AN ASSESSMENT OF THE TECHNICAL AND ECONOMIC BENEFITS OF DISTRIBUTED GENERATION

by

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Abstract

Large amounts of distributed generation have been installed in the grid, with even more to be connected in the near future. An important share of this future deployment is expected to come from renewable technologies, mainly wind turbines and photovoltaic cells. Multiple research, development, and demonstration projects from industry, government agencies, and universities around the world are currently aiming to make existing and future networks more efficient, intelligent, and reliable with the inclusion of distributed energy resources as an active part of power systems. Operation and planning of such systems require that stakeholders consider the benefits and problems that increased connection of distributed generation brings to the equation. This thesis presents a methodology for assessment of technical and economic benefits of distributed generation. A radial distribution feeder benchmark is used along with two publicly available analysis tools, developed to support power engineers in the evaluation of distributed generation projects. The proposed methodology is then illustrated using these tools, and results and conclusions are presented and discussed.

Résumé

Actuellement, de quantités importantes de production décentralisée sont installées dans les réseaux de distribution, et des niveaux encore plus élevés seront reliés prochainement. Une partie importante de ce futur déploiement est anticipée des technologies de sources renouvelables, principalement des éoliennes et des panneaux photovoltaïques. Plusieurs projets de recherche et développement, menés par divers intervenants autour du monde, ont pour but de rendre les réseaux de distribution plus efficaces, intelligents et fiables, y compris d’intégrer les sources d’énergie distribuées dans l’opération de ces derniers. La planification et l'opération de ces systèmes requièrent de tenir compte des bénéfices et des impacts qu'apporte un nombre croissant de producteurs distribués relié aux réseaux. Cette thèse propose une méthodologie pour l'évaluation de bénéfices techniques et économiques de la production décentralisée. Un circuit de distribution radial de base est utilisé comme référence. La méthodologie est mise en œuvre avec deux logiciels d'analyses développés pour soutenir l'évaluation de projets de production décentralisée. La méthodologie proposée est évaluée avec ces outils dans le circuit de distribution mentionné, et les résultats et les conclusions sont présentés et examinés.

Resumen

Actualmente, considerables cantidades de generación distribuida están siendo instaladas en las redes de potencia, y aun mayores niveles serán conectados en el futuro cercano. Se espera que una parte importante de este futuro despliegue corresponda a tecnologías de fuentes renovables, principalmente turbinas eólicas y celdas fotovoltaicas. Múltiples proyectos de investigación y desarrollo, involucrando la industria, agencias gubernamentales y universidades alrededor del mundo, tienen como objetivo hacer que las actuales y futuras redes de potencia sean más eficientes, inteligentes y confiables, incluyendo fuentes distribuidas de energía como parte activa de ellas. La planeación y operación de estos sistemas requiere tener en cuenta los beneficios e impactos que trae consigo un creciente número de generadores distribuidos conectados a las redes. Esta tesis propone una metodología para la evaluación de beneficios técnicos y económicos de la generación distribuida. Un circuito de distribución radial básico es usado como referencia. La metodología es implementada a través de dos programas de análisis (*software*) desarrollados para apoyar la evaluación de proyectos de generación distribuida. La metodología propuesta es evaluada con dichos programas en el circuito de distribución mencionado, y los resultados y conclusiones son presentados y discutidos.

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List of Abbreviations

ADN	*Active Distribution Networks*
AESO	*Alberta Electric System Operator*
AMI	*Advanced Metering Infrastructure*
AMR	*Automatic Meter Reading*
AVC	*Automatic Voltage Control*
AVR	*Advanced Voltage Regulator*
BOS	*Balance Of System*
CDM	*Clean Development Mechanism*
CER	*Certified Emission Reductions*
CHP	*Combined Heat and Power*
CIGRE	*International Council on Large Electric Systems*
CPI	*Consumer Price Index*
CSV	*Comma Separated Value*
CVR	*Conservation Voltage Reduction*
DER	*Distributed Energy Resource*
DG	*Distributed Generation*
DMS	*Distribution Management System*
DNO	*Distribution Network Operator*
DR	*Demand Response*
DSM	*Demand Side Management*
DSS	*Distribution System Simulator*
EfW	*Energy-from-Waste*
EPRI	*Electric Power Research Institute*
ESS	*Energy Storage System*
EU ETS	*European Union Emissions Trading Scheme*
EV	*Electric Vehicle*
FACTS	*Flexible AC Transmission Systems*
FIT	*Feed-In Tariff*
FRT	*Fault Ride-Through*
GHG	*Greenhouse Gas*
HAN	*Home Area Network*
ICT	*Information and Communication Technologies*
IED	*Intelligent Electronic Device*
IEEE	*Institute of Electrical and Electronics Engineers*

IESO	*Independent Electricity System Operator*
IPP	*Independent Power Producer*
IRR	*Internal Rate of Return*
ISO	*Independent System Operator*
JI	*Joint Implementation*
NIMBY	*Not In My Back Yard*
NPV	*Net Present Value*
NYISO	*New York Independent System Operator*
O&M	*Operation and Maintenance*
OECD	Organisation for Economic Co-operation and Development
OLTC	*On-Load Tap Changer*
OPF	*Optimal Power Flow*
PCC	*Point of Common Connection*
PC+P	*Production Cost plus Premium electricity rate*
pf	*Power Factor*
PHEV	*Plug-in Hybrid Electric Vehicle*
PQ&R	*Power Quality and Reliability*
pu	*Per-unit*
R&D	*Research and Development*
RES	*Renewable Energy Source*
RMS	*Root Mean Square*
RPS	*Renewable Portfolio Standard*
RTO	*Regional Transmission Operator*
RTU	*Remote Terminal Unit*
SCADA	*Supervisory Control and Data Acquisition*
STATCOM	*Static Synchronous Compensator*
SVC	*Static VAR Compensator*
T&D	*Transmission and Distribution*
tCO2e	*Tons of Carbon Dioxide Equivalent*
UNFCCC	*United Nations Framework Convention on Climate Change*
UPS	*Uninterruptible Power Supply*
V2G	*Vehicle-to-Grid*
VPP	*Virtual Power Plant*
WACC	*Weighted Average Cost of Capital*

Nomenclature

Γ_{DG}	*DG penetration level [%]*
$\overline{\Upsilon}(h)$	*Average electricity rate for h hours [$/MWh]*
Υ_{DG}	*Electricity rate paid to the DG [¢/kWh]*
Υ_{GHG}	*GHG emissions reduction incentive [¢/kWh]*
Υ_{IN}	*Total incentives received by the DG [¢/kWh]*
Υ_{LR}	*Loss reduction incentive [¢/kWh]*
Υ_{UD}	*Upgrade deferral incentive [¢/kWh]*
AR_{DG}	*DG total annual revenue [$]*
$CO2_{CR}$	*Greenhouse gas emissions reduction annual credit [$]*
C_{f_x}	*Feeder upgrade cost in year x [$]*
C_{f_y}	*Feeder upgrade cost in year y [$]*
E_{DG}	*Yearly DG energy production [kWh]*
E_L	*Feeder yearly energy losses [kWh]*
E_{L_DG}	*Feeder yearly energy losses with DG connected [kWh]*
E_{L_RED}	*Feeder yearly energy losses reduction due to DG [kWh]*
E_{SUB}	*Total energy measured at the primary substation [kWh]*
GHG_{RED}	*Greenhouse gas emissions annual reduction [tCO2e]*
L_{PEAK}	*Peak load of the feeder [kW]*
P_{DG}	*Distributed generator rated capacity [kW]*
P_G	*Distributed generator active power injection [W]*
P_L	*Active power of the load [W]*
P_{LOSS}	*System losses [W]*
Q_G	*Distributed generator reactive power injection [VAR]*
Q_L	*Reactive power of the load [VAR]*
UDA_{DG}	*Upgrade deferral benefit annuity [$]*
UD_{DG}	*Present value of upgrade deferral benefit [$]*
V_L	*Voltage at the load node [V]*
V_S	*Voltage at the substation [V]*
λ_{GHG}	*Greenhouse gas emissions credit rate [$/tCO2e]*
ΔV	*Voltage drop [V]*
$\Upsilon(h)$	*Electricity rate as a function of the number of hours [$/MWh]*
I	*Circulating current through a conductor [A]*
LRS	*Loss reduction savings [$]*
R	*Resistance of the distribution line [Ω]*

TES	*Total energy supplied to the feeder [kWh]*
TTO	*Total yearly number of transformer's tap operations*
TVE	*Total yearly number of voltage exceptions across the feeder*
V	*Phase-to-phase voltage [V]*
X	*Reactance of the distribution line [Ω]*
i	*Risk-free interest rate [%]*
x	*Number of years until feeder upgrade is required*
y	*Number of years until feeder upgrade is required with DG connected*
η	*Agreed annuity rate [%]*
α, β	*System dependant constants*

Chapter 1: Introduction

1.1 General Introduction

Whether it is a utility improving the quality and reliability of power supply, a system operator including renewable energy sources (RESs) into its portfolio, an independent power producer (IPP) investing on energy projects, or a small community or commercial location implementing a microgrid, distributed generation (DG) has become a reality in today's power systems as a key component for the implementation of such applications. Government agencies, transmission and distribution system operators, and academia are presently discussing how to deal with the increasing amount of DG that is being connected to the grid, trying to create a technical and regulatory framework that optimizes benefits for all the participants, including of course, the customer.

In addition, distributed generation included as part of countries' energy policies helps to address the major concerns that the electricity sector is facing: enough energy supply for all meeting the increasing demand, security of electricity supply, providing affordable access to electricity, and addressing sustainable development and climate change [1].

Table 1.1 Total electricity net consumption [TWh] [2]

	2003	2004	2005	2006	2007
Brazil	332.8	348.9	363.6	379.2	403.1
Canada	527.7	533.6	541.3	528.7	536.1
China	1,678.7	1,958.2	2,195	2,528.4	2,835
Colombia	35.9	37.9	38.9	39.6	38.6
France	435.2	446.7	449.8	445.2	447.2
Germany	535.5	541.7	543.4	547.4	547.3
India	428.2	457	483.3	525.4	568
Italy	295.2	302.3	307.1	314	315
Mexico	171.8	175.8	190	196	201
Spain	222.1	234.1	244.8	261.5	262.4
U.K.	342.2	342.4	350.3	349.3	345.8
U.S.	3,662.1	3,715.9	3,811	3,816.9	3,923.8
Venezuela	66.4	70.2	71	79.9	83.1
World	14,440.3	15,103.3	15,732.2	16,384.9	17,109.7

Therefore, power engineering is entering into challenging times. Innovative solutions are required to bring reliable and secure energy supply to customers, matching the increasing consumption of world's ever increasing population (Table 1.1 and Figure 1.1). DG combined with so-called Smart Grids technologies, and active distribution networks (ADN) enabling technologies, could provide the required flexibility to grid operation, in order to minimize the distributed energy resources (DERs) and RESs impacts, while maximizing their penetration and benefits.

