
			End-user fuels: may change use of other energy sources/fuels (for example: less natural gas, more coal)
4	Investment in new off-grid generation	New plants were not available; some older plants used more if new plants are substitutional	*Off-grid* : lower generation
			On-grid : higher generation to compensartre for lower off-grid
			End-user fuels: possible increase in consumption of other fuels and fuel switching

[24] Note that shorter-term and longer-term changes are relative terms that help to conceptually differentiate between measures to reduce energy consumption that can be relatively easily and quickly applied as opposed to others that require more planning, mechanical change and/or investment

#	Current system (with-policy) was affected by:	Counterfactual scenario	Counterfactual expected outcome
5	Changes in the use of off-grid generation driven by an increase in fuel prices to all on- and off-grid generating units. This channel assumes that the grid-supplied electricity price does not change.	Fuel prices for generation remains lower.	*Off-grid* : greater generation *On-grid* : (i) lower generation partially compensates for off-grid change; (ii) no change in grid supply to other consumers End-user fuels: may change consumption of other fuels to offset greater off-grid generation
6	Changes in how grid-supplied electricity is generated caused by an increase in fuel prices to all on-grid units only (removal of subsidy to incumbents). This channel assumes grid-supplied electricity price does not change and that end-user prices of other fuels do not change	Fuel prices remained lower for on-grid generation	*Off-grid* : no-change *On-grid* : (i) modifies dispatch order (no change in grid supply) End-user fuels: no change in consumption of other fuels
7	Change in constraints on grid-supply unit-level fuel use (leads to fuel substitution in existing plants. For example, removal of gas take or pay contracts, or additional gas availability)	Fuel supply for on-grid generation is limited by the constraints that were in place	*Off-grid* : higher generation *On-grid* : (i) change in unit-level availability, variable costs and dispatch order (ii). may increase electricity price End-user fuels: may increase use of other energy sources/fuels
8	Investment in new on-grid plants	New plants were not available, older plants used more or possible supply shortages	*Off-grid* : possibly higher generation *On-grid* : (i) possibly *lower* generation (ii) modifies dispatch order (iii) possibly higher electricity price End-user fuels: possible increase in consumption of other fuels
9	Increase in export of electricity or decrease in import of electricity from/to the grid	More on-grid electricity available for national uise	*Off-grid* : no change *or possibly less* *On-grid* : (i) grid-supplied demand is higher End-user fuels: no change or possibly less, switching to grid electricity

Chapter 3: Data Monitoring and Collection

Data is required for each year from the initial year in the model up to the most recent year with published data. It is crucial that, in all cases, the data source is cited in sufficient detail to enable others to locate the same data easily. Ideally, a specific document can be cited, giving its link on the internet and indicating the page or table that contains the data. Preference should be given to official sources and regularly published reports over ad-hoc studies.

Each year, the database will have to be updated with consistent data, preferably from the same sources, which is an important consideration when initially selecting the sources to be used.

Also, preference should be given to publicly available data so that there are no restrictions on sharing the populated model and its findings.

This section provides the list of data to be monitored and collected annually.

Five types of data are required:

1. That which documents macroeconomic variables and forecasts.
2. That documents the end-user demand for energy (Final Energy Consumption) by sector and by fuel type under the coverage of the policy in question.
3. That which documents the current operation of the electricity-supply system under the coverage of the policy in question and for all sectors and client classes.
4. That which documents the change in policy that occurred. For example, if the policy package being analyzed included electricity tariff subsidy reform, then documentation and data are required to show how the tariff levels have changed and to substantiate how it can be expected that electricity prices would have evolved had this policy package not been implemented. This is needed to lay out the counterfactual *Withoutpolicy* operation. As mentioned in Chapter 1, different *Withoutpolicy* baselines may need to be evaluated in the analysis.
5. Plausibility indicators are needed not to determine GHG emissions reductions but to validate that the policy change has, in fact, had a real effect on the economy.

Local data should be used and cited whenever possible for fuel energy content, specific gravity, specific emissions, global warming potential, etc. All data should be consistent with the 2019 Refinement to the 2006 IPCC guidelines for national greenhouse gas inventories.(see https://www.ipcc-nggip.iges.or.jp/public/2019rf/index.html). It is important to note that the 2019 refinement updates the science but does not replace the 2006 IPCC guidelines for national greenhouse gas inventories. If the cited reference or table has not been updated in the 2019 refinement, it should be accessed from the 2006 IPCC guidelines for national greenhouse gas inventories (see https://www.ipcc-nggip.iges.or.jp/public/2006gl).

1. Macroeconomic variables

Macroeconomic variables and forecasts have to be obtained from consistent sources, such as GDP, population, consumer price index (CPI), exchange rates, and the mass and trade value of fuel imports (or exports) of different commodity codes, used to establish the actual value of fuels and their internal-market subsidy levels. To attempt to develop local elasticities, data is required for 30 most recent years (citing source), and then data is required for each historic year in the modeling period, updated yearly.

Table 3 - Macroeconomic data

Data	Unit:
Population	million people
Urbanization	%
Household electrification of urban and rural households	%
Ave. Household size (urban and rural)	people/HH
GDP	LCU million
GDP contribution by sector	LCU million
CPI	
Exchange Rate	LCU/US$
Income per capita	LCU/yr
Mass and trade value of energy imports and exports	
By commodity code	
270119	kg and US$
271019	kg and US$
271121	kg and US$
270900	kg and US$
Heating and cooling degree days	deg-day

2. End-user energy demand

Consistent monitoring and collection of data are needed on the end-user demand for energy (Final Energy Consumption) by sector and by fuel type under the coverage of the policy in question. Energy and fuel sales are realized in different tariff brackets in many sectors. Data is required for 30 most recent years (citing source) to attempt to develop local elasticities, and then data is required for each historic year in the modeling period, updated yearly.

As the model is looking to analyze the price sensitivity of energy demand, it is preferable to monitor energy demand by sector in each tariff bracket to:(i) be able to model each tariff separately; or (ii) generate a weighted average for the sector and model the demand against average price for each fuel. Where energy pricing is more volatile (changing on a more frequent than annual basis), end-user consumption per tariff period is needed to generate the weighted annual average. Also, if any sector, sub-sector, or fuel is not included in the policy analysis, then data on that will not be required, except in the case of grid-supplied electricity, where data is required on the whole energy sector to calculate the emissions factors correctly.

The analysis must take into account all the operational constraints of the supply of energy to end-users. There may be several constraints, including the availability of energy supplies (electricity, coal, natural gas, oil, biomass, etc.) to end-users, where the constraints could be in terms of offtake, pricing, or geographical. Clear documentation of how the constraints, if they exist, are quantitatively translated in the methodology should be provided.

Table 4 - End-user energy demand data

Data	Unit:
Price (and tariff) data	
By economic sector and tariff group:	
Electricity tariff	LCU/MJ
Natural Gas price	LCU/MJ
Fuel Oil price	LCU/MJ
LPG price	LCU/MJ
Coal price	LCU/MJ
Consumption data	
By economic sector and tariff group:	
Electricity consumption	MWh
Natural Gas consumption	MJ
Fuel Oil consumption	MJ
LPG consumption	MJ
Coal consumption	MJ

3. Electricity system unit-level and system-level data

As any change in electricity demand can modify, based on least-cost seasonal dispatch, how that electricity will be generated, it is necessary to collect data on the real operation of all the generating units involved, including any constraints historically or currently placed on their operation.

The expected output of this step is a database that forms a basis for the analyses in the following steps. The database should be developed at the generating unit level and include all electricity-generating units under the policy's coverage in question. Unit-level inventory and database improve the accuracy of the analysis. . However, plant-level inventory is acceptable in the case that unit-level data are not available[25]. Note that this data should cover all fuels used for the generation, even if some fuels are not of interest to end-user demand. All data should be reported on an annual basis.

[25] A power plant may consist of several generating units. The units are sometimes commissioned in different years and with different engineering specifications. Therefore, impact measurement is more accurate at the unit-level and is preferred.

However, if energy pricing is more volatile (changing on a more frequent than annual basis), end-user consumption per tariff period is needed to generate the weighted annual average. Where possible, this data should be reconciled by the work done by the WB energy team in the context of power system analyses and planning work that's done in conjunction with the line ministry or utility. The list of data required for the inventory is provided below. They are unit-/plant-level data unless otherwise indicated in italic fonts. The data should be updated yearly, and sources should be cited.
All pricing data can be expressed in local currency units (LCU) or US$ using the applicable exchange rate (in Table 3)

1. Plant information
a. Plant name
b. Unit number
c. Plant location (region, state)
2. Unit Characteristics
- Type
- Sub-type
- Technology
- Grid-connect or off-grid
- Captive unit (Yes/No)
- Import (Yes/No)
- Year of commission
- Planned life to rehabilitation
- Rehabilitation or retrofit is undertaken (Yes/No). If yes, state the year and report: number of years extended, efficiency improvement rate, CO_2e emission reduction rate.

Table 5 - Example of power plant categories

Type	Sub-type	Technology
Thermal	Coal	Subcritical
		Supercritical
		Ultrasupercritical
		Integrated gasification combined cycle (IGCC)
		Circulating fluidized bed (CFB) subcritical
		Circulating fluidized bed (CFB) supercritical
	Natural Gas	Single-cycle gas turbine
		Combined cycle gas turbine (CCGT)
		Gas steam supercritical
	Oil	Single cycle

		Combined cycle
		Oil steam subcritical
	Diesel	Generator
Hydro	Hydro	Storage
		Run of river
		Pumped storage
		Mini, micro
Renewable	Wind	On-shore
		Off-shore
		On-shore mini, micro
	Solar	Photovoltaic, Utility grade
		Solar thermal
		Solar thermal with storage
		Photovoltaic, End-use Distributed
	Geothermal	Binary
		Dual flash
	Biomass	Biomass steam
	Waste	Biogas, landfill gas
Nuclear	Nuclear	Pressurized water reactor
		Advanced boiling water reactor

3. Capacity and generation
   - Installed capacity (MW)
   - Outages—planned and probabilistic forced (% of installed capacity)
   - Available capacity (MW) – data collected or calculated
   - If Hydro, effective utilization in dry and wet seasons (% of available capacity); and Length of the dry season (Number of dry days in the year *[as location-specific as possible])*
   - Electricity generation (MWh), if available
   - Capacity backups to support intermittent generation

4. Fuel consumption and efficiency
   - Primary fuel type
   - Secondary fuel type
   - Secondary fuel consumption (% of total)
   - Specific Energy consumption per unit of output (MJ/KWh)
   - Energy contents of all fuels (MJ/ton) *[fuel type level]*
   - Total Fuel Consumption per unit or plant (MJ), if available
   - CO_2e emission factors of all fuels (g/MJ) *[fuel type level]*

5. Non-Fuel, Generation Process Emissions

- Includes net emissions from reservoirs caused by biochemical processes and generating process emissions from other non-fossil fueled plants[26]

6. Energy Efficiency Improvement Costs
   - Utility costs of demand-side savings
   - Cost to decrease technical and non-technical transmission and distribution (T&D) losses

7. Investment Costs - For new and planned plants, only
   - Investment in plant and equipment ($/KW).
   - Investment in local pollutant emission control or GHG sequestration,
   - Investment in grid access and access/ transport of the fuel resource
   - Investment cost changes over time by technology and region
   - Management, insurance, and process contingency (% of investment cost)

