Report on a Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans

Prepared for:

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List of Acronyms

AQEW	Allocated Quantity of Energy Withdrawn
CCA	Capital Cost Allowance
CP	Coincident Peak
GA	Global Adjustment
GEGEA	Green Energy and Green Economy Act (also GEA)
HOEP	Hourly Ontario Energy Price
IESO	Independent Electricity System Operator
IRM	Incentive Ratemaking Mechanism
kW	Kilowatt
kWh	Kilowatt Hour
MW	Megawatt
MWH	Megawatt Hour
O&M	Operations & Maintenance
OEB	Ontario Energy Board
NCP	Non-Coincident Peak
PILs	Payment In Lieu Of Taxes
WMSC	Wholesale Market Service Charges

1. Introduction and Purpose

1.1 Overview

The Ontario Energy Board (OEB or Board) engaged Power Advisory LLC (Power Advisory) "to deliver a comprehensible methodology and easy to use spreadsheet-based model for estimating the impact on all relevant elements of distributor customer bills of a distributor's network infrastructure plan, portfolios of projects and individual projects/project alternatives within the plan, with special attention to plan elements related to distributor obligations as set out in the Green Energy Act" or (GEA).[1] The relevant elements include the impact on the distribution component of customer bills for all infrastructure projects and the potential impacts on the Global Adjustment (GA) and Wholesale Market Service Charges (WMSC) from investments that enable the expansion of renewable energy.

The development of the spreadsheet model is part of a broader undertaking by the OEB to review distribution system planning in response to the multiple new demands being placed on Ontario's electric distributors including initiatives that are necessary to implement the requirements of the GEA.[2] Electric distributors must also invest to replace infrastructure, maintain reliability and power quality, and meet anticipated load growth, contributing to the need to reflect potential bill impacts when developing a network investment plan.

1.2 Contents of This Report

Chapter 2 describes the considerations that are reflected in the design of the model, the model structure, and how the distributor works with the model. These objectives drive the design and structure of the model (the subject of Chapter 3) including the assumptions that are required, the calculations that are performed, and the pre-defined printable reports.

[1] Ontario Energy Board (OEB or Board) Request for Proposals For Distribution Network Investment Planning issued January 10, 2011, page 7.

[2] On October 27, 2010 the OEB began a policy initiative entitled, "A Renewed Regulatory Framework for Electricity" and opened three dockets to explore related issues including Distribution Network Investment Planning (EB-2010-0377) whose stated goal is "to ensure that distributor investment plans are demonstrably economically efficient and cost-effective and paced so as to match required expenditures with fair and reasonable rate adjustments and predictable changes to the elements of customer bills affected by the plans." As part of a separate, but closely related undertaking, the OEB is examining potential strategies to mitigate the impact of network investment plans on customer bills.

2. Model Purpose, Design Considerations, and Structure

2.1 Model Purpose

As indicated in the Introduction, the model is designed to estimate the potential impact of network investment plans on customer bills, including impacts on distribution charges from all new investment projects and any impacts on the GA and WSMC that result from the connection of new renewable resources. Estimating the potential impact on customer bills is particularly important at a time when there are many demands being placed on the distribution network including the need to maintain service levels and system reliability, in addition to meeting the requirements of the GEA. The OEB has recognized the value of a model that estimates potential customer bill impacts to the OEB, distributors and other stakeholders as they evaluate potential network investment plans. The model can be used to estimate the impacts of a single project or combinations of projects that comprise a network investment plan.

2.2 Model Design Considerations

The model design reflects the goal of estimating customer bill impacts without requiring either a vast amount of data to be input or data that may not be readily available to electric distributors. The core of model is a simplified or streamlined version of a distributor revenue requirement, cost allocation and rate design model that calculates the impact of investments on distribution charges. For example, electric distributors typically include considerable detail in certain calculations (e.g., payment-in-lieu-of-taxes or PILs) in their rate filings that must be precise for purposes of establishing new rates. The model maintains the basic computational approach while eliminating details that would be very difficult if not impossible for the user to project beyond the current year. The screening tool also anticipates that the cost allocation process can be reasonably performed by specifying less than a dozen primary allocation factors and by holding those factors constant over the study period. In short, the model is designed to provide a reasonably accurate estimate of the impact on the distribution charge components of customer bills without requiring the development of a full rate filing. This reflects the intent of the model to serve as a screening tool.

Thus, it does not calculate distribution charges with the same precision as a rate model used in a rate proceeding, but rather is designed to produce reasonably accurate estimates that are consistent with its use a screening tool. This approach also serves to limit the number of assumptions, the complexity of the model calculations and the size of the spreadsheet.