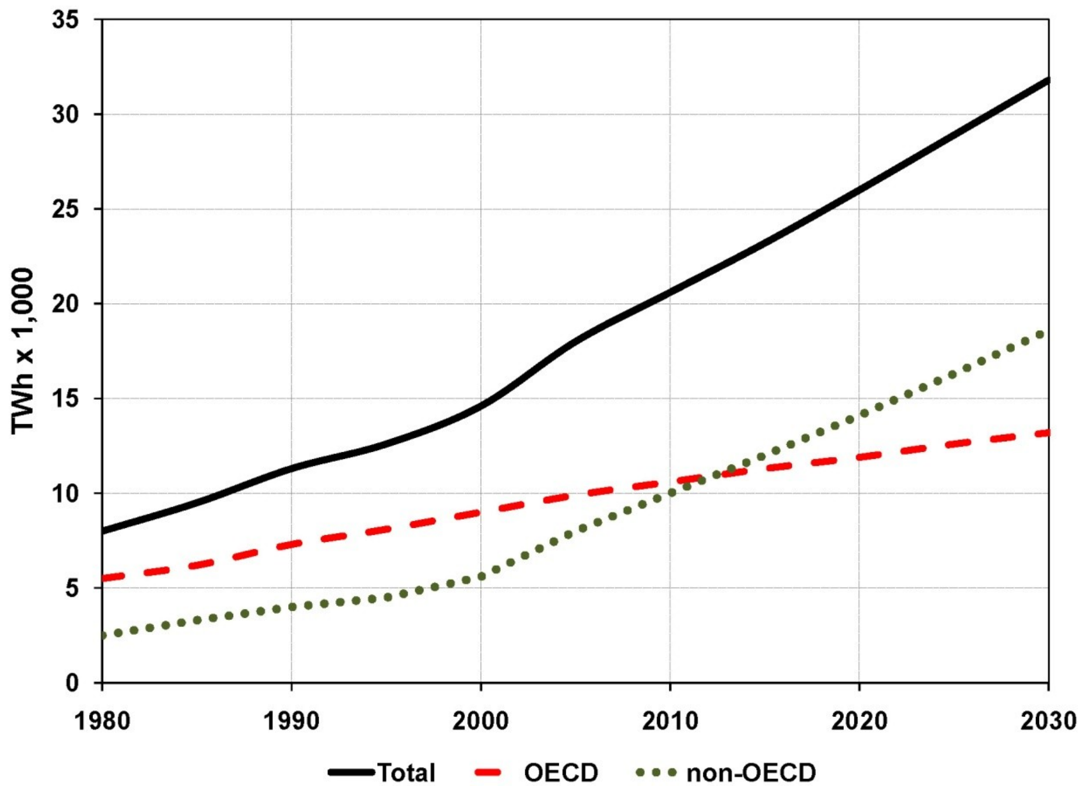

Figure 1.1 World net electric power generation 1980-2030 [2]

However, unplanned DG connections bring well known problems to power systems, especially to distribution networks where many of the new generators are expected. Such problems include, for example, changes in voltage profiles, changes in the behavior of the protection schemes, increased fault levels, bidirectional power flows, and potentially increased losses. These problems are exacerbated when renewables energy sources are used for electricity generation, due to its intermittent nature. Furthermore, when a utility is not the owner of the DG that has been connected to its network, different conflicts arise with the IPP such as connection charges, operation modes, fault management, and even infrastructure upgrade responsibilities.

Universities, government and research institutes have being contributing to the understanding of these issues by providing tools and methodologies that allow interested actors to better comprehend benefits and impacts of DG [3]. It is worth highlighting how important it is to include the economic aspect of such analyses, so managers, stockholders, and customers are also better informed in the decision making process.

Adequate power system planning and operation, including technical and economic impact assessment, will accelerate further DG deployment, maximizing its benefits, and improving social welfare in general, through market mechanisms for efficient allocation of such benefits. The outcome of such an assessment is also important for fostering DG investment in developing countries, in particular, fast-growing economies that require electricity supply supporting their competitive development [4]. Furthermore, DG plays a fundamental role in providing electricity to isolated communities; in 2005, approximately 32% of developing countries' population [1] did not have access to electricity, accounting for about 1.6 billion people [2].

Energy supply is crucial for social and economic development. A comprehensive understanding of DG impacts and benefits will permit its inclusion in long-term policies in the energy sector. Distributed generation technologies add diversification to flexible policies that look to maintain different energy sources.

1.2 Literature Review

This section presents a review of relevant literature describing the benefits and impacts that increasing levels of distributed generation are bringing to distribution networks.

1.2.1 Impacts of High DG Penetration

As previously mentioned, distributed generation represents an interesting investment opportunity for different stakeholders. Cheaper technologies, shorter installation times, support for renewable energies, and government incentives are pushing numerous projects around the world. However, high levels of unplanned and uncontrolled DG

[1] Developing countries considered for this statistic are those that are not members of the Organisation for Economic Co-operation and Development (OECD) or the so called non-OECD countries.

connections bring severe technical problems to distribution networks [5]. In this section, the most significant impacts of high DG penetration in distribution networks will be discussed.

1.2.1.1 Impact on Voltage Levels and Power Flow

Consider the simplified two-node distribution system illustrated in Figure 1.2. This radial system includes the substation as the power source, the distribution line, and a load connected at the opposite end.

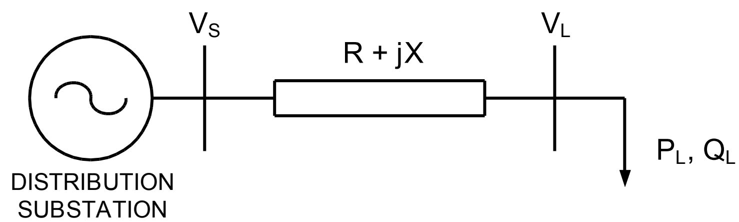

Figure 1.2 Two-node simplified radial distribution system

The voltage drop in root mean square (RMS) value along the line is defined by [6-7]:

$$\Delta V = V_s - V_L = \frac{RP_L + XQ_L}{V_L} \tag{1.1}$$

In distribution lines, the reactance-resistance ratio (X/R) is low, therefore the load active power has a great impact in the voltage drop along the conductor.

Hence, the distribution network operator (DNO) maintains an acceptable voltage level along the feeder by modifying the substation voltage through substation transformers equipped with on-load tap changer (OLTC), and by selection of the conductor size (reducing resistance). It is also possible to mitigate the voltage drop by installing switched capacitors near to the loads. This action modifies the reactive power flow through the line (Q_L).

The connection of distributed generation to the radial system (Figure 1.3) modifies Eq. (1.1) where the injection of active and reactive power by the DG is considered:

$$\Delta V = V_s - V_L = \frac{R(-P_G + P_L) + X(\pm Q_G + Q_L)}{V_L} \tag{1.2}$$

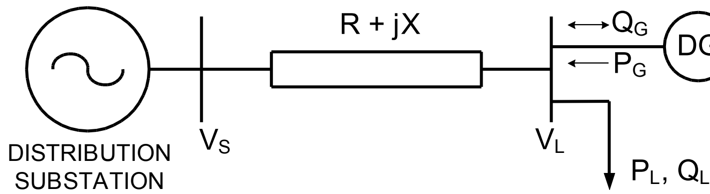

Figure 1.3 Two-node simplified radial distribution system with DG

From Eq. (1.2) it is clear that high levels of DG will produce a change in the power flow resulting in a negative voltage drop, i.e., the distributed generator will modify the voltage profile of the network, potentially resulting in high voltages at some points of the system [8-10]. This change in the voltage profile can also affect the operation of the OLTC automatic relay based on line drop compensation control, especially when the DG installed is an intermittent renewable energy source (RES). The worst case scenarios for the network operation are [11]:

- No generation and maximum load
- Maximum generation and maximum load
- Maximum generation and minimum load

Another problem related to increasing active power flow through the feeders, due to DG connections, is the management of total system losses. It should be stressed that the current flowing through a conductor of a feeder with DG is defined by [12-13]:

$$I = \frac{(P_L - P_G)}{\sqrt{3} * V * pf} \tag{1.3}$$

And the active power losses in that conductor, due to the current flowing through, are defined by:

$$P_{LOSS} = I^2 * R \tag{1.4}$$

From Eq. (1.3) and (1.4) the relationship between the system losses and the active power injected to the network (feeder losses without including transformer losses) is obtained. Although the benefit of reducing network losses brought by DG is recognized, high levels tend to reverse those gains and in extreme cases actually increase losses.

Likewise, increased circulation of current through lines and transformers could reach and surpass equipment thermal rating limits. Furthermore, it could be possible to severely overload the network in the event of an outage of a portion of the distribution feeder [8]. This situation can be mitigated by replacing equipment [12], or by network power flow and DG output management [14].

1.2.1.2 Impact on Fault Current Levels

The total fault current of a feeder is the vector sum of all the current sources in the network, including primary transformers, rotating loads and certain DG [15-17]. DG based on rotating machines will contribute to faults in distribution networks, potentially pushing the total fault current beyond installed equipment ratings [18]. The aggregated contribution of several units will surpass equipment ratings and generate protection scheme problems [9, 19].

The impact of DG on fault levels is illustrated in Figure 1.4. In this simplified system two possible problems may arise in the operation of the network under fault:

- The current contribution from the distributed generator could cause an unnecessary trip of the substation switch number 1, disconnecting the associated load from a healthy feeder. This is known as sympathetic tripping.
- The sum of the fault current contributions from the main grid and the distributed generator could exceed the short-circuit rating of switch number 2, leading to the destruction of the equipment.

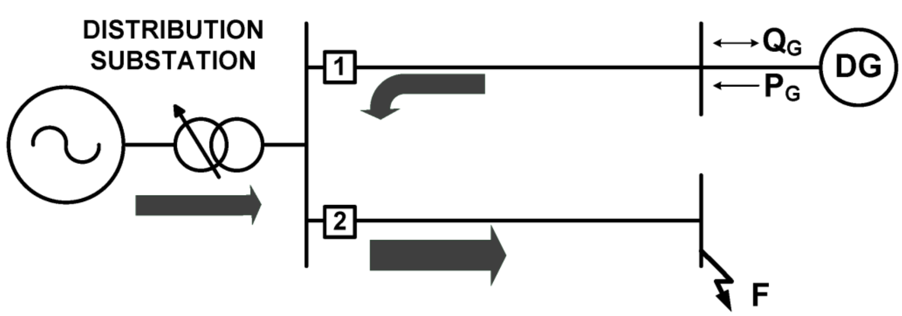

Figure 1.4 Fault current contribution from DG

1.2.1.3 Impact on Protection Schemes

The impact on fault current leads to challenges associated with protection schemes presently used in distribution networks. Increased connections of DG will affect protection settings and actions like fuse and switchgear coordination, sustained fault feeding clearance, interrupting equipment ratings, sympathetic or nuisance tripping, protection relay desensitization, recloser operation and unintentional islanding [20-21].