8. Operating Costs - For all plants

- Fixed operation and maintenance (O&M) cost ($/KW)
- If with emission control, indicate this cost separately
- If the electricity generator pays grid connection charges, show this cost separately
- Variable O&M cost ($/MWh)
- If with emission control, indicate this cost separately
- If the electricity generator pays transmission charges, indicate this cost separately
- Fuel costs for primary and secondary fuels paid by the electricity generator ($/MJ) should include transport, and other expenses (for example, off-site coal washing) *[sub-sector/macro level]*
- Program subsidies that reduced the $/MWh Levelized cost of generation from renewables

9. Electricity Prices - For all plants or at [sub-sector/macro level]
   - Producer Price ($/MWh) paid to the electricity generator
   - Price paid by end-users ($/MWh) by sector/category of user
   - Electricity consumption mix by sector/category of user

10. Electricity Demand, Imports, and Exports [system-level]

- Electricity annual demand (MWh) within the system

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[26] Following the World Bank guidance manual and model "Guidance manual: Greenhouse Gas Accounting for Energy Investment Operations" The World Bank's Energy Practice in collaboration with the Water Practice (see: https://documents.worldbank.org/en/publication/documents-reports/documentdetail/269221468178766476/guidance-note-greenhouse-gas-accounting-for-energy-investment-operations)

- Annual import of electricity (MWh) into the system and pricing
- Annual export of electricity (MWh) from the system and pricing

11. Transmission and distribution (T&D) losses (MWh) [system-level]
12. Annual load duration curve (LDC) based on hourly data, including exports [system-level]. The LDC is normally expressed as a percent of peak load against the percent of the time.
    Peak load (MW), if available [*system-level*]

Unit-/plant-level data may be found in annual reports and statistics of relevant load dispatch centers. If such reports do not contain sufficient details, additional coordination effort may be needed to obtain underlying data. All data should be collected at the unit/plant level, except for LDC, T&D losses, energy contents, CO_2e emission factors, fuel and electricity prices, and the number of dry days. Energy contents and CO_2e emission factors are specific to fuel types and grades. To the extent possible, these should rely on local data. However, if not available, the data can be collected from reliable sources such as IEA and the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

Fuel prices are prevailing prices for generating plants, including transport and prior processing. The price change in question should be validated against any official price change mandated by the government/the regulating authority. Additional unit/plant-level data may be required to quantify the operational constraints for Chapter III, and other macro-/sector-level historical time-series data (including subsidies and taxes data) may be needed for counter-factual "without project" analysis in Chapter V. Refer to these sections for analytical options and data requirements.
Care must ensure that all price and cost data are in the same units and represent the mid-term price of the period being evaluated. If the analysis covers one year of data, the mid-year value should be used.

13. Operational Constraints on the historical and current operation

The analysis must consider the actual operational constraints of the power plants and the system. There may be several constraints. However, this section recommends examining the following list of conditions:

i. Availability of fuel supplies (coal, natural gas, oil, biomass, etc.);
ii. Mandatory limit on plant running time;
iii. Regulatory requirement on emission control;
iv. Take-or-pay contracts for fuel supplies;
v. Must-run arrangements;
vi. Grid capacity bottlenecks; and
vii. Conditions and restrictions on electricity import

Clear documentation of how the constraints, if they exist, are quantitatively translated in the methodology should be provided. For example, the constraints may be in the form of a 10 million cubic meters limit of natural gas supply this year or a mandatory maximum limit of 5,000 hours per year running time of all sub-critical coal plants. The methodology must adequately reflect such constraints to achieve realistic dispatch analysis and accurate emission accounting. Also, they can affect fuel demand elasticities.

The constraint must take into account the technical characteristics of each unit and particularly the time each requires to start up and ramp down production. Setting these correctly will ensure that the plants needed to cover short-duration peak loads are technically capable of doing so. This avoids the impractical assignment of certain plants in intermediate and peak loads.

There can be a lot of discussion about nuclear plants' variable costs that center mainly on the cost of confinement of waste irradiated material. However, many nuclear power systems look to run them as base-load independently of this discussion. This may require establishing a dispatch order for the plants unrelated to their direct variable cost (see Equation 4). It should be documented here if this is needed in the system under evaluation.

Identify the applicability of the documented operating constraints on a generating unit-by-unit basis. In applying this methodology, several scenarios for operational conditions are possible. Therefore, a clear description of how the constraints apply to each generating unit in the methodology is needed. As an example of how certain constraints can be operationalized, a limit on plant running time and must-run arrangements could be incorporated as part of $OUT_{i,t}$ in **Error! Reference source not found.** and/or **Error! Reference source not found.**. Availability of fuels, take-or-pay contracts, and restrictions on electricity or fuel import could simply be set during the iteration of dispatch analysis (Section VII.A in Step 3). Emission control regulation could be modeled through $OUT_{i,t}$ in the case of emission cap, or through $UE_{i,t}$ and $OM_{i,t}$ in Equation 4 in the case of emission control equipment requirements or technology standards.

4. Documentation of the policy change being analyzed

Documentation must be assembled that quantifies the change in policy (see Table 1 for examples of policies that can be evaluated with this methodology and model).
This methodology has been developed to quantify the changes in CO_2e emissions that derive from each of the impact channels shown in Chapter 2: Impact Channels.

For each of these cases, documentation is required that clearly illustrates what can be expected to have happened if the current policy had not been enacted. How the system would have operated without this policy change is known in the present document as the counterfactual *Withoutpolicy* operation. Proving the counterfactual may require documentation of previous operating practices, previous government or electricity authority regulations, time-series data, or other sources. The documentation needs are described in greater detail in each of the methodological steps.

5. Plausibility indicators

Plausibility indicators are needed not to determine GHG emissions reductions but to validate that the policy change has, in fact, affected the real economy. These could be things such as the change in market share of LED lamps, the uptake of more efficient heating and cooling appliances (including heat pumps), the uptake of high-efficiency electric motors and variable speed industrial fans; records of industrial process changes, and demand-side installation of PV, etc.,

Chapter 4: Determining the applicability of this methodology to electricity generation

This methodology is applicable only if the energy system responds to changes in variable cost.

If electricity dispatch does not react directly to changing fuel costs, then the impact of fuel costs should be excluded from the calculation by using the same fuel costs for generation in both scenarios.

This section details an initial screening that must be carried out to demonstrate that economic dispatch is followed for grid-based electricity generation and that the methodology may be applied to changes in the pricing of the fuels used for generation.

If the unit only has fuel use data, then its annual generation may be estimated from Equation 1:

Analysis of the unit-level data obtained is performed following the sub-steps below to examine how electricity dispatch follows the economic/least-cost principle in practice and whether the system responds to fuel price change.

- Select only grid-connect units that have:
  - generation data for the year in analysis; or
  - fuel use data for the year in the analysis.
- Exclude any unit that receives a promotional variable incentive for its electricity sales (for example, a Feed-in tariff) or where the off-taker would be obliged to pay the generator for energy that is not taken (for example, payments for capacity or reserve);
- Calculate unit-specific (a) availability factors, (b) capacity factors, and (c) variable costs;

The calculation of unit-specific (a) availability factors, (b) capacity factors, and (c) variable costs use Equations 2, 3 & 4

The **net capacity factor** of a power plant is the ratio of its actual energy output over a period of time to its potential energy output if it were possible for it to operate at full nameplate capacity continuously over the same period of time.

The **energy availability factor** is the ratio of available energy to theoretically possible energy, considering the operating constraints in the period under the report. It characterizes the reliability of a plant in general, considering all complete and partial outages. The unavailable period is generally attributed to scheduled outages for maintenance purposes, unplanned maintenance, unplanned outages, and operating constraints.

The main components of the **variable cost** are fuel costs and operation and maintenance (O&M) costs. Calculating the variable cost for each power-generating unit at any given time is performed with Equation 5

Then, determine the percentage difference between availability factors and capacity factors for all units. It is an important indicator of how close each unit is to its maximum available capacity in that year. This is done using Equation 6.

- Then: Arrange unit-level data to present (a) the unit's sub-type and technology, (b) annual generation in MWh, (c) variable cost in $/MWh, and the *dF* indicator;
- Sort the unit-level data by *dF* in descending order;
- Split the units and data into two groups that are operated in the same load category, i.e., at peak load (defined as a load factor of fewer than 3,000 hours per year) or base load (defined as a load factor of more than 3,000 hours per year) and label the group with the lowest *dF* data "base load," and the other "peak load" consequently[27];
- Calculate weighted average variable costs for each of the two groups (weighted by the unit's annual generation; and
- Check whether the weighted average variable cost of "base load" is the lowest and that of "peak load" is the highest.
    - If yes, conclude that the system broadly adheres to the economic dispatch principle, and this methodology may be applied.
    - If not, this screening exercise suggests that dispatch likely deviates from the least-cost principle and does not respond to changes in variable cost. In this case, this methodology may not be applied to electricity generation but can still be applied to the final consumption (end-use) of electricity and fossil fuels.

[27] This applies the logic of the CDM methodology "CM0013: Consolidated baseline and monitoring methodology for new grid connected fossil fuel fired power plants using a less GHG intensive technology

Chapter 5: Determining the CO_2e emissions reduction caused by implementing the policy package

To determine the CO_2e emissions reduction, CO_2e emissions must be established from both the *Withpolicy* and *Withoutpolicy* operations.

Establishing CO_2e emissions from Withpolicy operation

For the end-user

Based on the end-user, final demand data collected, CO_2e emission levels under the *Withpolicy* operation[28] are determined using Equation 7 and applying country-specific emissions factors per fuel and sector or technology when these are available or from the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, tables 2.2 to 2.10 for stationary sources.

For electricity generation

For electricity generation, CO_2e emission levels under the *Withpolicy* operation[29] are determined in two ways using the following methodologies.

If the purpose of the analysis is only to report emissions, then the inventory method should be used. However, if the purpose of the analysis is to conduct an ex-post analysis of the emissions impact of energy pricing policy, then the dispatch analysis method is also required. In the case of some policies, the methodology to determine the effect of changes in other policies on power sector emissions will also affect “with-project” emissions.

The dispatch analysis method—which will also be used in developing the emissions levels from the counterfactual *Withoutpolicy* operation reference conditions later in the methodology— is applied to all cases and allows consistency of approach and comparability of the emission levels between *Withpolicy* and *Withoutpolicy* operation within a unified scope of analysis using Equation 9 & 10.

The difference between the emissions determined by the dispatch analysis method in the *Withpolicy* operation and those reported by the inventory method for the same operation will be considered as the systematic bias associated with the dispatch analysis method, as discussed later in the methodology.

Establishing CO_2e emissions from counterfactual Withoutpolicy operation

The CO_2e emissions levels under the counterfactual *Withoutpolicy* operation are determined from what could be expected to have happened without the policy by running the methodological procedures

[28] Note that the ‘with-policy’ scenario represents the actual and observable conditions.
[29] Note that the ‘with-policy’ scenario represents the actual and observable conditions.

through all "impact channels," based on the same calculation used in the "with-project" evaluation, to compute CO_2e emission levels.

Each impact channel requires different prior analyses using methodological steps before running the dispatch analysis.

Each step provides methodological procedures in adjusting from *Withpolicy* to *Withoutpolicy* operating conditions.

These methodological procedures modify;

1. the energy demand by fuel type in the end-use sectors,
2. the decision on investment to improve energy efficiency in the end-use sectors,
3. electricity demand in the end-use sectors,
4. the electricity generation profile and dispatch of grid-connect power plants,
5. the decision on investment and construction of new power plants,
6. the operation of off-grid and captive capacity,
7. Any constraints on fuel supply, the use of revenues received from the implementation of energy pricing policy from the currently existing *Withpolicy* operation to counterfactual *Withoutpolicy* simulation.

For the end-user

Using the results of these analyses, the inventory method is then used in all cases to evaluate the CO_2e emissions under this counterfactual *Withoutpolicy* operation applying equations 7 and 8.