The model relies on user inputs regarding new renewable capacity by technology and size that is connected as a result of these distribution system investments to estimate the impact on the WSMC and the GA. Renewable resources may result in direct benefits to the customers of an electric distributor that result from avoided transmission Network Service

charges, transmission Connection Service charges, and WMSCs. The direct benefits calculations also capture the transfer in cost recovery responsibility of a portion of the investments necessary to connect renewable resources from the electric distributor to provincial ratepayers. The connection of renewable resources may also impact the GA paid by all Ontario customers based on the amount of capacity added by technology and the difference between the contracted prices for renewable resources and the Hourly Ontario Energy Price (HOEP).

The model is designed to be used by both small and large utilities and can be adapted by the user to reflect the particular needs of the electric distributor.[3] Thus, the user can specify the customer classes that they would like to include (up to five), and the usage levels for each class to be used to estimate bill impacts (up to three per class).

The model produces bill impacts for five years, although the user can elect to enter projects for a shorter time period. For example, the user may be conducting a study that focuses only on rate impacts in the first few years.

The model is designed to make it relatively easy to set-up the data, identify the projects to be included in a network investment plan for a particular analysis, run the model, and review the results. Model documentation is incorporated within the spreadsheet tool for user convenience. Finally, overly prescriptive approaches are rejected in favor of flexibility where possible in order to reflect the fact that network investment plans and regulatory requirements are likely to change over time.

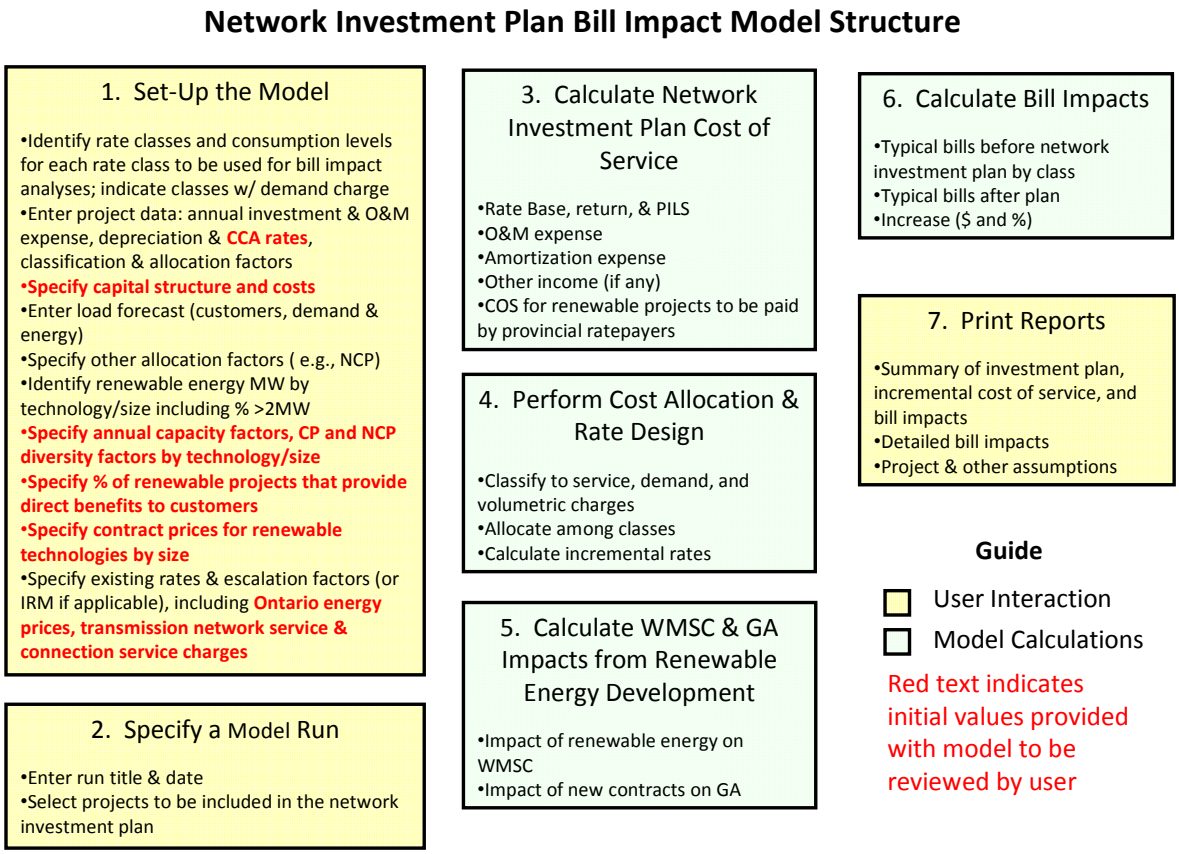
2.3 Model Structure

An overview of the model structure is presented in the diagram that appears on the top of the following page.