For example, relay desensitization occurs when embedded generation provides voltage support to the network under fault conditions, altering the voltage and current values seen by protection devices [22]. Also, this desensitization can be a result of modifying the ground current flows for single-phase ground faults.

Another issue widely discussed is the loss-of-mains or the unintentional islanding problem [9, 20]. Islanding is possible with DG based on synchronous generators, and induction generators and inverters with capacitors, since they do not rely on the grid for its excitation. Generator protection relays will unlikely act if the DG can sustain voltage and frequency in a portion of the circuit (Figure 1.5). Currently, utilities direct distributed generators to implement anti-islanding protection schemes in order to avoid potential hazardous operation of portions of the feeder. Multiple research projects are presently proposing innovative islanding detection schemes to comply with such a regulation [23]. Some of the risks of islanding include out-of-phase reconnection and utility line workers operating on energized circuits. However, the intentional or natural (remote communities) power island concept brings benefits like improved reliability and operation of self-contained power systems (microgrids and remote isolated power systems) [24-25].

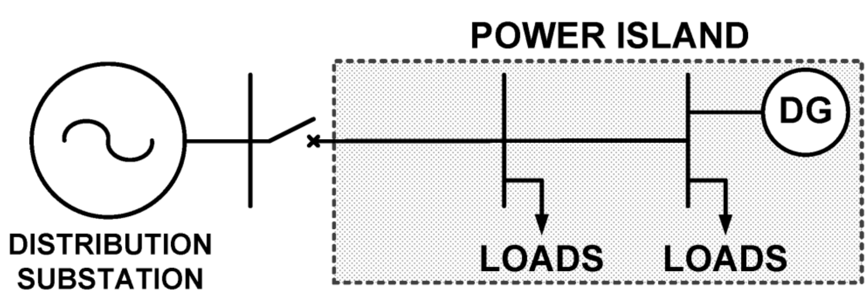

Figure 1.5 Islanding in a distribution feeder

1.2.2 Categorizing the Main Benefits of DG

As just discussed, systems with high penetrations of DG, if inappropriately planned, could result in a number of technical problems. However, much has been also researched on technical and economic benefits that DG provides to the electric grid [26-36]. A comprehensive understanding of these benefits by governments, regulators, and utilities will maximize the value of DG. The categorization listed in this section, according to sector participants, is presented following the structure proposed in [26]. Benefits that have been identified are able to provide a direct and measurable impact, hence a complete list of DG benefits would be more extensive if benefits that are more difficult to quantify were included, e.g., local economic impact (jobs creation) or “not in my back yard” (NIMBY) opposition to bigger power plants.

1.2.2.1 Customer and DG Owner Benefits

This category groups the most common benefits generally sought by big customers and IPPs when they decide to install DERs.

1.2.2.1.1 Electricity Sales

This benefit is the foundation of the business case. Independent power producers and utilities look for revenues in generation projects resulting from energy sales to the grid. Cheaper technologies, government subsidies and public pressure, especially with renewable sources, are pushing further DG deployment by attaching premiums to the price, thereby increasing revenue. Smaller equipment is available now even for small premises like houses and farms, and made more affordable by the aforementioned support mechanisms.

1.2.2.1.2 Consumption Reduction

Along electricity sales, consumption reduction is a key factor for DG deployment. For example, some projects now involve houses equipped with photovoltaic (PV) cells on the roof with a battery to offset the source’s intermittency, providing a reduction in their electricity bill. Larger facilities like industries, commercial buildings, and even nearby houses can benefit from the implementation of combined heat and power (CHP) equipment, in order to improve efficiency in procurement of their heat needs, while reducing fuel and electricity consumption.

1.2.2.1.3 Power Quality and Reliability

DERs have long been used by sensitive loads such as banks, hospitals and industries with specialized processes. The most common technologies are batteries and reciprocating engines for uninterruptible power supply (UPS) systems. However, improvements in power quality and reliability (PQ&R) of supply can be achieved with planned connections of DG and control of its output by the distribution network operator (DNO) [37-38]. Wider area PQ&R benefit through DG operation can include voltage profile improvement (with reactive power control), fault management, and intentional islanding.

1.2.2.2 Distribution Utility Benefits

DG owned or operated by the distribution utility brings well known benefits to the networks. When DNOs have control over DG output, most of the problems brought by the generators to distribution networks can be alleviated through control by distribution management systems (DMSs). Furthermore, the following benefits can offer quantifiable economic advantages to utilities, realized by the DMS.

1.2.2.2.1 Upgrade Investment Deferral

Since DG is connected near to the loads, low and medium levels of distributed energy resources (DERs) reduce the power flow coming from the main grid. This generation helps to offset peak demand and load growth. The demand reduction postpones the necessity for network upgrades (distribution lines and transformers mainly) [39-40]. However, this benefit requires high availability from the DG used for this purpose. The lack of firm DG capacity could bring reliability concerns to network operation.

1.2.2.2.2 Avoided Electricity Purchases

When the DG owner or operator offers the energy generated at a rate lower than the market electricity price, utilities can economically benefit from this price difference. This situation is more evident during peak load hours, where the electricity price is expected to be higher. This benefit can be increased when DG output is flexible and dispatchable, especially in markets with high price volatility.

1.2.2.2.3 Distribution Line Energy Loss Reduction

Depending on generator location and installed capacity, it is widely accepted by DNOs that DG can significantly reduce losses in distribution networks [41]. This concept is related to the demand reduction discussed before. When DG is connected near the loads, the power flow required from the grid is reduced, thus reducing current flow through feeder conductors. However the curve that associates network losses with DG installed capacity is U-shaped, meaning that very high levels of DG will actually lead to increased losses in the networks.

1.2.2.3 Power System Operator and Society Benefits

From a more general point of view, DG benefits can be reflected on larger power systems and society as well. Higher levels of DG penetration will have a positive impact in the following areas.

1.2.2.3.1 Electricity Market Price Reduction

High enough DG penetration on distribution networks would reduce demand to a level where such a decrease will have an influence on the electricity price. Large power systems with markets based on merit order, i.e., where generation is dispatched from the cheapest to the most expensive until the demand is met, will be affected if the demand is apparently reduced, i.e., supplied by an internal DG, such that it displaces the marginal generators, therefore reducing the electricity price.

1.2.2.3.2 Reserve Capacity and Ancillary Services

DERs are able to locally provide ancillary services at distribution levels, including DG with power electronic interfaces. Ancillary services comprise reactive power control (injection and absorption) and voltage control, frequency-load regulation, spinning reserve, and network stability [42-43]. DG aggregation and virtual power plant (VPP) management systems can provide such ancillary services at transmission levels [44].

Renewable energy sources can also contribute with power systems operation, when combined with energy storage systems (ESSs), or demand response (DR).

1.2.2.3.3 Environmental Benefits

DG based on RESs contributes reducing well discussed impacts on the environment caused by central fossil-fueled generation [27, 45]. Moreover, small CHP and internal combustion engines burning natural gas produce less greenhouse gases (GHGs) and particulate emissions than diesel and coal based thermal generation [2, 46].

1.3 Scope of the Work

This thesis presents a methodology for the assessment of technical and economic benefits brought by DG when connected to distribution networks with higher penetration levels. Technical benefits are analyzed from the distribution network operator (DNO) point of view. Quantifiable economic benefits are transferred to the independent power producer (IPP). The methodology is implemented with two publicly available tools, namely OpenDSS and RETScreen. The purpose is to analyze real and measurable technical benefits that DG could provide to distribution networks operation, and to explore which of them can be quantified in an economically efficient manner; i.e., without incurring in cross subsidies (Pareto efficiency)[2]. The benefits considered within the methodology are greenhouse gases reduction, system losses reduction, and distribution network upgrade investment deferral. These benefits were selected since they have been widely recognized by utilities and academia, and literature that describes their technical quantification is available. Other impacts like benefits for transmission networks, ancillary services provision, local economy benefits, etc. were not considered. Also, the methodology considers a single DG unit connected to a distribution feeder without demand response or energy storage system associated. The case when the feeder requires to be upgraded in order to accommodate the new DG has a negative impact either to the project or the utility and, consequently, this scenario has not been included in this study.

[2] Pareto efficiency is a concept in economics that refers to the situation where certain allocations that make one person better off are not possible to realize without making someone else worse off. For example, higher electricity rates paid to distributed generators (one better off) are obtained from charging higher rates to customers (someone worse off).

1.4 Contribution of the Work

Although much has been investigated about specific impacts and benefits, there is still a lack of clarity for DNOs and IPPs on how to put all the elements together, in order to comprehend the real viability of a DG project. The work described next attempts to offer a methodology that can be applied as a basic study in early planning stages, but that could develop into more elaborated methodologies and analyses by regulatory government agencies, system operators, utilities, and IPPs. The methodology is presented in generic steps offering a general approach such that it is applicable to any distribution feeder facing the connection of different distributed generator technologies.

1.5 Thesis Outline

The dissertation is organized as follows:

Chapter 2 presents a survey on active distribution network enabling technologies. These technologies are considered fundamental to allow the increasing amount of distributed generation that is been connected to distribution levels, and for the realization of many of the benefits associated with DG. The survey is extracted from the contribution made by the author on behalf of McGill University to the International Council on Large Electric Systems (CIGRE) C6.11 working group.

Chapter 3 describes the proposed methodology for the evaluation of benefits and impacts brought by increased penetration of distributed generation in distribution feeders. The framework for the analysis and the benchmark distribution feeder are described. The two public available simulation tools, developed to support DG projects planning, used to analyze technical and economic benefits, are presented.

Chapter 4 contains the results from the distribution feeders simulated. The base case is compared with the connection of distributed generation in the feeders, as well as with a conservation strategy, namely a network voltage reduction. Economic analysis of the proposed distributed generation project is also presented. The chapter closes with a discussion of the results obtained.

Chapter 5 summarizes the research done and the methodology implemented. It also includes conclusions according to simulation results and provides future work needed to support further deployment of distributed generation.

