ISGAN Project

Annex 3

BENEFIT & COST ANALYSES AND TOOLKITS

Final Report

AJOU UNIVERSITY

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International Smart Grid Association Network (ISGAN)

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List of Contents

List of Figures

List of Tables

Introduction and Executive Summary

The objective of ISGAN's Annex 3 is to develop a global framework and related analyses that can identify, define, and quantify in a standardized way the benefits which can be realized from the demonstration and deployment of smart grids technologies and related practices in electricity systems. To meet the required objective of this Annex, a program of work is designed and it includes the following three tasks:

Task 1: Assess Current Network Maturity Model and Update data

Subtask 1.1: Trial application of two network maturity analysis tools and results discussion

Subtask 1.2: Development of the questionnaire for the assessment of the level of smartness of transmission and distribution networks

Task 2: Analyze Current Benefit-Cost Analytical Methodologies and Tools

Subtask 2.1: Analyzing benchmark benefit-cost frameworks and tools

Subtask 2.2: Model research to overcome limit of current BCA frameworks and tools

Task 3: Develop Toolkits to Evaluate Benefit-Costs

Subtask 3.1: Development of Simplified cost-benefits analysis tool

Subtask 3.2: Technical Analysis of current BCA took-kit and Modification of Simplified tool-kit

In the previous two year report, initial discussions following the tasks specified above are carried out and examined.

For Task I, the report goes through several maturity frameworks available, especially those of Software Engineering Institute (SEI) and Katholieke Universiteit Leuven (KUL). The SEI has developed a management tool that can be used to measure the current state of a smart grid project, aiming to help utilities to identify the target and build proper strategies to reach it. The tool, Smart Grid Maturity Model (SGMM), utilizes a set of surveys called Smart Grid Compass. The drawback of this tool is the undocumented scoring method of the surveys once a result is obtained. Full assistance of an SGMM Navigator is required for the utility to understand and analyze the SGMM output. Meanwhile, the KUL references[1] introduce the characteristics, categories and key performance indicators of a smart electricity grid. The previous report also includes own survey methods developed by Annex III, although there has not much of progress after that.

For Task II, an extensive update of the BCA survey has been provided in the previous report. It started with various frameworks related to BCA, which include Frontier Economics and the Smart Grid Forum (SGF) in UK, Smart Grid Investment Model (SGIM) of SGRC, IMPLAN Model, McKinsey Tool, and general overviews of EPRI's methodology to BCA and its subsequent developments by DOE and JRC. After that, several BCA applications to country-specific or states cases are summarized. Some of the surveyed countries are Czech Republic, Netherland, Lithuania, Denmark, and USA states. For the comparison purpose, the summary for each case is carried out following some key points: background of the smart grid project, the methodology or toolkits used, the scope of the project (location, period, technologies),

[1] Refer to Dupont and Ronnie Belmans (2010)

the list and definition of benefits and costs, and deliverables (results, recommendations, policy and regulations). The 1st year's work of Task II can be compared with the previous year's work in the sense that how EPRI guideline has any impact on the work development of JRC and DOE frameworks, especially for the Smart Grid Computational Tool (SGCT), a BCA toolkit that is developed by US DOE. This report summarizes the findings from the previous works with the focus of selecting the benchmark smart grid tool kit for the development of own ISGAN tool kit for member countries.

For Task III, a simplified cost-benefit analysis tool is being developed taking SGCT of DOE as a benchmark tool kit, based on the previous year report on the development plan of ISGAN member countries' tool kit. A standalone program based on Object Oriented Programming (OOP) is now being developed replicating, revising and upgrading the currently available excel-based SGCT. As will be discussed, this tool kit has various advantages over other tools: First, this tool is open to public and anyone can take a look inside of the model deep enough to examine the visual basic application modules. JRCEU, McKinsey models were once discussed in Annex III before for any potential utilization for ISGAN member countries' tool kit. However, members acknowledge the fact that JRC works on excel based format and there seems to be not much difference between JRC's work and DOE. The difference lies in the fact that JRC never opened up the details of the functionalities and sample calculation of BC in their whole work process. McKinsey software was discussed but it is not open to public. Rather it is a commercial package with no specific advantage over to SGCT of DOE. Detailed engine is not fully explained and the scope of the analysis the tool kit provides does not seem to be very useful (Nigris 2012, Kim 2013).

The new tool kit being developed is named for the time being as 'Replicated Tool Kit' for convenience. Through the replication process, a lot of details have been identified, which, otherwise, would not have been known to us. Many of the parameters utilized in the process of benefit calculation may be required to be collected from outside, reflecting the region specific characteristics. Some of the default values provided by SGCT, although they are from USA case (refer to Appendix), may also be useful until those detailed information becomes available for ISGAN member countries even when they don't have them. In addition, there a at least 12 smart grid projects currently being conducted in USA (refer to III.2.24), and those projects are starting to produce some detailed information which might be potentially utilized by current SGCT. Not only those advantages, there are many interesting researches being conducted around the world and the work results could be very useful sources of updating this replication effort in the future, once this replication process allows us to identify the pros and cons of the current model.

The last chapter of the Expansion of Smart Grid Computational Tool is the wild idea of what could be accomplished in this whole process of simplified own ISGAN tool kit for member countries. Some of the ideas for the tool kit development become clearer as the process of the replication progresses. By the time of the completion of this year's work, we hope to have a very concrete idea on how to proceed to further develop this current work in the future for the benefit of every member country in ISGAN.

Task I: Assess Current Network Maturity Model and Update data

Subtask 1.1: Trial application of two network maturity analysis tools and results discussion
Subtask 1.2: Development of the questionnaire for the assessment of the level of smartness of transmission and distribution networks

I.1 Questionnaire of ISGAN'S Annex 3: Chronology

1. Brussels Belgium - On July 2nd-3rd, 2013
   A. National experts meeting for Annex 3 of ISGAN was conducted in Brussels, Belgium.
   B. In total, there are representatives from five countries (Italy, Korea, Sweden, Switzerland, USA) and JRC that present on that meeting.
   C. One of the main focuses on that meeting is the discussion of the questionnaire of smart grid maturity measurement that could be disseminated to member countries.
   D. The draft of the questionnaire has been prepared by the leading Italian team to be criticized and reshaped by the national experts.

Focus on the two main chapters;

Chapter 0: state of the art (Ajou, per fissure le basi; Psmart; alter info → pubblicare)

Chapter 1 – smartness assessment

The state of the art has been suitably illustrated and discussed in the valuable work by AJOU UNIVERSITY (see attach 2).

Other methods, based on national practices, have been investigated too (Psmart, see attach 3); those practices have proven to be precise and useful for evaluating and comparing homogeneous initiatives, but it seems very difficult to make a general use of such tools.

The Bellmans method (see attach 4) has been extended, and a free access web questionnaire has been prepared by softeco (see attach 5).

This model has been applied to different initiatives, and the relevant results will be discussed during the meeting.

Figure 1 Main Topic of Discussions at Brussels

   E. The other agenda for that meeting is the preparation for the executive meetings of ISGAN and the other two tasks of the ISGAN Annex 3.
   F. From the discussion, a new and updated survey has been produced. This survey would be disseminated by the member countries and gathered by the Annex 3 team to evaluate its effectiveness to measure the smartness of smart grid.
      - ✓ In the case of Korea, the survey was disseminated to the sole power utility, Korean Power Company (KEPCO).
      - ✓ Initial survey result was reported (Refer to Kim et al. 2014)

- ✓ Frequent follow-ups after the meeting and the attached survey questionnaire was drafted (Refer to Appendix)

2. Shanghai, China - 31st to 1st April 2014 (Shanghai Hengshan Hotel, Blossom Hall (3rd floor of the Hotel)
   A. Programme of 4th ISGAN Workshops - "Smart Grid Transition"
      - ✓ There is no explicit discussion on network maturity analysis and the measurement of smartness
3. Montreal, Canada - Wednesday, October 1, 2014
   A. IEA ISGAN Public WORKSHOP #5: Lessons Learned from Smart Grid Innovations

I.2 Current Status of Questionnaire of ISGAN'S Annex 3: As of Dec. 1st, 2014

Official Website is prepared at IEA-ISGAN home page such as following:

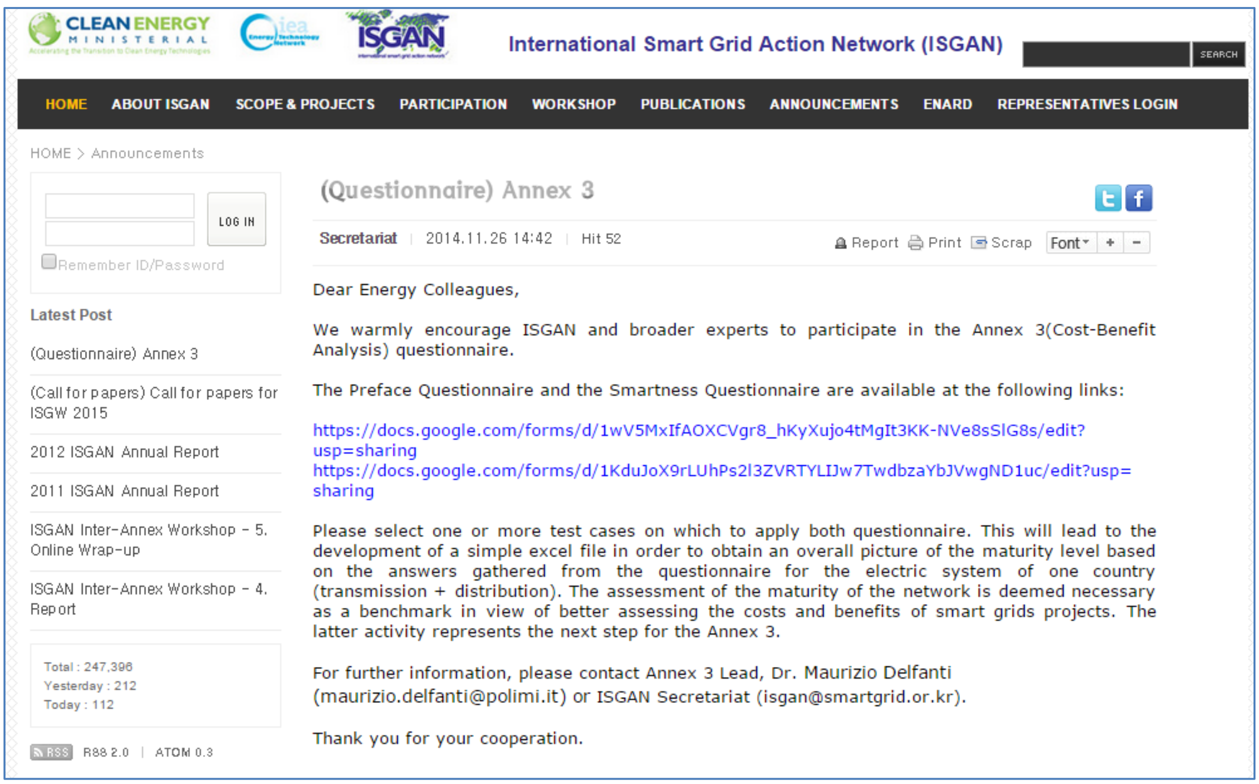
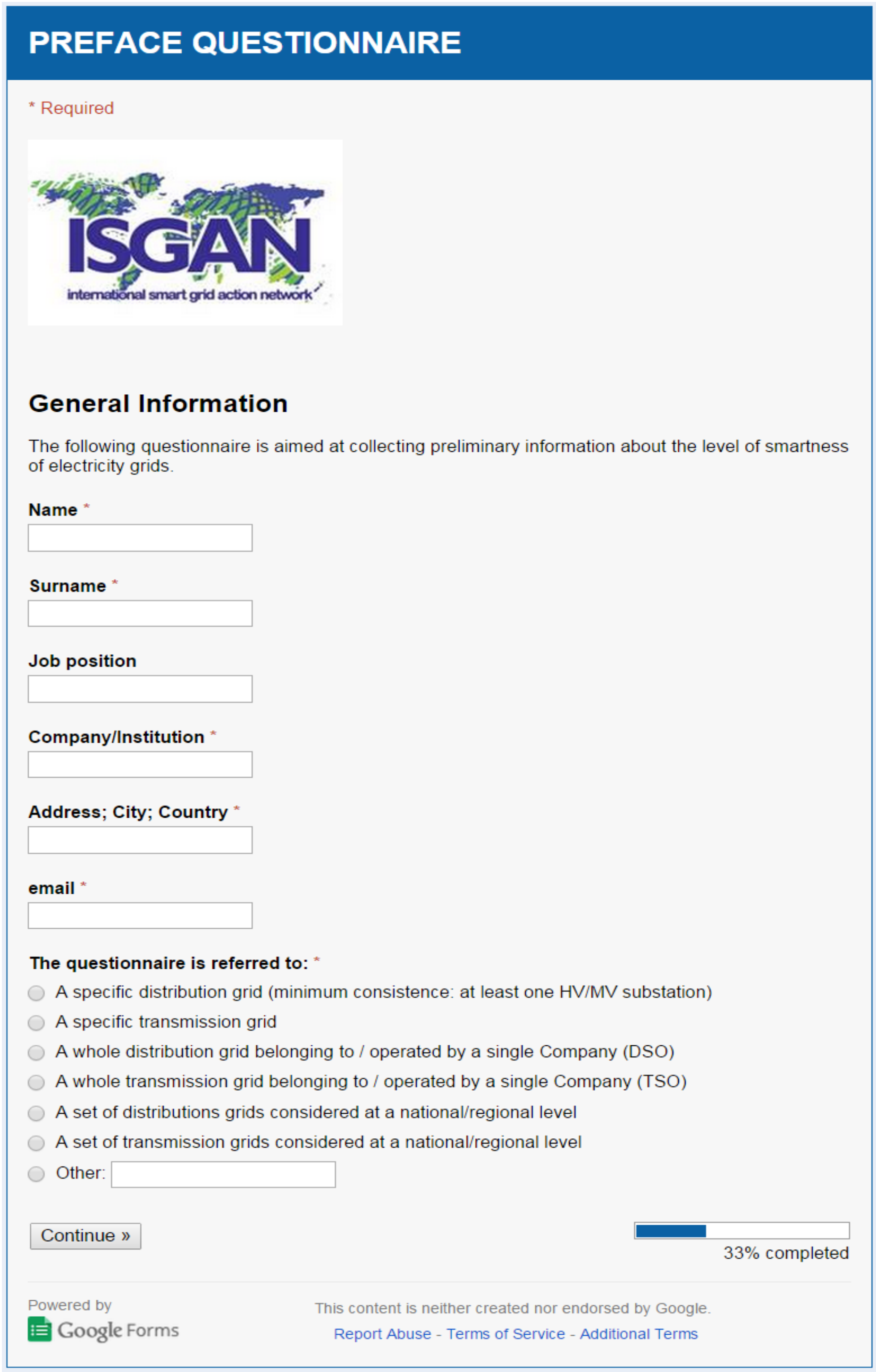


Figure 2 Current Questionnaire Website

Source: http://www.iea-isgan.org/?m=bbs&bid=Announcements&uid=1573



PREFACE QUESTIONNAIRE

* Required

General Information

The following questionnaire is aimed at collecting preliminary information about the level of smartness of electricity grids.

Name *

Surname *

Job position

Company/Institution *

Address; City; Country *

email *

The questionnaire is referred to: *

- A specific distribution grid (minimum consistence: at least one HV/MV substation)
- A specific transmission grid
- A whole distribution grid belonging to / operated by a single Company (DSO)
- A whole transmission grid belonging to / operated by a single Company (TSO)
- A set of distributions grids considered at a national/regional level
- A set of transmission grids considered at a national/regional level
- Other:

Continue »

33% completed

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Figure 3 First Page of Survey Questionnaire

Source: https://docs.google.com/forms/d/1wV5MxIfAOXCVgr8_hKyXujo4tMgIt3KK-NVe8sSlG8s/viewform?edit_requested=true

Task II: Analyze Current Benefit-Cost Analytical Methodologies and Tools

Subtask 2.1: Analyzing benchmark benefit-cost frameworks and tools
Subtask 2.2: Model research to overcome limit of current BCA frameworks and tools

II.1 Overview: Smart Grid BCA Frameworks

As professor Delfanti (Leader of Annex 3) properly summarized in his presentation material (Oct., 2014), the review of possible tools for cost benefit analysis has been completed with up-to-date information. Referring to Ajou (Kim at al., 2014), he summarizes the two Models

- ✓ EA Technology “Transform Model”: provides a detailed representation of a given electricity network and describes the impact that future scenarios may have on those existing networks. The Transform Model is based on four steps:
    - ☐Step 1: Scenarios
    - ☐Step 2: Existing Networks
    - ☐Step 3: Solutions
    - ☐Step 4: Modelling Combinations
- ✓ Synapse Energy Economics “Benefit – Cost Analysis for Distributed Energy Resources”: BCA results should be reported using the Societal Cost Test, the Utility Cost Test and the Rate Impact Measure test. The principal characteristics of the model are as follows:
    - A parameter-based model, which allows the network to be constructed of common elements
    - It is based on real data from distribution networks, local authorities, central government and a range of other sources
    - It can assess and optimize investment over a range of conventional and ‘smart’ strategies, and involving a wide range of solutions

Other frameworks of Smart Grid's Benefit and Cost Analysis available in the literature were surveyed in Kim et al. (2014).

II.1.1 Smart Grid Forum (SGF) of UK

According to SGF (1 May, 2011), the Smart Grid Forum (SGF) aims to bring together key opinion formers, experts and stakeholders in the development of GB smart grids to provide strategic input to help shape Ofgem[3] and DECC[4]’s thinking and leadership in this area. To help provide the network companies with a

[3] The Office of Gas and Electricity Markets
[4] The Department of Energy and Climate Change

common focus in addressing future networks challenges and to provide drive and direction for the development of smart grids, SGF drives policy change by:

- ✓ Developing a common understanding of the value that smart grids can deliver,
- ✓ Identifying barriers to network companies adopting smart grid solutions, and
- ✓ Putting smart grids in the context of wider policy developments.

5 workstreams (WS) identified were followings:

- ✓ Work Stream 1 "Assumptions and Scenarios"
- ✓ Work Stream 2 "Evaluation Framework"
- ✓ Work Stream 3 "The Ideal Network"
- ✓ Work Stream 4 "Closing doors"
- ✓ Work Stream 5 "ways of working"

After a long series of DECC/Ofgem SMART GRID FORUM mostly held in London, 11th DECC/Ofgem SMART GRID FORUM (22nd October 2013, BIS Conference Centre, 1 Victoria Street) identifies the current workstreams such as followings:

- ✓ Work Stream 1 "Assumptions and Scenarios"
- ✓ Work Stream 2 "Evaluation Framework"
- ✓ Work Stream 3 "The Ideal Network"
- ✓ Work Stream 4 "Closing doors"
- ✓ Work Stream 5 "Knowledge management" or development and launch of the knowledge portal
- ✓ Work Stream 6 "assessment of the options for the development of smart grids"
- ✓ Work Stream 7 It is not clear from meeting minutes, but it is likely an extension of WS5.
- ✓ Work Stream 8 "Vision and Routemap"

For BCA analysis, WS2 of evaluation framework seems to have been successfully accomplished. SGF meeting minutes of 4th, 5th and 6th already declares that. Following the presentation and draft report by Frontier Economics (March 2011, October 2011), Frontier Economics submitted the result of analysis as Frontier Economics (November 2011). The developed too is based on real options methodology which accounts the probability of salvaging option in each of the decision tree within the period of the project life. It is noted to be circulated within UK utilities.

(To be further updated in the final report)

II.1.2 BCA analysis of Smart Grid by Frontier Economics

Frontier Economics (Oct. 2011) presets the reason for using real options valuation for BCA as "to avoid lock-in to a particular investment path". For the investment with option values, it presents example cases such as, *investments that can be incrementally augmented in future periods; investments that promote learning, and which may therefore make future investments less costly or more feasible; and investments that entail high upfront costs, but reduce ongoing investment costs.*

Real options-based analysis in the face of uncertainty is chosen to allow the best strategy by factoring in the impact of new information into the analysis at a decision point in the future; and the possibility that the investment strategy can adjust when this new information becomes available.

Following diagram describes the methodology adopted by Frontier Economics for SGF.

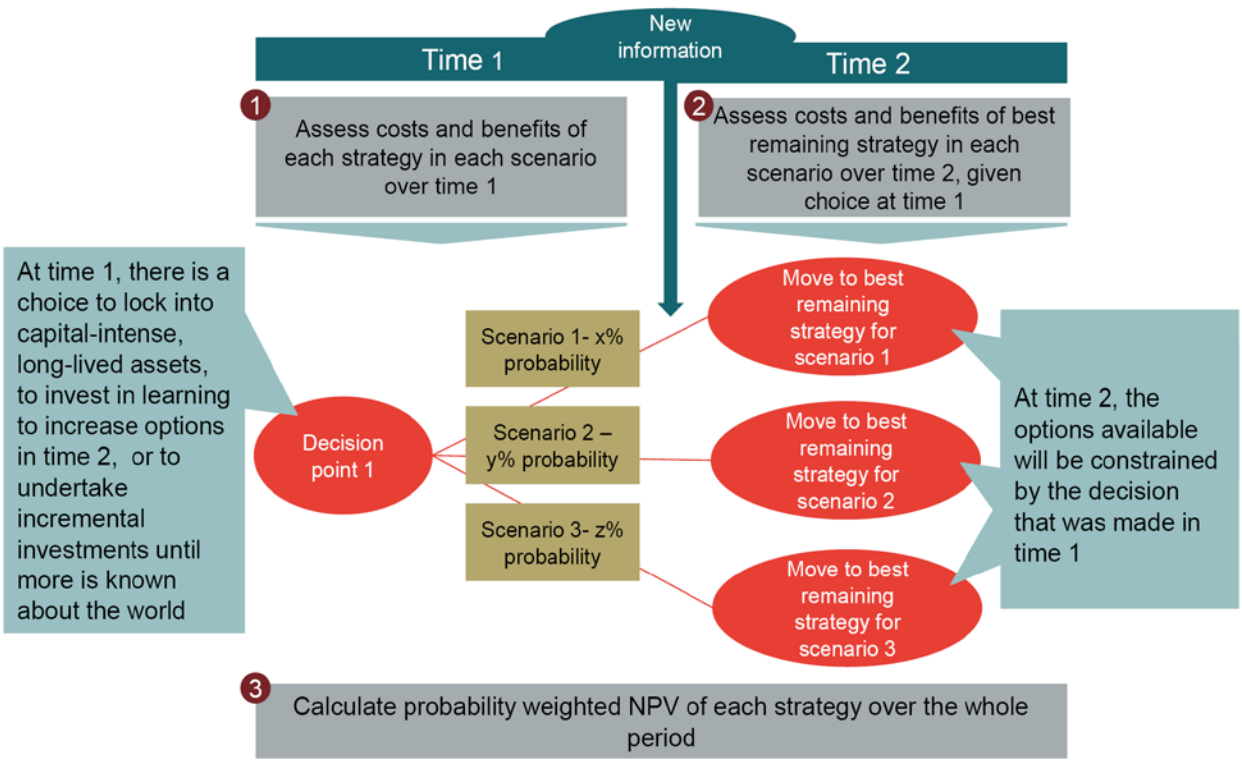


Figure 4 Real Options Valuation Process for SG BCA

Source: Frontier Economics (March 2011)

As the diagram shows, this model adopts two periods (Time 1 and Time 2) for analysis: the first time period from 2012 until 2023, and the second from 2023 out to 2050. The year 2023 is selected considering the fact that Government's *Carbon Plan* sets out scenarios for meeting the UK's 4th carbon budget covering the period from 2023 to 2027[10].

Based on three smart grid investment strategies, Top-Down (Top-down smart grid investment strategy), Incremental (Incremental smart grid investment strategy) and Conventional (Conventional strategy), the best available strategy is tried to be identified for each different scenarios for each of two different Time period. That is, some of the strategies chosen for Time period 1 may or may not be available for Time

[10] DECC (2011)

period 2, since, for example, Top-Down strategy selected for period 1 would prevent other strategies to be adopted for period 2 since it would strand a number as previously invested assets.

This report is focuses on the benefit, cost calculation of three different investment strategies and scenarios. Followings are the cost and benefit considered in their model:

- ✓ Distribution network reinforcement ☐
- ✓ Distribution network interruption costs ☐
- ✓ Distribution network losses ☐
- ✓ Generation costs ☐
- ✓ DSR “inconvenience” costs ☐
- ✓ Transmission network reinforcement

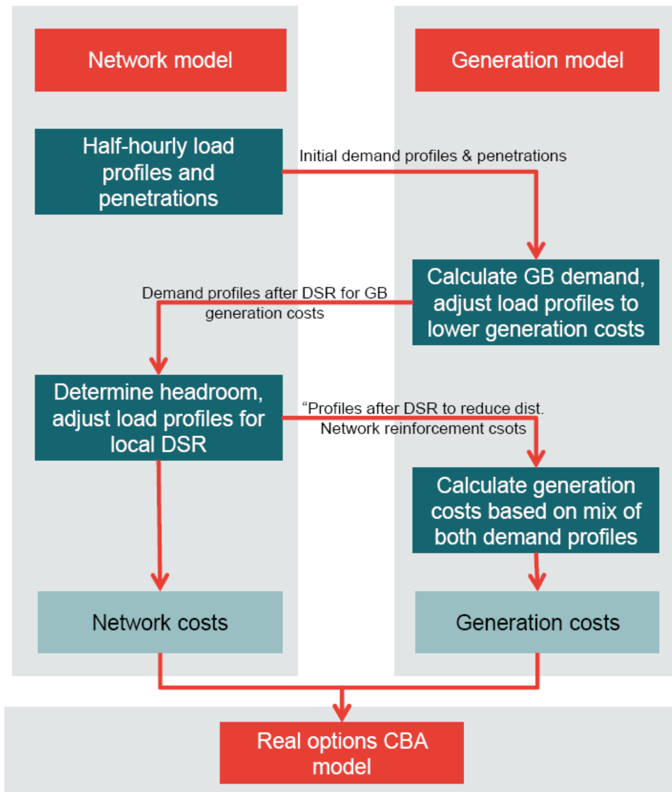


Figure 5 Model Interlinkages Accommodating DSR

Source: Frontier Economics (Oct. 2011)

Above diagram depicts how network model, generation model for proper representation of demand, for intermittent generation facilities such as wind and PV, and Real Options CBA model can be utilized in an interlinked manner.

Simply reviewing the details of model documentation on these aspects would not reveal the modeling details of real options CBA. But this report shows a way to overcome the problems of cost and benefit quantification arising from uncertainty.

As mentioned before, one of the focus of EPRI methodology, as well as other BCAs that follow its lead, is the benefit quantification. In the DOE's SGCT, the process of transforming smart grid elements (assets) to the monetized value of benefits is done.

The tool already has a list of Smart Grid assets that can be analyzed, which is divided into five categories: Customer Assets, AMI Assets, Distribution Assets, Transmission Assets, and Other Assets. In total, there are 21 possible assets--an increase from the 19 assets in EPRI report--provided by the tool. Then those assets are translated into 15 functions, such as automatic voltage and VAR control. The mechanism is a translator between functions and benefits in this toolkit. Each function would have several possible mechanisms that can be chosen by the user. The toolkit then translates those mechanisms into the benefits of smart grid. Lastly, the user would need to provide the data and values of the smart grid to fill out the parameters and variables needed to monetize those benefits.

II.1.3 BCA analysis of Smart Grid by JRC, EU

European Commission (EC)'s Joint Research Centre (JRC) also developed its own BCA framework as an improvement of the EPRI methodology. The joint effort between Members of EURELECTRIC and JRC resulted in a methodological framework to systematically estimate the different benefits of smart grid projects in seven steps, as follow.

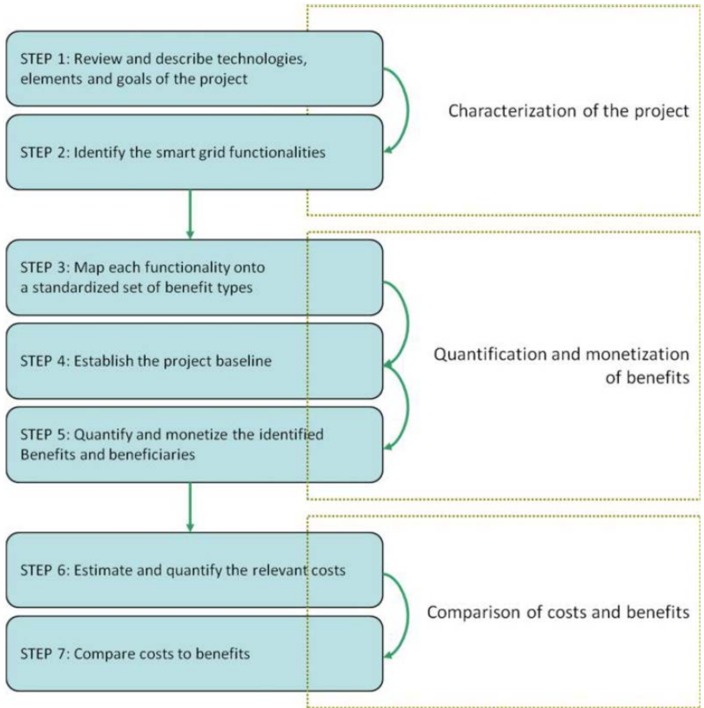


Figure 6 Cost Benefit Analysis Framework of JRC

Source: JRC (2012b)

In some of their reports, JRC outlines the seven steps of this BCA and its application to In Grid, a smart grid project in Portugal that is used as sample case of this proposed BCA framework. JRC also combines several of its other researches with the basic EPRI methodology. In "Assessing Smart Grid Benefits and Impacts: EU and U.S. Initiatives," (2012), EC JRC and US DOE compares the two frameworks developed by the two institutions. Figure below shows the comparison between the two:

European Union

Ideal Smart Grids defined in terms of Smart Grid **Services and Functionalities** (ANNEX II)

Definition of the outcome of the ideal Smart Grid in terms of **Benefits** (ANNEX III)

Metrics to measure progresses and outcomes: **54 Key Performance Indicators** (ANNEX III)

USA

Ideal Smart Grids defined in terms of Smart Grid **Characteristics** (ANNEX II)

Metrics to measure overall progresses and outcomes: **20 Build/Value metrics** (ANNEX III)

Figure 7 Comparison between EC JRC and US DOE Framework

Source: Giordano (JRC) and Bossart (DOE), 2012

II.1.4 BCA analysis of Smart Grid by McKinsey and Company

Another framework that was also considered in the ISGAN Executive Committee Meeting[11] for the Annex 3's BCA research is the one from McKinsey and Company. McKinsey already developed a BCA tool and was under trial within ERDF (European Regional Development Fund) and three other European DSOs (Distributed System Operators). The drawback of this proposal is the high cost for hiring McKinsey to do the job of tool development, that is, 70000 Euros.