As shown in this diagram, the model consists of the four major elements:

1. User Inputs: rate class definitions and typical bill usage levels, project definitions and costs, renewable capacity added by technology, financial cost assumptions (e.g., cost of capital, tax rates), cost allocation and rate design assumptions, and assumptions necessary to estimate the impact on customer bills from the ability to connect new renewable supplies (e.g., contract prices, capacity factors, transmission network service and connection service charges);

[3] Ontario's largest electric distributors may require a larger version of the model in order to accommodate a far greater number of projects than would be required for a small or medium-size distributor. As an alternative, it is possible to assess the impact of projects 25-50 in a separate version of the model and add the bill impacts from the two Investment Plan Scenarios.



2. Investment Plan Scenarios: specifying which projects are to be included in a specific network investment plan;

3. Calculations: calculations of the incremental cost-of-service, cost-of-service to be paid for by provincial ratepayers, WMSC impacts, GA impacts, cost allocation and rate design, and bill impacts; and

4. Reports: pre-defined summary reports.

The Excel file consists of several "sheets" or "tabs". The user interacts with the model using three of these tabs that address only the first two elements: one to run the model and two user input tabs that define the potential projects and establish all other assumptions.

The user inputs financial data for potential investment projects including how much the project costs, any increase in operations & maintenance (O&M) expenses or ability to generate "other income"[4] that are attributable to the project. The user also inputs

[4] Other income as that term is used for utility accounting purposes.

information regarding the cost of capital, tax rates, and existing customer charges. (The specific inputs are identified in Chapter 3.) Once this basic information has been entered into the model, the user can construct alternative network investment plans by selecting projects to be included in each Investment Plan Scenario.

It is anticipated that most of the data required to set-up the model is already available or easily compiled from one of two sources: (1) project information that must already be compiled by distribution planners in order to develop a network investment plan, and (2) a recent rate order or ongoing effort to prepare a rate case filing. There are also a number of assumptions that are more global in nature and not specific to an electric distributor (e.g., capital structure and Ontario energy prices.) While initial values have been provided, the user should review and modify these assumptions to either to reflect more current information or to specify values that are more representative of particular distributor circumstances (e.g., a lower effective tax rate).

In Steps 3 and 4 in the diagram, the model calculates the incremental impact of a plan (a combination of projects selected by the user) on the distribution cost of service and on the three main components of a customer bill: the monthly customer charge, the demand charge (if applicable), and the volumetric charge. As noted above, these calculations are based on a streamlined version of the cost-of-service ratemaking methodology used by Ontario's electric distributors.

In addition to the direct impacts on the cost of service, the model (Step 5) estimates the impact of O. Reg. 330/09 on the amount of the investment to be funded by the distributor, referred to as the direct benefits calculation, and the impacts on the WMSC and GA from new renewable projects enabled by the distribution investment. These calculations correspond to the regulations but also require the electric distributor to apply its judgment in assessing the impact of a particular project on the amount, type, and timing of renewable energy resources that may be added as a result of the investment.

In Step 6, the incremental impact of the plan is then added to existing charges in order to estimate the impact on customer bills at varying levels of usage expressed as $/month and as a percentage increase.[5] This is similar to the approach used in Ontario to estimate the impact of a rate order on customer bills.

[5] The existing charges include wholesale monthly service, demand, and volumetric charges as well as the ability to include charge "adders" using these three types of charges. The adders are necessary to estimate total bills prior to the consideration of the network investment plan. The model does not consider the Harmonized Sales Tax paid by customers.

2.4 Working with the Model

Working with the model involves three steps:

1. Initial Model Set-Up: specifying the rate classes to be examined, populating the model with project-specific data, and specifying all other assumptions necessary to estimate revenue requirements and bill impacts;

2. Specifying an Investment Plan Scenario: selecting the projects to be included in a network investment plan and providing a run title and date to appear on reports; and

3. Printing Pre-Defined Reports: printing one result and two assumption reports.

The model set-up provides flexibility in several areas in order to respond to the divergent needs of Ontario's electric distributors:

- Flexibility to enter up to twenty-five projects and up to three different investment components for each project;

- Flexibility to group the projects (other than those related to connection of new renewable resources) using categories specified by the user[6]; and

- Flexibility to enter data (*and obtain results*) for up to five years.