For electricity generation

The emission impact of fuel pricing policy under consideration, $\Delta CO2_t$, can be derived (in t CO_2e) from **Error! Reference source not found.**12.

This completes the measurement of emission impact at time t. The negative sign of $\Delta CO2_t$ indicates CO_2e emission reduction, whereas the positive sign indicates emission increase.

Uncertainty estimates are an essential element of any methodology. Uncertainty is caused (i) the presence of random errors based on the inherent variability of a system and the finite sample size of available data, random components of measurement error, or inferences regarding the random component of uncertainty obtained from expert judgment; (ii) systematic errors that may arise because of imperfections in models, measurement techniques, or other systems for recording or making inferences from data.

Good practice requires that potential sources of uncertainty are identified, quantified, and prevented wherever possible, such as by using appropriate QA/QC procedures. The 2019 Refinement to the IPCC 2006 guidelines for National Greenhouse Gas Inventories should be used to determine the uncertainty associated with the emissions reduction calculated using the present methodology. Initial uncertainty estimates can be related to factors described in the following sections.

Methodological bias

Because the bias errors in activity data are likely to be highly correlated, the difference between the reported value and the unknown true value is likely to be about the same relative magnitude and direction in the *Withpolicy* and *Withoutpolicy* operation, and this characteristic should be considered when estimating uncertainty in the results.

If a significant bias is detected, it may be desirable to revise model assumptions, energy final consumption constraints, plant operating constraints, and other parameters to reduce the bias.

In electricity generation, the difference between the total CO_2e emission from the power generation measured by the inventory method and by the dispatch method is indicative of the level of systematic bias associated with defining the *Withpolicy* emissions using the dispatch methodology and can be expected to occur in similar relative magnitude as the direction in the *Withoutpolicy* operation. Hence the relative uncertainty identified by these two methods (in Error! Reference source not found.**13.**can, as a first approximation, be applied to the emission reduction that this systematic bias can be reduced by adjusting plant operating parameters.

Emission factor uncertainties

For fossil fuel combustion, uncertainties in CO_2 emission factors are relatively low. The carbon content of the fuel determines them, and thus there are physical constraints on the magnitude of their uncertainty which vary by type of fossil fuel.
Petroleum products typically conform to fairly tight specifications, which limit the possible range of carbon content and calorific value, and are also sourced from a relatively small number of refineries. Coal, on the other hand, may exhibit a wide range of carbon contents and calorific values that can vary from field to field. The IPCC 1996 Guidelines (Table A1-1, Vol. I, p. A1.4) suggest an overall uncertainty value of 7 percent for the CO_2 emission factors of fossil fuel energy. However, the use of local values can reduce this estimate.

Activity data uncertainties

In addition to any systematic bias in the activity data resulting from incomplete coverage of the consumption of fuels, the activity data may be subject to random errors in the data collection that will vary from year to year.
Countries with sound data collection systems, including data quality control, may be expected to keep the random error in total recorded energy use to about 2-3 percent of the annual figure. This range reflects the implicit confidence limits on total energy demand seen in models using historical energy data and relating energy demand to economic factors.
Uncertainty ranges for stationary combustion activity data whose main activity is electricity or heat production are reproduced from the 2019 Refinement to the IPCC 2006 Guidelines (Chapter 2, Table 2.15)

Table 6 - Activity data uncertainty level estimates (from 2006 IPCC Guideline)

	Technique	Level of uncertainty
Well-developed statistical systems	Surveys	Less than 1%
Less-developed statistical systems	Surveys	1-2%

Combining uncertainties

The error propagation equation yields two convenient rules for combining uncorrelated uncertainties under addition (Equation 15) for relative uncertainties and multiplication (Equation 14) for absolute values:

Methodological steps

Methodology to determine the emissions from the final consumption of energy in end-use sectors

Applicability

This methodology is used in the *Withproject* operation only. It evaluates the end-user demand for energy (Final Energy Consumption) for each sector and fuel type chosen for analysis under the coverage of the policy in question (see Chapter 3).

Step 1: Determining the CO2e emissions from the final consumption of energy in end-use sectors

This is the preferred methodology.
Data is collected on energy consumption by fuel type in each sector.
Where available, country-specific emissions factors should be used in the calculation.
When these are not available, the emissions factors laid out in the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 on Stationary Combustion, tables 2.2 to 2.10 may be employed. Preference should be given to their Tier 3 methodology, followed by Tier 2, and lastly, Tier 1. The end-use emissions are calculated using equations 7 and 8.
The emissions for electricity are calculated using equations 25, 26, and 27.

Methodology to determine changes in end-use energy demand

Applicability

This methodology is used in the *Withoutpolicy* operation only to determine changes in end-use energy demand (electricity, natural gas, etc.)

This methodology aims to construct the energy demand level in the counterfactual *Withoutpolicy* operation. In other words, what would have been the level of energy demand, had the policy package not been implemented.

There are several ways to estimate the price impact on demand for energy. There may be increasing effort/cost associated with reducing the estimate's uncertainty. However, this more significant effort may result in a more attractive emission reduction without affecting the conservativeness of the calculation. A few approaches are discussed below.

Un-adjusted reference electricity demand

There is a large body of evidence that supports a general economic theory that energy demand is negatively correlated with energy price (Dahl 2011, Alberini and Filippini 2011, Cuddington and Dagher 2011, Dergiades and Tsoulfidis 2008, Ziramba 2008, Amarawickrama and Hunt 2008, Zachariadis and Pashourtidou 2007, Jamil and Ahmad 2011, Narayan and Smyth 2005, Holtedahl and Joutz 2004). Therefore, one would expect the level of energy demand (thus CO_2e emission) to be higher in the counterfactual *Withoutpolicy* operation, where energy price is lower or subsidized. This suggests that leaving electricity demand unadjusted in the reference case likely establishes a conservative emission level for the measurement of emission difference between the *Withoutpolicy* and the *Withpolicy* operation. However, when the price effect is used for demand adjustment, a larger ER will usually result.

Measuring price effect for demand adjustment

Energy price change likely impacts energy consumption, the magnitude of which depends on the country, sector(s), the amount of price change, its expected permanency, etc. One approach is to measure price elasticity for energy demand in a particular context and avoid using macro-level elasticity estimates that are typical findings from cross-country regression analysis in the literature.
Country-specific time-series econometric analysis of total energy consumption against energy price is suitable for the case of economy-wide energy price change. However, suppose the effect varies across sectors and consumer classes. In that case, such an economy-wide estimate is unlikely to apply when the energy price change is implemented only in certain sectors or in all sectors but with different magnitudes. Therefore, it is important to understand the energy price change policy under consideration as to whether it is economy-wide (uniformly applied across all sectors) or only for certain sectors/sub-sectors and the magnitude(s) of price change. Using elasticities evolved over time or based on the data collected from credible studies is a recommended approach.
This sub-section proposes a few options for measuring the price effect on energy demand. The choice depends on the nature of policy implementation and data availability. If none of these options can be adopted, users may revert to unadjusted reference emissions.

The demand adjustment (if applied) should be determined by analyzing the price effect by employing the most rigorous possible of the following approaches:

a. *Time-series econometric analysis*
b. *Panel econometric analysis*
c. *General equilibrium analysis*
d. *Adopting robust estimates from the literature*

a. *Time-series econometric analysis*

The dependent and explanatory variables have to be defined according to the scope of the price change policy (i.e., economy-wide, for specific sectors, or for specific consumer classes within sectors). For an economy-wide price change, total national-level energy consumption and average energy price time-series data may be used. For sector-specific price changes, an econometric analysis should be conducted individually for each sector. Sector-level energy consumption and sectoral average energy price time-series data may be used in this case.

A few broad principles of the analysis in this particular sub-section are:

1. The econometric specification should be chosen based on the literature and country-specific evidence. Control variables typically include per capita income, weather conditions/climate index, the price of substitute fuels for heating and cooling, demographic and geographical control factors, etc.
2. Appropriate co-integration techniques and robustness tests are recommended to avoid spurious correlation and to establish credible elasticity estimates.
3. Time series should comprise over 30 years of historical observations, and the range of historical price variation in line with the magnitude of price change in question should exist in the data series.
4. The period of the time series should not contain significant market or political changes that could markedly skew the elasticity of demand; for example, this could be the case if the economy shifted from centrally controlled to a free market economy or an easing of foreign exchange restrictions opened allowed households and increasing ability to acquire energy-consuming appliances.
5. Where data is available and substantiated by plausibility indicators, the mixture of short-run and long-run price demand elasticities can be used. When not, short run offers a more conservative approach[30]

The procedure below should be followed to derive the price effect.

i. Assemble a dataset that has the following characteristics[31]
   Dependent variable: energy consumption in natural logarithm[32]
   Explanatory variables:

[30] The use of short-run price elasticity is consistent with the principle of conservative baseline. This is also considered pragmatic for the purpose of carbon crediting or result-based payments for achieved emission reduction outcomes with manageable crediting/payment period of say five years, although the methodology leaves out possible long-run impacts (where there are no fixed capitals/factors).
[31] This requires additional historical dataset to that developed in Section II of this paper.
[32] This is most suitable for the case of economy-wide analysis and for the residential sector. For the case of other sectors, such as commercial and manufacturing, use total sectoral consumption.

per capita income in natural logarithm[33];
energy price in natural logarithm;
the prices of *substitute fuels* such as electricity, natural gas, oil, and petroleum products in natural logarithm;
total population;
urbanization rate
household electrification rate;
heating and cooling degree days[34]; and
other variables that may have a significant impact on energy consumption, such as dummy variables for external shocks.
Coverage: annual time series should contain over 30 observations, with the difference between the ending period and the measurement year less than or equal to 5 years. For example, if the analysis year is 2015, the series should cover the 1981-2010 period at minimum.

ii. Set up an econometric specification, which varies from one case to another.

iii. Conduct unit-root test for *all* dependent and explanatory variables using Equation 17. This is to test whether the data series are non-stationary in levels. Modeling with non-stationary variables can lead to spurious correlations.

iv. Conduct a unit-root test for the *first difference* of *all* dependent and explanatory variables, following the same procedure as in (iii).

If step (iii) suggests that a variable is non-stationary in level and step (iv) indicates that the first difference of the same variable is stationary, then conclude that the variable is *I(1)* – integrated of order one.

If both energy consumption and price are found to be *I(1)*, then move to step (v). If not, stop here and revert to applying un-adjusted demand for further analysis.

v. Perform cointegration test. This is to examine whether there exists a long-run equilibrium relationship between the variables that can be estimated in **Error! Reference source not found.**, although some/all of them are *I(1)*[35].

[33] This is most suitable for the case of economy-wide analysis and for the residential sector. For the case of other sectors, such as commercial and manufacturing, use total sectoral GDP.
[34] To calculate heating and cooling degree days, see for example: http://www.epa.gov/climatechange/pdfs/print_heating-cooling-2014.pdf
[35] The variables co-integrate and have a common trend if a linear combination of non-stationary variables (i.e. the resulting residuals) is stationary.

vi. Estimate energy price elasticity ($\rho_{k=0}$) using the OLS technique, based on the following error correction form in inEquation 18 [36]

vii. Read the coefficient $\rho_{k=0}$ and its standard error, and check (1) whether the coefficient shows the expected negative sign and (2) whether it is statistically significant.
If yes to both, use ρ_0 for demand adjustment, according to the magnitude of the price difference between the actual and the counterfactual level in the assessment year.
If no to either, proceed without demand adjustment.

viii. Calculate energy demand impact $\Delta\tilde{e}_t$ (in MWh or MJ), based on ρ_0 in Equation 19

ix. Repeat the econometric exercise for other sectors and/or consumer classes within sectors, if applicable and if data are available. Stop the procedure if econometrics is undertaken for economy-wide price change policy.

x. Sum up energy demand impacts across sectors/sub-sectors, and note the result for adjustment of demand to the counterfactual "reference" *TED*. For electricity, demand adjustment will be carried out prior to performing the Dispatch methodology on the *Withoutpolicy* operation.

xi. Account for the effect of the energy price change of one fuel on the consumption of *substitute fuels*.
Follow the above guideline and sub-steps to undertake a similar econometric analysis using *substitute fuels* as dependent variables. The aim is to obtain price elasticities of demand for substitution fuels and capture fuel switching due to energy price change.
If the exercises pass all statistical tests and robustness checks as set out above, then calculate the impact of price change on the consumption of substitution fuels (based on a formula adapted from Equation) and associated CO_2e emission impacts using appropriate emission factors (*EF*).