In their tool, the smart grid elements (applications) are classified into four different groups with different functionalities, those includes: AMI, customer application, grid automation, and integration of DG (Distributed Generation) and EV (Electric Vehicle). They also put the smart grid benefits into four major groups: demand shift and savings, longer life of assets, operational improvement, and reliability improvement. These categorizations are different than those proposed by EPRI, but still they share general similarities. In essence, most if not all smart grid benefits is based on the saving, reduced, or avoided costs of normal grid between the baseline and scenario. Figure below shows the groups of benefits proposed by McKinsey

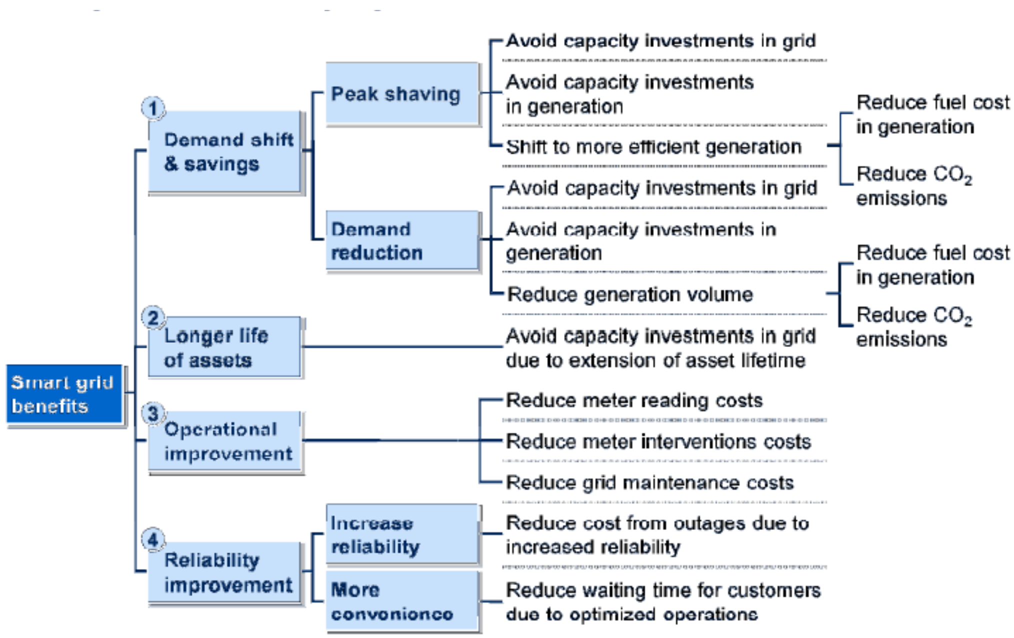


Figure 8 The Four Major Groups of Smart Grid Benefits according to McKinsey

Source: Nigris, 2012

[11] The framework was proposed in the 4th Executive Committee Meeting in Nice, France, September 26th-28th, 2012.

II.1.5 Smart Grid Investment Model (SGIM) of SGRC[12]

Initially as a research project to assist cooperative and municipal utilities with smart grid investment analysis, the SGRC transitioned to an independent research and consulting firm in January 2011. The model itself is completed on December 2011 and available to non-consortium members on February 2012. The main product of the SGRC is the Smart Grid Investment Model (SGIM). The SGRC has completed smart grid business case analysis for 16 utilities and is currently engaged in four new projects[13]. Each investment analysis project applies the SGIM to provide the most cost-effective and comprehensive smart grid business case analysis available. These utilizations of the model then has been maintained by the SGRC for future references so that new analysis of smart grid investment can be conducted more effectively and efficiently.

SGIM utilizes four basic steps to evaluate the benefits and costs of smart grid project, that includes:

- ✓ Identify each technology and program that fits within the smart grid purview,
- ✓ Identify benefits of each technology/program including cost savings, operational efficiency and reductions in customer kWh, peak kW and hourly load profiles over the next twenty years,
- ✓ Identify technology, installation, program and management costs based on utility and customer characteristics
- ✓ Compare benefits and costs to determine investment returns.

In general, the steps of SGIM utilization are illustrated in the figure below. Although each utility might have a unique information of load profiles, avoided power costs, and customer characteristics among others, the same quantitative BCA is applicable to all cases. To take into account the utility-specifics, as shown in figure below, combination of utility customer data and member utility data would be used to estimate end-use hourly load model for 20-year horizon. The model then applies various impacts--technology, program, economic and utility--to estimate the avoided costs (benefits)

[12] The SGRC is a research and consulting firm providing smart grid software and financial analysis with headquarters in Orlando, Florida. It was initiated by Dr. Jerry Jackson at Texas A&M University in 2010, which is an energy economist with experience in energy technology market analysis, financial model development, and project management.

[13] As mentioned in http://www.smartgridresearchconsortium.org/index.htm, accessed December 27th, 2013

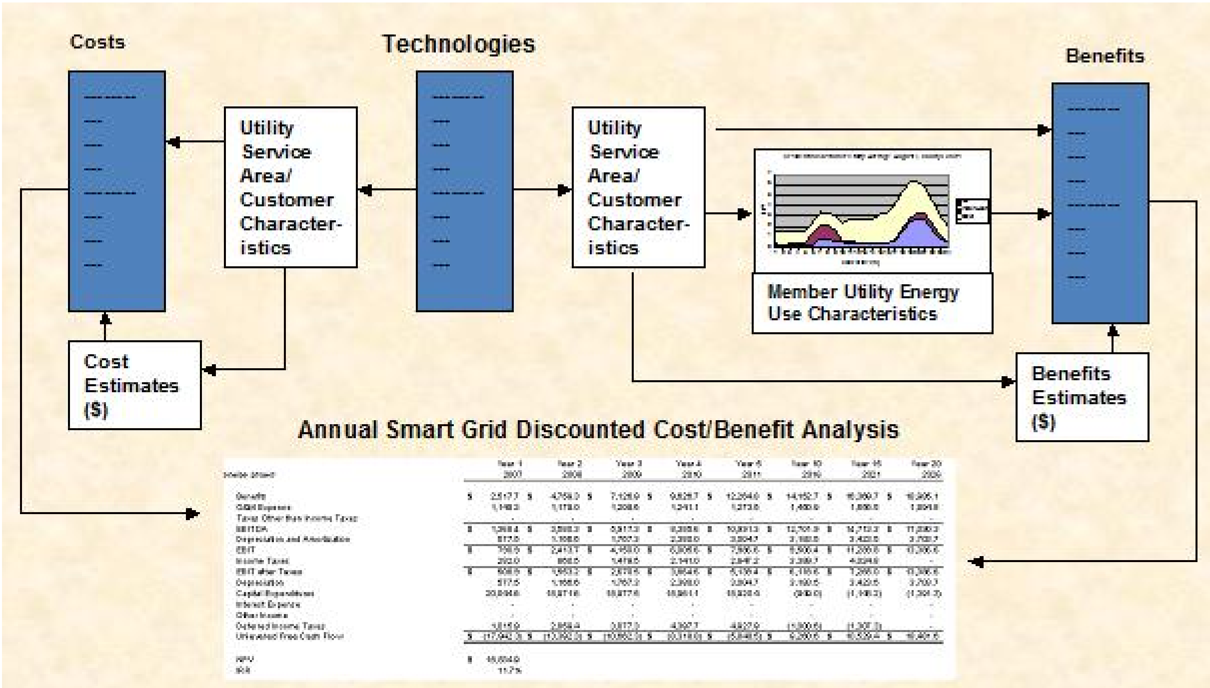


Figure 9 Basic Steps of BCA using SGIM

Source: Jackson, J. (2012)

On the application of the model, SGRC developed Excel based stand-alone program for the users inputting various specific data and analyzing the results. The first part of the program is a quantitative characterization of the base case electricity use. This base case would be later used as a reference point to the avoided costs calculation.

Then, a specific worksheet called GATEWAY is used to provide some information: selecting the technologies and/or programs that would be available through the smart grid investments, starting point to input detailed parameters related to the technologies/programs, showing selected summary BCA results (IRR, undiscounted breakeven period, discounted breakeven period, NPV) among others.

The detailed BCA results are presented in the DASHBOARD and other worksheets. The DASHBOARD also provides the user with appropriate buttons to evaluate the parameters applied in the analysis. The users can also modify the parameters that are supplied by the SGIM.

Some of the smart grid applications that can be analyzed by the SGIM include:

- ✓ AMI/Smart Meters
- ✓ Distribution Automation
- ✓ VAR Control
- ✓ Customer Technologies and Programs, such as Programmable Communication Thermostats (PCT), Pricing and Demand Response
- ✓ Communication and IT Application
- ✓ Meter Data Analytics

Although the model could be very good comparison and base for the improved SGCT program, the fact that it is a privatized model (not public) deters the possibility. Also, there is not enough documentation of the model and its utilizations to be based upon.

II.1.6 United States: Smart Grid Consumer Collaborative (SGCC)

By macroeconomic analysis, many researchers have forecast the cost and benefit of Smart Grid. As the real-world experience is growing, Smart Grid Consumer Collaborative (SGCC) reviewed available research quantifying benefits – economic, environmental, reliability, and customer choice – and costs associated with Smart Grid investments.

In this report, benefit cost analysis was fulfilled with reference case and ideal case. Reference (low end) case embodies conservative assumptions typical of the current average capability deployment. Ideal (high end) Case is based on the achievable, "the state of the possible" Smart Grid deployment goal. Also this report describes the benefit drivers for each Smart Grid capability. Benefit-cost analysis is done by calculation of Net Present Value for 13 year deployment of Smart Grid infrastructure and its operation. The table below compares the assumptions of Reference and Ideal case.

Table 1 Reference Case and Ideal Case benefit assumptions

Capability	Primary Benefit Drivers	Reference Case Assumptions	Ideal Case Assumptions
Integrated Volt/VAr Control	• Average reduction in peak demand • Average reduction in energy use	• 3.5% peak reduction • n/a	• 3.5% peak reduction • 2.7% energy reduction
Remote Meter Reading	• Type of meter reading (manual or automated) prior to Smart Meter rollout • Policy regarding move ins/move outs (is prorating allowed between meter reads or must meters be read on customer move dates?)	• Routine monthly meter reads previously automated • Prorating prohibited	• Meter reading previously manual • Prorating prohibited
Time-Varying Rates	•Customer participation rates (opt in) • Customer response level to price differentials	• 2% participation • 20% load shift • 4% usage reduction	• 20% participation • 20% load shift • 4% usage reduction

	• Conservation impact • Average peak demand per residential customer • Value of generation capacity avoided • Average usage per residential customer per year • Value of electricity use avoided	• 2.575kW/customer (1) • $134.28/kW year(1) • 11,280 kWh/ year (1) • $0.0682/kWh (1)	• 2.575kW/customer (1) • $134.28/kW year (1) • 11,280 kWh/year (1) • $0.0682/kWh (1)
Prepay and remote disconnect/ reconnect	•Customer participation rates • Conservation impact • Existence of remote disconnect prohibitions	• 2.5% participation • 11% usage reduction • No remote disconnect prohibitions	• 5% participation • 11% usage reduction • No remote disconnect prohibitions
Revenue Assurance	• Level of electricity theft prior to Smart Meter deployment • Average age of meters being replaced		
Customer Energy Management	•Customer participation rates • Feedback mechanism Type • Conservation impact	• 2% participation • In-home display • 5% usage reduction	• 5% participation • In-home display • 5% usage reduction
Service Outage Management; Fault Location and Isolation	• Value assigned to a minute of reliability improvement	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)	• $1.80/minute (weighted average opportunity cost to residential, commercial, industrial)
Renewable Generation Integration	• Difference in cost of relative to central resources • Difference in environmental impact vs. central • Value of environmental impact reductions • Ratio of customer-sited to central resources over time		

Note: (1) These assumptions are used throughout the report as appropriate.

Source: Smart Grid Consumer Collaborative (SGCC), Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs, October 2013.

In this report, the results show that the direct and indirect economic benefit of the grid modernization is larger than the cost of deployment of Smart Grid infrastructure and its maintenance. Also it indicates that the grid modernization has a significant benefit on the environment through conservation and renewable generation integration.

II.2 Summary of BCA Frameworks and Application Cases

The Methodology of EPRI (EPRI, 2010) could be considered as the general approach of estimating benefits and costs of a smart grid project. Other institutions that built their BCA tools upon the Methodology are US Department of Energy (DOE) with its Smart Grid Computational Tool (SGCT) and European Commission's Joint Research Centre (EC JRC) although with integration of its own elements such as smart grid characteristics, Key Performance Indicators (KPI), and qualitative analysis. Similar frameworks are developed by McKinsey and Smart Grid Investment Model (SGIM).

The main focus of these BCA is the definition of benefits. In general, most of the smart grid benefits is in form of reduced costs. As to which benefits are considered and how to quantify those benefits, each framework could have different interpretations compared to others. Some of the general benefits are reduced generation cost, reduced CO_2 emissions, reduced meter reading cost, reduced outages, and reduced cost of transmission and distribution system.

Interesting framework is presented by Frontier Economics, which works closely with Smart Grid Forum (SGF) of UK. The model they developed applies real options valuation, which is application of option valuation techniques to capital budgeting decisions. The reason is to avoid a stuck-in scenario where only one specified investment path can be chosen. In a sense, it is similar to integrating the advanced version of sensitivity analysis to the main BC Analysis itself. Also, the Frontier Economics combine their Real options BCA model with network model and generation model to provide the network and generation costs to the BCA model.

In IMPLAN discussion (as well as others) it is notified that impacts of smart grid could be more than a direct economic impact. Utilizing input output data, the model could analyze the indirect economic impacts and induced economic impacts of smart grid, in addition to the normative direct economic impacts.

The main focus of the comparison between the studies is the definition of benefits and costs. It can be observed that depending on the background and scope of each project, the list of benefits and costs would differ one from another. It must be noted also, that not all studies surveyed here has a clear documentation of the exact calculation (quantification and monetization) of the benefits, which could be tricky sometimes.

Taking Czech Republic case as an example, the smart grid project there focus more on reshaping the electricity load, thus the smart grid benefits are categorized into load leveling effect, time shifting effect, and off-peak time shifting effect. The calculation of these benefits, then, would base on the cost avoidance resulting from the project.

Meanwhile in Denmark, the benefits of smart grid is divided into savings on reserves and regulating power, savings on electricity generation, and savings on energy-saving initiatives. The method of benefits quantification--seeing this categorization--would be the reduced cost that stems from the reduced electricity consumption.

Both Czech Republic and Denmark cases have similarities that they don't consider much the benefits related with the transmission and distribution. As can be seen, most of the benefits are related with reduced generation or load saving. Netherland's report also shares the same point of view for benefits estimation. On the other hand, Lithuania does not consider the savings from generation side, but mostly deals with benefits related with smart metering.

The environmental benefit of smart grid, which is reduction of CO_2 emission, also becomes more important. The BCA report of Ireland is one of those that take this into account. In relation to CO_2 emissions, the McKinsey framework also made it into their list of smart grid's major benefits. The same goes for SGCC report, which covers several utilities.

In conclusion, the list and definition of benefits may differ between cases and a standardized list and definition that encompass the whole possible benefits must be generated. Table below compares the benefits definition from various BCA reports. It basically expands the similar table from the previous report. As usual, the benefits categorization coined by EPRI (2010) is used as the base. But the listed benefits might have unclear monetization method. The estimation of benefits, then, is quite a delicate process.

A further discussion is being made for the review of SGCT (Smart Grid Computational Tool Kit) developed by DOE following the guideline of EPRI (2012) for the selection of benchmark benefit-cost frameworks and tool.

Table 2 Benefits Comparison from Various BCA Reports

Benefits (EPRI 2010)			BCA REPORTS												
			EPRI 2004	EPRI 2011	FERC 2006	FSC 2008	IEE 2011	McKinsey	Czech	Denmark	Ireland	Lithuania	Netherland	New York	SGCC
Economic	Improved Asset Utilization	Optimized Generator Operation						X	X	X	X		X	X	X
		Deferred Generation Capacity Investments		X		X	X	X	X	X			X	X	X
		Reduced Ancillary Service Cost	X	X	X				X	X			X	X	X
		Reduced Congestion Cost	X	X					X	X			X		X
	T&D Capital Savings	Deferred Transmission Capacity Investments	X	X		X	X	X					X		
		Deferred Distribution Capacity Investments	X	X		X	X	X					X	X	
		Reduced Equipment Failures	X	X										X	
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost	X	X				X		X				X	
		Reduced T&D Operations Cost	X	X		X		X				X		X	
		Reduced Meter Reading Cost		X	X	X	X	X			X	X		X	X
	Theft	Reduced Electricity													X

	Reduction	Theft													
	Energy Efficiency	Reduced Electricity Losses	X	X								X	X	X	
	Electricity Cost Savings	Reduced Electricity Cost	X	X		X	X	X		X	X	X		X	X
Reliability	Power Interruptions	Reduced Sustained Outages	X	X	X	X	X	X						X	
		Reduced Major Outages	X	X	X	X	X	X						X	
		Reduced Restoration Cost	X	X	X	X	X	X				X	X		
	Power Quality	Reduced Momentary Outages	X	X	X	X		X				X		X	
		Reduced Sags and Swells	X	X											
Environ-mental	Air Emissions	Reduced CO2 Emissions	X	X		X	X	X			X				X
		Reduced SOx, NOx, and PM-10 Emissions	X	X											
Security	Energy Security	Reduced Oil Usage					X	X			X				
		Reduced Wide-scale Blackouts	X	X				X							

II.3 Smart Grid Computational Tool (SGCT)

II.3.1 Overview of SGCT

DOE's Smart Grid Computational Tools (SGCT) is a benefit cost analysis (BCA) tools developed by DOE which is strongly based on EPRI's Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects (2010).

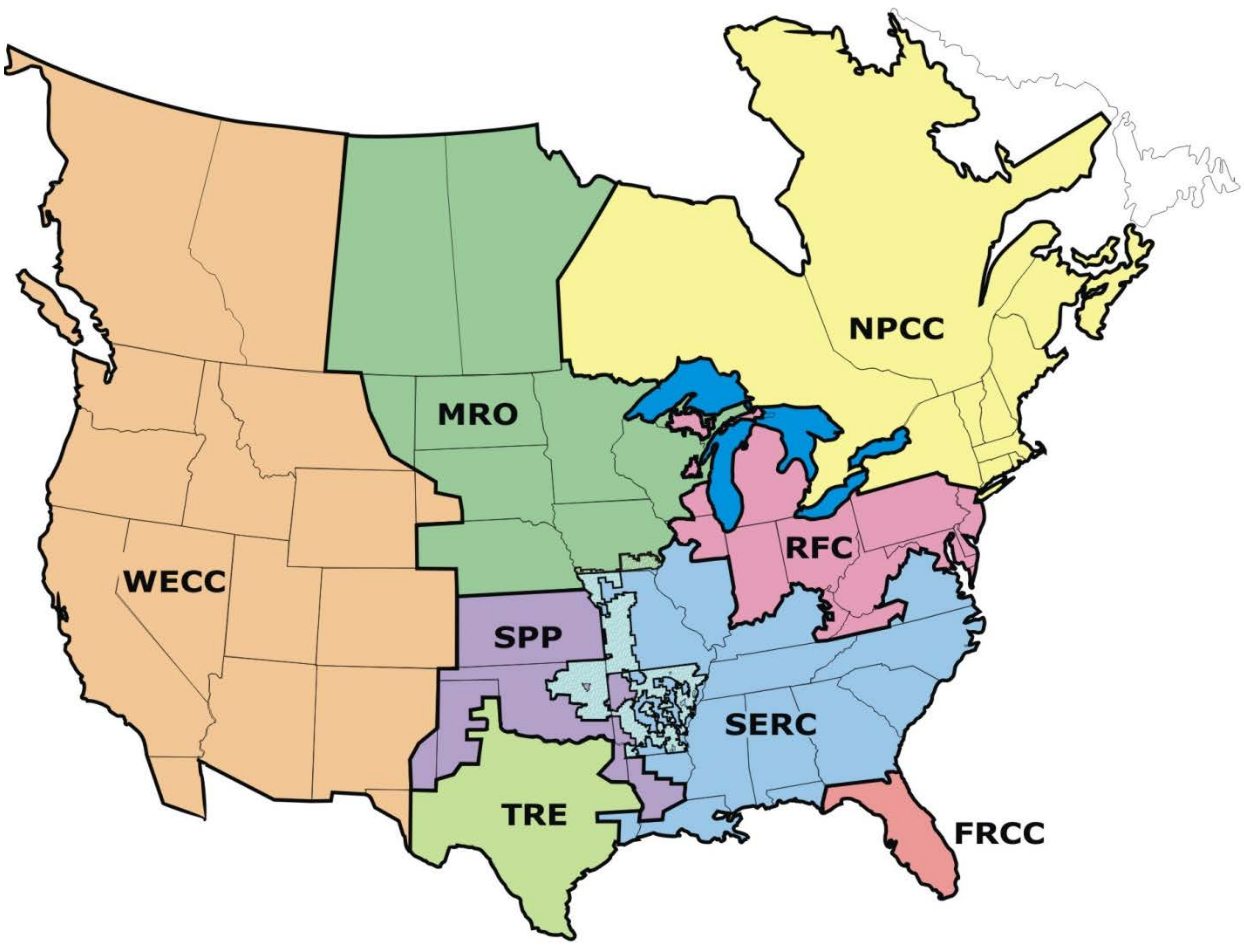


Figure 10 NERC Regions

Source: http://www.kestrelpower.com/services_NERC.php

The tool is designed to deliver some answers to smart grid projects' benefit related questions for the above designated NETC (North American Electric Reliability Corporation) regions.

Table 3 NERC Regions

NERC Region Abbreviation	NERC Region Name
FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RFC	Reliability*First* Corporation
SERC	SERC Reliability Corporation
SPP	Southwest Power Pool
TRE	Texas Regional Entity
WECC	Western Electricity Coordinating Council
ASCC	Alaska Systems Coordinating Council
HI	Hawaii
NA	No NERC Region

Source: DOE (2011)

This approach is then modified by SGCT in its own BCA process. The first modification is that SGCT bypasses or simplifies some of the 10 (ten) steps approach of EPRI. For example, there is no detailed characteristic needed in SGCT, only a mapping from assets-functions-mechanisms-benefits is needed.

II.3.2 Steps of SGCT

The step of project's baseline definition for benefits calculation is given to the user and the tools will only receive it as an input. Also, the quantified and monetized benefits steps are combined. The second modification is the addition of several additional analyses in the tools, such as sensitivity analysis.

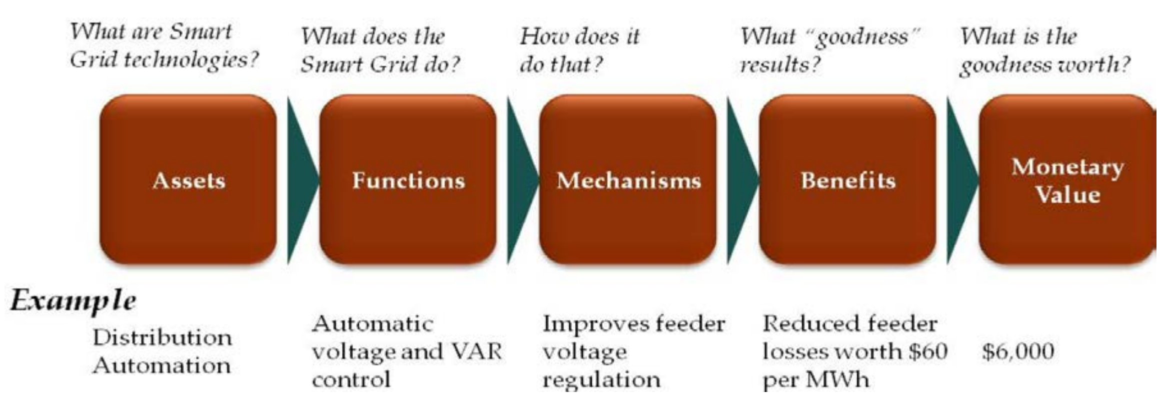


Figure 11 Illustration of the Translation of Smart Grid Assets to Benefit's Monetary Value
Source: DOE (2011)

The above diagram of SGCT characterizes smart grid projects by identifying the technology (assets) that will be installed and identifying what that technology will do (functions and mechanisms). Based on this characterization, the SGCT identifies the economic, reliability, environmental, and security benefits the smart grid project will yield.

Figure below shows the illustration of Assets to Functions to Mechanisms to Benefits mapping in SGCT. It can be seen that the function can be mixed, such as that an asset can have several functions as well as a function can be done by several assets. The same goes for any of the mapping, up to mechanisms to benefits mapping.

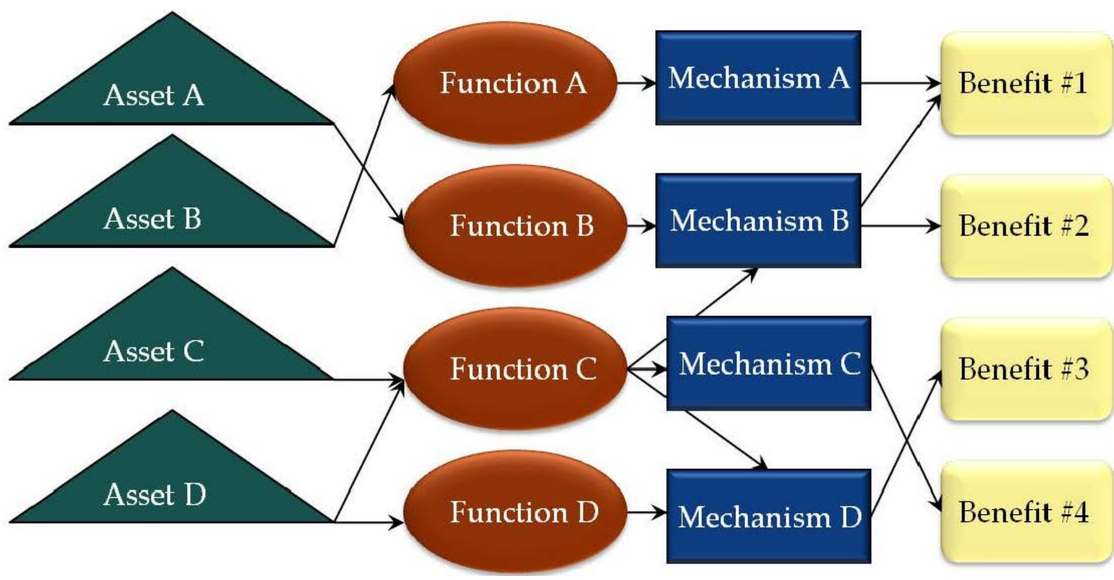


Figure 12 Illustration of Asset, Function, Mechanism, Benefit Mapping (Navigant, 2011)
Source: DOE (2011)

II.3.3 Detailed Steps of SGCT

The relationship between technology and benefit calculation is governed by the choices of functions and the related mechanisms shown above,

- Assets

The first step is to identify the smart grid assets that a project will implement.

- ✓ Advanced Interrupting Switch
- ✓ Advanced Metering Infrastructure (AMI)/Smart Meter
- ✓ Controllable/regulating Inverter

- ✓ Customer EMS/Display/Portal
- ✓ Distribution Automation
- ✓ Distribution Management System
- ✓ Enhanced Fault Detection Technology
- ✓ Equipment Health Sensor
- ✓ FACTS Device
- ✓ Fault Current Limiter
- ✓ Loading Monitor
- ✓ Microgrid Controller
- ✓ Phase Angle Regulating Transformer
- ✓ Phasor Measurement Technology
- ✓ Smart Appliances and Equipment (Customer)
- ✓ Software – Advanced Analysis/Visualization
- ✓ Two-way communications (high bandwidth)
- ✓ Vehicle to Grid Charging Station
- ✓ Very Low Impedance (High Temperature Superconducting) Cables
- ✓ Distributed Generator (diesel, PV, wind)
- ✓ Electricity Storage device (e.g., battery, flywheel, PEV etc.)

The list of assets could be regarded to expand in the future as there will be technological progress in this field of smart grid. Currently 22 types asset are defined in SGCT.

- ■ Functions

Followings are the type of functions identified in SGCT and the number of functions is 15.

- ✓ Fault Current Limiting
- ✓ Wide Area Monitoring and Visualization and Control
- ✓ Dynamic Capability Rating
- ✓ Power Flow Control
- ✓ Adaptive Protection
- ✓ Automated Feeder and Line Switching
- ✓ Automated Islanding and Reconnection
- ✓ Automated Voltage and VAR Control
- ✓ Diagnosis and Notification of Equipment Condition
- ✓ Enhanced Fault Protection
- ✓ Real-time Load Measurement and Management
- ✓ Real-time Load Transfer
- ✓ Customer Electricity Use Optimization
- ✓ Storing Electricity for Later Use
- ✓ Distributed Production of Electricity

- Mechanism

Once the function is chosen, there will be mapping relation provided by the SGCT to select related benefit. It will be discussed in the figure to be provided below.

- Benefits

There are four categories of benefits: Economic, Reliability, Environmental, and Security. Total of 22 benefits are calculated as the form of avoided cost due to the introduction of smart grid technologies. Following is a table of the List of Smart Grid Benefits.