As with any model, the greatest effort will be required to populate the model with distributor-specific inputs. As noted above, an effort has been made to rely on data that should be available or can be easily compiled. Once the data has been entered, the model is easy to run as the user selects the projects to be included in a particular Investment Plan Scenario.

2.5 A Note On Model Capabilities and Input Requirements

As noted above, the design of the model balances the competing objectives of greater model capability and a desire to avoid burdensome input requirements. The relationship between model capabilities and input requirements is shown in the diagram at the top of the next page.

[6] It is possible that the OEB will provide guidance on categories at some future date.

Model Capabilities and Related Input Requirements

	Capability	Description	Related Input Requirements
1	Incremental Revenue Requirements	Incremental cost-of-service for a multi-project network investment plan (vs. revenue requirements to be borne by provincial ratepayers)	• Direct Benefits % for renewable projects • Annual capital and O&M costs by project • Amortization term & CCA rate by project component • Capital structure, cost of capital and tax rate
2	Typical Bill Impacts by Class with Rate Design	Calculates incremental rates by class (chosen by user) and rate component for investment plan; adds these to existing rates; calculates bill impacts at user-specified usage levels	• Identify costs as service, demand or volumetric • Specify customer classes, typical bill usage levels, and existence of a demand charge • Load forecast by customer class • Other allocation factors (e.g., NCP: Year 1 only) • Existing rates with IRM formula inputs if applicable
3	WMSC Impact	Calculates avoided transmission network service, transmission connection service, and WMSC due to renewable projects	• Annual MW added by technology/size with percentage by under 2 MW (same for all years) • Capacity factor and CP and NCP diversity factors by technology/size • Current network & connection charges with escalation rates • AQEW forecast • % of expansion projects that provide direct benefits
4	GA Impact	Calculates impact of renewable projects on the Global Adjustment	• Contract Prices by technology/size • Realized HOEP % by technology/size

3. Model Inputs, Computations, and Reports

3.1 Model Inputs

The model is designed to require an initial set-up effort in order to populate it with distributor-specific data. There are three color codes that apply to inputs: light yellow is a user-specified numerical value or text label, light blue is a user choice from a drop-down menu, and purple indicates an input value provided with the model that can be overwritten by the user to reflect information that is either more appropriate for their service territory or more up-to-date information. The following subsections describe these model inputs or assumptions.

3.1.1 Identification of Customer Classes for Bill Impacts

The first set of inputs to be specified by the user are necessary to identify the electric distributor rate classes to be modeled (up to five) and to indicate whether each rate class has a demand charge in addition to an energy charge.

Customer Rate Classes

Class	Name	Demand Charge
Class A	Residential	No
Class B	Small GS (<50 kW)	No
Class C	Large GS	Yes
Class D	Large Users 1	Yes
Class E	Large Users 2	Yes

The user also specifies the consumption levels for each rate class that will be used to calculate bill impacts. The user enters this data in monthly kWh for classes that do not have a demand charge and as kW for classes with a demand charge.

Monthly Bill Impact Level

Class	Level 1	Level 2	Level 3	Measure
Residential	500	800	1,500	kWh
Small GS (<50 kW)	2,000	5,000	10,000	kWh
Large GS	100	500	1,000	kW
Large Users 1	1,500	3,000	5,000	kW
Large Users 2	6,000	8,000	10,000	kW

3.1.2 Potential Network Investment Projects

The second category of distributor-provided data defines potential network investment projects. The model is designed to allow up to five (5) network investment projects that are related to *GEGEA* requirements. It will also allow up to twenty (20) other network

investment projects – five in each of four categories defined by the user. A distinction between this first category and subsequent four categories is necessary to reflect the requirements of O. Reg. 330/09 and potential impacts of these projects on the GA and WSMC. **[Power Advisory Comment: interested in feedback on the number of projects whether it is important to have categories predefined after the first category]**

Populating this section of the model may be the most time-consuming exercise for electricity distributors. It is anticipated that the investment amounts and incremental impact of a project on O&M expenses will be data that is already compiled as part of an annual capital budgeting exercise. Input will also need to be provided by an individual familiar with rate calculations to select appropriate amortization and Capital Cost Allowance (CCA) treatment and to identify classification (the applicable charge) and allocation factors.[7]

The following input data that is required to specify a network investment project.