Chapter 2: A Survey on Active Distribution Networks

2.1 Definition

Due to the large number of distributed generation (DG) that have been connected to existing power systems, and the even greater amount that is expected to be deployed in the future, distribution network operators (DNOs) are forced to change from their old "business as usual" passive approach, regarding networks operation and planning [43]. Electricity distribution is evolving from passive unidirectional flow networks to active distribution networks (ADN) and smart grids (Figure 2.1). ADN includes technologies that allow large integration of distributed energy resources (DERs) within low and medium voltage systems, while dealing with the impacts that these distributed resources bring to network operation [47].

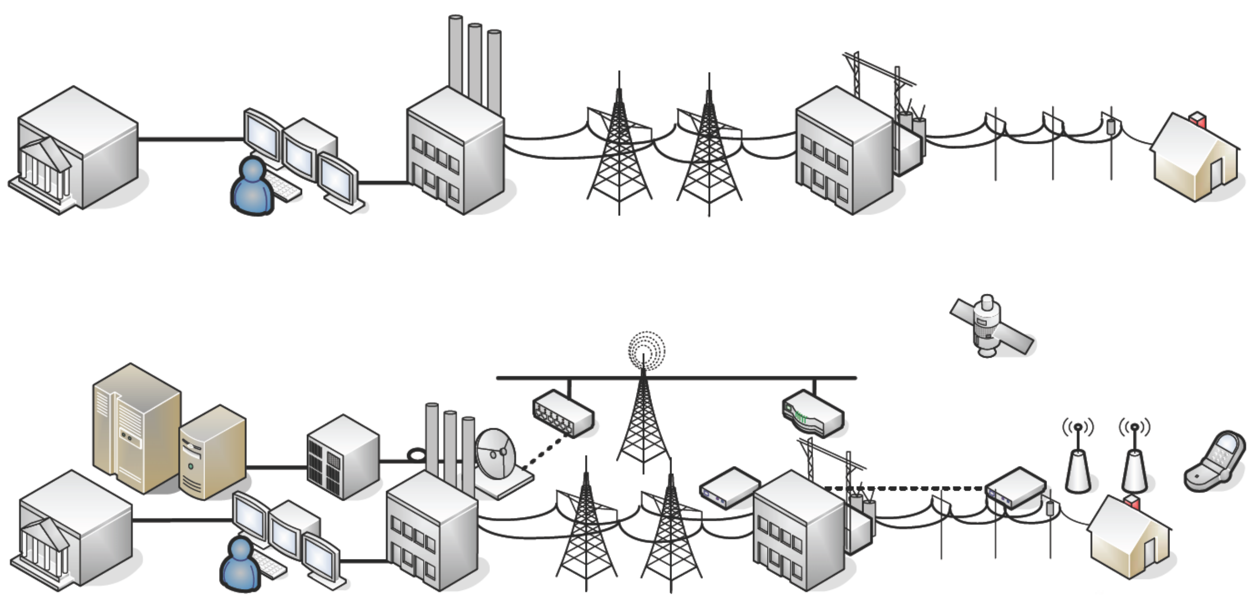

Figure 2.1 Electrical Infrastructure (top) and Intelligent Electrical Infrastructure (bottom) – EPRI Intelligrid Initiative [48]

Along these lines, the C6 Study Committee, "Distribution Systems and Dispersed Generation," of the International Council on Large Electric Systems (CIGRE), created the C6.11 Working Group, "Development and Operation of Active Distribution Networks," with the aim to identify the current status of ADN around the world, and to assess the technologies that support the transition from passive to active networks. A shared global definition of ADN came out as part of the working group tasks [49-50]:

"Active distribution networks are distribution networks that have systems in place to control a combination of distributed energy resources (generators, loads, and storage). Distribution system operators have the possibility of managing the electricity flow using a flexible network topology. DERs take some degree of responsibility for system support, which will depend on a suitable regulatory environment and connection agreement."

The contribution made by McGill University to CIGRE Study Committee C6 (SC C6: Distribution Systems and Dispersed Generation) Working Group C6.11 (Development and Operation of Active Distribution Networks) is presented in this chapter, in order to provide information about what has been done around the world, to allow increased DG and distributed energy resources (DERs) connection to the networks, through the implementation of advanced ADN technologies. In particular, the author's contribution corresponds to Chapter 3 "Current Status of Deployment of ADN," form the Working Group's report "Planning and Operation of Active Distribution Networks," to be published [49].

2.2 Current Status of ADN

Presently, active distribution networks have been deployed into grids around the world. Several projects are been studied through research and development (R&D) initiatives led by utilities, government agencies, universities and consortiums. Moreover, some projects have attained the pilot or demonstration stage, and use commercially available technologies.

A comprehensive list of ADN projects is available in [51-52], containing an active network management database compiled by University of Strathclyde. In addition, more projects can be obtained from utilities and energy sector government agencies' websites. The following section describes some of the most innovative technologies and concepts applied to ADN projects. Their descriptions were extracted from these websites and published reports, as indicated in the references.

Table 2.1 Active Distribution Network enabling technologies

Integration Level	Enabling Technologies	Application	Benefits
Hardware (advanced devices)	Power electronics (applied to distribution networks)	Active and reactive power control	• Grid stability • Increased power transfer
	Information and communication technologies (ICT)	Integration of intelligent devices and communication media	• ADN management • Coordination and control of new and existent elements of the network • Network information collection
	Advanced metering infrastructure (AMI)	Demand side management (with variable pricing structures)	• Reduce consumer costs / consumption • Peak load shaving / shifting
	Advanced protection devices	Active network management with high DG penetration	• Increased DG integration • Network reliability and power quality • FRT and islanding capabilities • Sensitivity and selectivity with communication based protections
	Energy storage system (ESS) and battery energy management	Islanding, load peak shaving / shifting, intermittent generation integration	• Increased renewable integration • Avoid network reinforcement • Peak load shaving / shifting • Islanding capabilities
Network states control	Power flow management	Optimal network management (with OPF) and active DG output constraint	• Increased energy export • Avoid network reinforcement • Peak load shaving
	Automatic voltage control (AVC)	Voltage regulation with high levels of DG	• Increased DG integration • Avoid voltage rise on networks
	Dynamic line rating (DLR)	Real-time thermal capacity of the network	• Increased capacity to accommodate DG • Avoid network reinforcement
Network operation (procedures/strategies)	Demand side management (DSM)	Load reduction / shifting, price responsive, direct load control	• Load control • Reduce consumer costs • Avoid network reinforcement • Peak load shaving / shifting

Integration Level	Enabling Technologies	Application	Benefits
	Virtual power plant (VPP)	DG aggregation control	• Integration of DG to optimal operation and economic maximization • Balancing of variable generation
	Microgrid (feeder islanding)	Operation of small communities, buildings, and substation feeders in islanded mode	• Autonomous power supply • Avoid network reinforcement • Lower network losses
	Distribution management system (DMS)	Active management of distribution networks with DG integrated	• SCADA • OPF • Integration with IEDs and RTUs • Web-access

2.3 ADN Enabling Technologies and Concepts

A list of ADN enabling technologies and concepts is presented in this section. These technologies and concepts were selected from a thorough analysis of pilot projects from around the world. The enabling technologies are grouped according to the integration level. Table 2.1 presents this categorization and summarizes the technologies and concepts selected, and their applications and benefits.

2.3.1 Hardware

ADN technologies under this category include the novel implementation of proven technologies to distribution networks (e.g. FACTS and ESS), and the innovation or improvement of equipment already in use (e.g. AMI and protection relays).

2.3.1.1 Power Electronic Devices

Power electronics devices, installed in transmission systems for power flow and voltage control, known as flexible AC transmission systems (FACTS), are being considered at distribution voltage levels. Due to voltage and power flow impacts brought by high levels of DG, utilities are adopting power electronics based technologies such as static VAR compensators (SVC) and static synchronous compensators (STATCOM) to distribution feeders [53-54]. Reactive power planning applied to transmission systems can be used in distribution networks for optimal placing of these devices [55].

2.3.1.2 Information and Communication Technologies

Information and communication technologies (ICT) are essential in the application and operation of ADN. Bidirectional communication allows control and collection of data from network equipment and end-users, including remote sensors, intelligent devices, DERs, and management systems. ICT are an integral component in every innovative project [56-60].

2.3.1.3 Advanced Metering Infrastructure

Advanced metering infrastructure (AMI), which includes automatic meter reading (AMR), provides bidirectional communication and control between distribution network operators (DNOs) and customer installations. Additionally, new meters act as the gateway to a home area network (HAN) with links to appliances. The implementation of such equipment allows DNOs to apply demand side management (DSM) programs on their networks. Advanced meters also enable information exchange that contributes to loss and fault management, power quality monitoring, energy usage data, and easy small DG connections [61-63].

2.3.1.4 Advanced Protection Devices

Advanced distribution protection schemes can be achieved by implementing innovative devices and active network management, e.g. communication based relays and automatic fault location. Feeder equipment and intelligent electronic devices (IEDs) with high integration levels (achieved using ICT) provide network protection in the presence of large amounts of DG [64-65]. Such protection devices can be integrated to fault management strategies like intentional islanding and automatic reconfiguration [66-67].

2.3.1.5 Energy Storage Systems

An energy storage system (ESS) includes all the equipment necessary for the storage and conversion of several forms of energy into electricity. For this purpose, energy can be stored as mechanical, thermal, electrical or chemical energy [68]. What makes ESS so valuable for power systems operation is its ability to act either as a load or as a generator. Additional benefits are brought since the storage systems are connected to the grid through power electronic interfaces, e.g. ancillary services and fast response for uninterruptible power supply. Furthermore, some technologies allow ESS to be configured in multiple ways and placed in different points in distribution networks (Figure 2.2) [69-73].

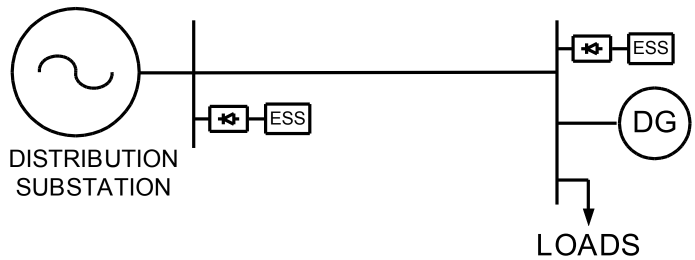

Figure 2.2 ESS placement in distribution networks

Main benefits reported from the use of ESS in distribution networks include the application of peak load shaving/shifting, improved utilization of assets (especially RES), provision of ancillary services, improved power quality and reliability, and the possibility of implement distributed storage [74-81]. In the last category, it is worth mentioning the increasing attention to research and development (R&D) projects on vehicle-to-grid (V2G) operation modes. V2G integrates the charging and discharging cycles from plug-in hybrid electric vehicles (PHEV) and electric vehicles (EV) into network operation, with the associated benefits for the DNO.