Table 4 List of Smart Grid Benefits

Benefit Category	Benefit Sub-category	Benefit
Economic	Improved Asset Utilization	Optimized Generator Operation Deferred Generation Capacity Investments Reduced Ancillary Service Cost Reduced Congestion Cost
	T&D Capital Savings	Deferred Transmission Capacity Investments Deferred Distribution Capacity Investments Reduced Equipment Failures
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost Reduced T&D Operations Cost Reduced Meter Reading Cost
	Theft Reduction	Reduced Electricity Theft
	Energy Efficiency	Reduced Electricity Losses
	Electricity Cost Savings	Reduced Electricity Cost
Reliability	Power Interruptions	Reduced Sustained Outages Reduced Major Outages Reduced Restoration Cost
	Power Quality	Reduced Momentary Outages Reduced Sags and Swells
Environmental	Air Emissions	Reduced CO_2 Emissions Reduced SO_x, NO_x, and PM-2.5 Emissions
Security	Energy Security	Reduced Oil Usage Reduced Wide-scale Blackouts

Source: DOE (2011)

Benefits			Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
Economic	Improved Asset Utilization	Optimized Generator Operation		•												•	•
		Deferred Generation Capacity Investments													•	•	•
		Reduced Ancillary Service Cost		•						•			•		•	•	•
		Reduced Congestion Cost		•	•	•									•	•	•
	T&D Capital Savings	Deferred Transmission Capacity Investments	•	•	•	•									•	•	•
		Deferred Distribution Capacity Investments			•								•	•	•	•	•
		Reduced Equipment Failures	•		•						•	•					
	T&D O&M Savings	Reduced T&D Equipment Maintenance Cost									•						
		Reduced T&D Operations Cost						•		•							
		Reduced Meter Reading Cost											•				
	Theft Reduction	Reduced Electricity Theft											•				
	Energy Efficiency	Reduced Electricity Losses				•				•			•	•	•	•	•
	Electricty Cost Savings	Reduced Electricity Cost													•	•	•
Reliability	Power Interruptions	Reduced Sustained Outages					•	•	•		•	•	•			•	•
		Reduced Major Outages		•					•				•	•			
		Reduced Restoration Cost					•	•	•		•	•	•				
	Power Quality	Reduced Momentary Outages										•				•	
		Reduced Sags and Swells										•				•	
Environmental	Air Emissions	Reduced CO_2 Emissions				•		•		•	•		•	•	•	•	•
		Reduced SO_x, NO_x, and PM-10 Emissions				•		•		•	•		•	•	•	•	•
Security	Energy Security	Reduced Oil Usage (not monetized)						•			•		•			•	
		Reduced Widescale Blackouts		•	•												

Smart Grid Assets	Fault Current Limiting	Wide Area Monitoring, Visualization, and Control	Dynamic Capability Rating	Power Flow Control	Adaptive Protection	Automated Feeder and Line Switching	Automated Islanding and Reconnection	Automated Voltage and VAR Control	Diagnosis & Notification of Equipment Condition	Enhanced Fault Protection	Real-Time Load Measurement & Management	Real-time Load Transfer	Customer Electricity Use Optimization	Storing Electricity for Later Use	Distributed Production of Electricity
	Delivery												Use	Other	
Advanced Interrupting Switch										•					
AMI/Smart Meters								•			•		•		
Controllable/regulating Inverter							•	•							
Customer EMS/Display/Portal													•		
Distribution Automation					•	•	•	•				•			
Distribution Management System			•		•	•	•	•			•	•			
Enhanced Fault Detection Technology										•					
Equipment Health Sensor			•						•						
FACTS Device				•											
Fault Current Limiter	•														
Loading Monitor			•						•			•			
Microgrid Controller							•								
Phase Angle Regulating Transformer				•											
Phasor Measurement Technology		•	•	•	•		•	•		•					
Smart Appliances and Equipment (Customer)													•		
Software - Advanced Analysis/Visualization		•	•												
Two-way Communications (high bandwidth)		•			•	•	•	•			•	•			
Vehicle to Grid Charging Station													•		
Very Low Impedance (High Temperature Superconducting) cables				•											
Distributed Generator (diesel, PV, wind)								•							•
Electricity Storage device (e.g., battery, flywheel, PEV etc)								•						•	

Functions

Figure 13 Asset, Function, Mechanism and Benefit

Above diagram is prepared simply to show the role of mechanism. Mechanism maps the choice of benefit to be considered when a function is selected. The red box in the above figure is the role of mechanism linking the choice of technology to the benefits to be calculated.

II.3.4 Overall Architecture of SGCT

There are basically three modules in SGCT, which are: 1. Project Characterization Module (PCM); 2. Data Input Module (DIM); and 3. Computational Module (CM), see figure below. The first module helps user determine the functionality of the projects. Basically it maps each assets provided by a smart grid project to onto a standardized set of benefit categories. It handles the first to fourth steps in EPRI's ten step approach. In the second module, user can input the required data to calculate project benefits. The list of anticipated benefits is derived from the first module and the list of inputs needed depends on the formula of each benefit's calculation. The module basically tackles the fifth, sixth and ninth steps of EPRI's ten step approach. The last module then calculates the project costs and benefits. It also provides a mean of sensitivity analysis, by changing the range of some basic inputs, such as costumer number, electricity price, and various inputs for benefits calculation.

Following diagram show the overall structure of SGCT.

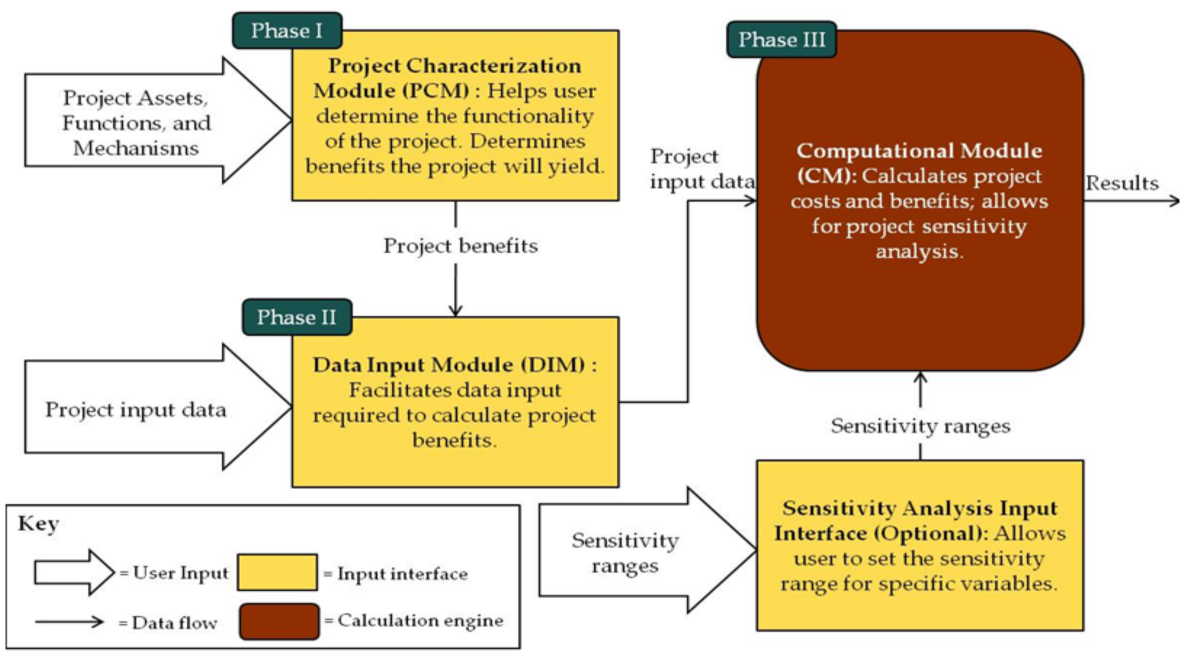


Figure 14 SGCT Architecture

Source: DOE (2011)

II.3.4.1 Project Characterization Module (PCM)

PCM provides a brief overview of SGCT, regarding the project's characteristics. Following is the PCM dialog box in SGCT.

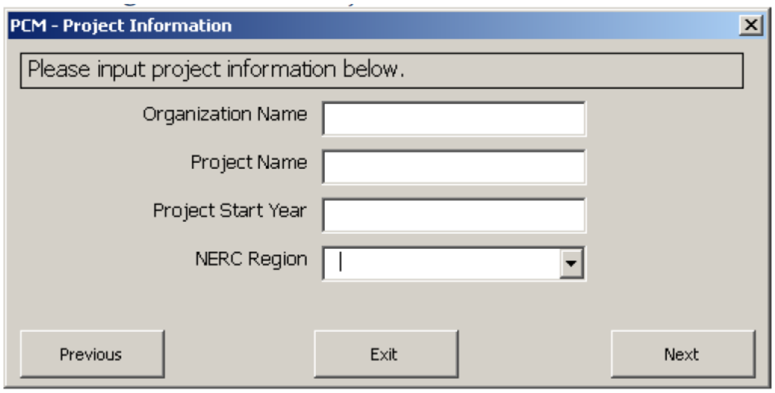


Figure 15 PCM Project Information Screen

Source: DOE (2011)

The choice for NERC region could be modified to include all the ISGAN member countries in the future. However, current SGCT can only be specified for either NREC region or non-NERC region. After this specification of project characteristics, a couple of pages should be managed to choose technologies and functions with default mechanism provided. The diagrams for such choices are given in the dialog boxes below.

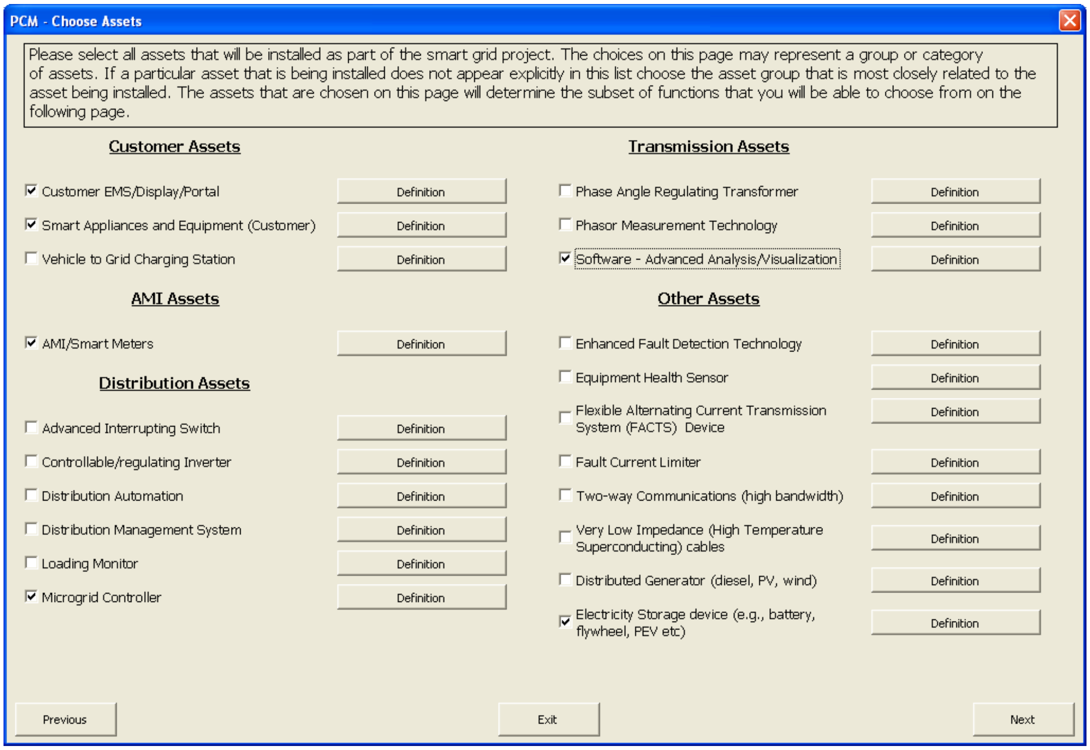


Figure 16 Choosing Assets in DOE's SGCT

Source: DOE (2011)

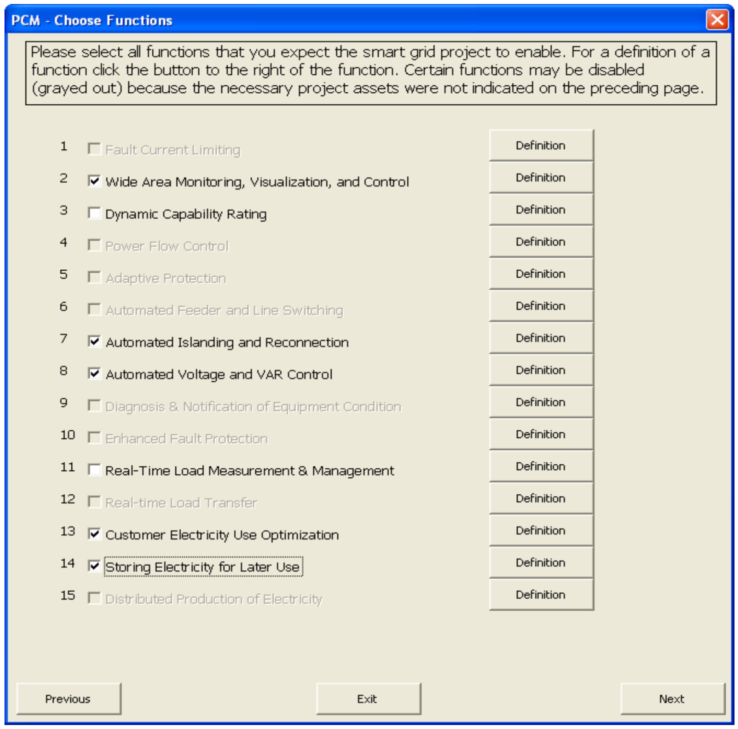


Figure 17 Choosing Functions in DOE's SGCT

Source: DOE (2011)

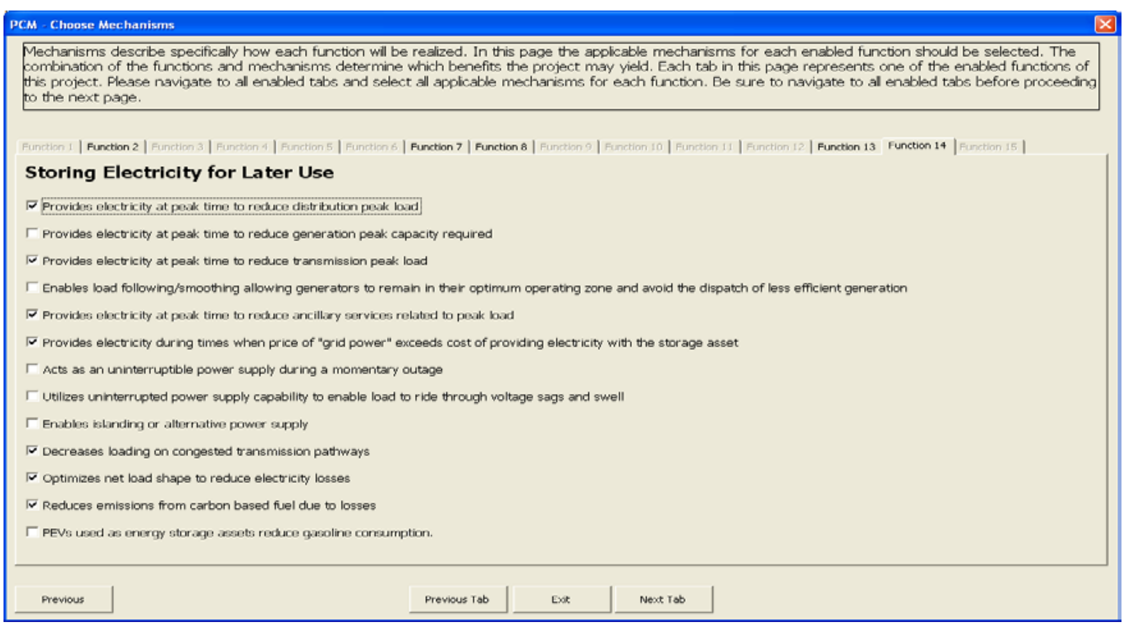


Figure 18 Choosing Mechanisms in DOE's SGCT

Source: DOE (2011)

II.3.4.2 Data Input Module (DIM)

Each steps for the DIM is briefly explained in the following DIM main page.

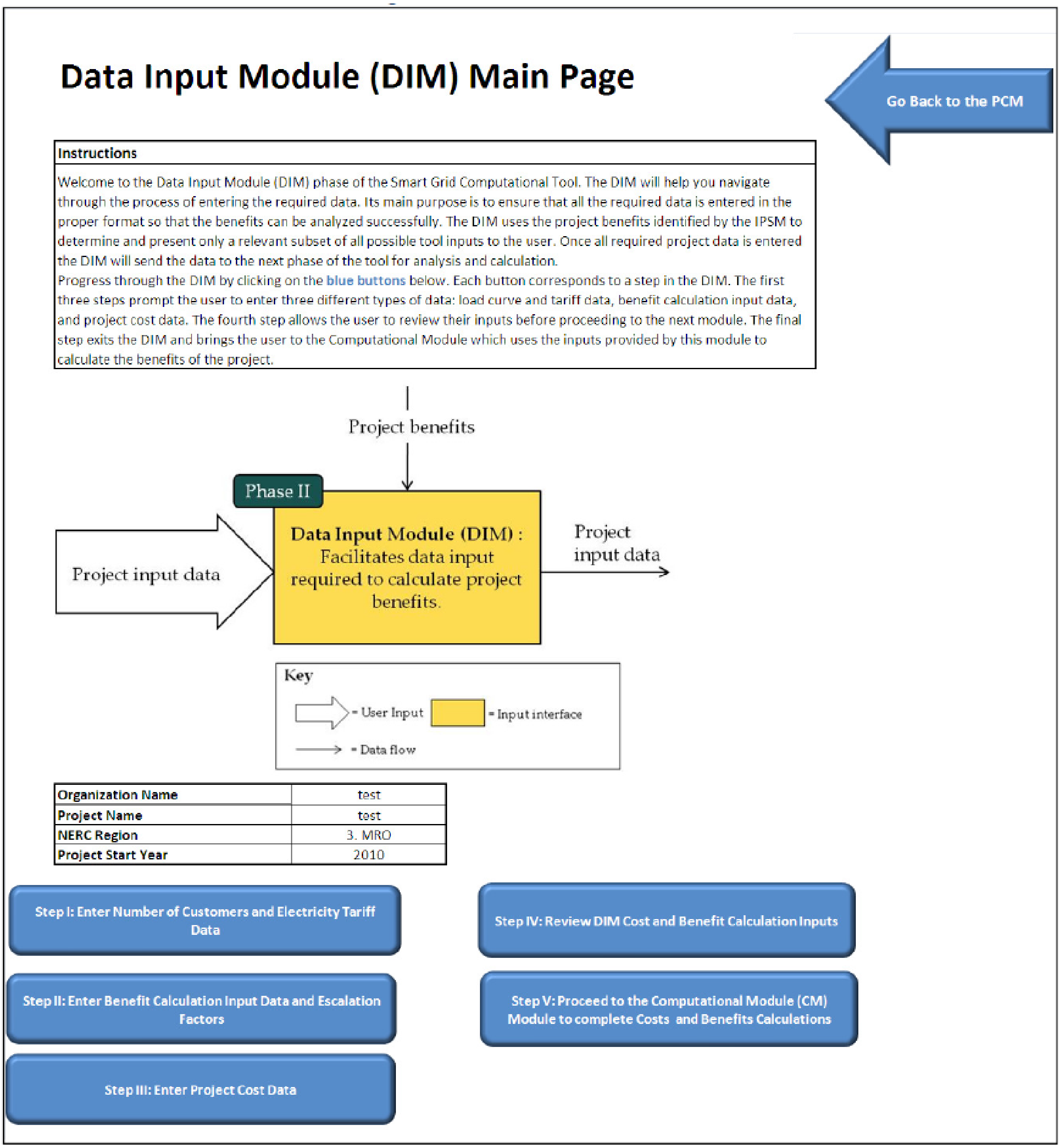
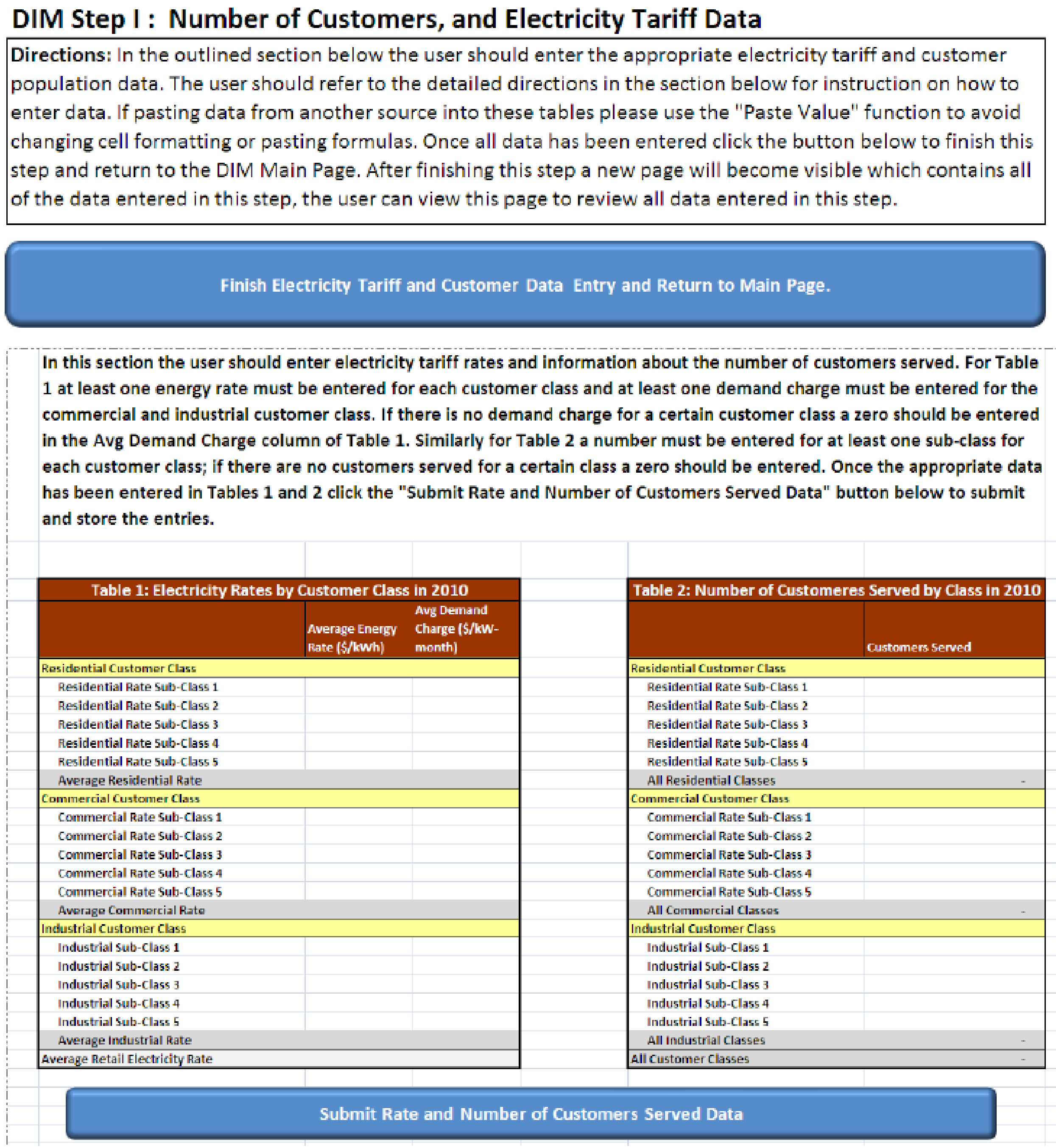


Figure 19 DIM main Page

Source: DOE (2011)



DIM Step I : Number of Customers, and Electricity Tariff Data

Directions: In the outlined section below the user should enter the appropriate electricity tariff and customer population data. The user should refer to the detailed directions in the section below for instruction on how to enter data. If pasting data from another source into these tables please use the "Paste Value" function to avoid changing cell formatting or pasting formulas. Once all data has been entered click the button below to finish this step and return to the DIM Main Page. After finishing this step a new page will become visible which contains all of the data entered in this step, the user can view this page to review all data entered in this step.

Finish Electricity Tariff and Customer Data Entry and Return to Main Page.

In this section the user should enter electricity tariff rates and information about the number of customers served. For Table 1 at least one energy rate must be entered for each customer class and at least one demand charge must be entered for the commercial and industrial customer class. If there is no demand charge for a certain customer class a zero should be entered in the Avg Demand Charge column of Table 1. Similarly for Table 2 a number must be entered for at least one sub-class for each customer class; if there are no customers served for a certain class a zero should be entered. Once the appropriate data has been entered in Tables 1 and 2 click the "Submit Rate and Number of Customers Served Data" button below to submit and store the entries.

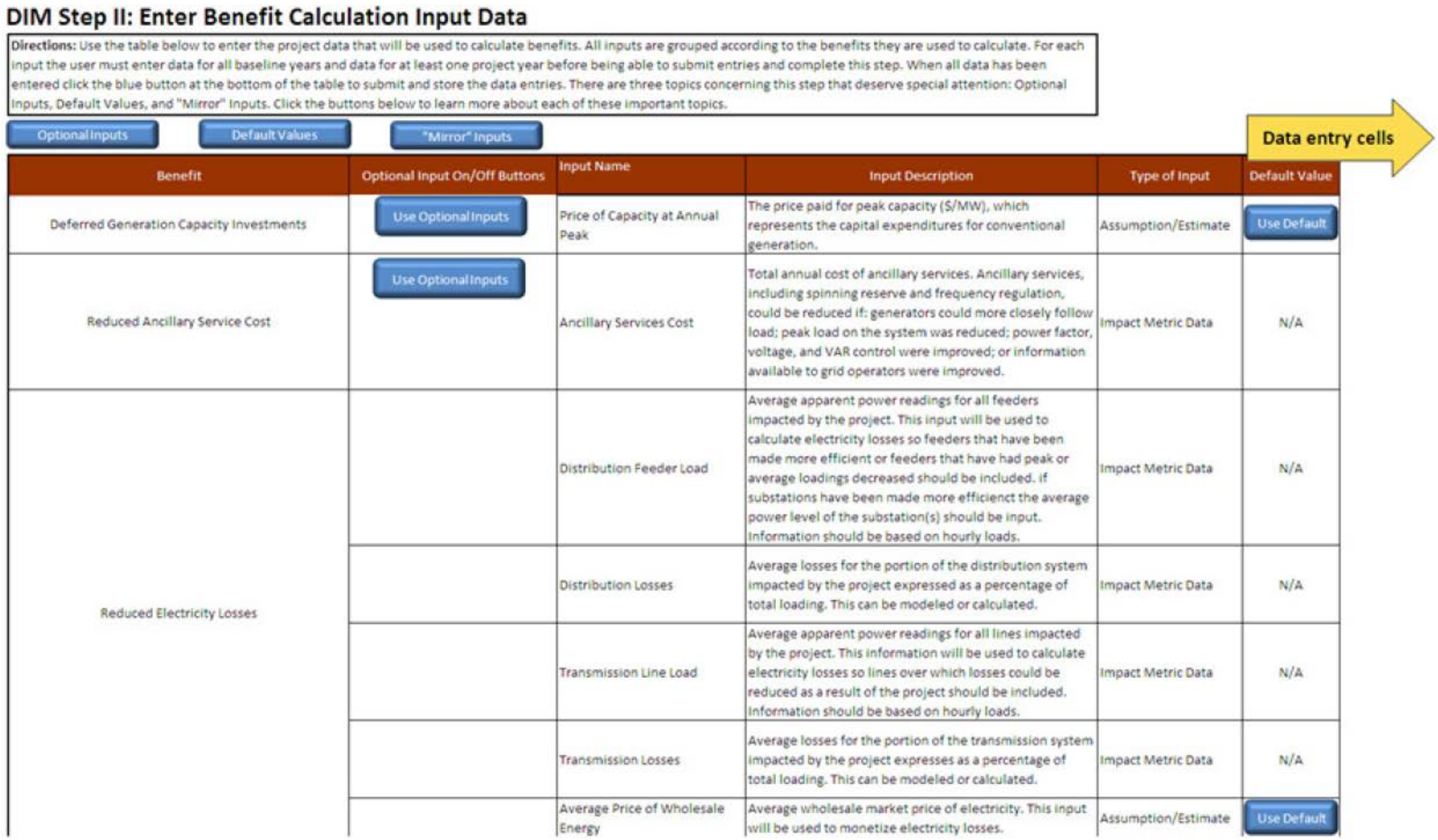
Table 1: Electricity Rates by Customer Class in 2010		
	Average Energy Rate ($/kWh)	Avg Demand Charge ($/kW-month)
Residential Customer Class		
Residential Rate Sub-Class 1		
Residential Rate Sub-Class 2		
Residential Rate Sub-Class 3		
Residential Rate Sub-Class 4		
Residential Rate Sub-Class 5		
Average Residential Rate		
Commercial Customer Class		
Commercial Rate Sub-Class 1		
Commercial Rate Sub-Class 2		
Commercial Rate Sub-Class 3		
Commercial Rate Sub-Class 4		
Commercial Rate Sub-Class 5		
Average Commercial Rate		
Industrial Customer Class		
Industrial Sub-Class 1		
Industrial Sub-Class 2		
Industrial Sub-Class 3		
Industrial Sub-Class 4		
Industrial Sub-Class 5		
Average Industrial Rate		
Average Retail Electricity Rate		

Table 2: Number of Customeres Served by Class in 2010	
	Customers Served
Residential Customer Class	
Residential Rate Sub-Class 1	
Residential Rate Sub-Class 2	
Residential Rate Sub-Class 3	
Residential Rate Sub-Class 4	
Residential Rate Sub-Class 5	
All Residential Classes	-
Commercial Customer Class	
Commercial Rate Sub-Class 1	
Commercial Rate Sub-Class 2	
Commercial Rate Sub-Class 3	
Commercial Rate Sub-Class 4	
Commercial Rate Sub-Class 5	
All Commercial Classes	-
Industrial Customer Class	
Industrial Sub-Class 1	
Industrial Sub-Class 2	
Industrial Sub-Class 3	
Industrial Sub-Class 4	
Industrial Sub-Class 5	
All Industrial Classes	-
All Customer Classes	-

Submit Rate and Number of Customers Served Data

Figure 20 DIM Step 1

Source: DOE (2011)



DIM Step II: Enter Benefit Calculation Input Data

Directions: Use the table below to enter the project data that will be used to calculate benefits. All inputs are grouped according to the benefits they are used to calculate. For each input the user must enter data for all baseline years and data for at least one project year before being able to submit entries and complete this step. When all data has been entered click the blue button at the bottom of the table to submit and store the data entries. There are three topics concerning this step that deserve special attention: Optional Inputs, Default Values, and "Mirror" Inputs. Click the buttons below to learn more about each of these important topics.