Plant Investment	2012	2013	2014	2015	2016	Classificati	Allocation	Amortizatio	CCA Rate
Investment 1.1.a	1,000,000	500,000	400,000			Demand	1 CP	40 Years	8.0%
Investment 1.1.b	1,500,000	350,000	200,000			Demand	4 CP	25 Years	8.0%
Investment 1.1.c	100,000	30,000				Customer	Customers	20 Years	8.0%
Total	2,600,000	880,000	600,000	0	0				

O & M Expenses	2012	2013	2014	2015	2016	Classificati	Allocation
Fixed 1.1	200,000	210,000	220,000	200,000	200,000	Demand	1 CP
Variable 1.1	20,000	25,000	30,000	35,000	40,000	Volumetric	Energy
Total	220,000	235,000	250,000	235,000	240,000		

Other Income	2012	2013	2014	2015	2016	Classificati	Allocation
Income 1.1	0	0	0	0	0	Volumetric	Energy
Total	0	0	0	0	0		

As shown above, the user enters up to three investment subcategories or project components, both fixed and variable O&M expenses, and other income for up to five years. It is possible to combine the components into a single entry. The purpose of having distinct components is to provide an opportunity to distinguish among project components and expense items for purposes of specifying the amortization rates, CCA rates, and classification and allocation factors.

3.1.3 Additional Impacts: Global Adjustment and O. Reg. 330/09

There are two sources of direct benefits attributable to renewable energy projects under O. Reg. 330/09: improvements in the distributor's ability to serve its customers (for example, the improvements in the ability to meet load growth or improvements to service quality), and avoided transmission network and connection charges and wholesale market service charges as a result of connection of a new renewable resource to the distributor's network.[8]

[7] A default CCA rate of 8% based on CCA Class 47 is included in the model but can be overwritten.

[8] See discussion in the Report of the Board – Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09 (EB-2009-0349).

The first source of direct benefits is reflected in the model through user entry of a percentage of each Category 1 project that provides direct benefits to the distributor's customers. Distributors must provide an estimate of this percentage in their Green Energy Plan.

The data required to estimate the second impact of O. Reg. 330/09 related to avoided transmission network and connection charges as well as avoided WMSCs requires the electricity distributor's market intelligence and judgment with respect to the type, amount and timing of new renewable energy resources that will be connected as a result of a particular project. There are two types of data. First, the user specifies the amount and timing of renewable energy resource additions by completing the following table for each project:

Capacity (kW)	2012	2013	2014	2015	2016	Renewable Resource (MW)	> 2 MW (%)
Capacity 1.1.a	1,000					Onshore Wind (All Sizes)	0.0%
Capacity 1.1.b		2,000				Biogas (≤ 0.5)	0.0%
Capacity 1.1.c			3,000			Biomass (≤ 10)	33.3%
Capacity 1.1.d				1,000		Waterpower (≤ 10)	0.0%
Capacity 1.1.e					1,500	Landfill Gas (≤ 10)	0.0%
Capacity 1.1.f				800		Solar Rooftop (≤ 0.01)	0.0%
Capacity 1.1.g	600				500	Solar Ground (≤ 0.01)	0.0%
Capacity 1.1.h							
Capacity 1.1.i							
Total	1,600	2,000	3,000	1,800	2,000		

The renewable resource categories are based on the Feed-In Tariff price schedule for renewable projects in Ontario. They are selected from a drop-down menu that identifies project types by both technology and size, to correspond to different pricing provisions. The user also specifies the percentage of capacity in each category that is represented by projects that exceed 2 MW in size as these projects do not result in avoided connection service charges under the direct benefits calculations.

The model also requires assumptions necessary to estimate the impact of renewable energy projects on the GA and the determination of customer benefits in accordance with the Board report determinations made under O. Reg. 330/09. The assumptions required to calculate the impact on the GA are the contract prices for each technology, and the realized HOEP for each technology. A portion of the contract prices increase at the rate of inflation for all projects other than solar.

Contract Price ($/kWh)

Resource (MW)	2012	Portion Esc.
Biogas (≤ 0.5)	0.1600	20.0%
Biogas (> 0.5 ≤ 10)	0.1470	20.0%
Biogas (> 10)	0.1040	20.0%
Biogas (On-Farm ≤ 0.1)	0.1950	20.0%
Biogas (On-Farm > 0.1 ≤ 0.25)	0.1850	20.0%
Biomass (≤ 10)	0.1380	20.0%
Biomass (> 10)	0.1300	20.0%
Landfill Gas (≤ 10)	0.1110	20.0%
Landfill Gas (> 10)	0.1030	20.0%
Onshore Wind (All Sizes)	0.1350	20.0%
Solar Ground (≤ 0.01)	0.6420	0.0%
Solar Ground (> 0.01 ≤ 10)	0.4430	0.0%
Solar Rooftop (≤ 0.01)	0.8020	0.0%
Solar Rooftop (> 0.01 ≤ 0.25)	0.7130	0.0%
Solar Rooftop (> 0.25 ≤ 0.5)	0.6350	0.0%
Solar Rooftop (> 0.5)	0.5390	0.0%
Waterpower (≤ 10)	0.1310	20.0%
Waterpower (> 10 ≤ 50)	0.1310	20.0%