2.3.2 Distributed Monitoring and Control

Distributed monitoring and control refers to ADN technologies and operative systems acting directly over feeder parameters like voltage and power flow at different points, i.e. not only at the primary substation.

2.3.2.1 Power Flow Management

Like in large power system planning and operation, optimal power flow (OPF) can be applied to distribution networks with DG connected to the feeders. Voltage control and DG capacity allocation and dispatch are actively managed with OPF [82-85]. In addition, when high levels of DG prevent maintenance of the voltage between limits, an active management system can be applied through generation curtailment, if such an agreement exists between generators and the DNO [86-88].

2.3.2.2 Automatic Voltage Control

Voltage control in distribution networks is normally executed by the automatic voltage control (AVC) relay acting on the substation primary transformer OLTC [89]. New technologies including ICT capabilities and active network management allow implementation of advanced voltage regulators (AVRs) (Figure 2.3). The operation of AVRs includes remote measurement and real-time state estimation of the feeders [90-92].

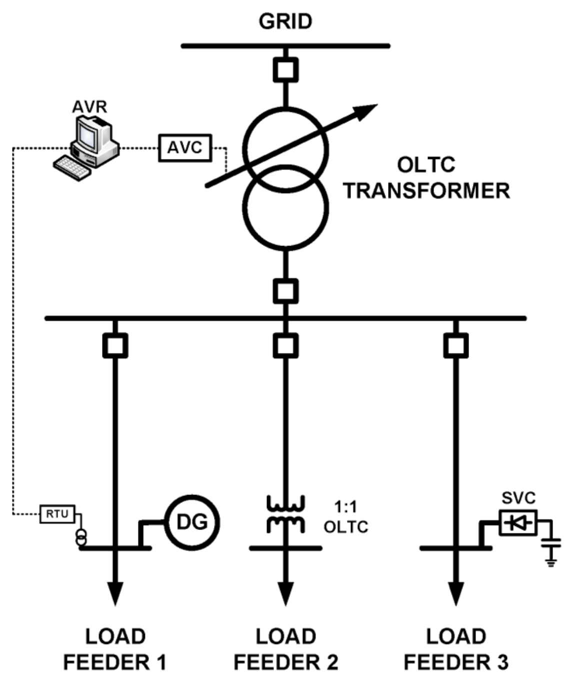

Figure 2.3 Advanced voltage regulator scheme

2.3.2.3 Dynamic Line Rating

Dynamic line rating (DLR) combines remote measurements from feeders (voltage, current, and conductor temperature) and weather stations (ambient temperature, wind). Then, DLR systems provide real-time information of the current flow capacity of the feeders. This information combined with active management systems defines the actual network capacity available to accommodate DG generation [93-95], and control generation accordingly.

2.3.3 Network Operation

ADN technologies and concepts also include procedures and strategies over the entire distribution network, or applied to large portions of it. Innovative network operation projects rely on advanced controllers with high integration of remote terminal units (RTUs) and IEDs through ICT applications.

2.3.3.1 Demand Side Management

Demand side management (DSM) programs aim to optimize the use of the network or its capacity by controlling or modifying load profiles. Shifting or shaving load profiles, especially during peak hours, help with voltage and frequency control, as well as with alleviating network congestion [63, 96-105]. DSM practices can be divided in two groups [106]:

- Price-based programs: Consists in a change in the normal pattern of electricity consumption by end-use customers (voluntarily), as a response to electricity price changes over the day. This program requires that dynamic electricity prices are communicated to participating customers.
- Incentive-based programs: DNOs offer an incentive payment to residential and industrial customers that allow shifting on time or reducing consumption, in response to emergency situations or network congestion. Some programs may include direct control of selected loads by the DNO.

As it was mentioned before, DSM requires an investment in AMI and availability of hourly pricing information (real-time pricing), if the first option described above is used [61, 107].

2.3.3.2 Virtual Power Plant

A virtual power plant (VPP) is an aggregation of smaller DG units and loads with an advanced controller that creates a single operation profile. Operation of smaller resources are coordinated to make the VPP to act as a single larger generator (or power plant) connected to the distribution network [44, 108-114]. DG integration seeks to maximize the economic viability of DER by enabling participation in the wholesale electricity market and the capacity to provide ancillary services.

2.3.3.3 Microgrids and Intentional Islanding

Similar to VPPs, a microgrid groups nearby DERs and loads under the same local controller or active management system. The difference lies in the capacity of a microgrid to operate disconnected from the main distribution network, i.e., the microgrid acts as a self-contained power system [70, 98, 115-123]. In order to operate as a microgrid, the grouped entities must be able to dynamically balance its demand, and provide voltage and frequency regulation [124]. In addition, electronically coupled DER units can provide stable and fast response voltage and frequency control for microgrids [125-126]. Also, the power island must have a point of common coupling (PCC) with the distribution network, a means of synchronization in order to connect back to the main grid, and adaptive protection schemes that can operate in islanding or grid-connected mode [127]. Moreover, isolated power systems are considered as microgrids too [25]. Microgrids or intentional islanding can be also applied to improve power quality and reliability (PQ&R) of certain sensitive load areas [128-129], although an adequate analysis of the island electricity rate is required in such cases [130].

2.3.3.4 Distribution Management Systems

DMSs have been in use by DNO since the beginning of distribution automation. Standard management systems usually include switchyard control and supervisory control and data acquisition (SCADA) at primary distribution substations. However, with increased DG penetration and implementation of ADN technologies, distribution networks require more advanced and robust DMSs, able to integrate information collection of such highly automated grids and control its operation [64, 84, 131-135]. Some features that an advanced DMS should have:

- Systems able to easily integrate with existent equipment
- High integration with different ICTs systems
- Data acquisition capacity from numerous RTUs across the networks
- OPF calculation capacity

- Control of remote IEDs like SVC and STATCOM, remote switches, protection devices, AMI and DSM, DLR, AVR for AVC, etc.
- DER (including ESS, DG and CHP turbines) and microgrids remote control capability
- Fault management and fast reconfiguration

2.4 Research Needs for the Future of ADN

Although there are several ADN technologies already installed around the world, a vast amount of research work remains. These research needs should be addressed in order to make ADN technologies more accessible and reliable for distribution networks. From the list of research projects and pilots analyzed for the survey presented in this section, some common barriers were encountered hindering the full deployment of ADN. These barriers and needs are briefly listed next:

- Despite the well recognized benefits, the most common need is to reduce the costs of the ADN equipment and implementation, in order to make these technologies more attractive to large-scale deployment by DNOs.
- DNOs require new technologies that are able to integrate with existent equipment and control.
- Implementation of additional devices and control strategies requires improved reliability of ADN components. This fact also applies for the integration of ICT for the ADN technologies implemented. DMSs relying on RTUs and IEDs for its normal operation become more sensitive to internal failures.
- Since government regulatory agencies have been encouraging the deployment of DG and RES, utilities also require changes allowing them to implement ADN technologies and programs. Agreements between DNOs, independent power producers (IPPs) and customers need to be developed under a regulatory framework that maximizes technical and economic benefits for all.
- Increased implementation of ICT based technologies adds a new threat to power systems operation, besides the reliability requirement. Improved information security is required to avoid attacks to communication infrastructure, operation control, and data storage (cyber security).

- Some DSM programs are based on the availability of the real-time variable price structure. This structure must be opened and communicated in a safe and optimal manner for customers and the electricity market.
- ADN technologies are constantly evolving thanks to the research effort made by universities and institutes. New and improved active management systems are a constant need. The research spectrum is vast, but some critical areas include: advanced protection schemes, voltage and frequency control, large-scale integration of intermittent renewable energies, microgrids and islanding safe operation, fault management, economic benefits allocation, changes in customer behavior for DSM programs, losses management, ICT integration, etc.
- Utilities also require new methodologies and simulation tools for planning distribution networks with high penetration of DG and ADN technologies. At present there is a significant lack of software tools for the proper modeling of ADN applications incorporated to distribution networks with distributed generation.

Chapter 3: A Methodology for Assessment of Distributed Generation Benefits

3.1 Overview of the Methodology

Nowadays, distribution network planning in the presence of high levels of distributed generation (DG) requires that planners consider DG technical and economic impacts [136]. Such an integrated approach will allow further deployment of DG into existing grids. The following methodology proposes a feasibility analysis for the connection of a distributed generator to a distribution feeder, accounting for well recognized and quantifiable benefits.

Figures 3.1 and 3.2 illustrate the proposed steps. The methodology begins with a model of the feeder with a significantly high penetration of DG (> 50% of the peak load). A power flow program analyzes the operation of the network considering the DG generation profile. Technical results feed a project analysis software that will provide financial indicators that allow assessment of the viability of the project.

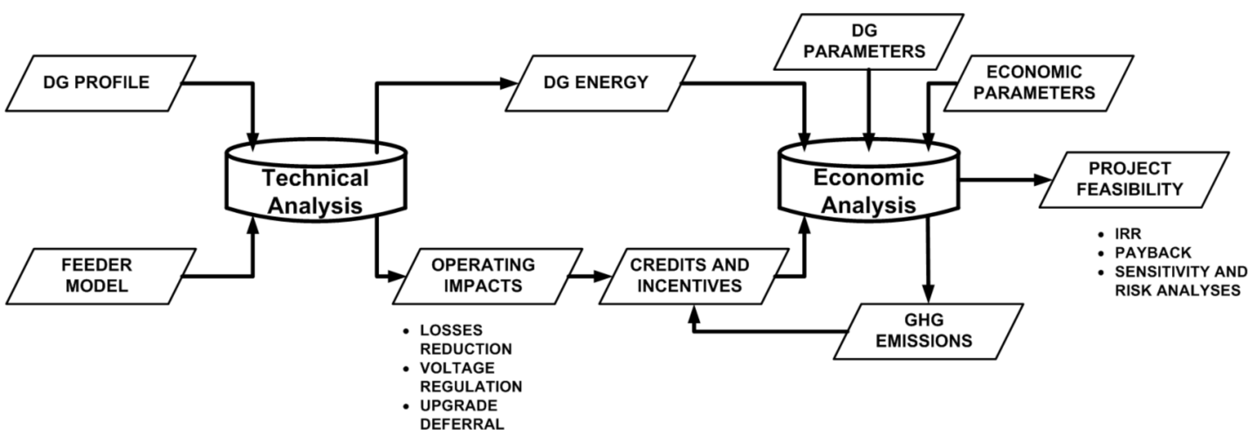

Figure 3.1 Data flow for the methodology proposed

The proposed methodology is applied to a radial distribution feeder in order to test its applicability. Discussion and conclusions will be derived from these simulations and will be presented in Chapter 4. The general approach can be adopted for any project as long as the distribution feeders and DG models are available. The feasibility analysis will be assumed from the point of view of an independent power producer; when the utility owns the DG, increased benefits are expected due to the possibility of the distribution network operator (DNO) to optimally control generation output.