Optional Inputs | Default Values | "Mirror" Inputs

Data entry cells

Benefit	Optional Input On/Off Buttons	Input Name	Input Description	Type of Input	Default Value
Deferred Generation Capacity Investments	Use Optional Inputs	Price of Capacity at Annual Peak	The price paid for peak capacity ($/MW), which represents the capital expenditures for conventional generation.	Assumption/Estimate	Use Default
Reduced Ancillary Service Cost	Use Optional Inputs	Ancillary Services Cost	Total annual cost of ancillary services. Ancillary services, including spinning reserve and frequency regulation, could be reduced if: generators could more closely follow load; peak load on the system was reduced; power factor, voltage, and VAR control were improved; or information available to grid operators were improved.	Impact Metric Data	N/A
Reduced Electricity Losses		Distribution Feeder Load	Average apparent power readings for all feeders impacted by the project. This input will be used to calculate electricity losses so feeders that have been made more efficient or feeders that have had peak or average loadings decreased should be included. If substations have been made more efficienct the average power level of the substation(s) should be input. Information should be based on hourly loads.	Impact Metric Data	N/A
		Distribution Losses	Average losses for the portion of the distribution system impacted by the project expressed as a percentage of total loading. This can be modeled or calculated.	Impact Metric Data	N/A
		Transmission Line Load	Average apparent power readings for all lines impacted by the project. This information will be used to calculate electricity losses so lines over which losses could be reduced as a result of the project should be included. Information should be based on hourly loads.	Impact Metric Data	N/A
		Transmission Losses	Average losses for the portion of the transmission system impacted by the project expresses as a percentage of total loading. This can be modeled or calculated.	Impact Metric Data	N/A
		Average Price of Wholesale Energy	Average wholesale market price of electricity. This input will be used to monetize electricity losses.	Assumption/Estimate	Use Default

Figure 21 DIM Step 2

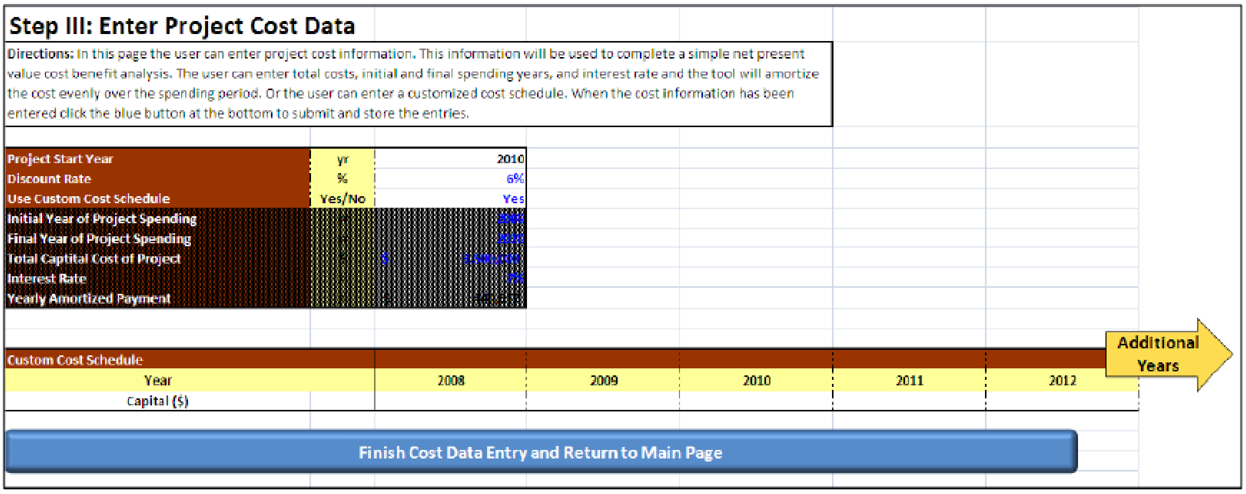
Source: DOE (2011)

Unit						Project				
	Baseline 2010	Baseline 2011	Baseline 2012	Baseline 2013	Baseline 2014	2010	2011	2012	2013	2014
$/MW	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00	$ 95,700.00
$	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1				
MVA	100.00	100.00	100.00	100.00	100.00	90.00				
%	3%	3%	3%	3%	3%	3%				
MVA	-	-	-	-	-	-				

Additional input cells

Figure 22 Data Input Sheet Data Entry Cells

Source: DOE (2011)



Step III: Enter Project Cost Data

Directions: In this page the user can enter project cost information. This information will be used to complete a simple net present value cost benefit analysis. The user can enter total costs, initial and final spending years, and interest rate and the tool will amortize the cost evenly over the spending period. Or the user can enter a customized cost schedule. When the cost information has been entered click the blue button at the bottom to submit and store the entries.

Project Start Year	yr	2010
Discount Rate	%	6%
Use Custom Cost Schedule	Yes/No	Yes
Initial Year of Project Spending	[illegible]	[illegible]
Final Year of Project Spending	[illegible]	[illegible]
Total Captital Cost of Project	[illegible]	[illegible]
Interest Rate	[illegible]	[illegible]
Yearly Amortized Payment	[illegible]	[illegible]

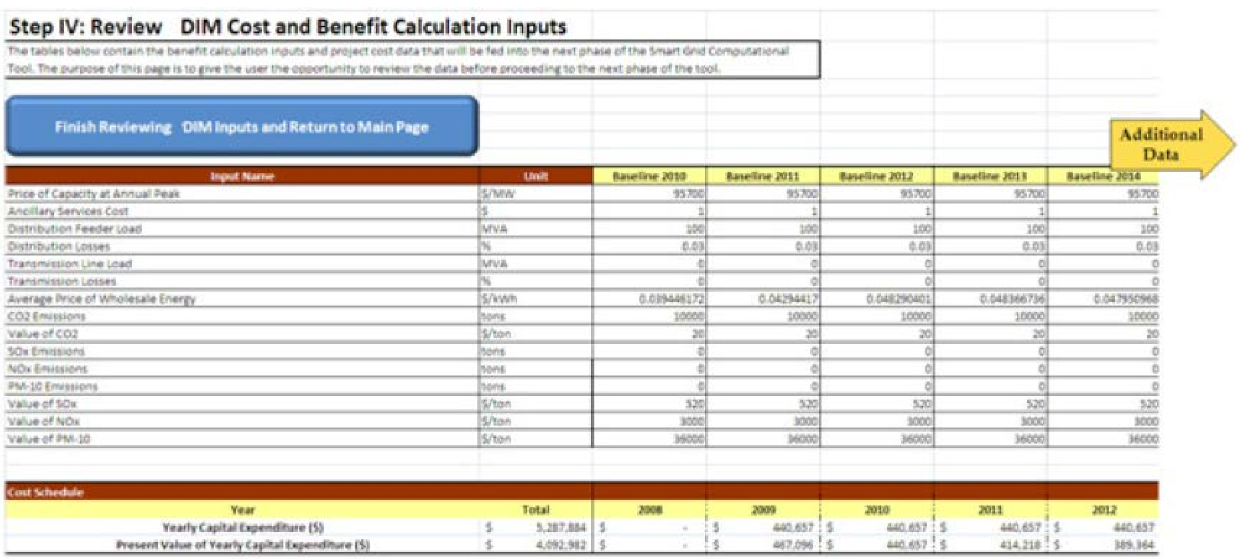
Custom Cost Schedule					
Year	2008	2009	2010	2011	2012
Capital ($)					

Additional Years

Finish Cost Data Entry and Return to Main Page

Figure 23 DIM Step 3

Source: DOE (2011)



Step IV: Review DIM Cost and Benefit Calculation Inputs

The tables below contain the benefit calculation inputs and project cost data that will be fed into the next phase of the Smart Grid Computational Tool. The purpose of this page is to give the user the opportunity to review the data before proceeding to the next phase of the tool.

Finish Reviewing DIM Inputs and Return to Main Page

Additional Data

Input Name	Unit	Baseline 2010	Baseline 2011	Baseline 2012	Baseline 2013	Baseline 2014
Price of Capacity at Annual Peak	$/MW	95700	95700	95700	95700	95700
Ancillary Services Cost	$	1	1	1	1	1
Distribution Feeder Load	MVA	100	100	100	100	100
Distribution Losses	%	0.03	0.03	0.03	0.03	0.03
Transmission Line Load	MVA	0	0	0	0	0
Transmission Losses	%	0	0	0	0	0
Average Price of Wholesale Energy	$/kWh	0.039446172	0.04294417	0.048290401	0.048366736	0.047950968
CO2 Emissions	tons	10000	10000	10000	10000	10000
Value of CO2	$/ton	20	20	20	20	20
SOx Emissions	tons	0	0	0	0	0
NOx Emissions	tons	0	0	0	0	0
PM-10 Emissions	tons	0	0	0	0	0
Value of SOx	$/ton	520	520	520	520	520
Value of NOx	$/ton	3000	3000	3000	3000	3000
Value of PM-10	$/ton	36000	36000	36000	36000	36000

Cost Schedule						
Year	Total	2008	2009	2010	2011	2012
Yearly Capital Expenditure ($)	$ 5,287,884	$ -	$ 440,657	$ 440,657	$ 440,657	$ 440,657
Present Value of Yearly Capital Expenditure ($)	$ 4,092,982	$ -	$ 467,096	$ 440,657	$ 414,218	$ 389,364

Figure 24 DIM Step 4

Source: DOE (2011)

II.3.4.3 Computational Module (CM)

The Computational Module is said to be the calculation engine of the SGCT (DOE, 2011). The primary purpose of the CM is to transform the input data either from the DIM default values or from user defined inputs into the costs and benefits of the smart grid project being analyzed. According to DOE (2011), default values are based on the following sources:

- ✓ EIA (Annual Energy Outlook 2009, Form 861, Form 411, etc.)
- ✓ Global Energy Decisions, Energy Velocity (FERC Form 714, etc.)
- ✓ SNL (FERC Form 1, etc.)
- ✓ Public filings, rate cases (PUC, FERC, ISO, etc.)

Then this computation module, CM, calculates costs and benefits on a yearly basis and presents summaries of these results to the user in tabular and graphical formats.

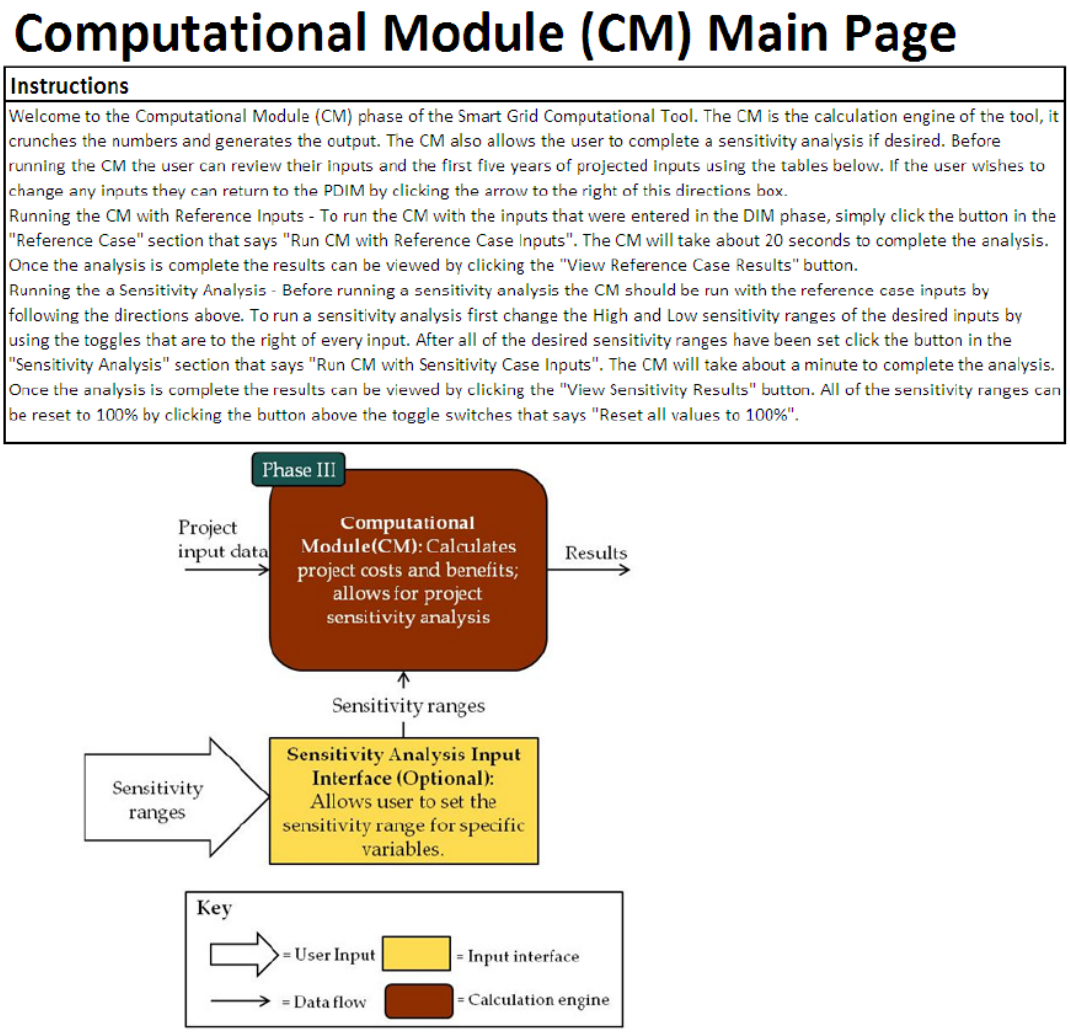
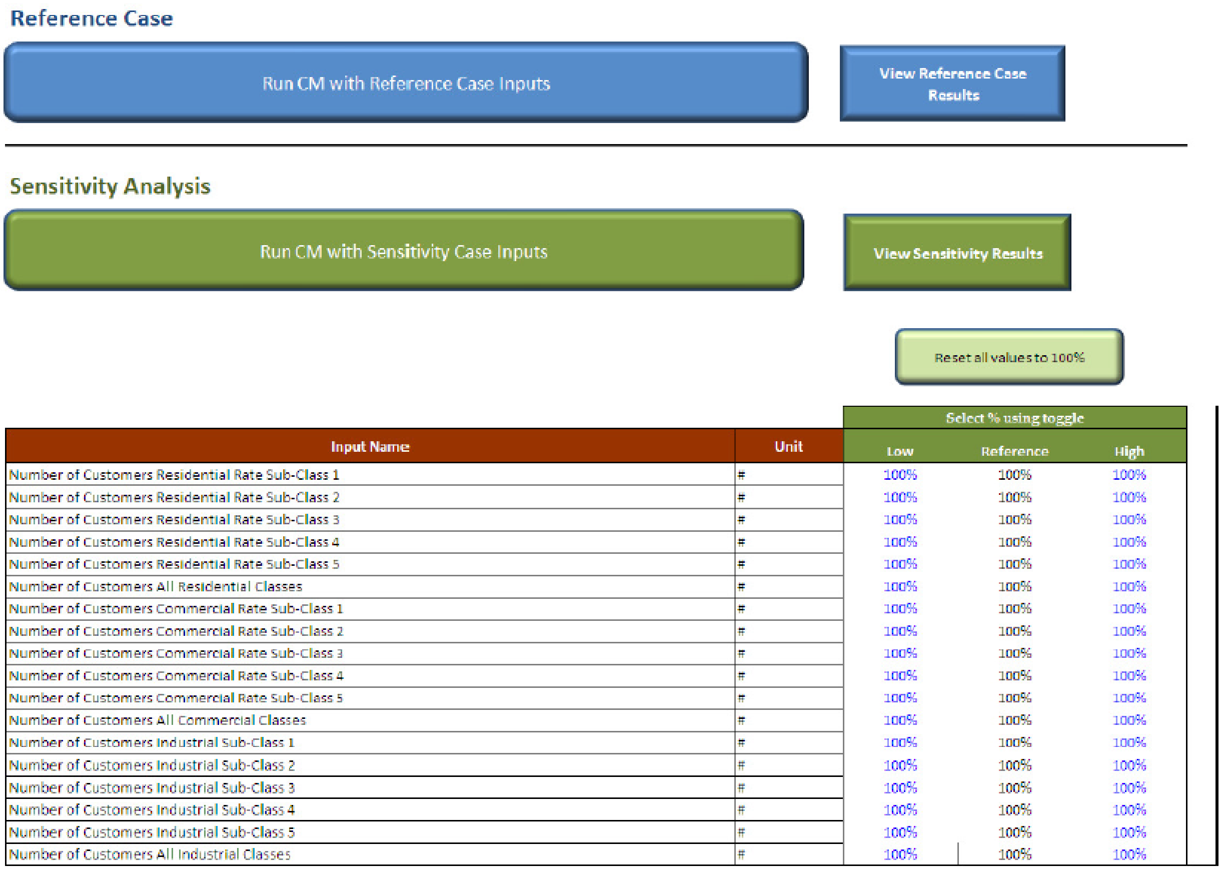


Figure 25 CM Main Page

Source: DOE (2011)



Input Name	Unit	Select % using toggle		
		Low	Reference	High
Number of Customers Residential Rate Sub-Class 1	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 2	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 3	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 4	#	100%	100%	100%
Number of Customers Residential Rate Sub-Class 5	#	100%	100%	100%
Number of Customers All Residential Classes	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 1	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 2	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 3	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 4	#	100%	100%	100%
Number of Customers Commercial Rate Sub-Class 5	#	100%	100%	100%
Number of Customers All Commercial Classes	#	100%	100%	100%
Number of Customers Industrial Sub-Class 1	#	100%	100%	100%
Number of Customers Industrial Sub-Class 2	#	100%	100%	100%
Number of Customers Industrial Sub-Class 3	#	100%	100%	100%
Number of Customers Industrial Sub-Class 4	#	100%	100%	100%
Number of Customers Industrial Sub-Class 5	#	100%	100%	100%
Number of Customers All Industrial Classes	#	100%	100%	100%

Figure 26 CM Main Page

Task III: Development of Toolkits to Evaluate Benefit-Costs

Subtask 3.1: Development of Simplified cost-benefits analysis tool
Subtask 3.2: Technical Analysis of current BCA took-kit and Modification of Simplified tool-kit

III.1 Development of Simplified Cost-Benefit Analysis Tool

III.1.1 Overview

In this chapter, a simplified cost-benefit analysis tool is being developed taking SGCT of DOE as a benchmark tool kit. As will be discussed later, this tool kit has various advantages over other tools: First, this tool is open to public and anyone can take a look inside of the model deep enough to examine the visual basic application modules. JRCEU, McKinsey models were once discussed in Annex III before for any potential utilization for ISGAN member countries' tool kit. However, members acknowledge the fact that JRC works on excel based format and there seems to be not much difference between JRC's work and DOE. The difference lies in the fact that JRC never opened up the details of the functionalities and sample calculation of BC in their whole work process. McKinsey software was discussed but it is not open to public. Rather it is a commercial package with no specific advantage over to SGCT of DOE. Detailed engine is not fully explained and the scope of the analysis the tool kit provides does not seem to be very useful (Nigris 2012, Kim 2013).

The new tool kit being developed is named for the time as 'Smart Grid BCA Toolkit Revised by EML' for convenience. Through the replication process, a lot of details have been identified, which, otherwise, would not have been known to us. Many of the parameters utilized in the process of benefit calculation may be required to be collected from outside in the future, reflecting the region specific characteristics. Some of the default values provided by SGCT, although they are only for USA cases (refer to accompanying manual), may also be useful until those detailed information becomes available for ISGAN member countries even when they don't have them. As discussed above at III.2.24, it is being reminded again that there are at least 12 smart grid projects currently being conducted in USA, and those projects are starting to produce some detailed information which might be potentially utilized by current SGCT.

Not only those advantages, there are many interesting researches being conducted around the world and the work results could be very useful sources of updating this replication effort in the future, once this replication process allows us to identify the pros and cons of the current model.

III.1.2 Detailed Architecture of DIM in Replicated Tool Kit

After the separation of UI and data, it is possible for us to design flexible and extensible UI at our disposal. For example, if data changes to new data or edits some data, UI does not have to be designed.

Since the controls in SGCT is fixed already by predefined data set, but controls in our program are created from data when program begins.

DB structure can be summarized as is shown below. Contents in the colored boxes in the following diagram presents some of data information included in several files.

- ✓ Data in blue box are PC (Project Characterization) data which consist of definition of assets, functions and benefits. PC data is defined in 'sys-def.xml'.
- ✓ Data in green box are defined data to calculate benefit and it defined in 'input-def.xml'.
- ✓ Data in brown boxes are rearranged default values and it is defined in 'defulat-values.xlsx.
- ✓ Lastly, data in black box is saved information data of project and it is defined in 'project-def.xml'.

Original default values are hidden in SGCT. User can save and load those data information which is being utilized by the software program.

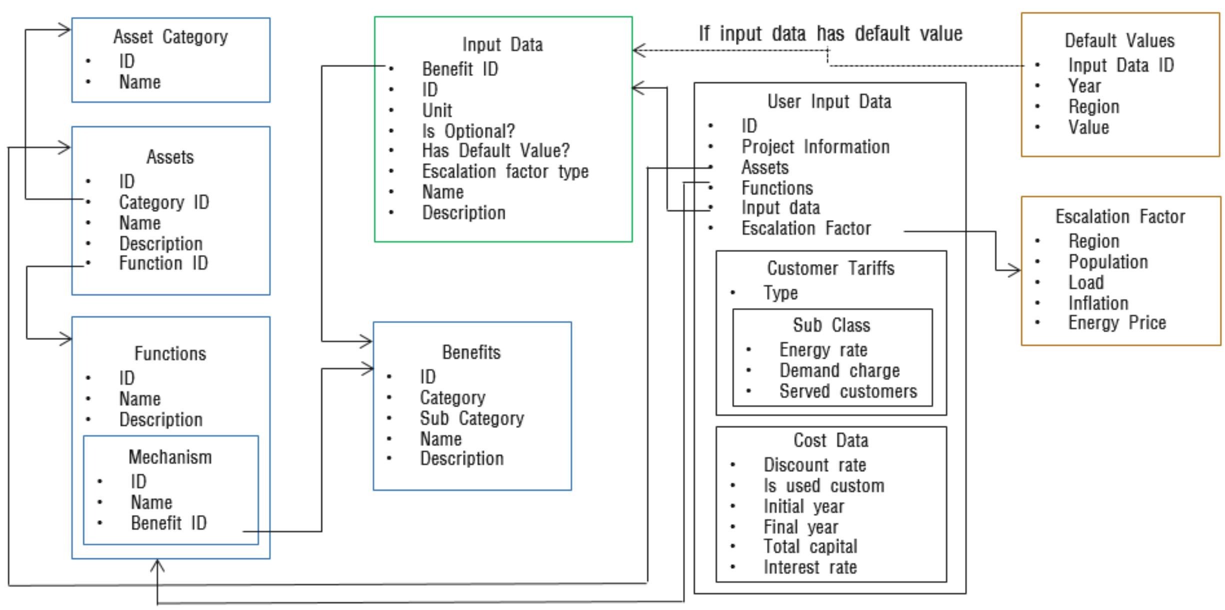


Figure 27 Detailed Architecture of DIM in Replicated Tool Kit

At the accompanying manual, each of the component boxes in the above diagram are presented in detail for the information it contains.

III.1.3 A Brief Comparison to SGCT and our program

There are basically three modules in SGCT, which are:

1. Project Characterization Module (PCM)
2. Data Input Module (DIM)

3. Computational Module (CM)

In the following, each of the modules indicated above will be compared to show its original form of SGCT and our Replicated Tool Kit.

III.1.3.1 Comparison of PCM in SGCT and our program

First, four dialog boxes from PCM are compiled in a single dialog box in the following page.

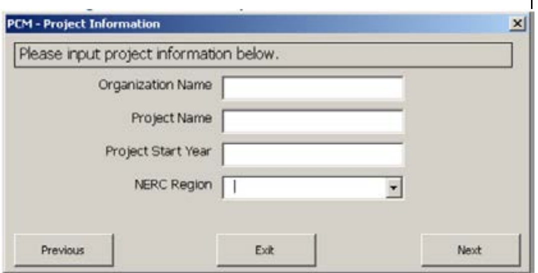


Figure 28 PCM Project Information Screen

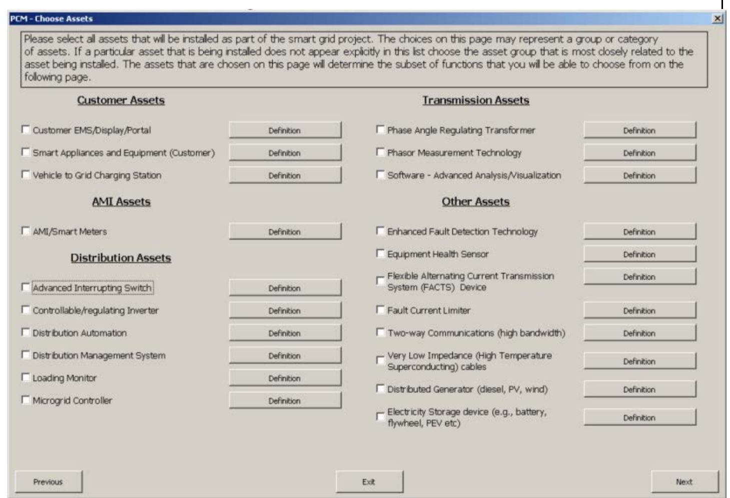


Figure 29 PCM Asset Selection Screen

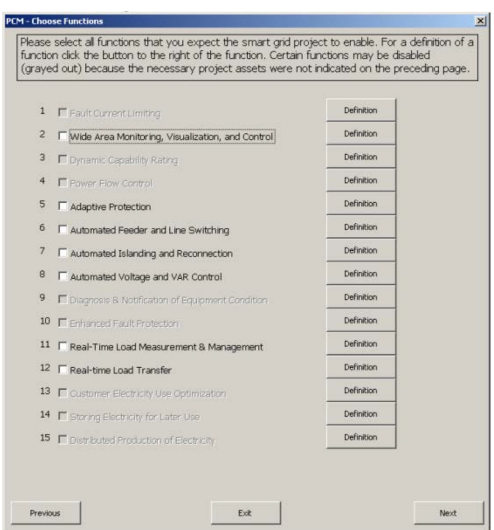


Figure 30 PCM Function Selection Screen

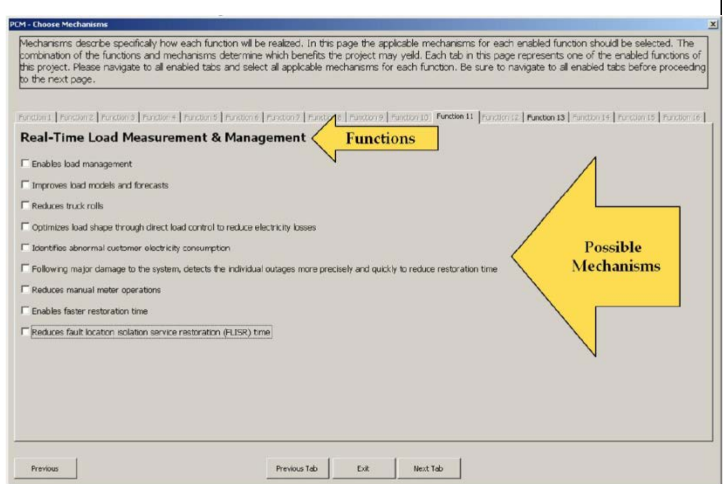


Figure 31 PCM Mechanism Selection Screen

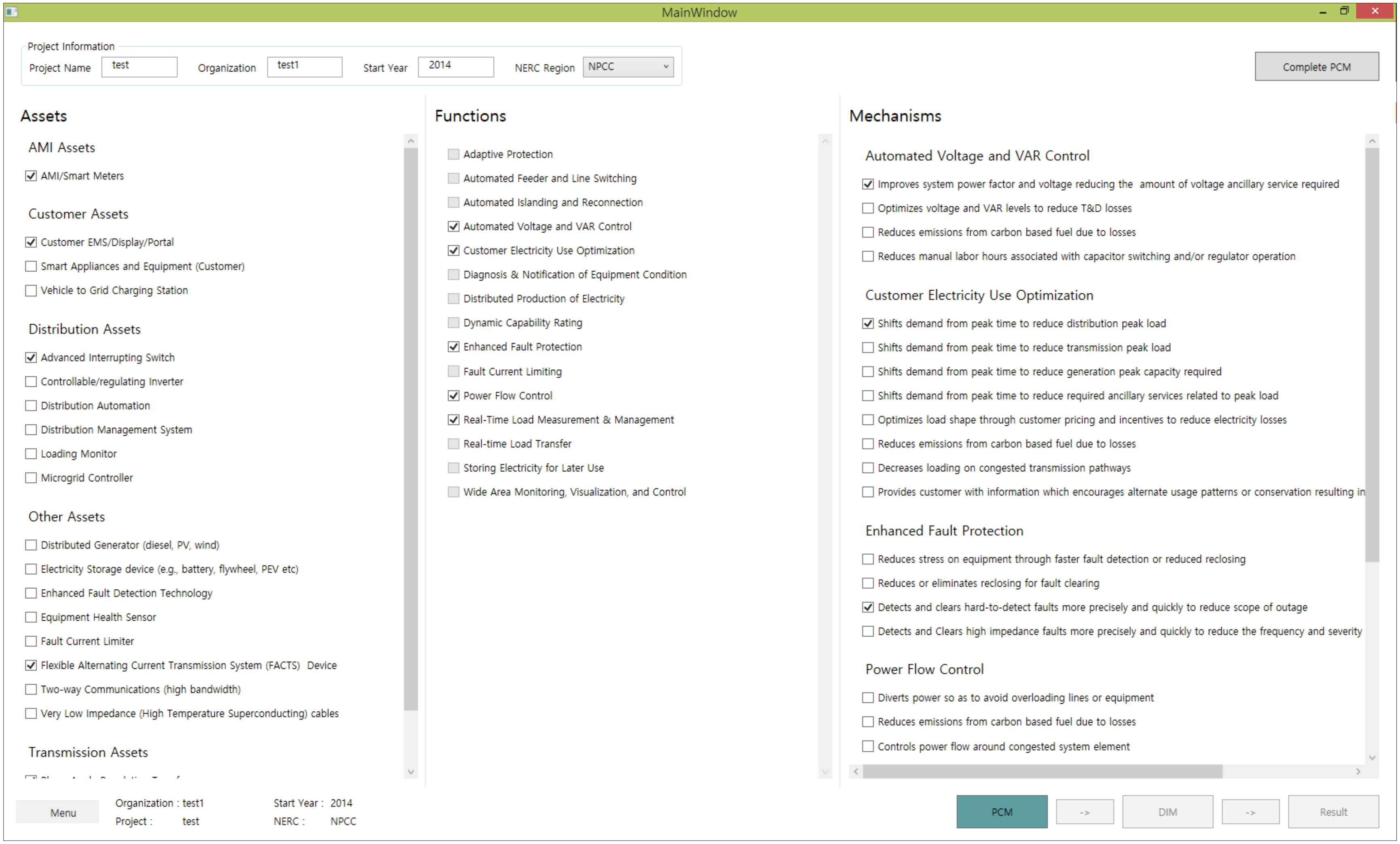


Figure 32 Project Information and Asset/ Function/Mechanism Selection Screen (Replicated Tool Kit)

The SCGT selects the benefits that the smart grid project should yield, given the assets, functions, and mechanisms user have selected. The PCM Benefits Screen displays related benefits.