Users may also follow the above sub-steps to conduct an econometric analysis using per capita income as an explanatory variable of interest (instead of fuel price) to obtain short-run income elasticity of demand for electricity and other fossil fuels as necessary.

b. *Adopting a robust estimate from the literature*

The existing estimates in the literature may be adopted, provided that (i) the econometric analysis design and the dependent variable used are appropriate for the type and scope of policy under consideration, and (ii) the econometric method follows the procedure and the requirements outlined in section a) above

[36] This is re-written from equation (16). See, e.g., Cuddington and Dagher (2011) how an error correction model is derived. The equation illustrates the case that includes three explanatory variables. Scharwz's Bayesian Information Criterion and/or Akaike Information Criterion can guide the selection of lags.

that involves unit-root and cointegration tests, as well as an estimate of short-term price elasticity of energy demand based on error correction model. Adopting short-term price elasticity of demand for substitution fuels from the literature follows the same guideline and requirements for statistical rigor.

c. ***Panel econometric analysis***

The panel cointegration technique may be used when a series of end-user surveys are available across multiple years. At least four rounds of surveys that span over 15 years, with the difference between the ending period and the measurement year less than or equal to 5 years, should be available. The technique is applicable only for end-user surveys that contain energy price and energy consumption information. The procedure is similar to the time-series analysis in section a). Nevertheless, users may refer to Breitung (2000) for the panel unit-root test, Pedroni (2004) for the panel cointegration test, and Narayan et al. (2007) for a panel estimation based on an error correction model.

d. ***General equilibrium analysis***

The linkage between energy price and demand could also be analyzed using a computable general equilibrium (CGE) model, usually constructed from a country's input-output (I-O) table or social accounting matrix (SAM). For this methodology, a static CGE that is well-calibrated for the assessment year can be utilized to estimate energy demand response to price shock.

An I-O table or a SAM may be used for the CGE analysis if they are (i) no longer than three years old from the assessment year [conditional on the justification that there has been no significant disruption or change to the economic structure], (ii) developed and used by a government agency for national economic planning purposes as evidenced in official plan/policy documents, and (iii) recommended for use after a critical review of model structure and all exogenous assumptions by a selected group of international CGE experts. The relationship between price and demand for substitute fuels could also be derived from the CGE simulation.

The CGE analysis option may be explored only if users are able to demonstrate that none of the econometrics-based options above is feasible and the analysis adheres to the above guideline.

Methodology to determine electricity system emissions using the Dispatch analysis approach

This methodology updates electricity demand impact for an update of reference $\sum_j TED_{j,t}$in **Error! Reference source not found.**11.

Applicability

This methodology is used in the *Withproject* and counterfactual *Withoutproject* operation to determine the electricity generation CO_2e emissions using dispatch analysis on the grid-connected units/plants.

It provides steps for calibrating dispatch methodology using the data and operational constraints from Chapter 3: Data Monitoring and Collection (Operational Constraints on the historical and current operation) for the *Withproject* operation, then running dispatch analysis and calculating total *Withproject* CO_2e emissions.

It also provides steps for using the data and operational constraints that modify existing operations to the counterfactual *Withoutproject* process, then running dispatch analysis and calculating total *Withoutproject* CO_2e emissions.

When used in the *Withproject* operation, the data and constraints in Chapter 3 are applied directly.

When used in the *Withoutproject* operation, these are modified due to the changes documented in Chapter 5 (Establishing CO_2e emissions from counterfactual Withoutpolicy operation) affecting:

1. electricity demand
2. Off-grid and captive generation
3. Grid-connected plant availability and operation

all in accordance with the additional prior analysis performed using the methodologies documented in this section

Step 1: Apply the operational constraints to the affected generating units/plants

From the documentation of each constraint provided in section II, identify on a generating unit-by-unit basis the applicability of each condition.

Modify the unit/plant-level data of those affected to account for the impacts of the constraint. This may limit (or lock in) plant running time, limit maximum generation, limit fuel availability, change fuel costs to the plant, or impact other unit/plant-level data or operating practices and characteristics.

Step 2***:*** Identify all off-grid and captive units/plants and tabulate their generation

Off-grid and captive units/plants are not dispatched. The energy each generates is determined by their connected load. In this step, the off-grid and captive units/plants are identified, and their generation, fuel use, and emissions are quantified over the modeling period.

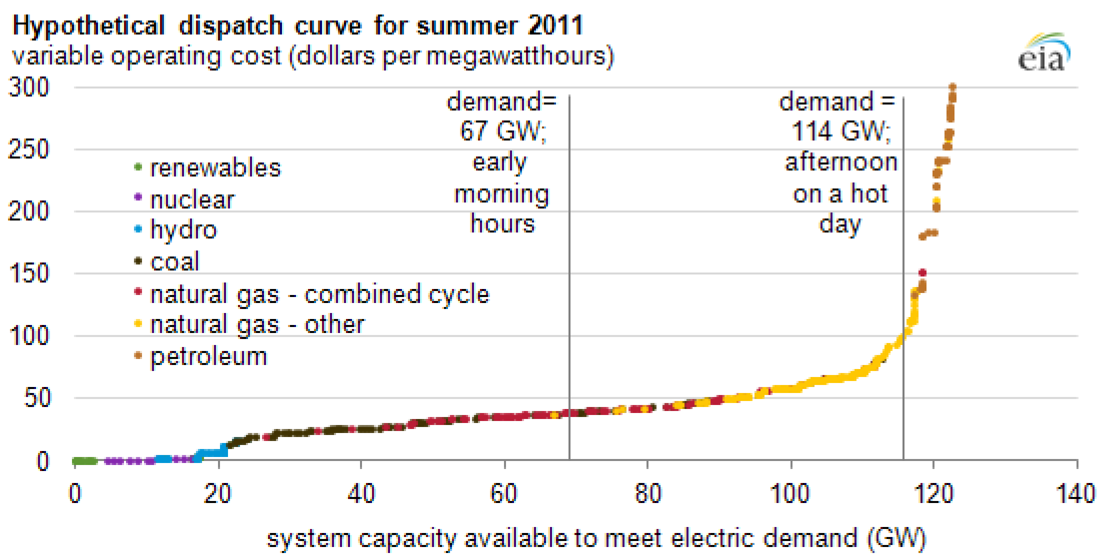
1. Select the non-grid connected units from Chapter 3
2. Arrange unit-level data to present (a) the unit's identification, (b) the unit's capacity in MW, (c) its availability factor as a percent of capacity, (d) its fuel(s) used, (e) its generation in MWh, and (f) its emissions in tons CO_2e
3. Develop a table showing each variable together with **total** off-grid and captive generation ($GEN_{c,t)}$) and emissions ($CO_2e_{c,t}$). See step 3 for definitions.

Step 3***:*** Determine the total grid-based generation need and CO2e emissions from off-grid and captive units/plants using Equations 20 and 21

Step 4***:*** Identify all grid-connected units and construct a dispatch curve

The variable operating (marginal) cost of electricity-generating units is a key factor in determining which units are dispatched to meet the electricity demand. Other things being equal, plants with the lowest variable costs are generally dispatched first, and plants with higher variable costs are brought online sequentially as electricity demand increases. The order in which units are dispatched to meet the demand can be represented in a **dispatch curve** (sometimes referred to as the electricity supply curve or merit order). A hypothetical example of a dispatch curve is provided in Figure 10.

Figure 10. A Hypothetical Dispatch Curve



Source: US Energy Information Administration

The dispatch curve depicts unit-/plant-level merit order based on the marginal cost of electricity generation in a particular year. The dispatch curve or merit order can be developed in a table of up to 8760 rows[37] (hours) and presented as a chart using the variable costs and the available capacity calculated from Chapters 3 and 5. The tabulated data will be helpful for the analysis in the next steps. The sub-steps below may be followed.

1. Select only grid-connect units from Chapter 3;
2. Arrange unit-level data to present (a) the unit's identification, (b) the unit's capacity in MW, (c) its availability factor as a percent of capacity, (d) its capacity factor, (e) the percentage difference between the two (*dF)* and (f) variable cost in $/MWh ;

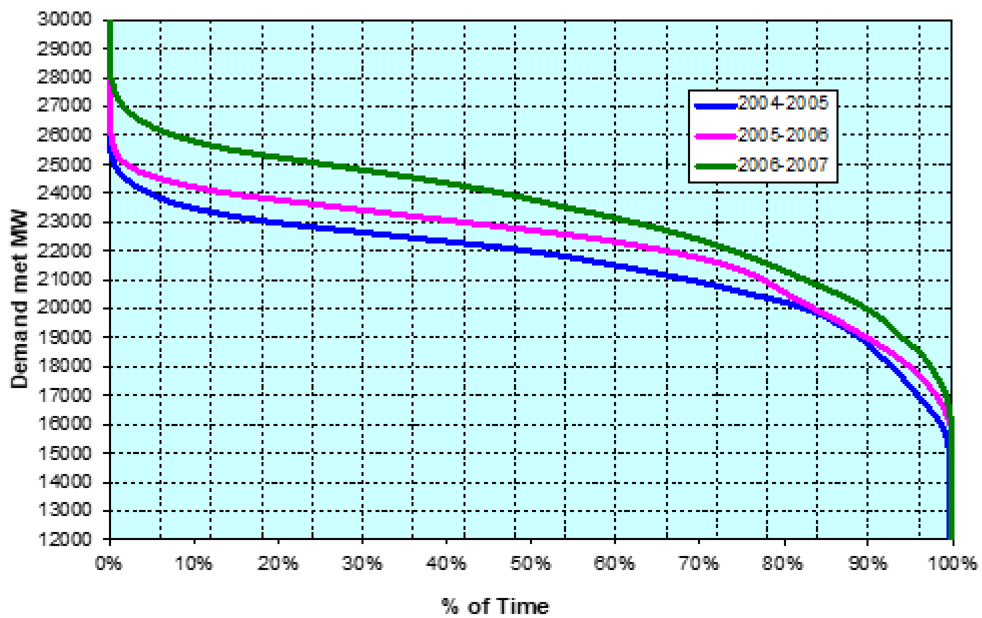
[37] or 8784 hours in a leap year

3. Sort the unit-level data by the variable cost in ascending order. In case of equal variable costs among a sub-set of units, rank by *dF* in ascending order within the group; and
4. Develop a table showing (a) the variable cost from lowest to highest in $/MWh and (b) cumulative available capacity in MW.

Step 5: Obtain the annual load duration curve

A load duration curve (LDC) exhibits the hourly profile of electricity demand over a certain period. Figure 3 shows an example of the annual LDC from India's Western Regional Load Dispatch Centre for three years. A typical source of hourly electricity demand data is load dispatch centers or power system operators. Raw hourly electricity demand data in MW (Figure 12) can be sorted in descending order to obtain an LDC (Figure 11).