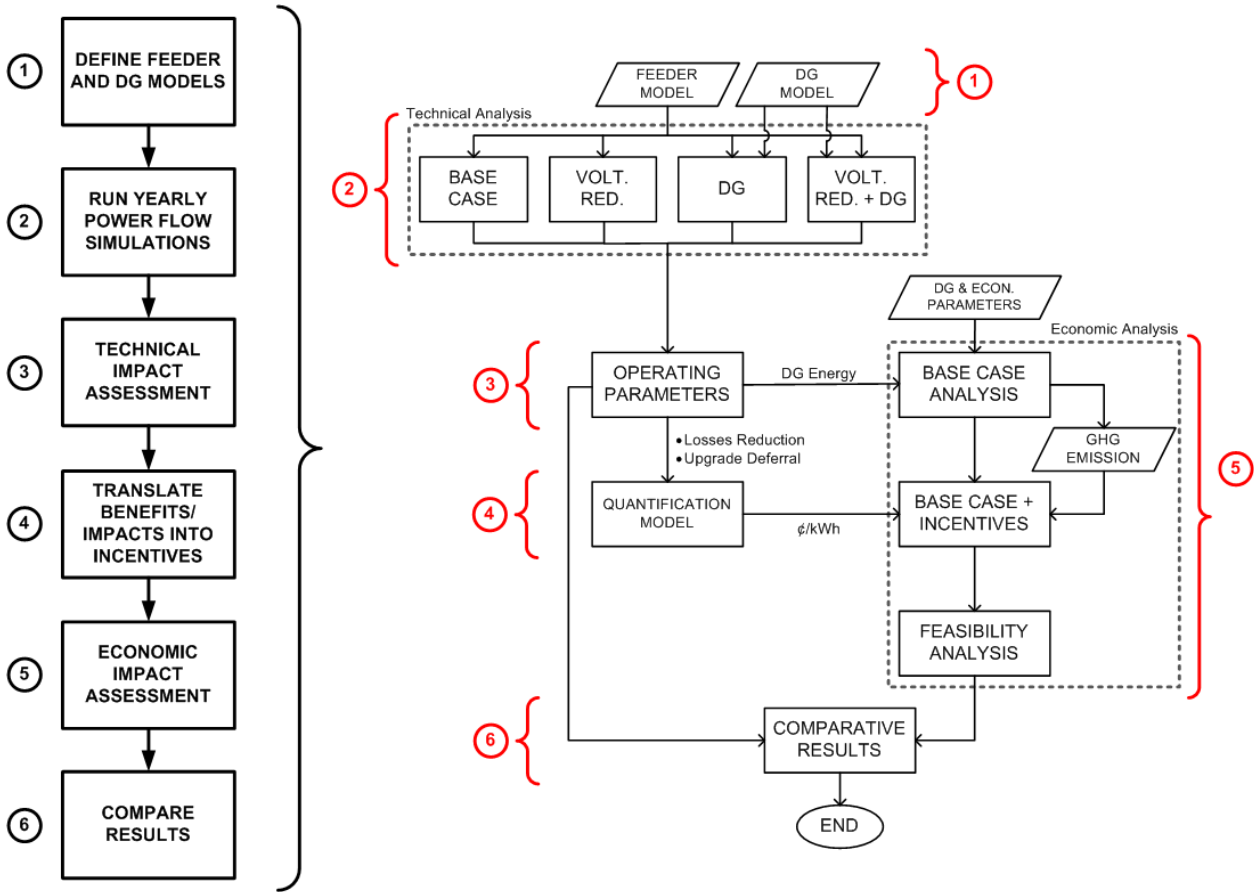

Figure 3.2 Flow chart describing the methodology and the interaction between both analyses

3.1.1 Technical Analysis

The technical analysis of impacts of connecting DG to distribution networks is based upon power flow simulations of the feeder and generators under study and is developed with the OpenDSS tool. The simulations are run under steady-state only, as the impacts of interest are limited to steady-state. However, due to operating changes that DG brings to distribution networks, dynamic security constraints can be also integrated in the optimal power flow, similar as it is done for transmission systems [137-138]. The analysis is carried out considering the IEEE Standards 1547-2003, “Standard for Interconnecting Distributed Resources with Electric Power Systems,” and following the IEEE 1547.2-2008, “Application Guide for IEEE Std 1547” [139-140].

In particular, in [140], Section F, system impact studies, proposes detailed impact studies that review the potential effect of a distributed resource unit on the area electric power system. The steps described next are based on the outline of a steady-state performance study proposed in Section F.3.1.2:

- Define the feeder and distributed generator models in the power flow tool (OpenDSS).
- Establish typical time profiles for loads connected to the feeder and generation from the distributed resource.
- Simulate the network power flow over the time specified by the load and DG profiles.
- Evaluate the feeder voltage profile. For normal operation, consider limits within ANSI C84.1 Range A (Table 3.1) [141].
- Evaluate the impact of DG connection on total system losses, regulator tap changers, and feeder overload.

Table 3.1 ANSI C84.1 service voltage range [141]

	Range A	Range B
Maximum	105%	106%
Minimum	95%	90%

An additional point of interest for utilities is to evaluate the impact of DG on active voltage management schemes. DNOs may actively reduce feeder voltages, aiming to reduce consumption, either at times of peak load or as a conservation strategy that is implemented throughout the year. Furthermore, since reference [140] recommends in Section H.8 to not have the distributed generator trip off during low voltage network operation, this strategy could be also applied to networks with DG connected. Therefore, in addition to the base case and DG connection simulations, these results will also be compared to the network performance with a conservation voltage reduction (CVR) scheme, applied at the substation voltage regulator, for the base case network and in the presence of DG.

3.1.2 Economic Analysis

The economic analysis proposed aims to explore the feasibility of a DG project including possible incentives from technical impacts brought by the distributed resource, if deemed positive. These incentives are expected to be allocated once the technical assessment provides the real benefits from joint operation of the network and DG, and whenever it is possible to quantify them.

The feasibility analysis will consist of the evaluation of the financial performance of the project. Such evaluation considers the DG equipment selected, financing parameters, project costs and revenues, and profitability. Not included in the feasibility analysis are the legal aspects of developing such projects, and the local environmental impacts of building and operating DG (negative impacts).

Although the software tool used (RETScreen) provides extensive help and information for the step-by-step analysis, some basic considerations of economic theory were studied from [142-143]. The relationship between the economic analysis tool and the results from the technical assessment are described in the following steps:

- The electricity generated by the distributed generator (DG Energy) can be input in the economic analysis software in two ways: by describing the generation equipment and energy source profile, or by using a goal-seek option[3]. Both options should match the energy profile used in the technical analysis. In addition, some economic parameters are required such as project fixed and variable costs, debt information, project lifetime, etc. This preliminary analysis represents the base case and will be compared with results from an incentive allocation scheme.
- From the base case simulation, the software will produce an analysis of the greenhouse gas (GHG) emissions from the distributed generation technology selected.

[3] Since RETScreen is based on MS Excel ®, it is possible to use the built-in function Goal Seek. Goal Seek is used when the result of a formula is known (or desired), but not the input values. Then, Excel calculates the values required to obtain the desired result.

- A quantification model is applied for the loss reduction and upgrade deferral technical benefits from DG. Such benefits are translated into economic benefits (incentives) and fed into the economic analysis tool. In addition, GHG emissions evaluated in tons of carbon dioxide equivalent (tCO_2e), are also added as incentives under a carbon emission trading scheme.
- The economic simulation is run again, this time including the incentives that could be quantified. The new profitability analysis for the DG project is then presented.
- The software allows the user to explore sensitivity and risk analyses for the project proposed. This is useful for evaluating projects in the electrical power industry since they are expected to last for several years and some of the costs and benefits must be estimated at preliminary stages; i.e., sensitivity and risk analyses evaluate the vulnerability of the profitability of the project to a number of chosen parameters [142].

3.1.3 Quantification Model for Incentives

Although technical benefits brought by DG to distribution networks are well recognized, there is still a lack of a clear mechanism to attribute them to the producer through an incentive allocation scheme. In general, due to the lack of economies of scale associated with distributed generation, these projects are often not financially feasible. However, extra incentives, provided the DG brings technical benefits to the feeder where it is connected, will facilitate further distributed generation deployment and ease financial burdens.

Whereas some utilities and government regulators apply DG incentives to attract investors, such schemes are very specific to certain areas or even political policies. A shortcoming of such policies is that when subsidizing specific technologies it is possible to fall into economic inefficiencies like, for example, extra payments to generators without providing clear benefits to networks, and the source of such incentives (generally at the rate payer’s expense).

The incentives presented next were found through literature review as those most commonly applied to DG projects. However, they were selected considering that they provide quantifiable technical benefits to distribution networks and customers, and quantification models were available for such applications.

3.1.3.1 GHG emissions reduction

The United Nations Framework Convention on Climate Change (UNFCCC) adopted an international agreement called the Kyoto Protocol in 1997 [144]. This protocol created three market-based mechanisms to allow countries to meet their GHG reduction targets. The three mechanisms -emissions trading, clean development mechanism (CDM), and joint implementation (JI)- created a commodity represented by tCO2e, which is traded in the so-called carbon emissions trading market. With RETScreen simulations, depending on the site selected to install the DG, the GHG emissions displaced from central grid generation are calculated in tons of dioxide carbon equivalent (tCO2e). Then, a credit rate is applied to this annual emissions reduction to obtain an annual income:

$$CO2_{CR} = GHG_{RED} * \lambda_{GHG} \tag{3.1}$$

If it is desired, this incentive can be expressed in function of the DG production unit (¢/kWh):

$$\Upsilon_{\mathrm{GHG}} = \frac{100 * CO2_{CR}}{\mathrm{E}_{\mathrm{DG}}} \tag{3.2}$$

Although the Kyoto Protocol was set for the period 2008-2012, and considering that an international framework for further reductions commitment remains uncertain [144], this credit will be applied over a period of 20 years. Given current environmental support for so called green projects, it is likely that some similar scheme will continue in place beyond 2012.