Proportion of Realized HOEP

Resource (MW)	Proportion
Biogas (≤ 0.5)	100.0%
Biogas (> 0.5 ≤ 10)	100.0%
Biogas (> 10)	100.0%
Biogas (On-Farm ≤ 0.1)	100.0%
Biogas (On-Farm > 0.1 ≤ 0.25)	100.0%
Biomass (≤ 10)	100.0%
Biomass (> 10)	100.0%
Landfill Gas (≤ 10)	100.0%
Landfill Gas (> 10)	100.0%
Onshore Wind (All Sizes)	100.0%
Solar Ground (≤ 0.01)	110.0%
Solar Ground (> 0.01 ≤ 10)	110.0%
Solar Rooftop (≤ 0.01)	110.0%
Solar Rooftop (> 0.01 ≤ 0.25)	110.0%
Solar Rooftop (> 0.25 ≤ 0.5)	110.0%
Solar Rooftop (> 0.5)	110.0%
Waterpower (≤ 10)	98.0%
Waterpower (> 10 ≤ 50)	98.0%

The inputs required to estimate the direct benefits from O. Reg. 330/9 are the Independent Electricity System Operator's (IESO) Allocated Quantity of Energy Withdrawn (AQEW), forecasts of avoided uniform transmission and wholesale market service charges, and diversity and capacity factors by technology.

AQEW Projection (MWh)

Projection	2012	CAGR
AQEW	139,708,079	0.10%

Transmission Rates ($/kW/Mo)

Charge	2012	Real Esc.
Network Service	3.22	0.50%
Connection Service	0.79	0.50%

Energy Charges ($/MWh)

Charge	2012	Real Esc.
Average HOEP	37.85	0.50%
Global Adjustment	27.18	0.50%
Wholesale Market Service	5.45	0.50%

Capacity & Diversity Factors

Resource (MW)	Capacity	CP	NCP
Biogas (≤ 0.5)	75.0%	80.0%	75.0%
Biogas (> 0.5 ≤ 10)	75.0%	80.0%	75.0%
Biogas (> 10)	75.0%	80.0%	75.0%
Biogas (On-Farm ≤ 0.1)	75.0%	80.0%	75.0%
Biogas (On-Farm > 0.1 ≤ 0.25)	75.0%	80.0%	75.0%
Biomass (≤ 10)	85.0%	90.0%	85.0%
Biomass (> 10)	85.0%	90.0%	85.0%
Landfill Gas (≤ 10)	84.0%	84.0%	84.0%
Landfill Gas (> 10)	84.0%	84.0%	84.0%
Onshore Wind (All Sizes)	30.0%	10.0%	22.0%
Solar Ground (≤ 0.01)	14.0%	90.0%	80.0%
Solar Ground (> 0.01 ≤ 10)	14.0%	90.0%	80.0%
Solar Rooftop (≤ 0.01)	13.0%	90.0%	35.0%
Solar Rooftop (> 0.01 ≤ 0.25)	13.0%	90.0%	35.0%
Solar Rooftop (> 0.25 ≤ 0.5)	13.0%	90.0%	35.0%
Solar Rooftop (> 0.5)	13.0%	90.0%	35.0%
Waterpower (≤ 10)	52.0%	50.0%	50.0%
Waterpower (> 10 ≤ 50)	52.0%	50.0%	50.0%

These values are provided with the model and are purple-shaded, indicating that they should be overwritten by the user if better data is available. Once this data has been entered, and all of the projects specified, the user does not need to return to this section of the model unless the distributor wants to modify a project or add a new project to the list of potential projects to be included in a network investment plan. The user selects the projects to be included on the sheet that defines an Investment Plan Scenario.

3.1.4 Cost of Service, Cost Allocation, and Bill Calculation Inputs

The fourth category of model assumptions are those required to calculate bill impacts and include information regarding the tax rates, and existing customer charges. As noted in Chapter 2, these assumptions should be available from a recent rate order or from an ongoing

effort by the distributor to prepare a rate case filing. The cost of capital assumptions are those that are approved by the OEB. There are three types of assumptions in this category.

The financial assumptions remain constant over the up to five-year period.