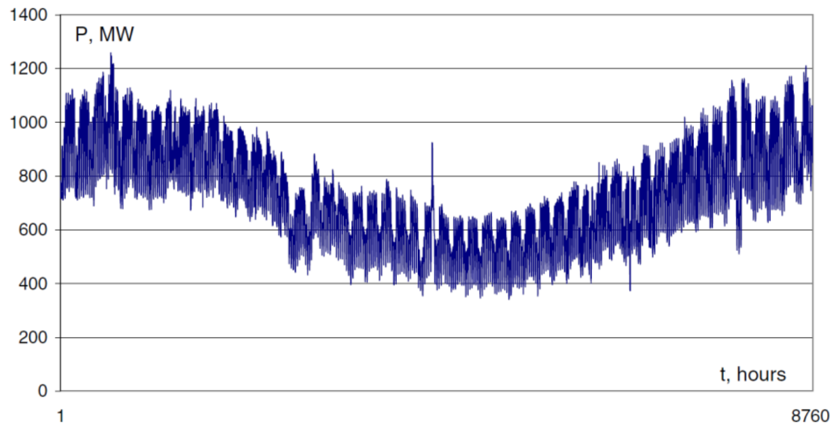
Figure 11 India's Western Regional LDC, 2004 - 2007



Source: ***Power Grid Corporation of India Ltd. Western Regional Dispatch Centre***

Ideally, LDC should be adjusted to reflect any actual electricity supply shortage for the hours in the year for dispatch analysis. Whether or not the adjustment is feasible in practice depends on data availability. In many developing countries, shortages occur during peak periods. In such cases, leaving out shortage adjustment on LDC from this analysis would likely result in a slight overestimate of electricity supply and CO_2e emission. However, a consistent approach to this between *Withpolicy* and "*Withoutpolicy* operation helps alleviate the problem when it comes to calculating emission impact.

Figure 12: Hypothetical LDC from Liik et al., 2004



A load duration curve (LDC) is customarily represented as the percent of peak load against the percent of the time. It depicts the ordering of electricity demand levels from the highest hourly load to the lowest hourly load. The area under an LDC represents the total electrical energy demand.

The advantage of expressing the LDC on a percent of peak load against a percent of time basis is that the same curve can be applied to scenarios with changing total energy demand. For use in any specific scenario in this methodology, the LDC has to be converted to absolute numbers.

Time period
If it is an annual calculation, the percent of time scale will become a linear scale from 0 to 8760 hours. However, other periods can be used, noting that seasonality has to be respected.

Step 6: Apportion the load duration curve into six time-blocks

The annual load data is then subdivided into six time periods, as shown in Table 7

Table 7 - Analytical time blocks

<table>
<tr><th>Winter</th><th>Summer</th></tr>
<tr><td colspan="2">Off-Peak</td></tr>
<tr><td>Midday</td><td rowspan="2">Day</td></tr>
<tr><td>Afternoon</td></tr>
<tr><td>Evening</td><td>Evening</td></tr>
</table>

This is schematically shown in Figure 13

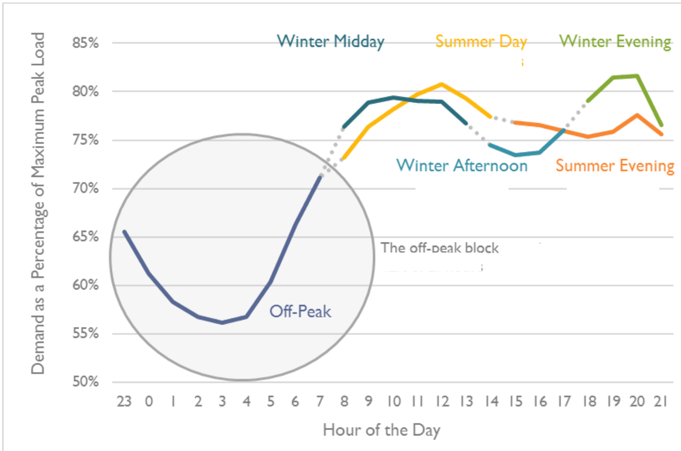


Figure 13 - Annual load-dispatch analysis performed of all power plants in each of 6 time-blocks

This is important because (i) the energy demand in each time block is different; and (ii) the generating resources available to supply that demand are also different, affecting primarily renewables (wind, solar) and hydro availability.

The subdivision into six time periods is done by first comparing the monthly average gid electricity consumption to monthly historical average temperature (deg C), precipitation (mm), and sunshine (hrs) to choose the separation between the two seasons.

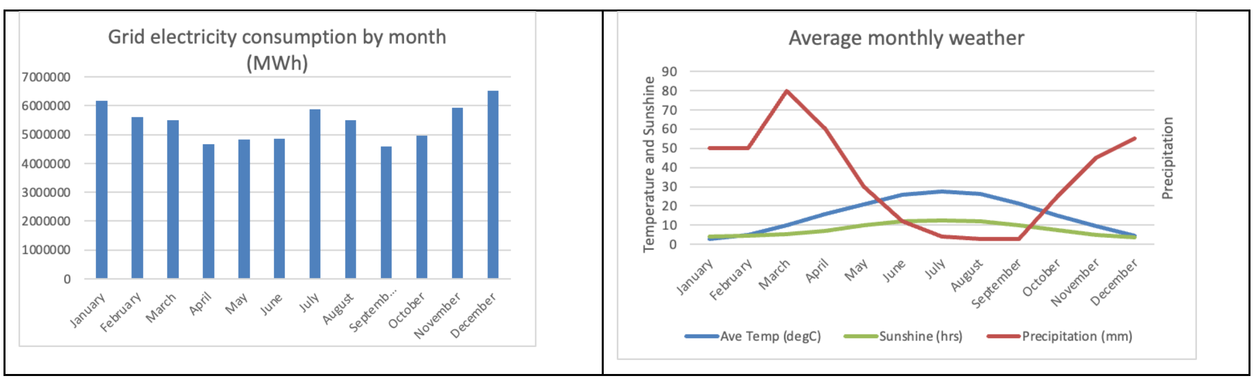


Figure 14 - Grid electricity (MWh) in Uzbekistan 2019 and Weather in Tashkent 2019

Once the seasons have been chosen, then the six time blocks are selected to represent best (i) summer and winter off-grid, (ii) winter midday, (iii) winter afternoon, (iv) summer day, (v) winter evening; and (vi) summer evening loads. In the analysis, each of these time blocks will be dispatched separately

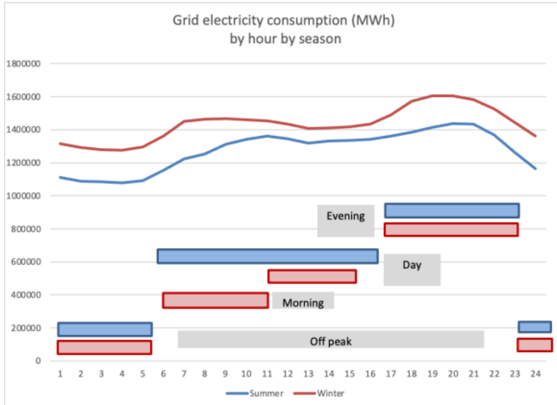


Figure 15 - Grid electricity consumption in Uzbekistan 2019

Peak load

If the system-level Peak load was available, then the percent of load scale would become a linear scale from 0 to this peak load (MW)

If the **system-level peak load is not available**, it can be **calculated** using Equation 30, which divides the total grid-connected generation by the time duration of the modeling period and by the percent area under the LDC curve.

Step 7: Carry out dispatch analysis

Dispatch analysis can be undertaken based on the dispatch curve and the LDC prepared in the preceding steps of this section. The analysis logic is to fill the area under the LDC in each time block from the lowest to the highest system-wide load size (MW), using the available generating units as per the dispatch curve and starting from the unit with the lowest variable cost to the one with the highest variable cost. The dispatch analysis can be operationalized through manual spreadsheet computation or a power dispatch simulation model[38]. For manual computation, the sub-steps are as follows.

1. Take the table developed from Step 4 above that contains the data for the dispatch curve for grid-connected units/plants.
2. Sort the unit-level data by variable cost and in ascending order. In case of equal variable costs among a sub-set of units, rank by *dF* in ascending order within the group;
3. Take the table containing LDC from Step 5;

As you add dispatched electricity to the LDC, the hours per year for which the next level should be added reduces (along the curve) from an initial value of T = 8760 hrs, hour by hour, to a final value of T = 1 hr for the absolute peak load.   The first units will be needed for baseload, where the demand will be supplied for the whole year (8760 hours). When this is covered, additional units will be required to cover the needs of the next period that is one hour shorter (T= 8759), and so on. The process involves adding

[38] If a power system simulation model is used, a documentation should be provided and demonstrate dispatch analysis principles that adheres to the guideline in this section.

the available capacity (AC) for each unassigned unit and determining how many hours it is needed (the value of period T) to match the LDC. Calculate the MWh that this represents. Then add the next unit's available capacity and repeat until the entire generation need is met.

4. Analyze one unit at a time, from the first-ranked unit with the lowest variable cost on the dispatch curve to the highest;
5. For each period (T) on the LDC, starting at T= 8760 and going down to T= 1, determine from the LDC the MW of additional required capacity (ARC*) and the energy (MWh) that this represents. From the first-ranked (lowest variable cost) unassigned unit, check whether its available capacity (AC expressed in MW) is less than this additional required capacity (ARC*).
   a. If it is <u>less</u>, then this unit will be able to operate at its full available capacity over the period of time that is less than or equal to its maximum working constrained time and up to that marked by the current value of (T), Calculate annual electricity generation from that unit (in MWh) using Equations 1 [39]:
   However, this unit does not supply all the capacity needed in the period (T), and there is still a need for an additional (ARC*- AC) MW of capacity over time T. Repeat the process with the next unit in the dispatch order until the demanded energy (ARC * T) for this hour is wholly covered.
   b. If AC is greater than the uncovered remnant of ARC, calculate the electricity generation using Equation 32 (in MWh) of this unit corresponding to this period (T):

However, this unit still has an **unused capacity** (AC-ARC) which can be applied to the demanded capacity for the next period (which will have a T, one hour shorter) in the LDC.

Additionally, there could still be a need to supply additional energy in the period (T), and there is still a need for an additional [(ARC*- AC) * T] MWh. Iterate the process with the next unit in the dispatch order until the demanded energy (ARC * T) for this hour is wholly covered.

   c. Iterate the process for each period starting at T= 8760 and going down to T= 1 until the whole energy demand of the LDC is covered. Be careful that:
      i. The constraints have been correctly set up to account each unit's technical characteristics with reference to the time each requires to start up and ramp down production. Setting these correctly will ensure that the plants that are required to cover short-duration peak loads are technically capable of doing so. This is to avoid impractical assignment of certain types of plants in intermediate and peak loads
      ii. That for systems with nuclear plants, their position in the dispatch order correctly reflects (as documented in constraints) the way that they are dispatched in practice.
6. Report unit-level electricity generation and total generation of the system at time *t*.

[39] Use 8784 hours per annum, instead of 8760 hours for all sub-steps for the years (*t*) with a leap day.

Step 8: Calculate total CO2e emission

The previous step results in unit-level electricity generation per year for each grid-connected unit/plant. Total CO_2e emission from all grid-connect units can be calculated through Equation 33

Apart from the grid-connect units, the emissions from off-grid and captive units should also be taken into account. In the case that unit-level information is available for off-grid and captive capacities, Equation 34 can be used to calculate CO_2e emission.

However, in some instances, unit-level data may not be available for off-grid and captive capacities. In such cases, CO_2e emission from non-grid-connect capacities should be calculated based on aggregate generation data and weighted averages of emission factors and technology efficiency.