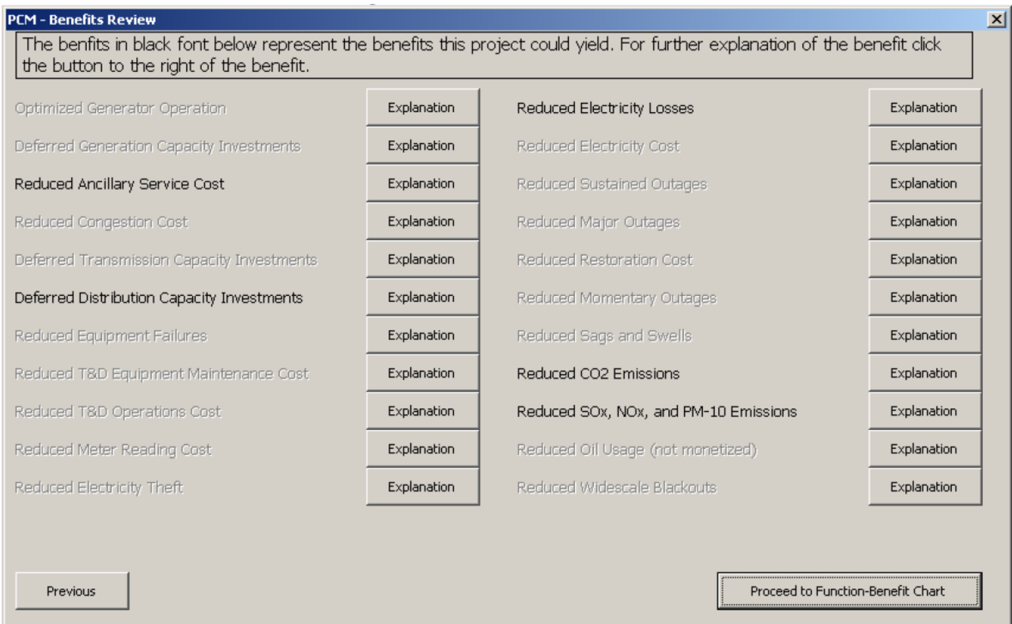


Figure 33 PCM Benefits Screen (DOE SGCT)

Following dialog box is from Replicated Tool Kit – left hand side of the box is still to be incorporated with further information on the detailed asset, function, mechanism and benefits. Current diagram is simple example of what it would be after the details are implemented in the code.

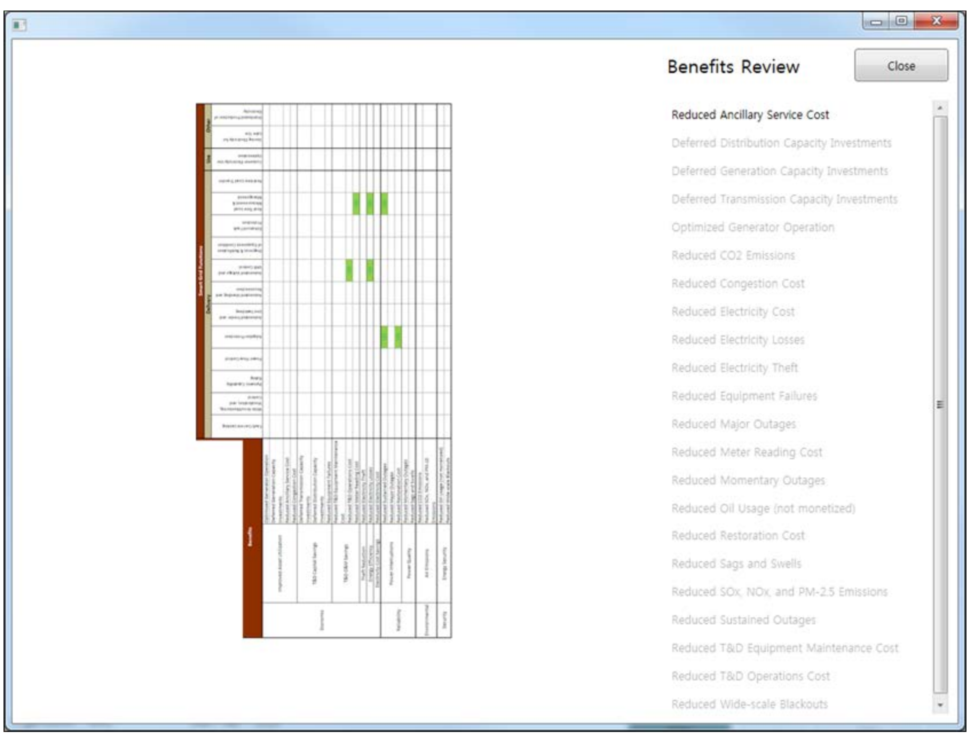


Figure 34 Benefits Screen (Replicated Tool Kit)

III.1.3.2 Comparison of DIM in SGCT and our program

In DIM Step I, the user is required to enter information on electricity tariff and customer population. This data entry is required regardless of which benefits were enabled by the PCM because it used in many of the benefit calculations. The two tables are the Electricity Rates by Customer Class and the Number of Customers by Class tables, or Table 1 and 2 respectively in upper left figure in the following table.

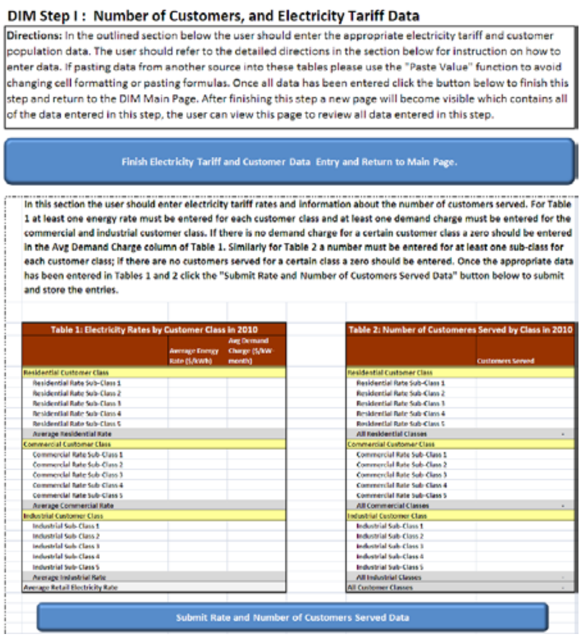


Figure 35 Electricity tariff data and customers served data entry tables

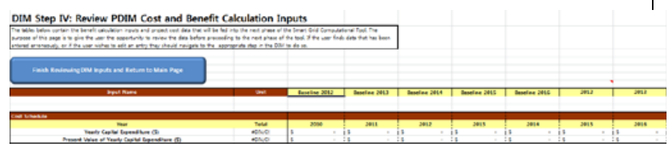


Figure 36 Cost calculation inputs

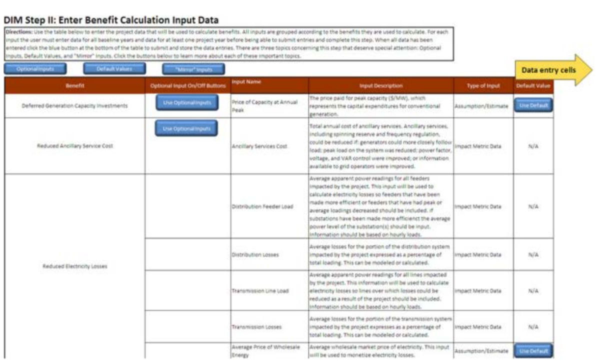


Figure 37 Escalation factor table

Figure 38 Data input sheet

The above four dialog boxes are now compiled in a single box presented in the following in Replicated Tool Kit.

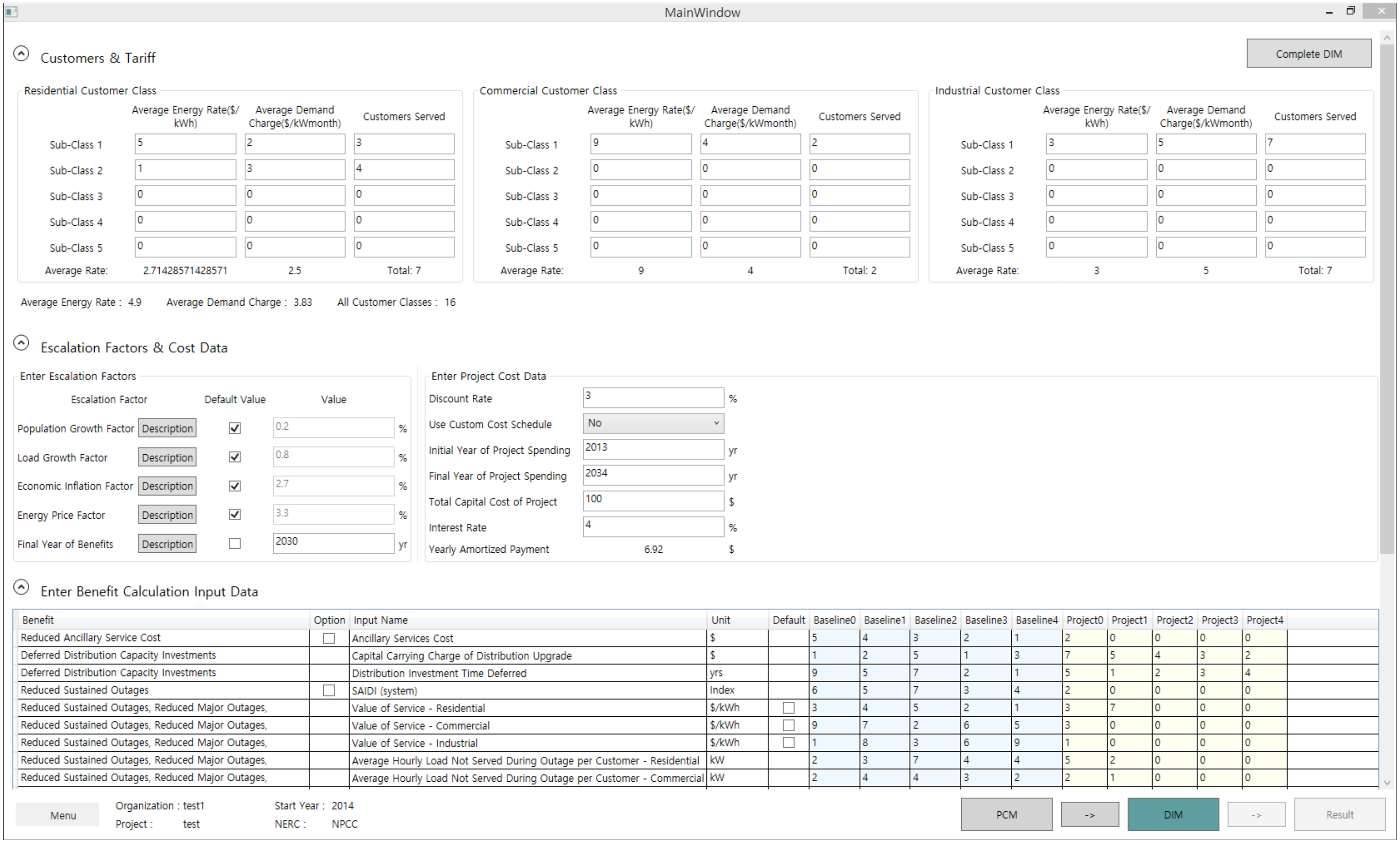
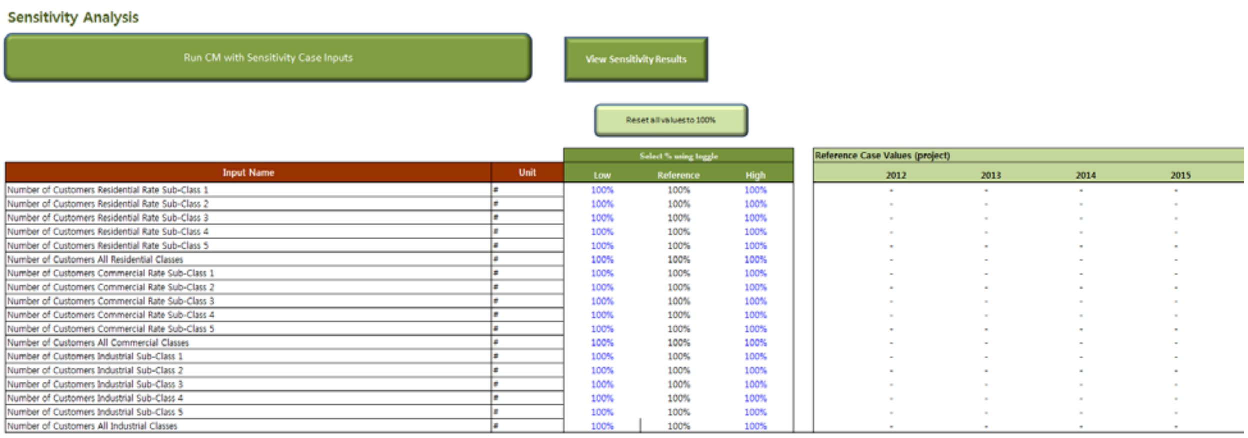


Figure 39 Data Input Module (DIM) Screen (Replicated Tool Kit)

III.1.3.3 Comparison of CM in SGCT and our program

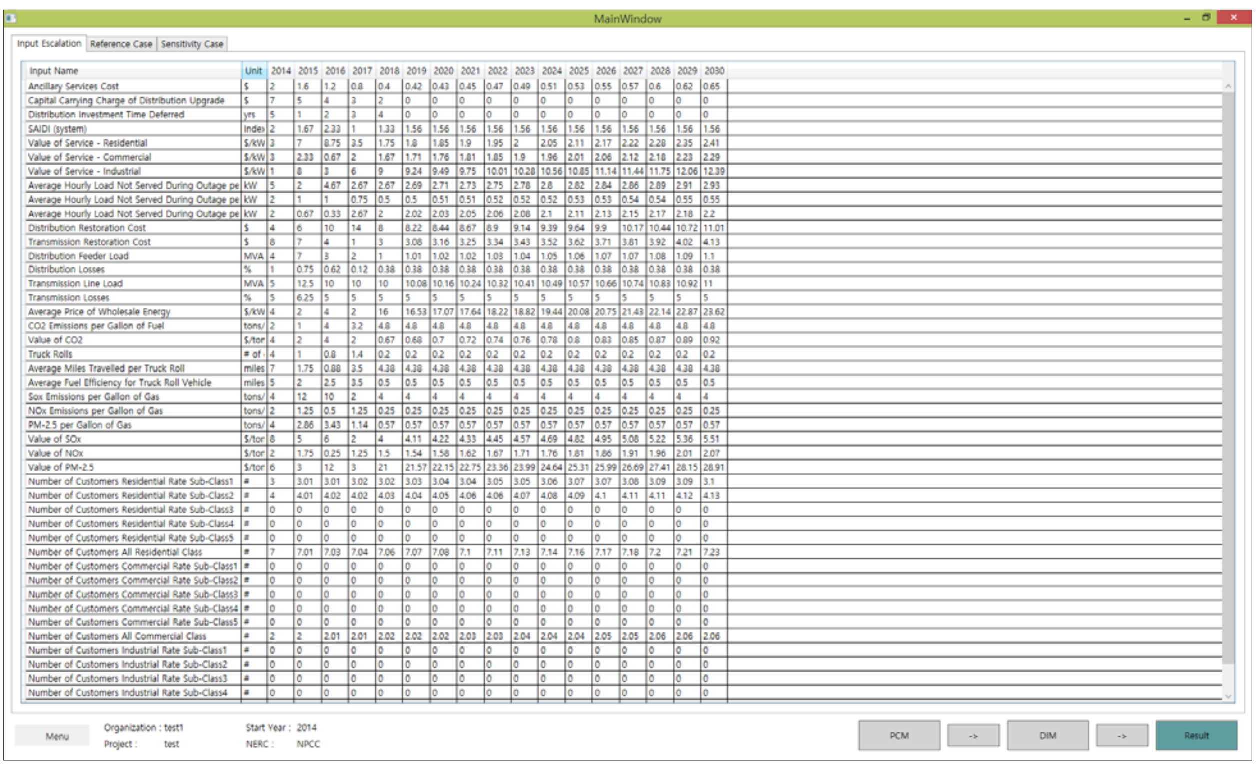
CM Main page allows you to run the cost-benefit analysis with the inputs entered in the DIM, collectively referred to as the Reference Case, or it allows for an analysis to be run with high and low sensitivity case inputs, collectively referred to as the Sensitivity Case.



Input Name	Unit	Select % using toggle			Reference Case Values (project)			
		Low	Reference	High	2012	2013	2014	2015
Number of Customers Residential Rate Sub-Class 1	#	100%	100%	100%	-	-	-	-
Number of Customers Residential Rate Sub-Class 2	#	100%	100%	100%	-	-	-	-
Number of Customers Residential Rate Sub-Class 3	#	100%	100%	100%	-	-	-	-
Number of Customers Residential Rate Sub-Class 4	#	100%	100%	100%	-	-	-	-
Number of Customers Residential Rate Sub-Class 5	#	100%	100%	100%	-	-	-	-
Number of Customers All Residential Classes	#	100%	100%	100%	-	-	-	-
Number of Customers Commercial Rate Sub-Class 1	#	100%	100%	100%	-	-	-	-
Number of Customers Commercial Rate Sub-Class 2	#	100%	100%	100%	-	-	-	-
Number of Customers Commercial Rate Sub-Class 3	#	100%	100%	100%	-	-	-	-
Number of Customers Commercial Rate Sub-Class 4	#	100%	100%	100%	-	-	-	-
Number of Customers Commercial Rate Sub-Class 5	#	100%	100%	100%	-	-	-	-
Number of Customers All Commercial Classes	#	100%	100%	100%	-	-	-	-
Number of Customers Industrial Sub-Class 1	#	100%	100%	100%	-	-	-	-
Number of Customers Industrial Sub-Class 2	#	100%	100%	100%	-	-	-	-
Number of Customers Industrial Sub-Class 3	#	100%	100%	100%	-	-	-	-
Number of Customers Industrial Sub-Class 4	#	100%	100%	100%	-	-	-	-
Number of Customers Industrial Sub-Class 5	#	100%	100%	100%	-	-	-	-
Number of Customers All Industrial Classes	#	100%	100%	100%	-	-	-	-

Figure 40 CM Main Page (DOE SGCT)

The above dialog box is now compiled as the following in Replicated Tool Kit.



Input Name	Unit	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Ancillary Services Cost	$	2	1.6	1.2	0.8	0.4	0.42	0.43	0.45	0.47	0.49	0.51	0.53	0.55	0.57	0.6	0.62	0.65
Capital Carrying Charge of Distribution Upgrade	$	7	5	4	3	2	0	0	0	0	0	0	0	0	0	0	0	0
Distribution Investment Time Deferred	yrs	5	1	2	3	4	0	0	0	0	0	0	0	0	0	0	0	0
SAIDI (system)	Inde	2	1.67	2.33	1	1.33	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
Value of Service - Residential	$/kW	3	7	8.75	3.5	1.75	1.8	1.85	1.9	1.95	2	2.05	2.11	2.17	2.22	2.28	2.35	2.41
Value of Service - Commercial	$/kW	3	2.33	0.67	2	1.67	1.71	1.76	1.81	1.85	1.9	1.96	2.01	2.06	2.12	2.18	2.23	2.29
Value of Service - Industrial	$/kW	1	8	3	6	9	9.24	9.49	9.75	10.01	10.28	10.56	10.85	11.14	11.44	11.75	12.06	12.39
Average Hourly Load Not Served During Outage pe	kW	5	2	4.67	2.67	2.67	2.69	2.71	2.73	2.75	2.78	2.8	2.82	2.84	2.86	2.89	2.91	2.93
Average Hourly Load Not Served During Outage pe	kW	2	1	1	0.75	0.5	0.5	0.51	0.51	0.52	0.52	0.52	0.53	0.53	0.54	0.54	0.55	0.55
Average Hourly Load Not Served During Outage pe	kW	2	0.67	0.33	2.67	2	2.02	2.03	2.05	2.06	2.08	2.1	2.11	2.13	2.15	2.17	2.18	2.2
Distribution Restoration Cost	$	4	6	10	14	8	8.22	8.44	8.67	8.9	9.14	9.39	9.64	9.9	10.17	10.44	10.72	11.01
Transmission Restoration Cost	$	8	7	4	1	3	3.08	3.16	3.25	3.34	3.43	3.52	3.62	3.71	3.81	3.92	4.02	4.13
Distribution Feeder Load	MVA	4	7	3	2	1	1.01	1.02	1.02	1.03	1.04	1.05	1.06	1.07	1.07	1.08	1.09	1.1
Distribution Losses	%	1	0.75	0.62	0.12	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38
Transmission Line Load	MVA	5	12.5	10	10	10	10.08	10.16	10.24	10.32	10.41	10.49	10.57	10.66	10.74	10.83	10.92	11
Transmission Losses	%	5	6.25	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Average Price of Wholesale Energy	$/kW	4	2	4	2	16	16.53	17.07	17.64	18.22	18.82	19.44	20.08	20.75	21.43	22.14	22.87	23.62
CO2 Emissions per Gallon of Fuel	tons/	2	1	4	3.2	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Value of CO2	$/tor	4	2	4	2	0.67	0.68	0.7	0.72	0.74	0.76	0.78	0.8	0.83	0.85	0.87	0.89	0.92
Truck Rolls	# of	4	1	0.8	1.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Average Miles Travelled per Truck Roll	miles	7	1.75	0.88	3.5	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38	4.38
Average Fuel Efficiency for Truck Roll Vehicle	miles	5	2	2.5	3.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Sox Emissions per Gallon of Gas	tons/	4	12	10	2	4	4	4	4	4	4	4	4	4	4	4	4	4
NOx Emissions per Gallon of Gas	tons/	2	1.25	0.5	1.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
PM-2.5 per Gallon of Gas	tons/	4	2.86	3.43	1.14	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57	0.57
Value of SOx	$/tor	8	5	6	2	4	4.11	4.22	4.33	4.45	4.57	4.69	4.82	4.95	5.08	5.22	5.36	5.51
Value of NOx	$/tor	2	1.75	0.25	1.25	1.5	1.54	1.58	1.62	1.67	1.71	1.76	1.81	1.86	1.91	1.96	2.01	2.07
Value of PM-2.5	$/tor	6	3	12	3	21	21.57	22.15	22.75	23.36	23.99	24.64	25.31	25.99	26.69	27.41	28.15	28.91
Number of Customers Residential Rate Sub-Class1	#	3	3.01	3.01	3.02	3.02	3.03	3.04	3.04	3.05	3.05	3.06	3.07	3.07	3.08	3.09	3.09	3.1
Number of Customers Residential Rate Sub-Class2	#	4	4.01	4.02	4.02	4.03	4.04	4.05	4.06	4.06	4.07	4.08	4.09	4.1	4.11	4.11	4.12	4.13
Number of Customers Residential Rate Sub-Class3	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Residential Rate Sub-Class4	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Residential Rate Sub-Class5	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers All Residential Class	#	7	7.01	7.03	7.04	7.06	7.07	7.08	7.1	7.11	7.13	7.14	7.16	7.17	7.18	7.2	7.21	7.23
Number of Customers Commercial Rate Sub-Class1	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Commercial Rate Sub-Class2	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Commercial Rate Sub-Class3	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Commercial Rate Sub-Class4	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Commercial Rate Sub-Class5	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers All Commercial Class	#	2	2	2.01	2.01	2.02	2.02	2.02	2.03	2.03	2.04	2.04	2.04	2.05	2.05	2.06	2.06	2.06
Number of Customers Industrial Rate Sub-Class1	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Industrial Rate Sub-Class2	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Industrial Rate Sub-Class3	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Number of Customers Industrial Rate Sub-Class4	#	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 41 CM Main Page (Replicated Tool Kit)

For other dialog boxes in SGCT including those of results, please refer to the accompanying manual for 'Smart Grid BCA Toolkit Revised by EML'.

III.2 Calculation of Benefit

Once the asset or technology is selected, then the user selected functions from default candidates will map those over to the benefit through mechanism. In the EPRI Methodological Approach, one of the focus is the concept of benefit. The term "benefit" is defined as an impact (of a Smart Grid project) that has value to a firm, a household, or society in general. To measure the size of benefits, quantification is needed. In addition, the quantified benefits should be expressed in monetary so that it can be compared with others. Basic formulation of the benefit calculation can be presented such as following:

$$Benefit = Cost_{baseline} - Cost_{Project}$$

$Benefit$ in the above equation represents the 'avoided cost' or 'reduced cost' due to the introduction of assets or new technology for smart grid. $Cost_{baseline}$ and $Cost_{project}$ represents the cost before the SG and after the SG, respectively.

Followings are the benefit calculation selected:

III.2.1 Optimized Generator Operation

- ✓ Annual Generation Cost ($)

Value ($) = [Annual Generation Cost ($))]$_{\text{Baseline}}$ – [Annual Generation Cost ($)]$_{\text{Project}}$

Optional Inputs

- ✓ Average Hourly Generation Cost ($/MWh)
- ✓ Avoided Annual Generator Dispatch (MWh)
- ✓ Annual Energy Storage Efficiency (%)
- ✓ Annual PEV Efficiency (%)

**Value ($)** = {[Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh)]$_{\text{Baseline}}$ – Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh)]$_{\text{Project}}$} * Average Efficiency(%)

> **Average Efficiency (%) =** For projects that yield this benefit as a result of Wide Area Monitoring, Visualization, and Control, the value will be 100%. For projects that just support Stationary Electricity Storage or Plug-in Electric Vehicles this value will be equal to the Annual Efficiency of these technologies. For projects that enable multiple functions which lead to this benefit an average of all efficiencies will be used.

*Note: default value of Average Hourly Generation Cost for all NERC regions are provided in the Appendix.

III.2.2 Deferred Generation Capacity Investments

- ✓ Total Customer Peak Demand (MW)
- ✓ Energy Storage Use at Annual Peak Time (MW)
- ✓ Distributed Generation Use at Annual Peak Time (MW) – Impact
- ✓ PEV Use at Annual Peak Time (MW) – Impact
- ✓ Price of Capacity at Annual Peak ($/MW),

Value ($) = [Price of Capacity at Annual Peak ($/MW) * Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)]$_{\text{Baseline}}$ - [Price of Capacity at Annual Peak ($/MW) * Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)]$_{\text{Project}}$

Optional Inputs

- ✓ Capital Carrying Charge of New Generation ($/yr)
- ✓ Generation Investment Time Deferred (yrs)

Value ($) = [NPV of Generation Investment Deferral($)]$_{\text{project}}$- [NPV of Generation Investment Deferral ($)]$_{\text{baseline}}$

NPV of Generation Investment Deferral ($) = Capital Carrying Charge of New Generation ($) *[1-(1-discount rate (%))^Time Deferred (yrs)]

*Note: default value of Price of Capacity at Annual Peak for all NERC regions are provided in the Appendix.

III.2.3 Reduced Ancillary Service Cost

- ✓ Ancillary Services Cost ($)

Value ($) = [Ancillary Service Cost ($)]$_{\text{Baseline}}$ - [Ancillary Service Cost ($)]$_{\text{Project}}$

Optional Inputs

- ✓ Average Price of Reserves ($/MW)
- ✓ Reserve Purchases (MW)
- ✓ Average Price of Frequency Regulation ($/MW)
- ✓ Frequency Regulation Purchases (MW)

- ✓ Average Price of Voltage Control ($/MVAR)
- ✓ Voltage Control Purchases (MVAR)

Value ($) = $[\Sigma$ (Price of Ancillary Service ($/MW) * Purchases (MW))$]_{Baseline}$ - $[\Sigma$ (Price of Ancillary Service ($/MW) * Purchases (MW))$]_{Project}$

*Note: default value of Average Price of Reserves, Average Price of Frequency Regulation, Average Price of Voltage Control for all NERC regions are provided in the Appendix

III.2.4 Reduced Congestion Cost

- ✓ Congestion Cost ($)

Value ($) = [Congestion Cost($)$]_{Baseline}$ - [Congestion Cost($)$]_{Project}$

Optional Inputs

- ✓ Congestion (MW)
- ✓ Average Price of Congestion ($/MW)

Value ($) = [Congestion (MW) * Price of Congestion ($/MW)$]_{Baseline}$ - [Congestion (MW) * Price of Congestion ($/MW)$]_{Project}$

*Note: default value of Average Price of Congestion for all NERC regions are provided in the Appendix.

III.2.5 Deferred Transmission Capacity Investments

- ✓ Capital Carrying Charge of Transmission Upgrade ($)
- ✓ Transmission Investment Time Deferred (yrs)

Value ($) = [NPV of Transmission Investment Deferral ($)$]_{project}$- [NPV of Transmission Investment Deferral ($)$]_{baseline}$

III.2.6 Deferred Distribution Capacity Investments

- ✓ Capital Carrying Charge of Distribution Upgrade ($/yr)
- ✓ Distribution Investment Time Deferred (yrs)

Value ($) = [NPV of Distribution Investment Deferral ($)]$_{project}$- [NPV of Distribution Investment Deferral ($)]$_{baseline}$

> **NPV of Transmission Investment Deferral ($)** = Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))

III.2.7 Reduced Equipment Failures

- ✓ Capital Replacement of Failed Equipment ($)
- ✓ Portion Caused by Fault Current or Overloaded Equipment (%)
- ✓ Portion Caused by Lack of Condition Diagnosis (%)

Value ($) = [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Project}$

III.2.8 Reduced Transmission & Distribution Equipment Maintenance Cost

- ✓ Total Transmission Maintenance Cost ($)
- ✓ Total Distribution Maintenance Cost ($)

Value ($) = [Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Baseline}$ –[Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Project}$

III.2.9 Reduced Transmission& Distribution Operations Cost

- ✓ Transmission Operations Cost ($)
- ✓ Distribution Operations Cost ($)

Value ($) = [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$

Optional Inputs

- ✓ Distribution Feeder Switching Operations ($)
- ✓ Distribution Capacitor Switching Operations ($)
- ✓ Other Distribution Operations Cost ($)

Value ($) = [Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{\text{Baseline}}$ - [= Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{\text{Project}}$

III.2.10 Reduced Meter Reading Cost

- ✓ Meter Operations Cost ($)

Value ($) = [Meter Operations Cost ($)]$_{\text{Baseline}}$ - [Meter Operations Cost ($)]$_{\text{Project}}$

III.2.11 Reduced Electricity Theft

- ✓ Number of Meter Tamper Detections –Residential
- ✓ Number of Meter Tamper Detections –Commercial
- ✓ Number of Meter Tamper Detections – Industrial
- ✓ Average Annual Customer Electricity Usage –Residential, Commercial, Industrial

**Value ($)** = [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Baseline}}$ - [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Project}}$

*Note: default value of Average Price of Wholesale Energy, Value of Service - Residential (Inflation Factor), Value of Service - Commercial (Inflation Factor), Value of Service - Industrial (Inflation Factor) for all NERC regions are provided in the Appendix.