Cost of Capital

Component	Cost	Weight
Return on Equity	9.58%	40.00%
Long-Term Debt	5.32%	56.00%
Short-Term Debt	2.46%	4.00%
Total		100.00%

Working Capital & Taxes

Component	Rate
Working Capital	15.00%
Total Tax Rate	25.00%

Inflation Rate

Component	Rate
Inflation Rate	2.50%

The second type of other assumptions is the load forecast and allocation factors, necessary to calculate incremental rate impact for the network investment plan. The number of customers, level of demand, and electricity sales serve as the denominator in the rate calculation for each of the up to five rate classes. The user specifies the initial year value and annual escalation rates by customer class or, if a five-year forecast is available, these values may be entered directly into the model.

The first year values for customers, demand, and sales are also used as allocation factors which, to reduce the amount of input required for other allocation factors, are assumed to remain constant over the five-year period.[9] The model is designed to incorporate six other common allocation factors: the number of bills and five demand cost allocation factors based either on coincident peak or non-coincident peak data.

The final set of bill impact assumptions are those required to calculate customer bills before consideration of the network investment plan. These reflect the current tariff with user specified assumptions regarding escalation of tariff elements over the five years.

[9] It is assumed that these factors do not change significantly over a relatively short period. The electric distributor will likely have values for only the current year and would otherwise have to forecast these factors. It should be noted as well that electric distributor cost allocation studies often incorporate large numbers of allocation factors, many of which are variations of these basic factors.

Distribution Charges

Customer ($/Mo)	2012
Residential	14.00
Small GS (<50 kW)	22.00
Large GS	300.00
Large Users 1	4,500.00
Large Users 2	6.00

Demand ($/kW)	2012
Residential	0.00
Small GS (<50 kW)	0.00
Large GS	2.25
Large Users 1	0.80
Large Users 2	0.00

Volumetric ($/kWh)	2012
Residential	0.0130
Small GS (<50 kW)	0.0180
Large GS	0.0000
Large Users 1	0.0000
Large Users 2	0.0130

The Incentive Ratemaking (IRM) formula is used to calculate base distribution rates for years 2 through 5.

IRM Formula

Component	Rate
Inflation Factor	2.50%
Productivity Offset	0.72%
Stretch Factor	0.50%
Double Counting Offset	0.00%

The IRM formula has been adjusted to include a "double-counting offset". This is intended to represent the fact that application of the current IRM formula already provides some ability for distributors to fund capital investments, including infrastructure replacement. However, the Board recognized that it may not provide adequate revenues to support extraordinary increases in capital expenditures as it approved an "Incremental Capital Module" as part of the 3rd generation incentive regulation mechanism.[10] The model has an initial value of 0% that should be reviewed by the user to establish a value that is appropriate for the distributor with one caution: once established, this value should be held constant across Investment Plan Scenarios.

[10] See the July 14, 2008 *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors* where it approved the concept and its September 17, 2008 *Supplemental Report* where it approved a distributor-specific formula to establish the materiality threshold.

Other rate elements, including smart grid adders and the debt retirement charge are included as "rate adders" in order to provide flexibility as new categories may be added over time.[11]

T & D Adders

Customer ($/Mo)	2012	2013	2014	2015	2016
Residential	1.55	1.55	1.55	1.55	1.55
Small GS (<50 kW)	1.55	1.55	1.55	1.55	1.55
Large GS	1.55	1.55	1.55	1.55	1.55
Large Users 1	1.55	1.55	1.55	1.55	1.55
Large Users 2	1.55	1.55	1.55	1.55	1.55

Demand ($/kW)	2012	2013	2014	2015	2016
Residential	0.00	0.00	0.00	0.00	0.00
Small GS (<50 kW)	0.00	0.00	0.00	0.00	0.00
Large GS	4.00	4.00	4.00	4.00	4.00
Large Users 1	3.50	3.50	3.50	3.50	3.50
Large Users 2	0.00	0.00	0.00	0.00	0.00

Volumetric ($/kWh)	2012	2013	2014	2015	2016
Residential	0.0150	0.0150	0.0150	0.0150	0.0150
Small GS (<50 kW)	0.0140	0.0140	0.0140	0.0140	0.0140
Large GS	0.0550	0.0550	0.0550	0.0550	0.0550
Large Users 1	0.0075	0.0075	0.0075	0.0075	0.0075
Large Users 2	0.0150	0.0150	0.0150	0.0150	0.0150

3.2 Model Calculations

There are four sets of calculations: the incremental cost-of-service, cost allocation and rate design, direct benefits, GA impacts, and bill impacts.