The overall CO_2e emission from the power generation system given by Equation 35:

Methodology to determine electricity system emissions using the Inventory approach

Applicability

This methodology is used in the *Withproject* operation only.

The Inventory analysis method serves two functions:

1. As a "reality-check" to the dispatch analysis of the *Withproject* operation. Significant differences could imply the presence of operational constraints that have not been adequately accounted for. Correcting such anomalies helps calibrate the dispatch analysis of *Withproject* operation.
2. To identify any systemic bias of the dispatch analysis of *Withproject* operation. This will be used in analyzing the measurement uncertainties of the results.

Determining the CO2e emissions of the generating system using local unit/plant-level data

This is the preferred methodology to determine the electricity generation CO_2e emissions from the power generation system based on the actual unit-level generation data using Equation 36.

This includes emissions from both grid-connected and captive plus other off-grid plants

If all the required data is not available, then the alternate methods laid out in the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Chapter 2 on Stationary Combustion may be employed with preference given to their Tier 3 methodology, followed by Tier 2 and lastly Tier 1. The calculation method depends on the availability of unit-level data for these generation sources.

Methodology to determine changes in investment in new grid-connect power plants

Applicability

This methodology is used in the counterfactual "without-project" operation only.

As a change in fuel price may impact the decision on investment and construction of new grid-connect power plants, this section guides the users in developing the counterfactual conditions of power capacity that would have been added to the existing fleet of power plants in a particular year. To put it differently, the section examines whether or not the observed plants that are commissioned in the measurement year *t* would have deployed different types/technologies had the fuel price in question remained subsidized or unchanged from the previous period.

To derive the counterfactual *Withoutpolicy* inventory of power plants, follow the steps below.

i. Observe *each* newly commissioned power plant in year *t* that does not use the fuel under policy consideration, and collect plant-/unit-level data, as guided by Chapters 3 and 4;

ii. Identify whether the plant is planned/operated as "baseload" or "peak load." In this context, "baseload" plants are defined as operating 3000 hrs or more per year, whilst "peak load" plants are defined as operating up to 3000 hrs per year.

iii. Using Chapter 3 as a reference, determine whether the fuel price under consideration is substantially used for electricity generation in "baseload" or "peak load";

If sub-step (ii) and (iii) suggest that it is substantially used in the same load category, proceed to the following sub-steps. If not, stop the procedure and consider the next newly commissioned plant, if any. Note that the new plant identified in sub-step (i) will be used in *Withoutpolicy* dispatch analysis.

Use data collected in sub-step (ii) to calculate the new plant's levelized cost of electricity generation[40], LCE^n using the exemplified Equation 37, which assumes all initial investment to occur in year 0, but should include all subsidies and taxes, other than the policy under consideration and debt service (equity and loans) where applicable.

- Identify all power plants that exist in year *t*, use the fuel under policy consideration, and operate in the same "baseload" or "peak load" category.
- Calculate the shares of sub-types/technologies (e.g. sub-critical, super-critical, and ultra-supercritical in the case of coal pricing policy) based on generation in year *t*.

[40] The use of LCE as key indicator for investment analysis implies that the capacity expansion plan follows least-cost principle.

- Add up the share of each sub-type/technology from the least to the most efficient technology.
- The technology at the 80th percentile share is selected as the baseline technology[41].
- The plant using baseline technology that has the available capacity (*AC*) closest to that of observed plant in sub-step (i) is selected as the *baseline power plant*.
- Check whether the constraints identified in Chapter 3 are binding. If yes, and the operation of the *baseline power plant* is not technically feasible, then the new plant identified in sub-step (i) will be used in baseline dispatch analysis.

- ***Calculate* the LCE of the baseline power plant based on the** *actual* ***Withpolicy*** fuel price (denoted, LCE_p^b)
  - If $LCE_p^b > LCE^n$, then proceed to sub-step (vii). Note that this also validates the observed investment in a new plant as the preferred choice and follows the least-cost principle.
  - If $LCE_p^b < LCE^n$, then conclude that the observed investment choice is not determined by economic rationale/least-cost principle and would maintain regardless of the fuel price scenarios. Stop the procedure here and consider the next newly commissioned plant, if any. Note that the new plant identified in sub-step (i) will be used in baseline dispatch analysis.

- ***Calculate*** the LCE of the baseline power plant based on the *Withoutpolicy* fuel price (denoted, LCE_s^b)
  - If $LCE_s^b < LCE^n$ then conclude that the investment decision would have switched to the baseline plant analyzed in this sub-step had the fuel price under consideration remained without increase. Proceed to sub-step (viii).
  - If $LCE_s^b > LCE^n$, then stop the procedure here and consider the next newly commissioned plant, if any. Note that the new plant identified in sub-step (i) will be used in baseline dispatch analysis.

- **Repeat the procedure in this section for** *every* **newly observed power plant that uses the fuel under policy consideration**. Note the inventory of *baseline power plants* that will be used in the dispatch analysis under the *Withoutpolicy* fuel price scenario. The baseline power plants will be included in the total fleet for analysis in years t+1, t+2, t+3,…up to the end of the assessment period.

It is unlikely that fuel price change would directly affect the operational schedules of power plants, such as plant efficiency improvement, renovation, retirement, and fuel substitution. However, the linkages may be established should the evidence shows that the price effect exists and users can

[41] This is consistent with CDM's methodology ACM0013 version 05.0.0. The calculation up to this bullet (under sub-step v) has to be done only once for the fuel under consideration. However, the next two bullets have to be carried out in the iteration.

identify/develop a credible method to supplement this methodology. Due to a lack of both, this paper leaves out the measurement of these potential impacts.

This methodology updates the stock of power plants as input to reference GES_tin Error! Reference source not found.**11**

Methodology to determine changes in the electricity supply from off-grid power plants

Applicability

This methodology is used in the counterfactual *Withoutpolicy* operation only.

This methodology evaluates whether or not the electricity supply observed from captive units, particularly diesel generators, and off-grid power plants, such as off-grid renewables, that are in operation in year *t* would have been replaced by electricity from the grid, had the fuel/electricity price under consideration remained subsidized/unchanged[42]. The methodology develops counterfactual *Withoutpolicy* conditions of off-grid electricity supply in a particular year. The sub-steps of analysis are as follows.

A. Observe *each* off-grid and captive unit that is in operation in year *t*;

B. Determine whether the site where the unit is located has access to grid electricity at the required voltage, energy offtake, and reliability of supply;
   a. If yes, then proceed to sub-step (iii)
   b. If not, stop here and maintain this particular unit in counterfactual *Withoutpolicy* analysis

C. Determine if the unit was in operation prior to the policy change (that moved from the *Withoutpolicy* case to the *Withpolicy* case).
   a. If yes, calculate the cost of electricity generation of the off-grid/captive unit (denoted,
   b. LCEo) considering its initial capital expenditure as a sunk cost using the following modification to Equation 38

D. Compare LCEo at any time *t* with electricity price under the *Withpolicy* scenario (denoted, EPp) and that under the *Withoutpolicy* operation (denoted, EPs)

If EPs<LCEo<EPp, then conclude that the off-grid supply would have been replaced by grid supply in the counterfactual "reference" operation. Proceed to sub-step (v).

If EPs<EPp<LCEo, then conclude that the observed off-grid supply is not determined by economic rationale/least-cost principle and would maintain regardless of the fuel price scenarios. Stop the

[42] The analysis considers off-grid/captive units as substitutes for or supplement to grid electricity supply. Electricity generation from off-grid/captive units is dependent on electricity price, and not directly by the fuel price under consideration.

procedure here and consider the next off-grid/captive unit, if any. Note that the off-grid/captive unit analyzed will be used in further *Withoutpolicy* operation analysis.

If LCEo<EPs<Epp, then conclude that the observed off-grid supply is the least-cost option regardless of the fuel price scenarios. Stop the procedure here and consider the next off-grid/captive unit, if any. Note that the off-grid/captive unit analyzed will be used in further *Withoutpolicy* operation analysis.

E. Repeat the procedure in this section for *each and every* off-grid/captive power plant that are in operation in year *t*. Note:
   i. (a) total off-grid electricity supply that would have been replaced by grid electricity in MWh;
   ii. (b) the inventory of off-grid/captive units that will be used in *Withoutpolicy* operation; and
   iii. (c) the total reference level of electricity supply from off-grid and captive sources
   iv. (d) the resultant total level of electricity supply from grid-connected units/plants taking into account the change in off-grid supply.

Calculate total counterfactual *Withoutpolicy* CO_2e emission from off-grid and captive units using Equation 37 fo $CO2_{c,t}$.

In the situation where unit-level data are not available for off-grid and captive generators, leave off-grid/captive electricity supply unadjusted in the counterfactual *Withoutpolicy* operation from the observed aggregates. This methodology updates the operation of off-grid and captive capacity to reference OFFt in Equation 11 .

Methodology to determine changes in the use of Revenues from policy implementation

This methodology assesses the second-order implication of changing the use of revenues from the policy – applies only when revenues are used to deliver Improvement (reduction) of T&D loss; Electricity demand conservation measures/projects in end-use sector(s); Development of new grid-connect power plants; power plants. Development of new off-grid power plants. For measures that affect the net income of energy consumers and for measures that affect direct consumption of electricity and fossil-fuels.

Applicability

This methodology is used in the counterfactual “without-project” operation only.

This methodology examines what would have occurred in the counterfactual *Withoutpolicy* operation had the revenues from policy implementation (e.g., subsidies removal, carbon taxes) not been utilized the way they are[43]. The methodology allows fiscal savings and revenue recycling to be included, but it is exogenous, input by the modeler in agreement with clients and donors.

The following sub-steps of analysis may be carried out.

Methodology to determine the impact of changes in other policies on power sector emissions.

Applicability

This methodology is used in the *Withpolicy* and counterfactual *Withoutpolicy* operations.

The methodology described in this paper is also applicable to policies other than fuel and electricity pricing in the power generation sector. Example applications are provided below, together with possible approaches to operationalizing them within the context of this framework.

1. Carbon Pricing

This methodology considers CO_2e charges on fossil fuels in the power generation sector based on the CO_2e contents. This CO2e pricing policy is similar to the carbon tax proposals in Mexico and South Africa. CO_2e charge affects the variable cost of each power-generating unit, and in turn alter the merit order in dispatch analysis. Equation 5 is modified to Equation 39, which allows for varying CO_2e charge rates on different fuels and across time.

The Levelized cost of electricity generation formula in Equation 35 and Equation 36 are also revised, with the total fuel cost (*FP'*) changed to incorporate the total expenditure associated with CO_2e charges. The *FP'* component of Equation 35 and Equation 36 should be revised as Equations 39 and 40.

Assuming cost pass-through from fuel costs to electricity pricing, all five impact channels are activated and the analysis follows all methodological steps to calculate the CO_2e emission impact of CO_2e charges.

2. Electricity Tariff Adjustment

For the electricity pricing policy alone, the analysis follows all the methodological steps described. The fact that fuel prices remain unchanged means that the merit orders are identical between the *Withpolicy* and *Withoutpolicy* operation, although the total electricity demand will be affected, and the load duration curve may be affected. In other words, only the impacts depicted in Figure 1 as a result of electricity price change are considered, whereas those from fuel price change are left out of the analysis.

3. Clean Electricity Dispatch and Plant Operation Regulations

[43] There are examples of how environmental/green tax revenues are deposited in specialized funds that are earmarked for re-investment in the power/energy sector.