3.1.3.2 Upgrade investment deferral

The second technical benefit that has a straightforward quantification method is the capacity of DG to defer network upgrades due to load growth. Expansion costs are recovered from the customers by utilities; therefore, deferring any upgrade investment should be reflected on end-user rates. Then, the benefit for utility/customers is represented by the time value of money concept of delaying the investment for a certain number of years [26, 39, 145].

Several assumptions must be taken to create an incentive under this category. This is because the extent of the benefit depends on different aspects such as: DG location, utility marginal costs, DG reliability, feeder configuration, utility upgrade scheme, load growth rate, etc. These assumptions will be pointed out in the steps listed next:

- First, it is necessary to determine when (which year) the feeder will present an overload due to load growth (forecast). Also, the upgrade scheme selected must be specified.
- After this, a new simulation is conducted to determine when, with a DG unit connected to the feeder, an overload will occur. It will be assumed that the same upgrade scheme will be applied.
- Then, the economic benefit is calculated as the difference of the present value of the cost of upgrading the feeder under the two previous scenarios (assuming the present year as year 1 and $y > x$):

$$UD_{DG} = \frac{C_{f\_x}}{(1+i)^x} - \frac{C_{f\_y}}{(1+i)^y} \tag{3.3}$$

- In order to keep this benefit for the customer interests, any incentive proposed should not be greater that the value obtained with Eq. (3.3). As it was mentioned before, utilities recover any upgrade investment from customers. Consequently, this incentive can be recovered from end-users too, provided there is a reduction or deferral in the portion of the electricity rate collected for system upgrades. In doing so, there will still be a benefit for the customer. An electricity rate impact analysis is out of the scope of this thesis.
- Now, a decision on how to transfer this incentive to the DG owner must be taken. A direct assignment of this benefit as a one-time credit is not adequate due to the uncertainty and risks on future DG operation. Moreover, this amount would need to be recovered immediately from customers. Instead, this study proposes to

establish a perpetual annuity (perpetuity) based on the amount of the benefit. This approach is based on the fact that as long the DG is connected, that capacity is permanently displaced, not only before the first upgrade, but also it will defer a second upgrade after the first one, and so on. A yearly increment of the annuity, according to an inflation rate for example, can be negotiated. Then, the benefit is calculated as the present value of the perpetual annuity:

$$UDA_{DG} = \frac{UD_{DG}}{\eta} \tag{3.4}$$

- Finally, in order to deal with the risk of DG energy production, the annuity is translated into an incentive in $¢/kWh$. This incentive will be added to the electricity rate received by the DG operator. The approach then relates the benefit to the generator energy output. Consequently, the DG obtains a higher benefit if it guarantees higher reliable and firm capacity. The Eq. (3.4) is converted into a unitary output term:

$$\Upsilon_{UD} = \frac{UDA_{DG} * 100}{E_{DG}} \tag{3.5}$$

To illustrate this incentive methodology, the following example is presented for the test feeder under study:

If it is assumed that all the loads connected to the benchmark network grow at a rate of 3% per year, then, overloads will start affecting the feeder at year 9. The utility's upgrade strategy consists of doubling the capacity of the substation and conductors overloaded. The primary transformer is rated at 5 MVA, thus the upgrade will give a new substation capacity of 10 MVA. According to references [146-147], the marginal cost of distribution equipment for more than 110 utilities in the U.S. in 1998 was 290 $/kVA. With the U.S. consumer price index (CPI) average for the last 20 years as inflation rate (2.7%), this marginal cost is equivalent to 400 $/kVA in 2010 [148]. Again, this cost is moved forward 9 years to obtain the future value of the upgrade investment, using a CPI forecast of 2%. Finally, the total upgrade cost is brought back to present value using the U.S. Treasury Bond with a maturity of 30 years as the free-risk rate (4.375%) [149].

With the same analysis but now for a distributed generator connected to the benchmark feeder at node 680, with a rated capacity of 2 MVA (approximately 60% of the peak load) and operating at unity power factor, overloads appear in year 20. The economic analysis for the future upgrade investment remains the same.

Then, the present value of the upgrade deferral benefit:

$$UD_{DG} = \frac{C_{f\_9}}{(1+i)^9} - \frac{C_{f\_20}}{(1+i)^{20}} = \$\ 713{,}050.00$$

This represents a benefit of approximately 350 $/kW of DG installed, close to values reported in [26, 39, 145]. Finally, assuming that the utility has a weighted average cost of capital (WACC) of 8%, and the utility agrees with the DG owner to use this rate to calculate the annuity, the upgrade deferral incentive will be:

$$\Upsilon_{UD} = 0.33\ ¢/kWh$$

In addition, suppose that a demand side management (DSM) plan is implemented before year 20 targeting small consumers to shift their consumption at peak load hours, and that this action defers the upgrade by 2 years more. Although this is not an action attributed to the DG, if customers and the utility agree to transfer such a benefit to the distributed generator operator, then the benefit goes up to 410 $/kW of DG installed and the upgrade deferral incentive to 0.38 ¢/kWh. It should be mentioned that this is still viable since the main benefit of DSM for customers is the load shifting to low electricity rate hours, or grant programs from DNOs.

It is important to emphasize two points:

- As it was shown with the numerical example, the calculation of this incentive implies several assumptions that make it very specific to each situation. Different feeders or additional DG can greatly alter the results. The methodology proposed is applied in a first-come, first-served basis for new DG, in order to incentivize distributed resource connections in feeders without them.
- This incentive will be assigned only to the conventional natural gas fueled generator due to the necessary reliability implied. As it was mentioned before, DG must provide firm capacity in order to fully exploit the benefit, especially during peak loads. Renewable intermittent sources are uncontrollable and sometimes with low correlation with peak load periods; e.g. photovoltaic cells.

However, RES when combined with an energy storage system (ESS) have the flexibility required to gain access to such an incentive, since the storage system brings reliability and controllability to the system [81]. A business case could be built for ESS installation from incentives like the one proposed.

3.1.3.3 Loss Reduction

As it was discussed in the literature review, when DG is connected close to the loads, it has the ability to reduce losses due to the reduction in current flow from the primary substation. However, since DG is also injecting current into the feeder, this technical benefit depends on feeder characteristics, generator capacity, location and dispatch, and load profiles. It is worth mentioning that network losses in the presence of DG follow a U-shaped curve according to the generator output; i.e., high DG levels and low load consumption periods could increase system losses.

Therefore, in a similar manner to upgrade deferral, the extent of any incentive based on loss reductions depend largely on specific studies for each situation. Nevertheless, the economic benefit is based in the simple notion that any reduction in losses translates into the distribution network operators (DNOs) avoiding having to buy that energy from the wholesale market. In addition, these purchases are recovered from customers by utilities. If customers and DNOs want to encourage DG investments on their networks in order to gain from different benefits brought by distributed resources, the portion of the electricity rate corresponding to network losses could be transferred, in whole or in part, as an incentive.

Based on the facts previously mentioned, the following steps represent a simple model for the quantification of this benefit. With the implementation of advanced DMSs, powerful computational tools could perform real-time analysis of system losses, including hourly price schemes for up-to-date economic valuation of the benefit:

- With a power flow analysis tool estimate energy loss reduced by running a yearly simulation with and without DG connected to the feeder under study (in MWh).

$$E_{L\_RED} = E_L - E_{L\_DG} \tag{3.6}$$

- Define an electricity rate to estimate total savings due to energy losses reduced. Since a distributed resource could be operated only for certain number of hours per year, depending on its own strategy, the price analysis presented in [26] is implemented. Doing so, this strategy will compensate with higher rates for DG operating only at peak (high price) hours, although the overall yearly reduction will be lower. Consider a price duration curve from electricity market historical data (Figure 3.3). This data can be fitted as a power regression curve, obtaining an equation for the electricity price as a function of the peak price hours, Eq. (3.7).

$$\Upsilon(h) = \alpha * h^{\beta} \tag{3.7}$$

- Then, apply the definition of the average of a function to this equation to find the electricity rate to be applied to this benefit, Eq. (3.8). The number of hours τ must agree with the operation scheme used in Eq. (3.5).

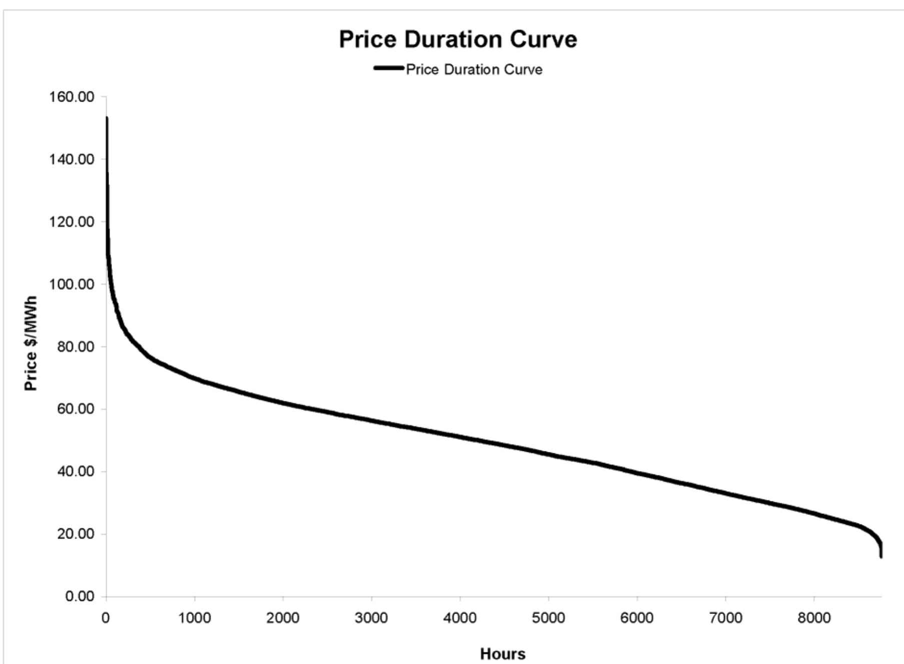

Figure 3.3 Average price duration curve for the period 2003-2009 in Ontario, Canada [150]

$$\overline{\Upsilon}(h) = \frac{1}{\tau}\int_{0}^{\tau} \alpha * h^{\beta} dh \tag{3.8}$$

- With the energy loss reduced and the average electricity rate, it is possible to find the total savings due to loss reduction. Notice that customers will not be affected with the implementation of this incentive, as long as the incentive does not surpass these savings.

$$LRS = E_{L\_RED} * \overline{\Upsilon} \tag{3.9}$$

- Similar to the upgrade deferral case, the total savings are converted to output units (¢/kWh) in order to link this benefit with the DG operation. Again, higher DG reliability will imply higher income from this incentive. Notice that E_{DG} is the total DG energy used in the first step to find loss reduction with Eq. (3.6).

$$\Upsilon_{LR} = \frac{100 * LRS}{E_{DG}} \tag{3.10}$$

An example of this incentive is presented next, applying the methodology for one year of operation on the benchmark feeder.