3.2.1 Incremental Cost-of-Service

The incremental cost-of-service is calculated based on a traditional cost of service methodology employed in Ontario. The elements that are calculated include gross plant, amortization expense, accumulated amortization, working capital, rate base, interest expense, return on equity, O&M expenses, and PILs. The calculation of PILs reflects the CCA provisions. A gross-up factor is applied to PILs to calculate total revenue requirements attributable to the network investment plan.

3.2.2 Cost Allocation and Rate Design

As the second step, the rate base and cost of service elements are each classified to the three charges on customer bills: the customer, demand, and volumetric charges. Demand-related costs are classified as volumetric for rate classes that do not have a demand charge.

The cost of service is also allocated among the customer classes specified by the user using allocation factors that have been selected by the user. The end result is the revenue

[11] It is assumed that the individual entering this data will be familiar with the tariff schedule and can combine these additional charges as appropriate.

requirements to be recovered from each customer class and from among the customer, demand or volumetric charges within each rate class.

3.2.3 Impacts on the Global Adjustment and the WSMC

There are two additional impacts that are related to the addition of renewable energy projects. The first such adjustment is an adjustment to the GA to reflect the impact of the specific project or projects on the GA. This impact is calculated for each renewable energy technology and size tranche within a technology and is attributable to the difference between the Contract Price and the realized HOEP multiplied by the project output. As a final step, in order to estimate the $/MWh impact on the GA, the total impact on the GA is divided by the Ontario IESO's AQEW.

The second impact that must be taken into account is related to the impact of the requirements of O. Reg. 330/09 on the WMSC. Under the terms of this regulation, an electric distributor is allowed to shift a portion of the recovery of its investments necessary to connect renewable projects to be recovered from all provincial ratepayers. The electric distributor remains responsible for direct benefits that are realized by their own customers. There are two categories of direct benefits. The first category is charges that are avoided by the distributor as a result of connecting renewable resources. The model estimates these direct benefits by adding together avoided network service charges, avoided connection service charges, and avoided wholesale market service charges as follows:

- Avoided Network Charges: calculated as the network charge x installed capacity for FIT projects (by technology) x coincident peak diversity factor (by technology)[12]

- Avoided Connection Charges: calculated as the connection charge x installed capacity for FIT projects under 2 MW (by technology) x non-coincident peak diversity factor (by technology)

- Avoided WMSC: calculated as production from FIT projects x the WMSC

The second category of direct benefits result from improvements in the ability of the distributor to serve its customers that result from investments in its distribution network that are necessary to connect renewable resources. These include increased ability to add new load, maintain or enhance reliability, and improve service quality. Distributors must estimate the proportion of direct benefits provided by each project when filing their GEA Plan. This same percentage is entered into the model when defining projects under Category 1: Expansion and Renewable Enabling Improvements. Once entered, the incremental cost-of-

[12] In the *Report of the Board: Framework for Determining the Direct Benefits Accruing to Customers of a Distributor under Ontario Regulation 330/09*, the Board determined that microFIT projects should be excluded from the assessment of direct benefits for materiality reasons.

service is calculated based only on this percentage of a project's investments, O&M expenses and Other Income.

The cost-of-service attributable to these Category 1 investments that do not result in direct benefits (e.g., a percentage calculated as one minus the percentage of each project that provides direct benefits) is borne by all provincial ratepayers. The model applies the same cost-of-service principles to estimate the annual amount to be borne by provincial ratepayers and divides this amount by the AQEW to arrive at an estimated increase in the WMSC in each year.

3.2.4 Bill Impacts

Finally, bill impacts are calculated through a four-step process. First, the model calculates the rates that would be in effect absent the network investment plan based on user inputs regarding current rates and escalation rates for the subsequent four years. Second, the model calculates customer bills based on the typical bill consumption levels that have been entered for each class.[13] Third, the model calculates the incremental impact on bills attributable to the network investment plan using the revenue requirements by rate class/charge element and the same typical bill consumption levels. The fourth step calculates the dollar and percentage increase in bills that are attributable to the network investment plan.

3.3 Reports

The model has four pre-defined and formatted reports. The first report is a 3-page summary that presents a summary of the network investment plan, including direct benefits and impact on the GA as well as the resulting revenue requirements and summary of bill impacts. The second report provides more detail on bill impacts by rate class as it breaks out the impacts on distribution charges, the GA and WSMC. The third and fourth reports enable the user to print out the network investment plan assumptions and other assumptions, respectively. All reports are formatted to include the Investment Plan Scenario name and date.

[13] These will be less than the total bill paid by a customer to the extent that the assumptions either do not capture minor bill elements and because consumption taxes are not included.