III.2.12 Reduced Electricity Losses

- ✓ Distribution Feeder Load (MW)
- ✓ Distribution Losses (%)
- ✓ Transmission Line Load (MW)
- ✓ Transmission Losses (%)
- ✓ Average Price of Wholesale Energy ($/MWh)

Value ($) = [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Baseline}}$ - [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Project}}$

III.2.13 Reduced Electricity Cost

- ✓ Total Residential Electricity Cost ($)
- ✓ Total Commercial Electricity Cost ($)
- ✓ Total Industrial Electricity Cost ($)

Value ($) = [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Baseline}}$ - [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Project}}$

*Note: default value of Average Price of Wholesale Energy, Value of Service - Residential (Inflation Factor), Value of Service - Commercial (Inflation Factor), Value of Service - Industrial (Inflation Factor) for all NERC regions are provided in the Appendix.

III.2.14 Reduced Sustained Outages

- ✓ SAIDI (System)
- ✓ Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial
- ✓ Average Hourly Load Not Served During Outage per Customer by class (kW)

**Value ($)** = Σ{ [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}

Optional Inputs

- ✓ SAIDI (Impacted Feeders or Lines)
- ✓ Total Customers Served by Impacted Feeders or Lines (#) – Residential, Commercial

**Value ($)** = Σ{ [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}

*Note: default value of Average Price of Wholesale Energy, Value of Service - Residential (Inflation Factor), Value of Service - Commercial (Inflation Factor), Value of Service - Industrial (Inflation Factor), Value of Service - PQ (Inflation Factor) for all NERC regions are provided in the Appendix.

III.2.15 Reduced Major Outages

- ✓ Outage Time of Major Outage (hr) – Residential, Commercial, Industrial
- ✓ Average Hourly Load Not Served During Outage per Customer by class (kW)
- ✓ Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial

Value ($) = Σ{ [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}

III.2.16 Reduced Restoration Cost

- ✓ Distribution Restoration Cost ($)
- ✓ Transmission Restoration Cost ($)

Value ($) = [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Baseline}}$ - [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{\text{Project}}$

Optional Inputs

- ✓ Number of Outage Events (#)
- ✓ Restoration Cost per Event ($/event)

Value ($) = [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Baseline}}$ - [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{\text{Project}}$

III.2.17 Reduced Momentary Outages

- ✓ MAIFI (System)
- ✓ Value of Service (VOS) – Power Quality ($/interruption)

Value ($) = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$

Momentary Interruptions (# of interruptions) = MAIFI (Index) * Σ{Total Customers Served by class (#)}

Optional Inputs

- ✓ MAIFI (Impacted Feeders)
- ✓ Total Customers Served on Impacted Feeders (momentary) (#) – Residential, Commercial, Industrial

Value ($) = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$

Momentary Interruptions (# of interruptions) = MAIFI of Impacted Feeders (Index) * Σ{Total Customers Served by class on the Impacted Feeders (#)}

*Note: default value of Value of Service - PQ (Inflation Factor) for all NERC regions are provided in the Appendix.

III.2.18 Reduced Sags and Swells

- ✓ Number of High Impedance Faults Cleared (# of events)
- ✓ Value of Service (VOS) – Sags and Swells ($/event)

Value ($) = [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Baseline}$ - [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Project}$

III.2.19 Reduced CO2 Emissions

For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition

- ✓ Truck Rolls (# of events)
- ✓ Average Miles Travelled per Truck Roll (miles/event)
- ✓ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)
- ✓ CO2 Emissions per Gallon of Fuel(tons/gallon)

**Value ($)** = Σ{Net CO2 Emissions Avoided (tons)}* Value of CO2 ($/ton)

Net CO2 Emissions Avoided (tons) = $[CO_2 \text{ Emissions (tons)}]_{Baseline}$ - $[CO_2 \text{ Emissions (tons)}]_{Project}$

Net CO2 Emissions Avoided (tons) = $[\text{CO2 Emissions Avoided(tons)}]_{Project}$ - $[\text{CO2 Emissions Avoided (tons)}]_{Baseline}$

*Note: default value of Average Fuel Efficiency for Feeder Service Vehicle, Average Fuel Efficiency for Diagnosis/Notification Service Vehicle, Average Fuel Efficiency for Real Time Load Measurement/Management Service Vehicle for all NERC regions are provided in the Appendix.

Optional Inputs

- ✓ Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ For PEV with Reduced Gasoline Consumption Mechanism
- ✓ kWh of Electricity Consumed by PEVs (kWh)
- ✓ Electricity to Fuel Conversion Factor (gallons/kWh)

For all other Functions (Including PEV with Offset Central Generation Mechanism)

- ✓ CO2 Emissions (tons)
- ✓ Value of CO2 ($/ton)

*Note: default value of Electricity to Fuel Conversion Factor, CO2 Emissions per Gallon of Fuel, Value of CO2 for all NERC regions are provided in the Appendix.

III.2.20 Reduced SOX, NOX, and PM-2.5 Emissions

For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition

- ✓ Truck Rolls (# of events)
- ✓ Average Miles Travelled per Truck Roll (miles/event)
- ✓ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)
- ✓ Emissions per Gallon of Fuel(tons/gallon) – SOx, NOx

**Value ($)** = Σ{Net Emissions Avoided (tons)* Value of Emissions ($/ton)}

Net Emissions Avoided (tons) = [Emissions (tons)]$_{Baseline}$ - [Emissions (tons)] $_{Project}$

Net Emissions Avoided (tons) = [Emissions Avoided(tons)]$_{Project}$ - [Emissions Avoided (tons)] $_{Baseline}$

Optional Inputs

- ✓ Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading

For PEV with Reduced Gasoline Consumption Mechanism

- ✓ kWh of Electricity Consumed by PEVs (kWh)
- ✓ Electricity to Fuel Conversion Factor (gallons/kWh)
- ✓ For all other Functions (Including PEV with Offset Central Generation Mechanism)
- ✓ SOx Emissions (tons)
- ✓ NOx Emissions (tons)
- ✓ PM-2.5 Emissions (tons)
- ✓ Value of Emissions ($/ton) – SOx, NOx, PM-2.5

*Note: default value of SOx Emissions per Gallon of Gas, NOx Emissions per Gallon of Gas, PM-2.5 per Gallon of Gas for all NERC regions are provided in the Appendix.

III.2.21 Reduced Oil Usage

For PEVs (with reduced gasoline consumption mechanism):

- ✓ kWh of Electricity Consumed by PEVs (kWh)
- ✓ Electricity to Fuel Conversion Factor(gallons/kWh)

Value (gallons of oil) = Net Avoided Fuel Use (gallons)* Fuel to Oil Conversion Factor (gallons oil/gallon fuel)

Net Avoided Fuel Use (gallons) = [Fuel Use (gallons)]$_{Baseline}$ - [Fuel Use (gallons)] $_{Project}$

Net Avoided Fuel Use (gallons) = [Avoided Fuel Use (gallons)]$_{Project}$ - [Avoided Fuel Use (gallons)] $_{Baseline}$

For all other Functions

- ✓ Truck Rolls (# of events)

- ✓ Average Miles Travelled per Truck Roll (miles/event)
- ✓ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)

Optional Inputs

- ✓ Number of Operations Completed (# of events) –Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
- ✓ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading

*Note: default value of Average Fuel Efficiency for Truck Roll Vehicle for all NERC regions are provided in the Appendix.

III.2.22 Reduced Wide-scale Blackouts

- ✓ Number of Wide-scale Blackouts (# of events)
- ✓ Estimated Cost of each Wide-scale Blackout ($/event)

Value ($) = [Number of Wide-scale Blackouts (# of events) * Estimated Cost of each Wide-scale Blackout ($/event)]$_{\text{Baseline}}$ - [Number of Wide-scale Blackouts (# of events) * Estimated Cost each Wide-scale Blackout ($/event)]$_{\text{Project}}$

III.2.23 Potential Barriers in Benefit Calculation and in Expansion of SGCT for ISGAN Member Countries

In the Appendix, all the default values for the followings are summarized:

- ✓ Average Hourly Generation Cost
- ✓ Price of Capacity at Annual Peak
- ✓ Average Price of Reserves
- ✓ Average Price of Frequency Regulation
- ✓ Average Price of Voltage Control
- ✓ Average Price of Congestion
- ✓ Average Price of Wholesale Energy
- ✓ Value of Service - Residential (Inflation Factor)
- ✓ Value of Service - Commercial (Inflation Factor)
- ✓ Value of Service - Industrial (Inflation Factor)
- ✓ Restoration Cost per Event
- ✓ Value of Service - PQ (Inflation Factor)
- ✓ Average Fuel Efficiency for Truck Roll Vehicle
- ✓ CO2 Emissions per Gallon of Fuel

- ✓ Value of CO2
- ✓ SOx Emissions per Gallon of Gas
- ✓ NOx Emissions per Gallon of Gas
- ✓ PM-2.5 per Gallon of Gas
- ✓ Value of SOx
- ✓ Value of NOx
- ✓ Value of PM-2.5
- ✓ Average Fuel Efficiency for Feeder Service Vehicle
- ✓ Average Fuel Efficiency for Diagnosis/Notification Service Vehicle
- ✓ Average Fuel Efficiency for Real Time Load Measurement/Management Service Vehicle
- ✓ Electricity to Fuel Conversion Factor

It is noted, however, there are a couple of things to be discussed.

First, there are many parameters in the benefit calculation which is not given for NERC regions. Examples for such are provided in the following:

III.2.2 Deferred Generation Capacity Investments

- ☐ Total Customer Peak Demand (MW)
- ☐ Energy Storage Use at Annual Peak Time (MW)
- ☐ Distributed Generation Use at Annual Peak Time (MW) – Impact
- ☐ PEV Use at Annual Peak Time (MW) – Impact
- ☐ Price of Capacity at Annual Peak ($/MW),

III.2.5 Deferred Transmission Capacity Investments

- ☐ Capital Carrying Charge of Transmission Upgrade ($)
- ☐ Transmission Investment Time Deferred (yrs)

III.2.6 Deferred Distribution Capacity Investments

- ☐ Capital Carrying Charge of Distribution Upgrade ($/yr)
- ☐ Distribution Investment Time Deferred (yrs)

III.2.7 Reduced Equipment Failures

- ☐ Capital Replacement of Failed Equipment ($)
- ☐ Portion Caused by Fault Current or Overloaded Equipment (%)
- ☐ Portion Caused by Lack of Condition Diagnosis (%)

III.2.8 Reduced Transmission & Distribution Equipment Maintenance Cost

- ☐ Total Transmission Maintenance Cost ($)
- ☐ Total Distribution Maintenance Cost ($)

III.2.9 Reduced Transmission& Distribution Operations Cost

- ☐ Transmission Operations Cost ($)
- ☐ Distribution Operations Cost ($)

- ☐ Distribution Feeder Switching Operations ($)
- ☐ Distribution Capacitor Switching Operations ($)
- ☐ Other Distribution Operations Cost ($)

III.2.11 Reduced Electricity Theft

- ☐ Number of Meter Tamper Detections –Residential
- ☐ Number of Meter Tamper Detections –Commercial
- ☐ Number of Meter Tamper Detections – Industrial

III.2.15 Reduced Major Outages

- ☐ Outage Time of Major Outage (hr) – Residential, Commercial, Industrial
- ☐ Average Hourly Load Not Served During Outage per Customer by class (kW)
- ☐ Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial

III.2.16 Reduced Restoration Cost

- ☐ Distribution Restoration Cost ($)
- ☐ Transmission Restoration Cost ($)

- ☐ Number of Outage Events (#)
- ☐ Restoration Cost per Event ($/event)

Second, even if some of default values are given for NERC regions, it would not be easy for users not in USA to find such values out of scratch. Examples for such include:

III.2.3 Reduced Ancillary Service Cost

- ☐ Average Price of Reserves ($/MW)
- ☐ Reserve Purchases (MW)
- ☐ Average Price of Frequency Regulation ($/MW)
- ☐ Frequency Regulation Purchases (MW)
- ☐ Average Price of Voltage Control ($/MVAR)
- ☐ Voltage Control Purchases (MVAR)

III.2.17 Reduced Momentary Outages

- ☐ MAIFI (System)
- ☐ Value of Service (VOS) – Power Quality ($/interruption)

☐ Total Customers Served on Impacted Feeders (momentary) (#) – Residential, Commercial, Industrial

III.2.19 Reduced CO2 Emissions
For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition
☐ Truck Rolls (# of events)
☐ Average Miles Travelled per Truck Roll (miles/event)
☐ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)
☐ CO2 Emissions per Gallon of Fuel(tons/gallon)

☐ Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ For PEV with Reduced Gasoline Consumption Mechanism
☐ kWh of Electricity Consumed by PEVs (kWh)
☐ Electricity to Fuel Conversion Factor (gallons/kWh)

III.2.20 Reduced SOX, NOX, and PM-2.5 Emissions
For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition
☐ Truck Rolls (# of events)
☐ Average Miles Travelled per Truck Roll (miles/event)
☐ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)
☐ Emissions per Gallon of Fuel(tons/gallon) – SOx, NOx
Optional Inputs
☐ Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
For PEV with Reduced Gasoline Consumption Mechanism
☐ kWh of Electricity Consumed by PEVs (kWh)
☐ Electricity to Fuel Conversion Factor (gallons/kWh)
☐ For all other Functions (Including PEV with Offset Central Generation Mechanism)
☐ SOx Emissions (tons)
☐ NOx Emissions (tons)
☐ PM-2.5 Emissions (tons)
☐ Value of Emissions ($/ton) – SOx, NOx, PM-2.5

III.2.21 Reduced Oil Usage
For PEVs (with reduced gasoline consumption mechanism):
☐ kWh of Electricity Consumed by PEVs (kWh)

☐ Electricity to Fuel Conversion Factor(gallons/kWh)

For all other Functions
☐ Truck Rolls (# of events)
☐ Average Miles Travelled per Truck Roll (miles/event)
☐ Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile)
Optional Inputs
☐ Number of Operations Completed (# of events) –Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading
☐ Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading

III.2.22 Reduced Wide-scale Blackouts
☐ Number of Wide-scale Blackouts (# of events)
☐ Estimated Cost of each Wide-scale Blackout ($/event)

To estimate the benefit according to EPRI guideline as is the case of DOE SGCT, as well as the cost, there are three dimensional frameworks that must be analyzed upon, as shown in figure below.

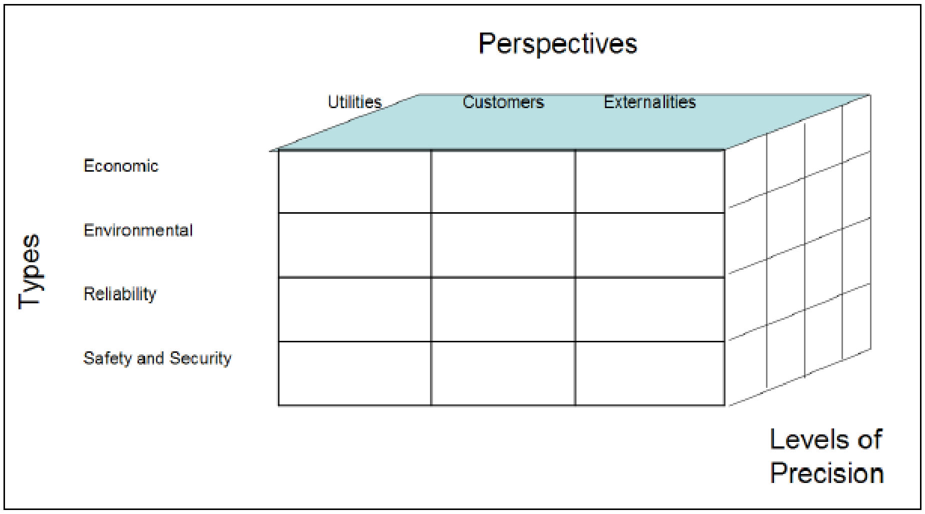


Figure 42 The Three Dimensions of Benefit and Cost of Smart Grid

Source: EPRI, 2010

The first dimension is the four fundamental categories (types) of benefits, that is economic, environmental, reliability, and safety and security. The second is the different perspectives of the benefits themselves, as seen by three beneficiaries: utilities, customers, and society as a whole. The third dimension, though, is proven to be the most difficult one to tackle: the levels of precision. The only reasonable way of characterizing the general level of precision is to use broad categories such as (EPRI, 2010):

- ✓ Modest level of uncertainty in quantitative estimates and/or in monetization
- ✓ Significant uncertainty in quantitative estimates and/or in how to monetize
- ✓ Highly uncertain
- ✓ Cannot be quantified

In the following, it is discussed that DOE has some carefully designed projects to overcome such difficulties as the precision of the required answers increases.

III.2.24 Ways to Overcome the Barriers

According to NRCEA and CRN (2013), the National Rural Electric Cooperative Association (NRECA) has organized the NRECA-U.S. Department of Energy (DOE) Smart Grid Demonstration Project to install and study a broad range of advanced Smart Grid technologies in a demonstration that involves 23 electric cooperatives in 11 states. For purposes of evaluation, the technologies deployed have been classified into three major sub-classes, each consisting of four technology types. Following is the list of demonstration projects:

Table 5 Demonstration projects

Enabling Technologies	**Advanced Metering Infrastructure**
	Meter Data Management Systems
	Telecommunications
	Supervisory Control and Data Acquisition
Demand Response	In-Home Displays & Web portals
	Demand Response Over AMI
	Prepaid Metering
	Interactive Thermal Storage
Distribution Automation	Renewables Integration
	Smart Feeder Switching
	Advanced Volt/VAR Control
	Conservation Voltage Reduction

Note: Bold types are applied for the cases with information available.

Not all of the Demonstration projects has reported information available. However there are 6 projects which have reports on the progress of the related projects:

- ✓ Advanced Metering Infrastructure
- ✓ Meter Data Management Systems
- ✓ Telecommunications
- ✓ Prepaid Metering
- ✓ Smart Feeder Switching
- ✓ Conservation Voltage Reduction

In the following, a brief summary of those projects are provided and the information gathered from those demonstration projects will further provide more accurate parameters for SGCT in the future.

Advanced Metering Infrastructure (AMI)

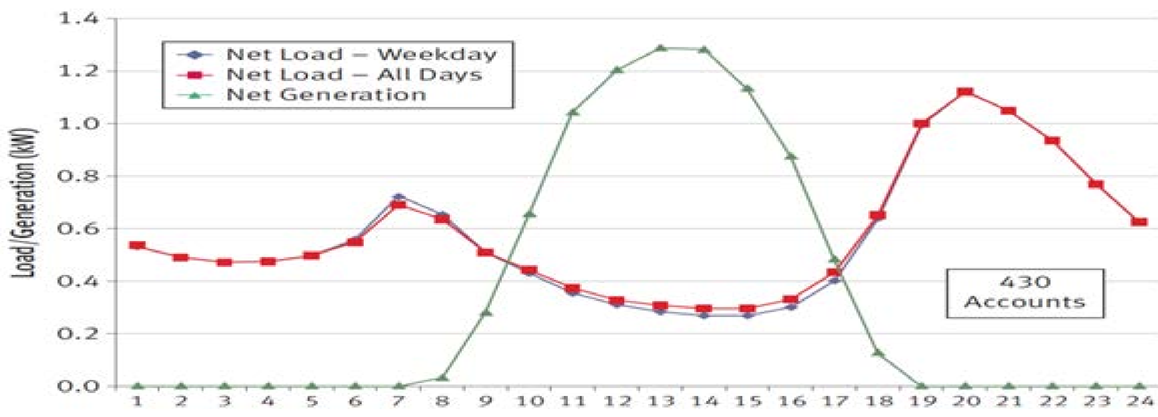


Figure 43 Net Metering Load vs. Generation Profiles - Residential.

Source: Cody (2014a)

"Average net load and generation profiles of selected net metering consumers on the KIUC system from March 2013 are shown above. The data represent net delivered and net received energy, rather than the full load requirements and total generation of the net metering customers." (Cody, 2014a)

Meter Data Management Systems

MDMS systems have four potential values which are Real-Time Information Sharing, Bidding Demand Response and Other Storage Resources into MISO, Monitoring Line Losses and Power Theft, and Load Forecasting. The below is an example of one of the types of aggregation the MT-MDMS provides.

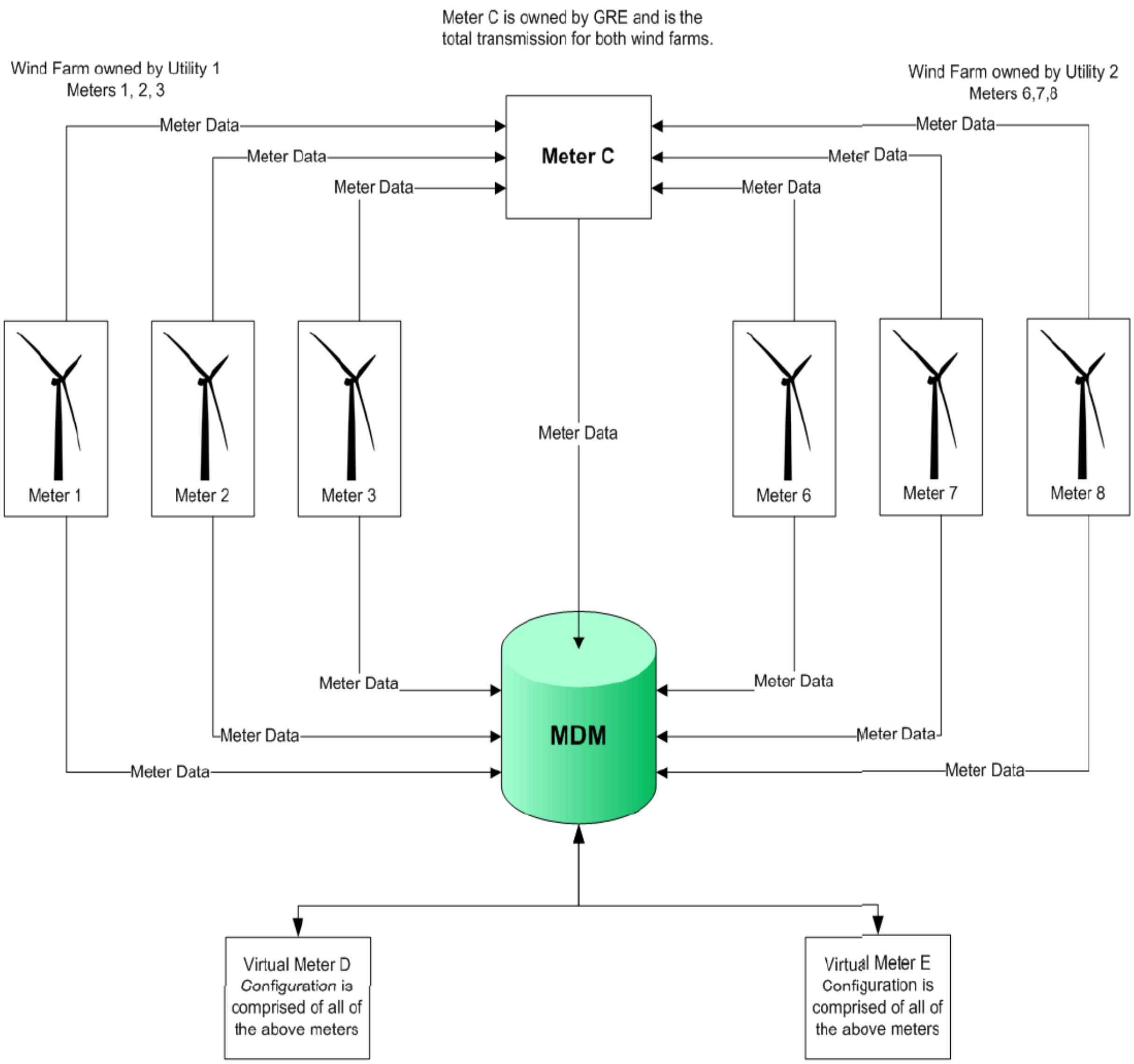


Figure 44 Aggregation MT-MDMS provides

Soruce: Walker (2014)

If sum(meters(1+2+3+6+7+8)) + Meter C = 0 then
  Virtual Meter D = 0
  Virtual Meter E = 0

Else If sum(meters(1+2+3+6+7+8)) = 0 AND Meter C > 0 then
  Virtual Meter D = Meter C * .5
  Virtual Meter E = Meter C * .5

Else
  Virtual Meter D = Meter C / sum(meters (1+2+3+6+7+8)) * sum(meters (1+2+3))
  Virtual Meter E = Meter C / sum(meters (1+2+3+6+7+8)0 * sum(meters (6+7+8))

Figure 45 If-Then Aggregation Logic

Source: Walker (2014)

Telecommunications

In the Smart Grid, communication has a distinct role which enables other technologies to be valid.

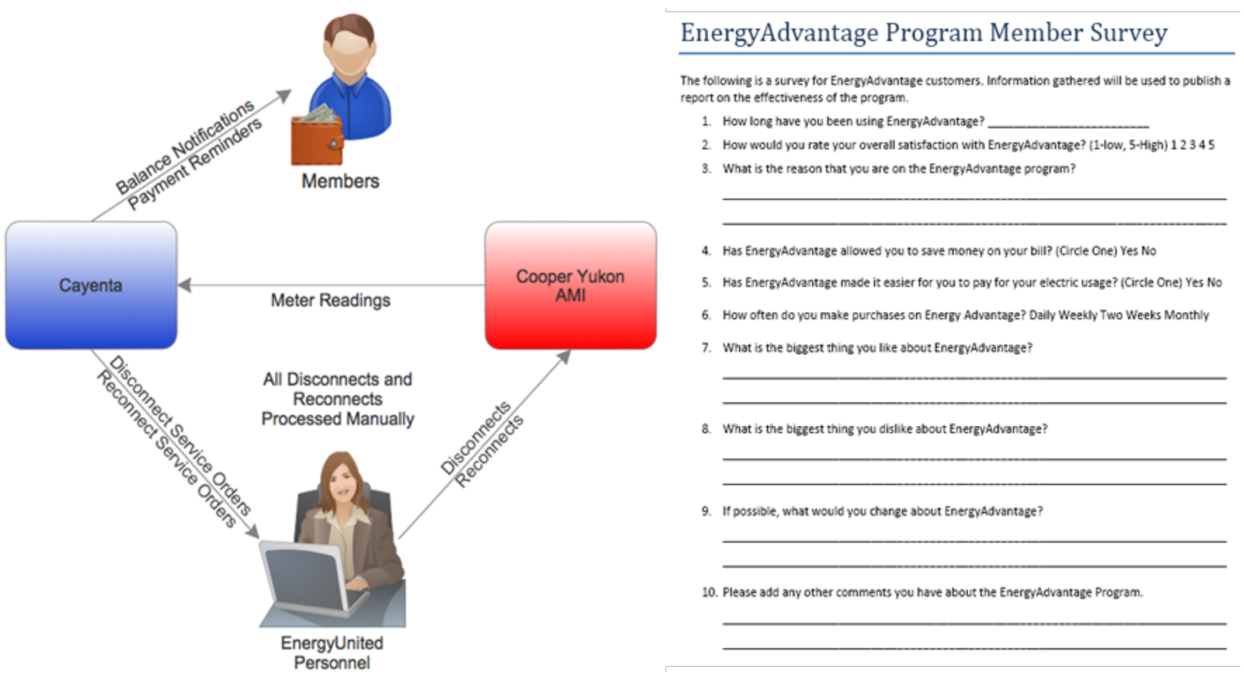
Communication thus plays a unique role in the Smart Grid—it is the enabling technology for other enabling technologies. In other words, benefits from communication are difficult to measure. It surely does not direct impact on others such as utility, the end user, or society in general. And it is related with multiple functions.

This ambiguous value has challenges to measure. Cody (2014f) listed four types of challenges: The first thing comes up toward someone interested in estimating the value of a potential communication upgrade. The second thing comes up because just one communication system can enable multiple smart grid functions. Cody (2014f) gave us an example that a single radio network may support both prepaid metering and demand response. Calculating the return on investment (ROI) of a communication up grade requires knowing the value of each supported Smart Grid function, any of which may be uncertain. In some cases, the communication upgrade may end up supporting functions that are implemented only later. Perhaps these functions would not even be considered until after the new communications are in place—the available bandwidth inspires system planners to consider functions that previously were unfeasible. For example, a utility that installs fiber to support smart feeder switching may find itself with excess bandwidth and later elect to use that bandwidth to support volt/VAR control. A utility with excess bandwidth is likely to look for ways to derive value from it. The third thing arises because it is moving target. As time goes by, the communication upgrade will be need periodically. So we might decide whether installing a new one or upgrading the old one continuously. In this context, a fourth thing is that the Smart Grid functions supported by communications are also moving targets. Those functions need to have bandwidth.

Prepaid Metering

Sioboda (2014) review three prepayment program under development at three distribution cooperatives as a part of the National Rural Electric Cooperative Association-U.S. Department of Energy (NRECA-DOE) Smart Grid Demonstration Project (SGDP)[52]. The report provides an overall status for each program design. But this report present the statistics gathered on the Energy Advantage Program Member Survey from EnergyUnited because the programs at DMEA and KEA are not yet in operation.

The level of participation for of EnergyUnited prepayment program is roughly about 1% of meter-based members. And the systems involved in offering prepayment to EU members are the Customer Information System (CIS) from Cayenta, and the advanced metering infrastructure (AMI) solution from Cooper Power Systems. The figure below shows the how the program designed and what EnergyUnited asked for their customer to assess the Energy Advantage Program Member Survey.



EnergyAdvantage Program Member Survey

The following is a survey for EnergyAdvantage customers. Information gathered will be used to publish a report on the effectiveness of the program.