Supplementary command-and-control measures are sometimes adopted to achieve better environmental outcomes. For example, a cleaner electricity dispatch strategy to utilize more frequently lower-emitting power plants in the system is considered as part of the US EPA's Clean Power Plan[44]. Regulations may be put in place on the operation/running time of plants that are less efficient. Furthermore, standards on emission control equipment and measures in power plants are quite common.

Such policies may be evaluated using the framework described in this paper. Alternative dispatch rules, as well as certain plant operation regulations, can be operationalized through the formulation of dispatch constraints. Emission control measures may affect dispatch constraint and variable cost of power generating units, thus altering the merit orders associated with dispatch analysis and other impact channels under the *Withpolicy* and *Withoutpolicy* operation. The setup of the scenarios depends on the specific design of the policy under consideration.

Formulae used in the methodology

Equation 1

Estimating Annual generation from fuel use data

If the unit only has fuel use data, then its annual generation may be estimated from:

$$GEN_{i,t} = \sum_{f=1}^{n} w_{f,i,t} \cdot FC_{f,i,t} / (3.6 \cdot 10^3 \cdot UE_{i,t})$$

GEN = total net generation from unit *i* at time *t* (MWh);

UE = unit efficiency of unit *i* at time *t* (MJ/kWh);

FC = fuel consumed type f, used in unit i at time t (MJ);

w = proportion of fuel type f used on an energy (MJ) basis in unit i, $\sum_f w = 1$*;*

3.6 = Conversion from MJ to kWh

Equations 2, 3 & 4

The calculation of unit-specific (a) availability factors, (b) capacity factors, and (c) variable costs use

Capacity factor[45]:

[44] http://www2.epa.gov/carbon-pollution-standards

[45] In the case that unit-level annual electricity generation (GEN) data is not available, the average capacity factor at type/sub-type levels from an official report may be used.

Equation 1

$$CF_{i,t} = GEN_{i,t}/(8760 \cdot IC_{i,t})$$

Availability factor for hydroelectric units[46]:

Equation 2

$$AF_{i,t} = (1 - OUT_{i,t}) \cdot \left(s_{w,t} \cdot c_{w,t} + s_{d,t} \cdot c_{d,t}\right)$$

For other units (thermal, renewable, and nuclear), availability factor:

Equation 3

$$AF_{i,t} = 1 - OUT_{i,t}$$

Where,

CF = net capacity factor of unit *i* at time *t* (%);

AF = energy availability factor of unit *i* at time *t* (%);

GEN = total net generation from unit *i* at time *t* (MWh);

IC = installed capacity of unit *i* (MW);

OUT = total planned and forced outages of unit *i* at time *t* (% of total installed capacity). Planned outages include non-generation due to resource limitations (for example, PV and wind) and technology limitations (for example, aircraft technology turbines for peaking generation);

s = proportion of seasonal **wet** and **dry** days in year *t*, $s_w + s_d = 1$; and

c = effective utilization (% of total installed capacity) in wet and dry seasons

Equation 5

Calculating the variable cost for each power-generating unit at any given time

The variable cost for each power-generating unit at any given time t can be calculated by equation (5).

[46] In the case that unit-level outages (OUT) information is not available, the average outages at type/sub-type levels from an official report may be used.

Equation 4

$$VC_{i,t} = \sum_{f=1}^{n} w_{f,i,t} \cdot FP_{f,i,t} \cdot 3.6 \cdot 10^3 \cdot UE_{i,t} + OM_{i,t}$$

Where,

VC = total variable cost of electricity generating unit *i* at time *t* ($/MWh);

FP = fuel price type *f*, used in unit *i* at time *t* **($/MJ**);

w = proportion of fuel type *f* used on an energy (MJ) basis in unit *i*, $\sum_f w = 1$;

UE = unit efficiency at time *t* (MJ/KWh); and

OM = O&M cost for unit *i* at time *t* ($/MWh), including emission control if any

Equation 6

Calculating the percentage difference between availability factors and capacity factors, denoted dF, for all units.

A relatively small dF indicates that a unit operated close to its maximum available capacity in that year and vice versa

Equation 5

$$dF_{i,t} = \frac{(AF_{i,t} - CF_{i,t})}{AF_{i,t}}$$

Equation 7 & 8

Determining the, CO2e emission levels under the Withpolicy operation

$$\text{Emissions}_{\text{GHG, Fuel}} = \text{Fuel Consumption}_{\text{fuel}} \times \text{Emissions Factor}_{\text{GHG, fuel}}$$

Where:

EmissionsGHG ,fuel = emissions of a given GHG by type of fuel (kg GHG)

Fuel Consumptionfuel = amount of fuel combusted (TJ)

Emission FactorGHG,fuel = default emission factor of a given GHG by type of fuel (kg gas/TJ). For CO2, it includes the carbon oxidation factor, assumed to be 1.

To calculate the total emissions by gas from the source category, the emissions as calculated in Equation 7 are summed over all fuels:

Equation 8

$$\boldsymbol{Emissions_{GHG}} = \sum_{fuels} Emissions_{GHG,fuel}$$

Equation 9 & 10

The dispatch analysis method used to determine CO2e emission levels will also be used in developing the emissions levels from the counterfactual Withoutpolicy operation reference conditions later in the methodology

Equation 9

$$Emissions_{GHG,Fuel} = Fuel\ Consumption_{fuel} \times Emissions\ Factor_{GHG,fuel}$$

Where:

EmissionsGHG ,fuel = emissions of a given GHG by type of fuel (kg GHG)

Fuel Consumptionfuel = amount of fuel combusted (TJ) in generation of electricity

Emission FactorGHG,fuel = default emission factor of a given GHG by type of fuel (kg gas/TJ). For CO2, it includes the carbon oxidation factor, assumed to be 1.

To calculate the total emissions by gas from the source category, the emissions as calculated in Equation 9 are summed over all fuels, and non-combustion emissions from biochemical processes and process emissions from other non-fossil fueled plants.

Equation 10

$$Emissions_{GHG} = \sum_{fuels} Emissions_{GHG,fuel} + \sum_{Other\ bio\ sources} Emissions_{GHG,biosource}$$

Includes net emissions from reservoirs caused by biochemical processes and generating process emissions from other non-fossil fueled plants.

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To express the total electricity supply and demand balance and setout the overall framework for the evaluation of counterfactual Withoutpolicy operation.

Equation 11

$$GES_t - TDL_t + OFF_t + \ IMP_t == \sum_j TED_{j,t}$$

Where,

GES = grid electricity supply in year t (MWh);

OFF = total electricity supply from off-grid and captive sources in year t (MWh);

IMP = total electricity imports in year t (MWh);

TDL = total transmission and distribution loss in year t; and

TED = electricity demand from sector j (industry, residential, commercial, agriculture, transport, etc.) in year t.

Error! Reference source not found.**12.**

To derive the emission impact of fuel pricing policy under consideration,

Equation 12

$$\Delta \boldsymbol{CO2_t} = \boldsymbol{CO2_t^{Withpolicy}} \quad - \boldsymbol{CO2_t^{Withoutpolicy}}$$

Where:

$CO2_t^{Witholicy}$= total observed CO2e emission from the end-user consumption of energy at time t, and:

$CO2_t^{Withoutpolicy}$ = total calculated CO2e emission under “without-policy” conditions.

The emission impact of the fuel pricing policy under consideration, $\Delta CO2_t$, can be derived (in t CO2e), This completes the measurement of emission impact at time t. The negative sign of $\Delta CO2_t$ indicates CO2e emission reduction, whereas the positive sign indicates emission increase.

Error! Reference source not found.**13.**

To estimate the emission reduction uncertainty (t CO2e) due to systematic bias,

Equation13

$$U = \frac{(E_d - E_i)}{E_d} \cdot (E_o - E_d)$$

Where:

U= emission reduction uncertainty (t CO2e) due to systematic bias

Ed = emissions from the dispatch methodology of Withpolicy operation

Ei = emissions from the inventory methodology of Withpolicy operation

Eo = emissions from the dispatch methodology of Withoutpolicy operation

Equations 14 & 15

To combine uncertainties

The error propagation equation yields two convenient rules for combining uncorrelated uncertainties under addition (**Error! Reference source not found.**15) and multiplication (**Error! Reference source not found.**14):

Equation 14

$$U_{total} = \sqrt{U_1^2 + U_2^2 + \cdots U_n^2}$$

where:

Utotal = the percentage uncertainty in the product of the quantities (half the 95 percent confidence interval divided by the total and expressed as a percentage)

U1 = the percentage uncertainties associated with each of the quantities.

Equation 15

$$U_{total} = \frac{\sqrt{(U_1 \cdot x_1)^2 + (U_2 \cdot x_2)^2 + \cdots . (U_n \cdot x_n)^2}}{\mathrm{I} x_1 + x_2 + \cdots x_n \mathrm{I}}$$

where:

Utotal = the percentage uncertainty in the sum of the quantities (half the 95 percent confidence interval divided by the total (i.e., mean) and expressed as a percentage).

x1 and U1 = the uncertain quantities and the percentage uncertainties associated with them, respectively.

Equation 16

The functional form of an econometric specification provided only as an example.

Equation 16

$$e_t = \beta_0 + \beta_1 p_t + \beta_2 ps_t + \beta_3 y_t + \ldots + \epsilon_t$$

Where e = energy consumption in natural logarithm; p = energy price in natural logarithm; ps = price of substitute fuel in natural logarithm; y = per capita income in natural logarithm, and ϵ is the error terms.

Equation 17

Conduct unit-root tests for all dependent and explanatory variables.

Augmented Dickey-Fuller (ADF) test is recommended. Alternatively, Philips-Perron (PP) test may be used. However, ADF test performs better than PP test in finite samples 47. ADF test involves estimating a form of the following equation by Ordinary Least Square (OLS) technique

Equation 17

$$\Delta x_t = \alpha_0 + \theta t + \gamma x_{t-1} + \delta_1 \Delta x_{t-1} + \ldots + \delta_k \Delta x_{t-k} + \varepsilon_t$$

Where, *x* = each variable; *t* = time periods; Δ is the difference operator

The ADF tests the null hypothesis of a unit root. The t-statistics for the estimated coefficient γ is the ADF statistics, which is compared with critical values provided in MacKinnon (1996). If the null hypothesis is rejected, then conclude that the tested variable is stationary.

Error! Reference source not found. presents the general specification form, but the preferred one should be selected based on systematically omitting insignificant variables (trend, constant, and/or lags).

The simplest way of choosing the lag *k* is to test down from the higher order and check the ADF statistics of different lags. Alternatively, Scharwz's Bayesian Information Criterion and/or Akaike Information Criterion can guide the selection of lags.

The ADF test and the PP test are usually available in econometric software packages

Equation 18

Estimate energy price elasticity $(\boldsymbol{\rho_{k=0}})$ using OLS technique based on the error correction form.

[47] See, Davidson and MacKinnon (2004).

Equation 18

$$\Delta e_t = \hat{\beta}_0 + \varphi(e_{t-1} - \hat{\beta}_1 p_{t-1} - \hat{\beta}_2 ps_{t-1} - \hat{\beta}_3 y_{t-1}) + \sum_{k=1}^{l} \theta_k \Delta e_{t-k} + \sum_{k=0}^{m} \rho_k \Delta p_{t-k} + \sum_{k=0}^{n} \sigma_k \Delta ps_{t-k} + \sum_{k=0}^{n} \omega_k \Delta y_{t-k} + \mu_t$$

Equation 19

Calculate energy demand impact.

Equation 19

$$\Delta \tilde{e}_t = \rho_0 \cdot \Delta p \cdot e_t / p_t$$

Where: Δp = price difference between *Withpolicy* (i.e., observed) energy price and *Withoutpolicy* (i.e., subsidized) price; *e* = observed energy demand in year *t*; and *p* = observed energy price in year *t*.