1. How long have you been using EnergyAdvantage? ____________________
2. How would you rate your overall satisfaction with EnergyAdvantage? (1-low, 5-High) 1 2 3 4 5
3. What is the reason that you are on the EnergyAdvantage program?
4. Has EnergyAdvantage allowed you to save money on your bill? (Circle One) Yes No
5. Has EnergyAdvantage made it easier for you to pay for your electric usage? (Circle One) Yes No
6. How often do you make purchases on Energy Advantage? Daily Weekly Two Weeks Monthly
7. What is the biggest thing you like about EnergyAdvantage?
8. What is the biggest thing you dislike about EnergyAdvantage?
9. If possible, what would you change about EnergyAdvantage?
10. Please add any other comments you have about the EnergyAdvantage Program.

Figure 46 Cayenta/EU CIS High-Level Architecture and EA Program Member Survey

Source: Sioboda (2014)

The results are based on the 2,554 prepayment contracts which include purchase frequency, consumption pattern before and after the program participation. The result shows that some customers perceive that they conserve energy and also save money. But the statistical validity of data, effectiveness energy efficiency and conservation, and the other problems has to be solved.

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[52] The three cooperatives are EnergyUnited (EU), Delta-Montrose Electric Association (DMEA), and Kotzebue Electric Association (KEA).

Smart Feeder Switching

Pinney (2014) discusses the deployment experience of Smart Feeder Switching (SFS) applications at nine rural which experienced natural disasters and damaged the electric distribution system. They investigated models to represent and predict the benefits of these technologies, with extensions to automating screening and engineering analysis for future deployments. This study defines an analytical methodology for quantifying the value of two SFS operational benefits: (1) more rapid restoration following a fault and (2) reduced losses through feeder load balancing.

The benefits of SFS can be disaggregated into 4 parts which including Operational Benefits, Utility Benefits, Customer Benefits, and Society Benefits. The figure below shows the benefits realized.

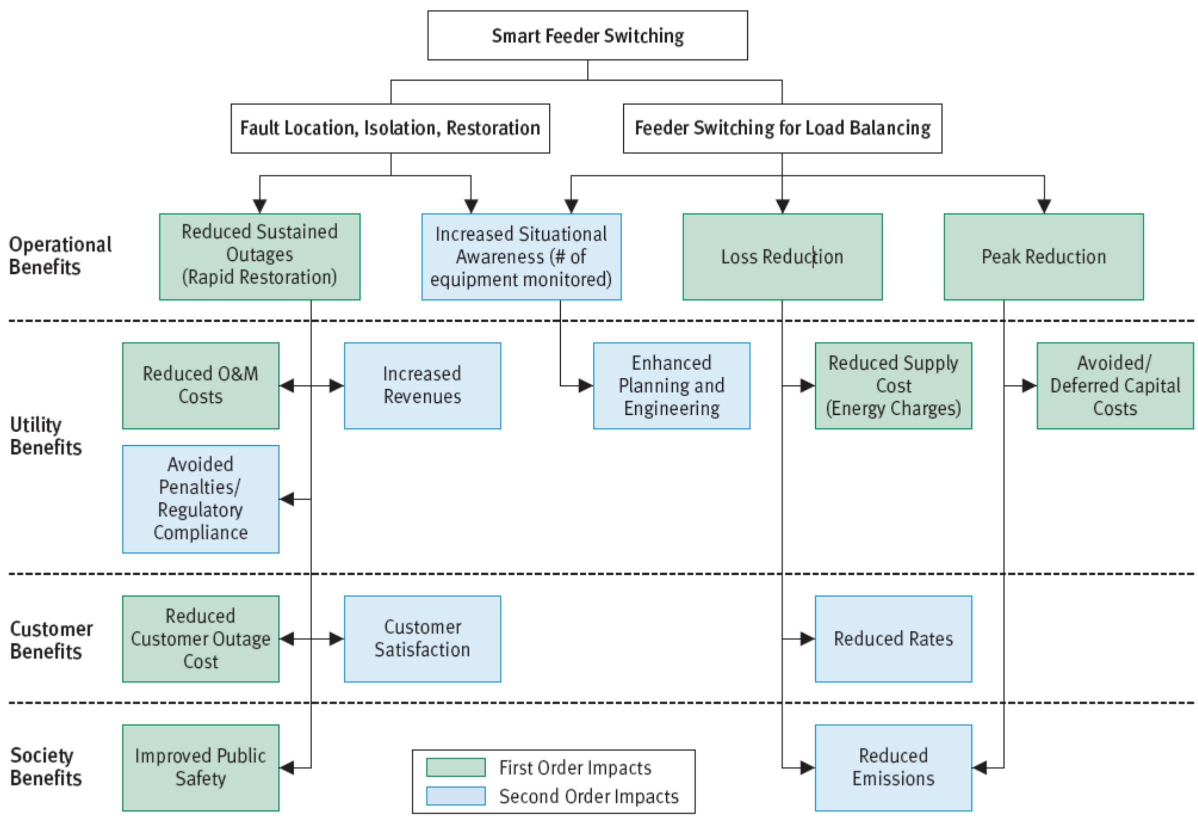

Figure 47 Smart Feeder Switching Benefits

Note: Benefits were categorized as having either first or second order impacts. First order impacts are considered to be the main drivers of SFS systems.

Source: Pinney (2014)

1. Gaining experience with increasingly prevalent distribution automation technology was an important driver behind cooperative participation in these demonstrations.

2. Non-labor costs were consistent per automated switch, but costs per customer average interruption duration index (CAIDI) minute of improvement, when calculable, were variable due to the diverse system types under study.

3. Multiple cooperatives were able to bring large percentages (30%–50%) of their feeders into configurations that enabled self-healing through back-feeds and automatic source transfers.

Conservation Voltage Reduction

Lowering system voltage save energy at low cost without risking on end-users' appliances. Pinney(2014 a) investigated the conservation voltage reduction (CVR) technology in 4 rural area. In this report, the benefits of conservation voltage reduction has examined primarily for the utility and customers. The CVR benefits are peak demand reduction, loss reduction. And the principal cost is hardware implemented for the project. Also the cost includes energy sales loss of utility. The table below shows the cost and benefit on the monthly basis.

Table 6 Costs and Benefits for Re-Regulation of Test Feeder

		Historical Loads (kW)		Peak Red.		Energy Red.		Loss Red.		Net
Month	Season	Avg	Peak	kW	$	kWh	$	kW	$	$
January	Winter	2740	4236	0	0	19.45	-778	0.06	4	-774
February	Winter	2483	3312	0	0	10.20	-408	0.03	2	-406
March	Spring	2031	2964	0	0	22.59	-904	0.17	10	-893
April	Spring	2107	3025	0	0	26.58	-1063	0.20	12	-1051
May	Spring	2344	4076	0	0	5.19	-208	0.02	1	-206
June	Summer	2769	5811	0	0	20.50	-820	0.07	4	-816
July	Summer	3967	6746	0	0	0.00	0	0.00	0	0
August	Summer	3274	5204	0	0	0.00	0	0.00	0	0
September	Fall	2130	4904	0	0	27.78	-1111	0.21	13	-1099
October	Fall	1752	2337	4.94	29613	7.97	-319	0.06	4	29297
November	Fall	2208	3545	0	0	0.29	-12	0.00	0	-11
December	Winter	2482	3365	0	0	10.16	-406	0.03	2	-404

Source: Pinney (2014 a)

III.2.25 Summary of the Benefit, Functions, Input Parameters and Monetization of Benefit

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Optimized Generator Operation	• Wide Area Monitoring, Visualization, & Control • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Annual Generation Cost ($) Optional Inputs • Average Hourly Generation Cost ($/MWh) • Avoided Annual Generator Dispatch (MWh) • Annual Energy Storage Efficiency (%) • Annual PEV Efficiency (%)	**Standard Calculation:** **Value ($)** = [Annual Generation Cost ($)]$_{Baseline}$ - [Annual Generation Cost ($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh) * Average Efficiency (%)]$_{Project}$ – [Average Hourly Generation Cost ($/MWh) * Avoided Annual Generator Dispatch (MWh) * Average Efficiency (%)]$_{Baseline}$ **Average Efficiency (%) =** For projects that yield this benefit as a result of Wide Area Monitoring, Visualization, and Control, the value will be 100%. For projects that just support Stationary Electricity Storage or Plug-in Electric Vehicles this value will be equal to the Annual Efficiency of these technologies. For projects that enable multiple functions that lead to this benefit an average of all efficiencies will be used.
Deferred Generation Capacity Investments	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Total Customer Peak Demand (MW) • Energy Storage Use at Annual Peak Time (MW) • Distributed Generation Use at Annual Peak Time (MW) – Impact • PEV Use at Annual Peak Time (MW) – Impact • Price of Capacity at Annual Peak ($/MW), Optional Inputs • Capital Carrying Charge of New Generation ($/yr) • Generation Investment Time Deferred (yrs)	**Standard Calculation:** **Value ($)** = [Price of Capacity at Annual Peak ($/MW) * {Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)}]$_{Baseline}$ - [Price of Capacity at Annual Peak ($/MW) * {Total Customer Peak Demand (MW) – Energy Storage Use at Annual Peak Time (MW) – Distributed Generation Use at Annual Peak Time (MW) – PEV Use at Annual Peak Time (MW)}]$_{Project}$ **Optional Calculation:** **Value ($)**= [Capital Carrying Charge of New Generation ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of New Generation ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$
Reduced Ancillary Service Cost	• Wide Area Monitoring Visualization and Control • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles • Customer Electricity Use Optimization	• Ancillary Services Cost ($) Optional Inputs • Average Price of Reserves ($/MW) • Reserve Purchases (MW) • Average Price of Frequency Regulation ($/MW) • Frequency Regulation Purchases (MW) • Average Price of Voltage Control ($/MVAR) • Voltage Control Purchases (MVAR)	**Standard Calculation:** **Value ($)** = [Ancillary Services Cost ($)]$_{Baseline}$ - [Ancillary Services Cost ($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{Baseline}$ - [Σ (Price of Ancillary Service ($/MW) * Purchases (MW))]$_{Project}$
Reduced Congestion Cost	• Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Power Flow Control • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles • Customer Electricity Use Optimization	• Congestion Cost ($) Optional Inputs • Congestion (MW) • Average Price of Congestion ($/MW)	**Standard Calculation:** **Value ($)** = [Congestion Cost($)]$_{Baseline}$ - [Congestion Cost($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Congestion (MW) * Average Price of Congestion ($/MW)]$_{Baseline}$ - [Congestion (MW) * Average Price of Congestion ($/MW)]$_{Project}$

Figure 48 Summary of Benefit Input Parameters and Calculations (1)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Deferred Transmission Capacity Investments	• Fault Current Limiting • Wide Area Monitoring, Visualization, & Control • Dynamic Capability Rating • Power Flow Control • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Transmission Upgrade ($) • Transmission Investment Time Deferred (yrs)	**Value ($)**= [Capital Carrying Charge of Transmission Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of Transmission Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$ Note: this should only be calculated once since all years of deferral are included
Deferred Distribution Capacity Investments	• Dynamic Capability Rating • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Capital Carrying Charge of Distribution Upgrade ($/yr) • Distribution Investment Time Deferred (yrs)	**Value ($)**= [Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Project}$ - [Capital Carrying Charge of Distribution Upgrade ($) *(1-(1-Discount rate (%))^Time Deferred (yrs))]$_{Baseline}$ Note: this should only be calculated once since all years of deferral are included
Reduced Equipment Failures	• Fault Current Limiting • Dynamic Capability Rating • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection	• Capital Replacement of Failed Equipment ($) • Portion Caused by Fault Current or Overloaded Equipment (%) • Portion Caused by Lack of Condition Diagnosis (%)	**For Fault Current Limiting, Dynamic Capability Rating, & Enhanced Fault Protection:** **Value ($)** = [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Fault Current or Overloaded Equipment (%)]$_{Project}$ **For Diagnosis & Notification of Equipment Condition:** **Value ($)** = [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Baseline}$ - [Capital Replacement of Failed Equipment ($) * Portion Caused by Lack of Condition Diagnosis (%)]$_{Project}$
Reduced Transmission & Distribution Equipment Maintenance Cost	• Diagnosis & Notification of Equipment Condition	• Total Transmission Maintenance Cost ($) • Total Distribution Maintenance Cost ($)	**Value ($)** = [Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Baseline}$ –[Total Distribution Equipment Maintenance Cost ($) + Total Transmission Equipment Maintenance Cost ($)]$_{Project}$
Reduced Transmission& Distribution Operations Cost	• Automated Feeder and Line Switching • Automated Voltage and VAR Control	• Transmission Operations Cost ($) • Distribution Operations Cost ($) Optional Inputs • Distribution Feeder Switching Operations ($) • Distribution Capacitor Switching Operations ($) • Other Distribution Operations Cost ($)	**Standard Calculation:** **Value ($)** = [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$ **Optional Calculation**: **Value ($)** = [Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Baseline}$ - [= Distribution Feeder Switching Operations ($) + Distribution Capacitor Switching Operations ($) + Other Distribution Operations Cost ($) + Transmission Operations Cost ($)]$_{Project}$
Reduced Meter Reading Cost	• Real-Time Load Measurement & Management	• Meter Operations Cost ($)	**Value ($)** = [Meter Operations Cost ($)]$_{Baseline}$ - [Meter Operations Cost ($)]$_{Project}$

Figure 49 Summary of Benefit Input Parameters and Calculations (2)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Electricity Theft	• Real-Time Load Measurement & Management	• Number of Meter Tamper Detections – Residential • Number of Meter Tamper Detections – Commercial • Number of Meter Tamper Detections – Industrial • Average Annual Customer Electricity Usage – Residential, Commercial, Industrial	**Value ($)** = [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Baseline}}$ - [Σ{ Number of Meter Tamper Detections by class (#) * Average Annual Customer Electricity Usage by class (kWh) * Average Percentage of Load not Measured by class (%) * Average Duration of Theft by class (% of year) * Average Retail Electricity Rate by class ($/kWh)}]$_{\text{Project}}$ **Average Percentage of Load not Measured by class (%)** = This is a DOE assumption that varies by class **Average Duration of Theft by class (% of year)** = This is a DOE assumption that varies by class **Average Retail Electricity Rate by class ($/kWh)** = Weighted Average of electricity rate by customer class
Reduced Electricity Losses	• Power Flow Control • Automated Voltage and VAR Control • Real-Time Load Measurement & Management • Real-Time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage	• Distribution Feeder Load (MW) • Distribution Losses (%) • Transmission Line Load (MW) • Transmission Losses (%) • Average Price of Wholesale Energy ($/MWh)	**Value ($)** = [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Baseline}}$ - [(Distribution feeder load (MW) * Distribution losses (%) + Transmission line load (MW) * Transmission losses (%)) * 8760 (hr/yr)* Average Price of Wholesale Energy ($/MWh)]$_{\text{Project}}$
Reduced Electricity Cost	• Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• Total Residential Electricity Cost ($) • Total Commercial Electricity Cost ($) • Total Industrial Electricity Cost ($)	**Value ($)** = [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Baseline}}$ - [Total Residential Electricity Cost ($) + Total Commercial Electricity Cost ($) + Total Industrial Electricity Cost ($)]$_{\text{Project}}$
Reduced Sustained Outages	• Adaptive Protection • Automated Feeder and Line Switching • Automated Islanding and Reconnection • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection • Real-Time Load Measurement & Management • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	• SAIDI (System) • Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial • Average Hourly Load Not Served During Outage per Customer by class (kW) <u>Optional Inputs</u> • SAIDI (Impacted Feeders or Lines) • Total Customers Served by Impacted Feeders or Lines (#) – Residential, Commercial	<u>**Standard Calculation:**</u> **Value ($)** = Σ{ [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (System) * Total Customers Served within a class (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$} <u>**Optional Calculation:**</u> **Value ($)** = Σ{ [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [SAIDI (Impacted Feeders or Lines) * Total Customers Served by Impacted Feeders or Lines (#) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}
Reduced Major Outages	• Wide area Monitoring, Visualization & Control • Automated Islanding and Reconnection • Real-Time Load Measurement & Management • Real-Time Load Transfer	• Outage Time of Major Outage (hr) – Residential, Commercial, Industrial • Average Hourly Load Not Served During Outage per Customer by class (kW) • Value of Service (VOS) ($/kWh) – Residential, Commercial, Industrial	**Value ($)** = Σ{ [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Baseline}}$ - [Outage Time of Major Outage by class(hr) * Average Hourly Load Not Served During Outage per Customer by class (kW) * VOS by class ($/kWh)]$_{\text{Project}}$}

Figure 50 Summary of Benefit Input Parameters and Calculations (3)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Restoration Cost	• Adaptive Protection • Automated Feeder and Line Switching • Automated Islanding and Reconnection • Diagnosis & Notification of Equipment Condition • Enhanced Fault Protection • Real-Time Load Measurement & Management	• Distribution Restoration Cost ($) • Transmission Restoration Cost ($) Optional Inputs • Number of Outage Events (#) • Restoration Cost per Event ($/event)	**Standard Calculation:** **Value ($)** = [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{Baseline}$ - [Distribution Restoration Cost ($) + Transmission Restoration Cost ($)]$_{Project}$ **Optional Calculation:** **Value ($)** = [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{Baseline}$ - [Number of Outage Events (# of events) * Restoration Cost per Event ($/event)]$_{Project}$
Reduced Momentary Outages	• Enhanced Fault Protection • Stationary Electricity Storage	• MAIFI (System) • Value of Service (VOS) – Power Quality ($/interruption) Optional Inputs • MAIFI (Impacted Feeders) • Total Customers Served on Impacted Feeders (momentary) (#) – Residential, Commercial, Industrial	**Standard Calculation:** **Value ($)** = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$ Momentary Interruptions (# of interruptions) = MAIFI (Index) * Σ{Total Customers Served by class (#)} **Optional Calculation:** **Value ($)** = [Momentary Interruptions (# of interruptions) * VOS – Power Quality ($ per interruption)]$_{Baseline}$ - [Momentary Interruptions (# of interruptions) * VOS ($ per interruption)]$_{Project}$ **Momentary Interruptions (# of interruptions)** = MAIFI of Impacted Feeders (Index) * Σ{Total Customers Served by class on the Impacted Feeders (#)}
Reduced Sags and Swells	• Enhanced Fault Protection • Stationary Electricity Storage	• Number of High Impedance Faults Cleared (# of events) • Value of Service (VOS) – Sags and Swells ($/event)	**Value ($)** = [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Project}$ - [Number of High Impedance Faults Cleared (# of events) * VOS – Sags and Swells ($/event)]$_{Baseline}$

Figure 51 Summary of Benefit Input Parameters and Calculations (4)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced CO_2 Emissions	• Power Flow Control • Automated Feeder and Line Switching • Automated Voltage and VAR Control • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Real-time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	**For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition** • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) • CO_2 Emissions per Gallon of Fuel(tons/gallon) **Optional Inputs** • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading **For PEV with Reduced Gasoline Consumption Mechanism** • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) **For all other Functions (Including PEV with Offset Central Generation Mechanism)** • CO_2 Emissions (tons) • Value of CO_2 (\$/ton)	**Value (\$)** = Σ[Net CO2 Emissions Avoided (tons)]* Value of CO2 (\$/ton) **Net CO2 Emissions Avoided (tons)** = $[CO_2 \text{ Emissions (tons)}]_{Baseline} - [CO_2 \text{ Emissions (tons)}]_{Project}$ **Net CO2 Emissions Avoided (tons)** = $[\text{CO2 Emissions Avoided(tons)}]_{Project} - [\text{CO2 Emissions Avoided (tons)}]_{Baseline}$ **For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition:** **CO2 Emissions (tons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * CO2 Emissions per Gallon of Fuel (tons/gallon) **Optional Calculation:** **CO2 Emissions (tons)** = Σ[Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)] * CO2 Emissions per Gallon of Fuel (tons/gallon) **For PEV with Reduced Gasoline Consumption Mechanism:** **CO2 Emissions Avoided (tons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * CO2 Emissions per Gallon of Fuel (tons/gallon) **For all other Functions (Including PEV with offset central generation):** **CO2 Emissions (tons)** = Calculated and reported by the project directly.

Figure 52 Summary of Benefit Input Parameters and Calculations (5)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced SO_x, NO_x, and PM-2.5 Emissions	• Power Flow Control • Automated Feeder and Line Switching • Automated Voltage and VAR Control • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Real-time Load Transfer • Customer Electricity Use Optimization • Distributed Generation • Stationary Electricity Storage • Plug-in Electric Vehicles	<u>**For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition**</u> • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) • Emissions per Gallon of Fuel(tons/gallon) – SO_x, NO_x <u>**Optional Inputs**</u> • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading <u>**For PEV with Reduced Gasoline Consumption Mechanism**</u> • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) <u>**For all other Functions (Including PEV with Offset Central Generation Mechanism)**</u> • SOx Emissions (tons) • NOx Emissions (tons) • PM-2.5 Emissions (tons) • Value of Emissions ($/ton) – SO_x, NO_x, PM-2.5	**Value ($)** = Σ[Net Emissions Avoided (tons)* Value of Emissions ($/ton)] **Net Emissions Avoided (tons)** = [Emissions (tons)]$_{Baseline}$ - [Emissions (tons)]$_{Project}$ **Net Emissions Avoided (tons)** = [Emissions Avoided(tons)]$_{Project}$ - [Emissions Avoided (tons)]$_{Baseline}$ <u>**For Automated Feeder and Line Switching; Real Time Measurement and Management; Diagnosis & Notification of Equipment Condition:**</u> **Emissions (tons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) * Emissions per Gallon of Fuel (tons/gallon) <u>**Optional Calculation:**</u> **Emissions (tons)** = Σ[Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)] * Emissions per Gallon of Fuel (tons/gallon) <u>**For PEV with Reduced Gasoline Consumption Mechanism:**</u> **Emissions Avoided (tons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) * Emissions per Gallon of Fuel (tons/gallon) <u>**For all other Functions (Including PEV with offset central generation):**</u> **Emissions (tons)** = Calculated and reported by the project directly.

Figure 53 Summary of Benefit Input Parameters and Calculations (6)

Benefit	Functions & Enabled Energy Resources	Input Parameters	Monetization Calculation
Reduced Oil Usage	• Automated Feeder and Line Switching • Diagnosis & Notification of Equipment Condition • Real-Time Load Measurement & Management • Plug-in Electric Vehicles	<u>**For PEVs (with reduced gasoline consumption mechanism):**</u> • kWh of Electricity Consumed by PEVs (kWh) • Electricity to Fuel Conversion Factor (gallons/kWh) <u>**For all other Functions**</u> • Truck Rolls (# of events) • Average Miles Travelled per Truck Roll (miles/event) • Average Fuel Efficiency for Truck Roll Vehicle (gallons/mile) <u>**Optional Inputs**</u> • Number of Operations Completed (# of events) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Miles Traveled per Operation (miles/event) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading • Average Fuel Efficiency for Service Vehicle (miles/gallon) – Feeder Switching and Maintenance, Diagnosis and Notification, Meter Reading	**Value (gallons of oil) =** Net Avoided Fuel Use (gallons)* Fuel to Oil Conversion Factor (gallons oil/gallon fuel) **Net Avoided Fuel Use (gallons) =** [Fuel Use (gallons)]$_{Baseline}$ - [Fuel Use (gallons)] $_{Project}$ **Net Avoided Fuel Use (gallons) =** [Avoided Fuel Use (gallons)]$_{Project}$ - [Avoided Fuel Use (gallons)] $_{Baseline}$ <u>**For PEVs (with reduced gasoline consumption mechanism):**</u> **Avoided Fuel Use (gallons)** = kWh of Electricity Consumed by PEVs (kWh) * Electricity to Fuel Conversion Factor (gallons/kWh) <u>**For all other Functions:**</u> **Fuel Use (gallons)** = Truck Rolls (# of events) * Average Miles Travelled per Truck Roll (miles/event) ÷ Average Fuel Efficiency for Truck Roll Vehicle (miles/gallon) <u>**Optional Calculation:**</u> **Fuel Use (gallons) =** Σ[Number of Operations Completed(# of events) * Average Miles Traveled per Operation (miles/event) ÷ Average Fuel Efficiency for Service Vehicle (miles/gallon)]
Reduced Wide-scale Blackouts	• Wide Area Monitoring & Visualization • Dynamic Capability Rating	• Number of Wide-scale Blackouts (# of events) • Estimated Cost of each Wide-scale Blackout ($/event)	**Value ($)** = [Number of Wide-scale Blackouts (# of events) * Estimated Cost of each Wide-scale Blackout ($/event)]$_{Baseline}$ - [Number of Wide-scale Blackouts (# of events) * Estimated Cost each Wide-scale Blackout ($/event)]$_{Project}$

Figure 54 Summary of Benefit Input Parameters and Calculations (7)

III.3 Calculation of Cost

III.3.1 Present Valuation of Cost in SGCT

Current SGCT calculates the cost in following 3 steps:

1. Determine a nominal cost schedule – this is accomplished in two ways:
   A. the user can directly enter a nominal cost schedule
   B. SGCT can calculate a cost schedule based on user inputs.

2. Determine a present value cost schedule
3. Determine the NPV of the project

According to DOE (2011), the cost entered into the SGCT should represent the total installed cost of the project and should include all capital costs and direct labor costs, i.e. construction, installation, integration, testing, and commissioning. Cost input made by the user of SGCT even allows two year prior from the project start until 2040. Followings are the cost calculation related inputs:

Table 7 Cost Calculation Input

Input	*Description*
Initial Year of Project Spending	The first year in which payments for project capital costs are made.
Final Year of Project Spending	The last year that payments for project capital costs are made
Total Capital Cost of the Project	The total capital cost of the project including direct labor costs, i.e. construction, installation, integration, testing, and commissioning.
Interest Rate	The interest rate that would be paid on financing the total capital cost of the project.

Source: DOE (2011)

Input nominal cost schedule is calculated by amortizing total capital cost evenly over the period of the project according to the following equation:

$$A = P\frac{r(1+r)^t}{(1+r)^t - 1}$$ [53]

where A, P, r, t represents Yearly Amortize Cost, Total Capital Cost of the Project, Interest Rate, Total time (years) over which cost is amortized, respectively. Yearly nominal value is treated with additional discount factor such as

[53] This equation's discount factor for the project starting year is 1.

$$d_t = (1 - r_d)^t$$

where d_t, r_d, t represents Discount factor in year t, Discount rate, Discount year, (year 0 correspond to the project starting year. Negative year values are used for expenditures that occur before the project starting year). Even if it is not explicitly noted, this discount rate may reflect the inflation rate so that it can treat the nominal value in terms of real one.

Following is the cost calculation section of DOE SGCT.

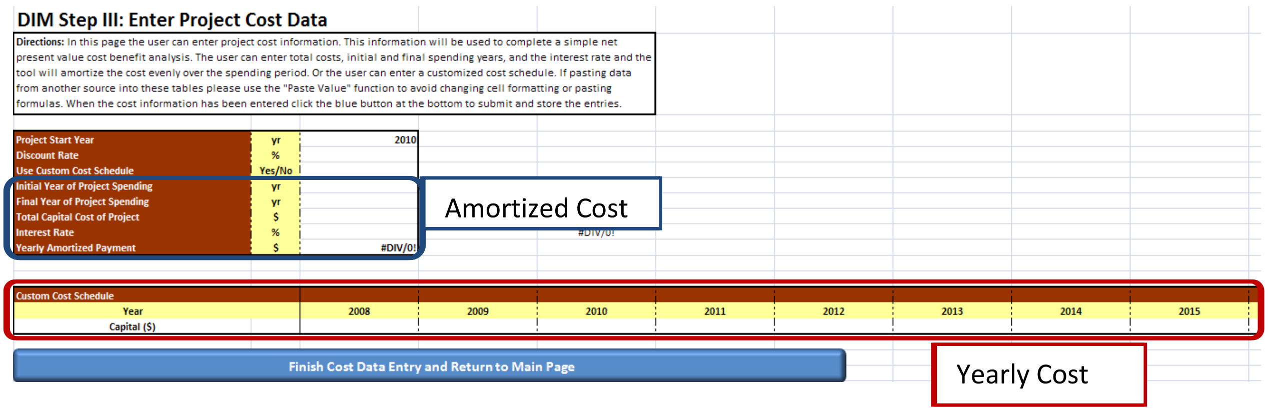

Figure 55 Cost Input in SGCT Macro

III.3.2 Present Valuation of Cost in Replicated Tool Kit

Current formulation of cost calculation is simple total cash flow calculation without any direct link to the implementation of technology specific investment. Replicated Tool kit can accommodate a new cost calculation module with its direct linkage to the technology specific investment and related variable cost to be handled separately for each technology.

A further discussion will be given in the next chapter for future revision of such representation of cost related cash flow calculation.

III.4 Expansion of Smart Grid Computational Tool

III.4.1 Overview

The main purpose of Smart Grid Computational Tool (SGCT) development is to assist the smart grid players on conducting the benefit and cost analysis of smart grid project based on the guidelines made by the EPRI. For this purpose, the SGCT is made focusing on:

- Defining the boundaries of a smart grid project, such as project period, area of implementation, technologies to be deployed, etc.
- Identification of the potential benefits from the project based on the relationship of assets, functions, mechanisms and benefits
- Quantification and monetization[54] of the identified benefits
- Inputting the project costs
- The comparison and analysis of the costs and benefits of the project

In order to properly conduct the smart grid Benefit Cost Analysis, the SGCT is equipped with several mappings (assets to functions, functions to mechanisms, mechanisms to benefits), functions and forms to calculate the benefit calculations, some default parameters, project cost form, up to the results' visual presentation and some sensitivity analysis options.

In SGCT, most if not all benefit calculation is based on the avoided cost principle. Therefore, the user is required to define and estimate the baseline scenario for its smart grid project and derive the parameters needed to calculate the benefits. Since the Benefit Cost Analysis of a smart grid project is usually conducted for a certain time period to the future, the baseline scenario and its parameters for those years must be estimated, too. Then, to calculate the avoided costs (benefits) resulting from the smart grid project, the similar set of avoided cost parameters must be gathered and/or estimated, too. Then the comparison between the Baseline and Project costs is set as smart grid benefits.

Since the SGCT is more focused on the smart grid BCA itself, the users are needed to input many parameters exogenously. Unfortunately, not all parameters are easy to be gathered or estimated by the users. Sometimes, those parameters can only be provided through some calculation processes or simulation running utilizing other software/model.