Equations 20 to 27

Estimate the energy-price elasticity using survey-based panel data in conjunction with administrative data on energy demand from power utilities

The price elasticity of demand is a measure of the responsiveness of the quantity demanded to a change in price. In the context of electricity, the elasticity can be used to determine how changes in electricity prices affect the consumption of electricity by households or firms. Formally, the elasticity can be expressed:

Equation 20

$$e_p = \frac{dQ/Q}{dP/P}$$

Where e_p is the price elasticity, Q is the quantity of the demanded good (either gas or electricity), and P is the price, in this context referred to as the energy tariff.

Using household electricity consumption, cross-sectional demand elasticities can be estimated based on a standard utility maximization approach:

Equation 21

$$U_{it} = U(E_{it}, Z_{it})$$

where U_{it} is the utility of household i at time t , which is a function of the consumption of electricity (E_{it}) and other goods (Z_{it}). Household maximize utility subject to a budget constraint.

Equation 22

$$Y_{it} = p_t^e E_{it} + p_{it}^z Z_{it}$$

The term Y_{it} is total income of household i at time t (here, approximated in the following using total consumption), p_t^e is the unit price of electricity at time t (assumed to be same across households and regulated by the government), and p_{it}^z is a price index for all non-electricity goods. Maximization yields a demand function for electricity.

Equation 23

$$E_{it} = E(Y_{it}, p_t^e)$$

The estimation proceeds using a log-log method to estimate the elasticities associated with each term, such that

Equation 24

$$\ln(E_{it} p_t^e) = \alpha + \rho \ln E_{it-1} p_{t-1}^e + \beta \ln Y_{it} \ + \ Controls$$

If electricity price does not change, then:

Equation 25

$$\ln(E_{it} p^e) = \alpha + \rho \ln E_{it-1} p^e + \beta \ln Y_{it} \ + \ Controls$$

When there is a price shock, we have:

Equation 26

$$\ln(E_{it} p^e (1 + \Delta p)) = \ln E_{it} p^e + \ln(1 + \Delta p) = \alpha + \rho \ln E_{it-1} p^e + \beta \ln Y_{it} \ + \ Controls$$

Hence, we can use the following empirical strategy to identify the impact of price change

Equation 27

$$\ln(E_{it} p^e) = \alpha + \rho \ln E_{it-1} p^e + \beta \ln Y_{it} \ + D_t + \ Controls$$

Where D_t is a dummy variable indicating if there is a policy change related to electricity price.

Where q The objective is to estimate β which corresponds to e_p in equation 1. elasticity can be calculated as the percentage change in the quantity of gas or electricity consumed for a 1% change in the price.

Equations 28 and 29

Determine the total grid-based generation need and CO2e emissions from off-grid and captive units/plants

The total amount of electricity to be generated by the grid-connected units and plants over the modeling period needs to be determined using Equation 28

Equation 28

$$GEN_{g,t} = (DEM_{nal} + DEM_{exp} - DEM_{imp} - GEN_{c,t})/(1 - T\&D_{tot})$$

The emissions from the off-grid and captive units/plants is given by

Equation 29

$$CO2_{c,t} = \sum_f \sum_i w_{f,i,t} \cdot EF_{f,t} \cdot UE_{i,t} \cdot GEN_{c,t}$$

Where:

$GEN_{c,t}$ = total generation from off-grid and captive unit c at time t (MWh)

$GEN_{g,t}$ = total generation from grid-connected unit g at time t (MWh)

DEM_{nal} = Electricity annual demand [system-level] (MWh) within the system

DEM_{imp} =-Annual import of electricity [system-level] (MWh) into the system

DEM_{exp} =Annual export of electricity [system-level] (MWh) from the system

$T\&D_{tot}$=Transmission and distribution (T&D) losses as percent of generation [system-level] (MWh)

$CO_2e_{c,t}$ = total CO2e emission from off-grid and captive units at time t (kgCO2e);

w = **proportion of fuel type** *f* used in unit *i*, $\sum_f w = 1$;

EF = **emission factor of fuel** *f* at time *t* (gCO_2e/MJ);

UE = **unit efficiency** at time *t* (MJ/KWh); and

GEN = total generation from unit *i* at time *t* (MWh)

Equation 30

Calculate system-level peak load

Equation 30

$$SL_p = GEN_{tot} \,/(T \cdot \sum_{LDCt=1\ to\ 100\%} LDC_{l\%})$$

Where:

SLp = System-level peak load (MW)

GENtot = Total grid generation (MWh) in the modeling period

T = Duration of the modeling period in hours

LDCt% = time percent on the LDC curve from 1% to 100%

LDCl% = load percent on the LDC curve from time percent =1% to 100%

Equations 31 and 32

Calculate annual electricity generation from each unit

If the unit does not supply all the capacity needed in the period (T),

Equation 31

$$\mathrm{GEN_{i,t}} = \mathrm{AC_{i,t}} \cdot \mathrm{T_{i,t}}$$

If the unit can supply more than the capacity needed in the period (T),

Equation 32

$$GEN_{i,t} = ARC_t^* \cdot T$$

where:

GEN **= total generation (MWh) from unit** ***i*** **at time** ***t*****;**

*ARC** = the load (MW) needed during that hour as shown by the LDCze identified in (iv);

AC = available capacity of unit *i* at time *t*: $AC_{i,t} = AF_{i,t} \cdot IC_{i,t}$;

T = the hour on LDC that corresponds to *AC.* Where the T goes from its maximum value (8760) to 0.

Equations 33, 34 and 35

Calculate total CO2e emission

Equation 33

$$CO2e_{\boldsymbol{g},t} = \frac{\sum_f \sum_i w_{f,i,t} \cdot EF_{f,t} \cdot UE_{i,t} \cdot GEN_{i,t}}{10^3}$$

Where:

$CO_2e_{g,t}$ = total CO_2e emission from grid-connect units at time *t* (tons CO_2e);

w = proportion of fuel type *f* used in unit *i*, $\sum_f w = 1$;

EF = emission factor of fuel *f* at time *t* (g CO_2e/MJ);

UE = unit efficiency at time *t* (MJ/KWh); and

GEN = total generation from unit *i* at time *t* (MWh)

Apart from the grid-connect units, the emissions from off-grid and captive units should also be taken into account. In the case that unit-level information is available for off-grid and captive capacities, equation (26) can be used to calculate CO_2e emission.

Equation 34

$$CO2e_{\boldsymbol{c},t} = \frac{\sum_f \sum_c w_{f,c,t} \cdot EF_{f,t} \cdot UE_{c,t} \cdot GEN_{c,t}}{10^3}$$

Where:

$CO_2e_{o,t}$ = total CO_2e emission from non-grid-connected units at time *t* (kgCO_2e);

EF = emission factor of fuel used by unit *c* at time *t* (gCO_2e/MJ);

UE = unit efficiency at time *t* (MJ/KWh); and

GEN = total generation from unit *c* at time *t* (MWh)

However, in some instances, unit-level data may not be available for off-grid and captive capacities. In such cases, CO_2e emission from non-grid-connect capacities should be calculated based on aggregate generation data and weighted averages of emission factors and technology efficiency.

The overall CO_2e emission from the power generation system is:

Equation 35

$$CO2_t = CO2_{g,t} + CO2_{c,t}$$

Equation 36

Determining the CO2e emissions of the generating system using local unit/plant-level data

Equation 36

$$CO2_t = \sum_f \sum_i w_{f,i,t} \cdot EF_{f,t} \cdot UE_{i,t} \cdot GEN_{i,t}$$

Where,

CO_2e = total CO_2e emission from the entire power system at time *t* (CO_2e);

w = proportion of fuel type *f* used in unit *i*, $\sum_f w = 1$;

EF = emission factor of fuel *f* at time *t* (g CO_2e /MJ);

UE = unit efficiency at time *t* (MJ/KWh); and

GEN = total generation from unit *i* at time *t* (MWh)

Equations 37

Calculating the Levelized cost of grid electricity generation

Equation 37

$$LCE_t^n = \frac{INV_0 + \sum_{t=1}^{T} \frac{(FP'_t + OM'_t)}{(1+r)^t}}{\sum_{t=1}^{T} \frac{GEN_t}{(1+r)^t}}$$

Where,

LCE = levelized cost of electricity generation ($/MWh);

INV_0 = initial capital expenditure ($);

FP' = total fuel cost at time *t* ($), observed or calculated as $FP'_t = \sum_{f=1}^{n} w_{f,t} \cdot FP_{f,t} \cdot UE_t \cdot GEN_t$;

OM' = total O&M cost at time t ($), observed or calculated as $OM'_t = OM_t \cdot GEN_t$;

GEN = electricity net generation at time *t* (MWh);

r = discount rate[48]; and

t = (1, T) is the plant's lifetime.

Equation 38

Calculating the levelized cost of off-grid electricity generation

Equation 38

$$LCE_t^n = \frac{\sum_{t=1}^{T} \frac{(FP'_t + OM'_t)}{(1+r)^t}}{\sum_{t=1}^{T} \frac{GEN_t}{(1+r)^t}}$$

Where,

LCE = levelized cost of electricity generation ($/MWh);

FP' = total fuel cost at time *t* ($), observed or calculated as $FP'_t = \sum_{f=1}^{n} w_{f,t} \cdot FP_{f,t} \cdot UE_t \cdot GEN_t$;

OM' = total O&M cost at time t ($), observed or calculated as $OM'_t = OM_t \cdot GEN_t$;

GEN = Net electricity generation at time *t* (MWh);

r = discount rate[48]; and

t = (1, T) is the plant's remaining lifetime.

The costs include subsidies and taxes, other than the policy under consideration.

If no, calculate the cost of electricity generation of the off-grid/captive unit (denoted, LCE^o) using the same LCE formula as provided in Equation 27

[48] A descriptive social (economic) discount rate should be used in this analysis:-There are two main approaches to estimating social discount rates. The prescriptive approach, prescribes values for the pure rate of time preference and the elasticity of the marginal utility of consumption. The descriptive approach looks at investments in the real world and aims to capture the actual behavior of market participants in setting discount rates. The descriptive approach stresses the importance of the opportunity cost of capital as reflecting foregone returns in undertaking public investment. Many authors favoring the descriptive approach generally suggest discount rates for developing countries in the 8-12% range. In any financial analysis, the discount rate used should reflect the true cost of capital (debt plus equity) to the project developer.

Equations 39 and 40

Calculating the variable cost of electricity with carbon pricing

Equation 39

$$VC_{i,t} = \sum_{f=1}^{n} w_{f,i,t} \cdot (FP_{f,i,t} + CT_{f,t} \cdot EF_{f,t}) \cdot 3.6 \cdot 10^3 \cdot UE_{i,t} + OM_{i,t}$$

Where,

$VC_{i,t}$ = total variable cost of electricity generating unit *i* at time *t* ($/MWh);

$FP_{f,I,t}$ = fuel price type *f*, used in unit *i* at time *t* ($/MJ);

$W_{f,I,t}$ = proportion of fuel type *f* used in unit *i*, $\sum_f w = 1$;

$CT_{f,t}$ = CO_2e tax rate ($/g CO_2e);

$Ef_{f,t}$ = emission factor of fuel *f* at time *t* (g CO_2e /MJ);

$UE_{I,t}$ = unit efficiency at time *t* (MJ/KWh); and

$Om_{i,t}$ = O&M cost for unit *i* at time *t* ($/MWh) including emission control if any

Equation 40

$$FP'_t = \sum_{f=1}^{n} w_{f,t} \cdot (FP_{f,t} + CT_{f,t} \cdot EF_{f,t}) \cdot 3.6 \cdot 10^3 \cdot UE_t \cdot GEN_t$$