One of the possible paths of the SGCT expansion is to make the users of the toolkit more comfortable in assessing the BCA of their smart grid projects. This might include the integration with other simple

[54] The difference of quantification and monetization lie in the benefits units. Quantification gives a measurable quantity of the smart grid benefit; meanwhile monetization calculates the monetary value of the benefit. For example, the quantification of CO_2 emission reduction would show how many tons of CO_2 is reduced due to smart grid project. Then using the carbon price information, benefit is monetized. It must be noted, though, that quantification can also be done in terms of monetary value.

models to assist users on providing benefit calculation's parameters, more details in cost input form, and addition of qualitative analysis to make the output of the tool more comprehensive.

III.4.2 Smart Grid Scenario: Socioeconomics, Technical, and Regulatory Context

One of the main parts in conducting smart grid Benefit and Cost Analysis is the project scenario development. In his paper, Chardonnet and de Boissezon (2013) create several scenarios (or visions) that are built under two assumptions of socioeconomics context and three assumptions of smart grid technical and regulatory deployment. For the socioeconomics context, the two scenarios are based on *Grenelle de l'Environnement* and *NegaWatt* scenarios. Each scenario has its own parameters. The listed parameters are:

- GDP Growth Rate
- Population
- Fuel Prices
- Electricity retail tax rate
- CO_2 Emission Price
- Electric vehicles
- Nuclear energy in the electrical mix
- BBC standard share in buildings
- Power quality standard

On the other hand, the EPRI Report also mentions several 'escalation factor's that would affect the benefit parameters, which in turn affecting the Benefits and Costs Analysis. The escalation factors are:

- Population
  In the case of AMI application, the population would be important to determine the number of AMI operation and cost, etc.
- Load growth
  The load growth would affect greatly the utilization of transmission and distribution related parameters, such as the need of voltage regulation devices, as well as the generation parameters such as storage needed, etc.
- Inflation
  The inflation is one of the main escalation factors that could affect the various cost values, such as emission, blackout, maintenance cost, etc.
- Energy price
  Since the electricity generation needs various forms of energy, these prices would be important, especially for parameters like average generation cost.

The combination of those parameters could also contribute to the other parameters such annual generation cost and total electricity cost. Figure below shows the complete list of parameters that would be affected by the aforementioned escalation factors. In addition to those factors, there are also several important parameters that must be inputted by the users such as the number of power consumer (could be derived from population) and price of electricity (could be part of energy price).

Escalation Factor	*Inputs that are projected by escalation factor*
Population	Number of Meter Tamper Detections – Residential, Commercial, Industrial Number of Meter Reading Operations kWh of Electricity Consumed by PEVs
Load Growth	Avoided Annual Generator Dispatch Energy Storage Use at Annual Peak Time Distributed Generation Use at Annual Peak Time PEV Use at Annual Peak Time Reserve Purchases Frequency Regulation Purchases Voltage Control Purchases Congestion Distribution Feeder Load Transmission Line Load
Inflation	Capital Replacement of Failed Equipment Total Transmission Equipment Maintenance Cost Total Distribution Equipment Maintenance Cost Distribution Operations Cost Transmission Operations Cost Distribution Feeder Switching Operations Distribution Capacitor Switching Operations Other Distribution Operations Cost Meter Operations Cost Value of Service – Residential, Commercial, Industrial Distribution Restoration Cost Transmission Restoration Cost Restoration Cost per Event Value of Service - PQ Value of Service - Sags & Swells Value of CO2, SOx, NOx, PM-2.5 Estimated Cost of each Wide-scale Blackout
Energy Price	Average Hourly Generation Cost Price of Capacity at Annual Peak Average Price of Reserves Average Price of Frequency Regulation Average Price of Voltage Control Average Price of Congestion Average Price of Wholesale Energy
Energy Price & Load Growth	Annual Generation Cost Ancillary Services Cost Congestion Cost
Energy Price & Population Growth	Total Electricity Cost – Residential, Commercial, Industrial

Figure 56 the Importance of Escalation Factors which Affects the Benefit Parameters in SGCT

Source: Navigant Consulting, 2011

Combining the two cases above, the current SGCT can be expanded to allow better representation and utilization of the socioeconomics parameters listed. For example, the tool can be expanded to provide option of population percentage for defining the number of electric customers in residential, commercial, and industrial sectors. It can also be expanded to as much consumer class as possible depending on the electric price structure.

Table 8 Default Escalation Factors given in SGCT

Region	Population (%)	Load (%)	Inflation (%)	Energy Price **(%)**
NPCC	0.2	0.8	2.7	3.3
RFC	0.3	1.4	2.1	2.5
MRO	0.4	2.3	2.1	1.5
FRCC	2.0	2.6	2.9	2.5
SERC	0.9	2.2	2.4	1.8
SPP	0.4	1.8	2.1	1.4
TRE	1.6	2.2	2.3	3.9
WECC	1.3	1.6	2.4	2.2
ASCC	1.1	2.2	2.6	2.5
HI	0.6	0.6	0.6	0.6
Empty	0	0	0	0

In the scenario building, a solid definition of technology to be applied is another important factor in conducting smart grid benefit cost analysis. For the example of Chardonnet and de Boissezon (2013), the technology parameters include: penetration of distributed generation monitoring and control, active demand participation rate, storage capacity, dynamic pricing structures, distribution grid self-healing, and penetration of electric vehicle off peak load management.

Each technology above would have different parameters to be inputted by the users. The current SGCT can be expanded to reduce the confusion of the users by providing some potential parameters (probably with some default/example value). Also, the tool can help by guiding the users to provide the parameters using embedded models, which are explained next.

III.4.3 Load Curve Modelling

The load curve is an important parameter in the calculation of smart grid benefits. The reason for this is that a lot of smart grid benefits come from the load related avoided costs. For example, the smart grid can reduce the costly peak load. Then, to quantify this benefit, the users must know the load profile of the grid system in the baseline and after the project is conducted. It must be noted that the separate modelling of load curve can be seen as the expansion of the load growth escalation factor mentioned before.

It must be noted that the other Smart Grid BCA programs also put an emphasis on modelling the load curve of a power system. For example, the UK case of Frontier Economics utilizes a parametric network model called WinDebut developed by EA Technologies. Figure below shows how the BCA integrates the BCA (real options model) with the network model and generation model (to be discussed later) and the interactions between the models.

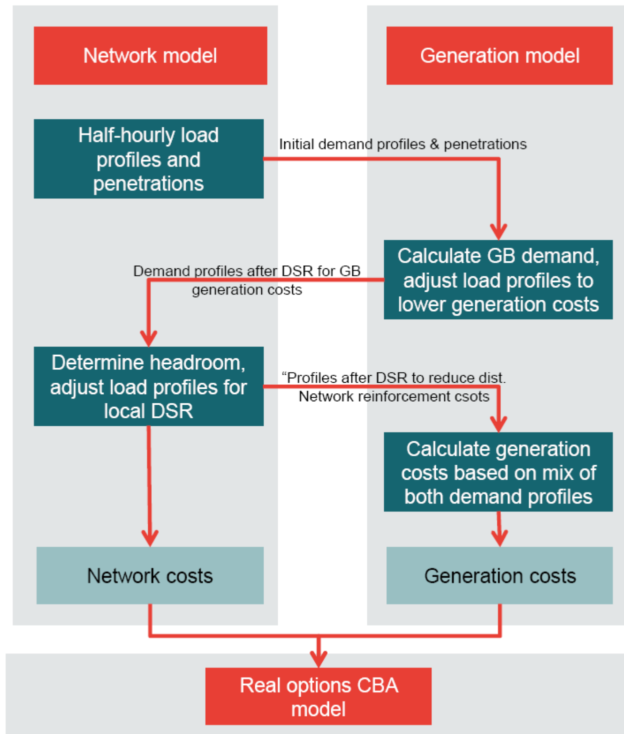

Figure 57 Frontier Economics and OFGEM Uses Parametric Network model to Do Load Curve Modelling
Source: Frontier Economics (March 2011)

Another example is the Smart Grid Investment Model (SGIM) that utilizes member utility data such as historical billing data, historical 8760 system loads, weather data and other parameters to forecast the monthly kWh and hourly loads for the whole smart grid BCA period. Figure below shows the utilization of utility energy and hourly load models in SGIM.

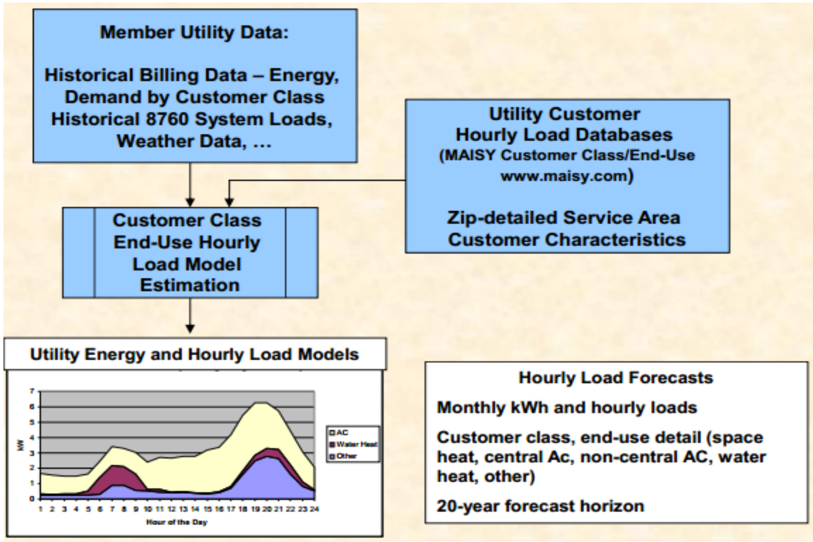

Figure 58 Smart Grid Investment Model Utilizing Hourly Load Models for Load Curve Modelling

Source: Jackson (2012)

Knowing the load pattern would enable the users to properly calculate the benefits parameter into the toolkit. It can also help them to visualize the concept of avoided cost as a form of smart grid benefit. A good example is showing the comparison of load curve in the baseline and project case so that the user can see the actual reduction (probably most change must happen in the peak load) and the value of this reduction (or the benefit).

The current SGCT should be developed further to be able to model the load curve integrally within the toolkit. Then the tool must be able to automate the parameters input of the BCA from the output of the load curve model. The modeling of the curve itself can range from a simple estimation from the current load curve, parametric network model, to a nodal network model. It must be noted that to do this, various parameters are still needed.

III.4.4 Generation Program Modelling

In the generation program modelling, the users should be able to determine the mix of electricity generation for the whole period of the project. This information is important for many parts of benefit calculation, such as the generation cost. As seen in the previous section, the UK case of Frontier Economics also utilizes the generation model integrally within their BCA. In the paper by Chardonnet and de Boissezon, the generation assets optimization software called EUROSTAG – SCANNER is used to do the computation. Another software that might do similar work is the WASP (Wien Automatic System Planning).

Other important benefit parameters that can be affected by the proper generation modelling is emission and electricity price. The different power generation mix would result in different emission. The policy available could also provide different scenario of the smart grid analysis. For example, the renewable policy could reduce the CO_2 emission even without the smart grid deployment. But on the other hand, the smart grid is needed to improve the quality of the transmission sector so that the intermittent renewable energy can be fully integrated into the power system.

The current SGCT can be expanded to include this generation mix modelling. Some of the important parameters could be the energy price forecast. Different energy forecast could result in different energy mix. A simple cost minimization program could be embedded into the current toolkit. Basically the points up to now are dealing with the creation of proper baseline scenario and parameters before even putting smart grid project scenario.

III.4.5 Integration with Qualitative Assessment

The current SGCT only focuses on the quantitative assessment of the smart grid project. Meanwhile, the qualitative assessment of project itself is not touched. The users are expected to do this kind of analysis separately from the BCA itself. Some models that can be used to analyse the qualitative aspect of the smart grid project is Smart Grid Maturity Model (SGMM) or other 'smartness' measurement. To comprehensively understand the smart grid project, both of these analyses must be conducted by the smart grid players.

Another approach to this duality problem is proposed by the European Commission Joint Research Centre (EC JRC). The JRC first take out the EPRI Methodology of smart grim BCA Assessment and modify it with its own benefits definition. To do so, they developed similar yet unique mapping from smart grid assets or technologies to the benefits through functionality. Then, they add the qualitative analysis that is the Key Performance Index (KPI) into the same BCA. This KPI is another product of JRC specifically designed to assess the performance of a smart grid. In other words, this is just yet another form of smartness measurement. Figure below shows the concept of overall assessment concept of JRC applied to smart metering roll-out project.

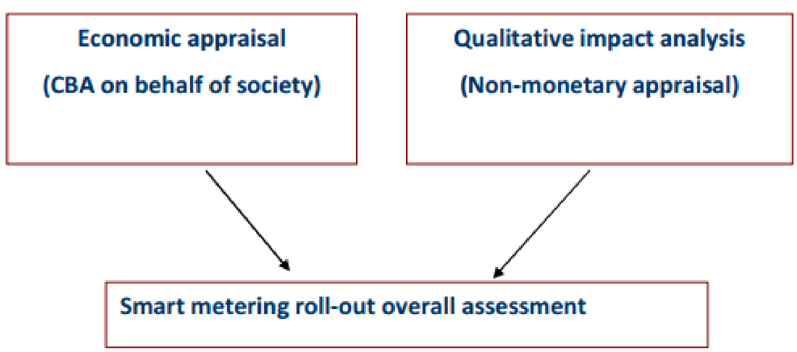

Figure 59 Integrating Quantitative and Qualitative Appraisal to Provide Smart Grid Project's Overall Assessment
Source: JRC (2012b)

Although the details of the smartness assessment of smart grid cannot be quantified directly, there are several ways to somehow show the level of smartness using some numbers. In the SGMM case, they already developed a set of surveys (questionnaires) for the smart grid players who want to assess their own smart grid 'level'. With this, the same user can properly estimate its current position within 6 smart grid categories five possible levels. Then it can also project a desired level of improvement that must be achieved using the smart grid project.

Another option is to use some Key Performance Indexes or points that are deemed important for the Smart Grid project's target and assign some weighted values to them. In the case of JRC, they utilize the Merit Deployment Matrix, which can be visualized in the figure below.

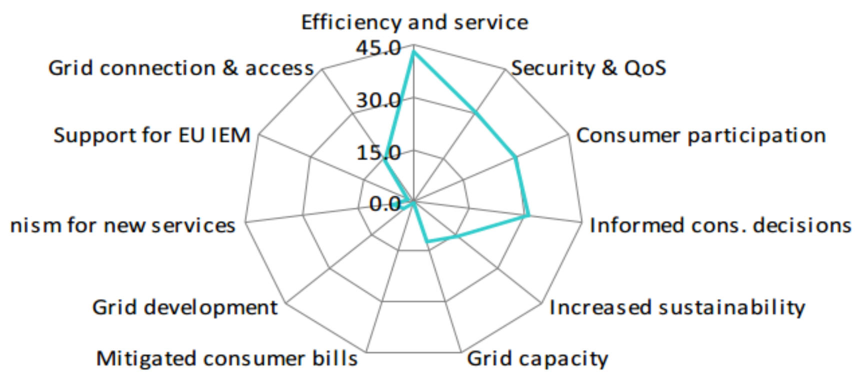

Figure 60 An Example of Visualization of Merit Deployment Matrix

Source: JRC (2012b)

The current SGCT can be expanded in such a way so that the users can also do some quantitative analysis using the same toolkit as the quantitative assessment. The toolkit can integrate either the surveys type of analysis such as the case of SGMM or the Key Performance Index type of analysis such as the case of JRC. Since both types are actually quite similar, the toolkit can actually use the combination of both methods. Although for this case to be realized, more research still needs to be done.

III.4.6 Detailed Cost Representation

The cost representation in the current SCCT is a bit too simplified. The good thing is the users only need to input the overall project cost and the discount rate to calculate the NPV of the costs during the whole project period. But the downside is that the users need to do the actual calculation of smart grid project cost outside of the toolkit. This was probably done originally due to the possible difficulty on putting the complicated cost calculation in the macro form. But utilizing the new version of the toolkit that is developed using C++ (Object Oriented Programming) the detailed process of cost calculation can be integrated in the toolkit.

There are many costs that can be attributed to smart grid project. Below is the potential list of costs from one of the smart metering roll-out cases in Europe.

Table 9 Some Potential Costs in Smart Grid Project

General category	Type of cost to be tracked for roll-out and to be estimated for the baseline
CAPEX	Investment in the smart metering system
	Investment in IT
	Investment in communications
	Investment in in-home displays (if applicable)
	Generation
	Transmission
	Distribution
	Avoided investment in conventional meters (negative cost, to be added to the list of benefits)
OPEX	IT maintenance costs
	Network management and front-end costs
	Communication/data transfer costs (inc. GPRS, Radio Communications, etc)
	Scenario management costs
	Replacement/failure of smart metering systems (incremental)
	Revenue reductions (e.g. through more efficient consumption)
	Generation
	Distribution
	Transmission
	Meter reading
	Call centre/customer care
	Training costs (e.g. customer care personnel and installation personnel)
Reliability	Restoration costs
Environmental	Emission costs (CO_2 control equipment, operation and emission permits)
Energy security	Cost of fossil fuels consumed to generate power
	Cost of fossil fuels for transportation and operation
Other	Sunk costs of previously installed (traditional) meters

Source: JRC (2012b)

The current SGCT can be expanded to expand the cost input form so that it can fully model and calculate the complete calculation of smart grid project costs. As shown in the figure above, the overall cost of smart grid project can be divided into several categories: capital cost, operation and maintenance cost, reliability cost, environmental cost, energy security cost, and other cost.

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Appendix: Default Values for DOE Smart Grid Computational Tool

Table 10 Average Hourly Generation Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	91.6	87.1	72.4	73.0	72.4	73.2	74.4	77.3	77.5	77.6	80.9	83.3	84.2	83.2	83.3	84.7	85.9	88.9	91.0	92.7	94.5	95.6	96.2
RFC	69.0	67.0	58.6	58.3	57.7	58.1	58.5	59.1	59.9	60.4	61.4	62.7	63.0	63.2	64.0	65.2	66.5	68.4	70.1	71.9	73.3	73.6	75.0
MRO	38.2	39.1	39.8	38.7	38.8	38.9	38.8	38.1	37.5	37.2	36.9	36.7	36.4	35.9	35.8	35.8	35.8	35.4	35.1	35.2	35.6	36.6	37.8
FRCC	87.5	91.6	80.0	83.2	85.3	85.4	85.4	85.8	86.1	86.0	86.6	88.4	90.7	90.7	90.6	90.8	91.6	92.9	94.7	96.8	98.0	99.0	99.6
SERC	56.7	57.4	54.0	53.3	52.6	52.1	51.5	50.9	51.0	51.2	51.6	51.6	51.7	51.7	52.1	52.5	53.6	54.8	56.1	57.5	58.4	59.3	60.0
SPP	56.9	60.0	54.5	55.8	53.5	53.7	53.7	53.7	54.5	54.9	55.4	56.0	56.0	55.6	55.8	56.4	57.5	58.9	60.0	61.5	62.4	63.3	64.1
TRE	76.7	74.0	62.2	62.0	61.5	64.0	64.9	64.9	66.4	69.6	71.8	75.4	77.9	78.4	79.5	80.7	81.9	84.6	88.0	91.5	93.7	94.6	95.5
WECC	63.2	64.4	59.8	57.7	55.5	54.2	53.4	53.3	53.9	55.2	55.9	56.7	56.7	56.2	56.0	58.1	59.4	60.7	62.4	63.8	65.0	66.3	67.2
ASCC	63.2	64.4	59.8	57.7	55.5	54.2	53.4	53.3	53.9	55.2	55.9	56.7	56.7	56.2	56.0	58.1	59.4	60.7	62.4	63.8	65.0	66.3	67.2
HI	63.2	64.4	59.8	57.7	55.5	54.2	53.4	53.3	53.9	55.2	55.9	56.7	56.7	56.2	56.0	58.1	59.4	60.7	62.4	63.8	65.0	66.3	67.2

Table 11 Price of Capacity at Annual Peak (1)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NPCC	46,829	46,829	50,144	39,137	29,167	35,958	50,224	63,772	63,466	63,136	62,831	64,199
RFC	40,150	40,150	40,150	40,150	39,194	50,795	64,377	66,021	70,702	75,091	79,833	84,813
MRO	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
FRCC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
SERC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
SPP	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
TRE	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
WECC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
ASCC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
HI	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700

Table 12 Price of Capacity at Annual Peak (2)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	76,909	89,004	100,504	100,478	100,472	100,484	100,510	100,475	100,454	100,513	100,509
RFC	96,727	102,203	110,401	114,992	114,133	105,800	105,515	109,794	114,412	119,436	124,817
MRO	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
FRCC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
SERC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
SPP	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
TRE	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
WECC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
ASCC	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700
HI	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700	95,700

Table 13 Average Price of Reserves

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
RFC	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3	16.3
MRO	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
FRCC	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
SERC	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
SPP	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
TRE	12.8	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7
WECC	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4
ASCC	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
HI	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3

Table 14 Average Price of Frequency Regulation

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	33.4	33.4	34.1	34.8	35.5	35.6	35.7	35.7	35.8	35.8	35.8	35.9	35.9	35.9	36.0	36.0	36.1	36.2	36.2	36.3	36.3	36.4	36.5
RFC	36.9	40.2	40.2	40.6	41.0	41.1	41.2	41.2	41.3	41.4	41.5	41.6	41.7	41.8	41.9	41.9	42.0	42.1	42.1	42.2	42.2	42.3	42.3
MRO	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0
FRCC	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0
SERC	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0
SPP	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0
TRE	14.9	16.2	16.2	16.4	16.5	16.6	16.6	16.6	16.7	16.7	16.8	16.8	16.8	16.9	16.9	16.9	16.9	17.0	17.0	17.0	17.0	17.1	17.1
WECC	19.3	21.1	21.1	21.3	21.5	21.5	21.6	21.6	21.7	21.7	21.8	21.8	21.9	21.9	22.0	22.0	22.0	22.1	22.1	22.1	22.1	22.2	22.2
ASCC	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0
HI	26.1	28.5	28.5	28.8	29.0	29.1	29.1	29.2	29.3	29.3	29.4	29.5	29.5	29.6	29.7	29.7	29.7	29.8	29.8	29.9	29.9	29.9	30.0

Table 15 Average Price of Voltage Control (1)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NPCC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
RFC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
MRO	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
FRCC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
SERC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
SPP	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
TRE	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
WECC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
ASCC	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8
HI	2,187.5	2,220.3	2,253.6	2,287.4	2,321.7	2,356.6	2,391.9	2,427.8	2,464.2	2,501.2	2,538.7	2,576.8

Table 16 Average Price of Voltage Control (2)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
RFC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
MRO	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
FRCC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
SERC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
SPP	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
TRE	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
WECC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
ASCC	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3
HI	2,615.4	2,654.6	2,694.5	2,734.9	2,775.9	2,817.5	2,859.8	2,902.7	2,946.2	2,990.4	3,035.3

Table 17 Average Price of Congestion

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
RFC	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
MRO	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2
FRCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SERC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SPP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TRE	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
WECC	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
ASCC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HI	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 18 Average Price of Wholesale Energy

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	0.06	0.06	0.07	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.12	0.13	0.13	0.14	0.14	0.14	0.15
RFC	0.07	0.05	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.11
MRO	0.04	0.03	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06
FRCC	0.09	0.07	0.08	0.09	0.11	0.11	0.11	0.10	0.11	0.11	0.11	0.11	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14	0.14	0.14	0.15
SERC	0.06	0.04	0.05	0.06	0.07	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09
SPP	0.06	0.04	0.05	0.06	0.07	0.07	0.07	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10
TRE	0.08	0.05	0.06	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.12	0.12	0.13	0.13	0.14	0.14	0.14
WECC	0.06	0.05	0.06	0.06	0.07	0.07	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
ASCC	0.06	0.05	0.06	0.06	0.07	0.07	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
HI	0.06	0.05	0.06	0.06	0.07	0.07	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10

Table 19 Inflation Factor

	Residential	Commercial	Industrial
NPCC	2.20	282.00	15.30
RFC	2.20	282.00	15.30
MRO	2.20	282.00	15.30
FRCC	2.20	282.00	15.30
SERC	2.20	282.00	15.30
SPP	2.20	282.00	15.30
TRE	2.20	282.00	15.30
WECC	2.20	282.00	15.30
ASCC	2.20	282.00	15.30
HI	2.20	282.00	15.30
Empty	2.20	282.00	15.30

Table 20 Restoration Cost per Event (1)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
NPCC	3,000.0	3,081.0	3,081.0	3,164.2	3,164.2	3,249.6	3,249.6	3,337.4	3,337.4	3,427.5	3,427.5	3,520.0
RFC	3,000.0	3,063.0	3,063.0	3,127.3	3,127.3	3,193.0	3,193.0	3,260.0	3,260.0	3,328.5	3,328.5	3,398.4
MRO	3,000.0	3,063.0	3,063.0	3,127.3	3,127.3	3,193.0	3,193.0	3,260.0	3,260.0	3,328.5	3,328.5	3,398.4
FRCC	3,000.0	3,087.0	3,087.0	3,176.5	3,176.5	3,268.6	3,268.6	3,363.4	3,363.4	3,461.0	3,461.0	3,561.3
SERC	3,000.0	3,072.0	3,072.0	3,145.7	3,145.7	3,221.2	3,221.2	3,298.5	3,298.5	3,377.7	3,377.7	3,458.8
SPP	3,000.0	3,063.0	3,063.0	3,127.3	3,127.3	3,193.0	3,193.0	3,260.0	3,260.0	3,328.5	3,328.5	3,398.4
TRE	3,000.0	3,069.0	3,069.0	3,139.6	3,139.6	3,211.8	3,211.8	3,285.7	3,285.7	3,361.2	3,361.2	3,438.5
WECC	3,000.0	3,072.0	3,072.0	3,145.7	3,145.7	3,221.2	3,221.2	3,298.5	3,298.5	3,377.7	3,377.7	3,458.8
ASCC	3,000.0	3,078.0	3,078.0	3,158.0	3,158.0	3,240.1	3,240.1	3,324.4	3,324.4	3,410.8	3,410.8	3,499.5
HI	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0

Table 21 Restoration Cost per Event (2)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	3,520.0	3,615.1	3,615.1	3,712.7	3,712.7	3,812.9	3,812.9	3,915.8	3,915.8	4,021.6	4,021.6
RFC	3,398.4	3,469.8	3,469.8	3,542.6	3,542.6	3,617.0	3,617.0	3,693.0	3,693.0	3,770.5	3,770.5
MRO	3,398.4	3,469.8	3,469.8	3,542.6	3,542.6	3,617.0	3,617.0	3,693.0	3,693.0	3,770.5	3,770.5
FRCC	3,561.3	3,664.6	3,664.6	3,770.9	3,770.9	3,880.2	3,880.2	3,992.8	3,992.8	4,108.6	4,108.6
SERC	3,458.8	3,541.8	3,541.8	3,626.8	3,626.8	3,713.8	3,713.8	3,803.0	3,803.0	3,894.2	3,894.2
SPP	3,398.4	3,469.8	3,469.8	3,542.6	3,542.6	3,617.0	3,617.0	3,693.0	3,693.0	3,770.5	3,770.5
TRE	3,438.5	3,517.6	3,517.6	3,598.5	3,598.5	3,681.3	3,681.3	3,766.0	3,766.0	3,852.6	3,852.6
WECC	3,458.8	3,541.8	3,541.8	3,626.8	3,626.8	3,713.8	3,713.8	3,803.0	3,803.0	3,894.2	3,894.2
ASCC	3,499.5	3,590.5	3,590.5	3,683.8	3,683.8	3,779.6	3,779.6	3,877.9	3,877.9	3,978.7	3,978.7
HI	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0	3,000.0

Table 22 Average Fuel Efficiency for Truck Roll Vehicle

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
RFC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
MRO	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
FRCC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
SERC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
SPP	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
TRE	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
WECC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
ASCC	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
HI	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3
Empty	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3

Table 23 CO2 Emissions per Gallon of Fuel

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-'30
NPCC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
RFC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
MRO	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
FRCC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
SERC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
SPP	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
TRE	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
WECC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
ASCC	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
HI	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null
Empty	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	0.0097	null

Table 24 Value of CO2

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
RFC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
MRO	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
FRCC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
SERC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
SPP	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
TRE	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
WECC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
ASCC	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
HI	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4
Empty	20	20	20	20	20	20	20	20	20	20	20	20	20	20.4	20.8	21.2	21.6	22.1	22.5	23.0	23.4	23.9	24.4

Table 25 SOx Emissions per Gallon of Gas

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-‘30
NPCC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
RFC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
MRO	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
FRCC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
SERC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
SPP	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
TRE	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
WECC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
ASCC	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
HI	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null
Empty	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	2.2E-07	null

Table 26 NOx Emissions per Gallon of Gas

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NPCC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
RFC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
MRO	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
FRCC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
SERC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
SPP	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
TRE	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
WECC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
ASCC	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
HI	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null
Empty	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	0.00017	null

Table 27 Value of SOx

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
RFC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
MRO	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
FRCC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
SERC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
SPP	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
TRE	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
WECC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
ASCC	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
HI	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640
Empty	520	520	520	520	520	520	520	520	520	520	520	520	520	531	542	553	565	577	589	601	614	627	640

Table 28 Value of NOx

	2008-'12	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
RFC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
MRO	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
FRCC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
SERC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
SPP	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
TRE	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
WECC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
ASCC	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
HI	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693
Empty	3000	3063.0	3127	3193	3260	3329	3398	3470	3543	3617	3693

Table 29 Value of PM-2.5

	2008-'20	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NPCC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
RFC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
MRO	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
FRCC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
SERC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
SPP	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
TRE	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
WECC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
ASCC	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
HI	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9
Empty	36000	36756.0	37527.9	38316.0	39120.6	39942.1	40780.9	41637.3	42511.7	43404.4	44315.9

Table 30 Average Fuel Efficiency

	Feeder Service Vehicle	Diagnosis/Notification Service Vehicle	Real Time Load Measurement/Management Service Vehicle
NPCC	20.3	20.3	20.3
RFC	20.3	20.3	20.3
MRO	20.3	20.3	20.3
FRCC	20.3	20.3	20.3
SERC	20.3	20.3	20.3
SPP	20.3	20.3	20.3
TRE	20.3	20.3	20.3
WECC	20.3	20.3	20.3
ASCC	20.3	20.3	20.3
HI	20.3	20.3	20.3
Empty	20.3	20.3	20.3

Table 31 Electricity to Fuel Conversion Factor

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021-'30
NPCC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
RFC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
MRO	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
FRCC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
SERC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
SPP	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
TRE	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
WECC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
ASCC	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
HI	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null
Empty	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	null