If a natural gas generator with a capacity of 2 MVA and operating at unity power factor over 8760 hours is connected to node 680, the total energy loss is reduced from 468.55 MWh to 203 MWh.

As mentioned, the total savings depend on the rate structure of the wholesale market from where the DNO purchases the energy, including the energy required to cover losses. Table 3.2 contains the price duration curve constants for the Ontario Independent Electricity System Operator (IESO) 2003-2009 data [150], PJM Interconnection (Regional Transmission Operator – RTO) 2008-2009 data [151], New York Independent System Operator (NYISO) 2008-2009 data [152], and Alberta Electric System Operator (AESO) 2007-2009 data [153].

Table 3.2 Price duration curve constants for different system operators in North America

System Operator	$\boldsymbol{\alpha}$	$\boldsymbol{\beta}$	$\overline{\boldsymbol{\Upsilon}}_{\boldsymbol{\tau=8760h}}$ $[\$/\boldsymbol{MWh}]$
Ontario IESO	583.74	-0.313	49.57
PJM Interconnection	965.31	-0.372	52.49
NYISO	1069.4	-0.383	53.56
AESO	9506	-0.644	77.19

If it is assumed that the DG is connected to a feeder in the AESO area, then the total loss reduction savings and the loss reduction incentive are:

$$LRS = (468.55 - 203) * 77.19 = \$\ 20{,}493.95$$

$$\Upsilon_{LR} = 0.11\ ¢/kWh$$

Although this example resulted in a small incentive, the methodology should encourage DG deployment in feeders with high losses and/or high energy prices. If the incentive is applied in a first-come, first-served basis, utilities will signal independent power producers (IPPs) to install DG where it is more beneficial. In addition, notice that areas with high electricity rates are usually systems with generation based on expensive fossil fueled power plants and constrained transmission networks; therefore, any reduction in losses will yield additional power system, societal, and environmental benefits, which were not quantified here.

On the other hand, if the DER connected is based on RES, the uncontrollable and low capacity factor characteristics will lead to a much lower incentive for loss reduction. This issue reinforces the fact that RES technologies (without ESS) bring fewer technical benefits to distribution networks than conventional technologies. Nevertheless, large scale deployment of RES brings other well discussed benefits to power systems, such as GHG emissions reduction.

The duration of this incentive will also require some assumptions that must be agreed upon between the DNO and the DG operator. Load growth, feeder upgrades, and electricity rate changes will all affect the quantification of the loss reduction benefit.

3.1.3.4 Total Annual DG Revenues

The annual revenues accrued by the DG considering the benefits described, will be defined in the present assessment by the electricity rate paid to the DG plus total incentives received by the DG (Υ_{IN}): the upgrade investment deferral incentive, the loss reduction incentive, and greenhouse gas emissions reduction incentive, Eq. (3.11):

$$AR_{DG} = \left(\frac{\Upsilon_{DG} + \Upsilon_{IN}}{100}\right) * E_{DG} \tag{3.11}$$

$$\Upsilon_{IN} = \Upsilon_{UD} + \Upsilon_{LR} + \Upsilon_{GHG} \tag{3.12}$$

Where Υ_{DG} (¢/kWh) is the electricity rate paid to the DG by the DNO or the independent system operator (ISO). This parameter could be specified by the wholesale market price, the production cost plus a premium, or as part of a feed-in tariff (FIT) program like the one offered in [154].

3.2 Benchmark Feeder

In order to test the proposed methodology, a distribution feeder was modeled in OpenDSS. The model was verified to assure the correctness of the simulations implemented. Reference [155] provides validated benchmarks for different radial distribution test feeders. These test feeders where developed to create a common set of data to verify simulation results since the reference supplies the solutions of the power flows and voltage profiles for every feeder.

The IEEE 13 Node Test Feeder is selected as the base case simulation (Figure 3.3). This feeder is a short but highly loaded 4.16 kV system. The circuit is unbalanced and it has a voltage regulator at the primary transformer in the substation. The complete set of data is annexed in Appendix A.

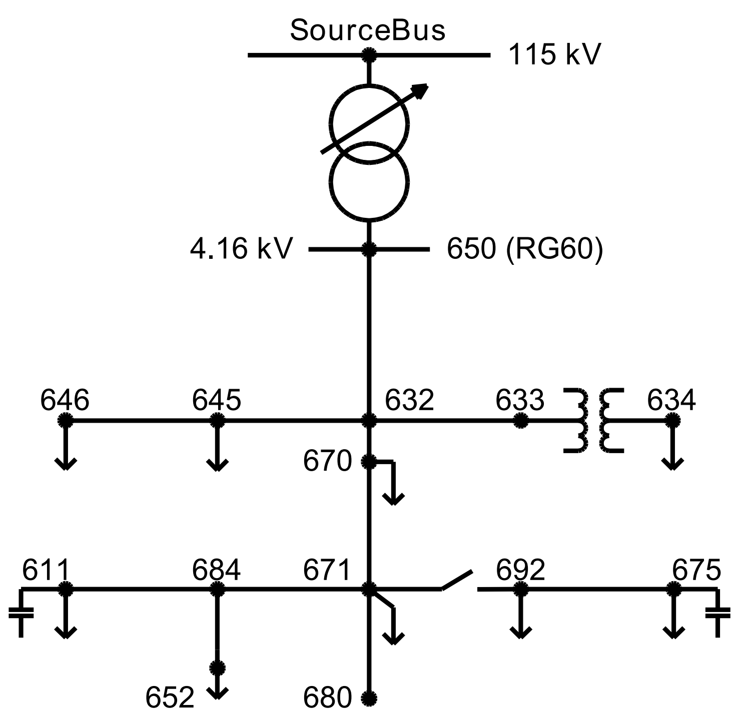

Figure 3.4 The IEEE 13 Node Test Feeder

In addition, the feeder is considered to have some active distribution network (ADN) technologies implemented. For example, for the voltage reduction simulation, an advanced voltage regulator (AVR) is in place, that registers the voltage profile across the network using remote terminal units (RTUs), and controls the substation transformer voltage regulator, issuing alarms when the profile goes out of limits. Dynamic line rating (DLR) is exerted at the controller level in order to register overloads in the feeder. A demand side management (DSM) scheme can be applied to verify the impact of such strategy on shifting peak load and therefore, on upgrade deferral investments. However, the central control, or distribution management system (DMS), was not considered controlling the DG output in this work.

3.3 Assumptions

Additional information required for the implementation of the methodology is presented in this section. More detailed information about how this data was applied using each tool is given in Appendices B and C, as previously indicated.

3.3.1 Load Profile

In order to run simulations over a period of time, a yearly profile was applied to the loads connected in the distribution feeder. This profile allows a network simulation closer to real conditions. The load profile applied to the radial distribution systems corresponds to the profile described in the IEEE reliability test system (IEEE RTS-96) [156]. The advantage of this profile is that it accounts for seasonal, weekly, and daily variations over one year (Figure 3.5).

3.3.2 Distributed Generators

Conventional and renewable sources bring different benefits and impacts to power systems. DG based on different energy sources brings such differences to distribution networks at the technical and economic levels. Consequently, the methodology will be tested with the connection of a conventional and a renewable technology. This approach allows the comparison of benefits and impacts in addition to the technical and economic issues expected.

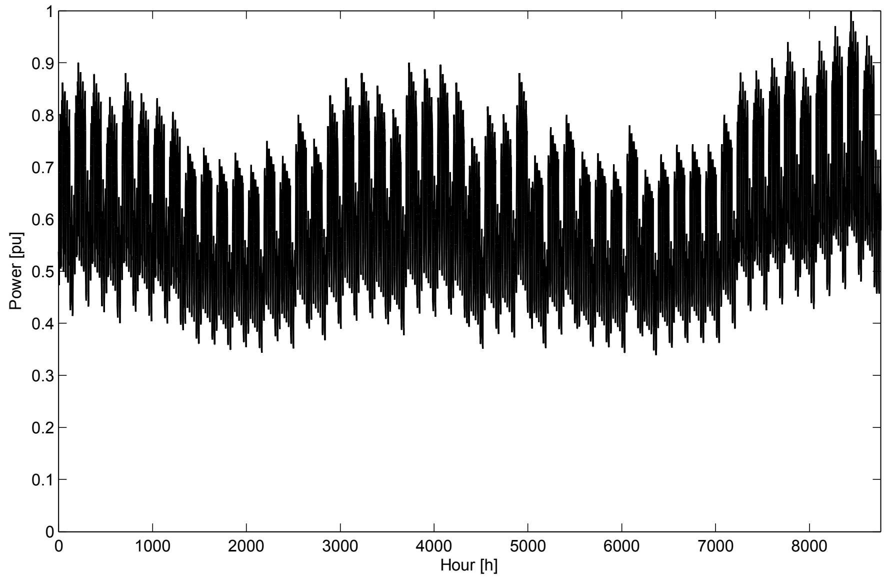

Figure 3.5 IEEE RTS-96 one year load profile

According to [139], distributed resources should not participate in active voltage regulation. Therefore, for technical simulations, generators will be operated at unity power factor. However, the reference declares that distribution network operators (DNOs) asking DER operators to absorb or supply reactive power is out of the scope of the standard. Additional benefits could be achieved when DNOs have control over DG according to operating circumstances. Also, the DG is considered connected at the feeder voltage, i.e. the generator step-up transformer is neglected. In this study, only one generator connected to the feeder is simulated, but with proper analyzes the methodology could be expanded to the case of multiple DG connections [157].

Conventional source: Traditionally, reciprocating engines, and especially internal combustion engines, have been used at distribution levels as backup, a means to increase reliability of electricity supply for individual customers. These engines combined with an appropriate supply or storage of fuel can sustain generation over long periods of time. Although burning fossil fuels has the disadvantage of GHG emissions, natural gas engines have been proposed as a clean technology for DG, including both reciprocating engines and gas turbines. A natural gas fueled reciprocating engine is used for the present analysis, in order to simulate a continuous supply of electricity to the feeder under study. Maintenance and failure downtimes are not considered in the technical simulations, although they can be easily implemented as a total energy output percentage.

Renewable source: The main concern for power systems implementing electricity generation from renewable sources such as wind and solar radiation is their broadly discussed intermittent nature. A variable output generator is simulated in order to explore the impact this intermittency has on the results of the proposed methodology. A wind generation profile is obtained from [158], with a capacity factor of 26.5% (Figure 3.6).

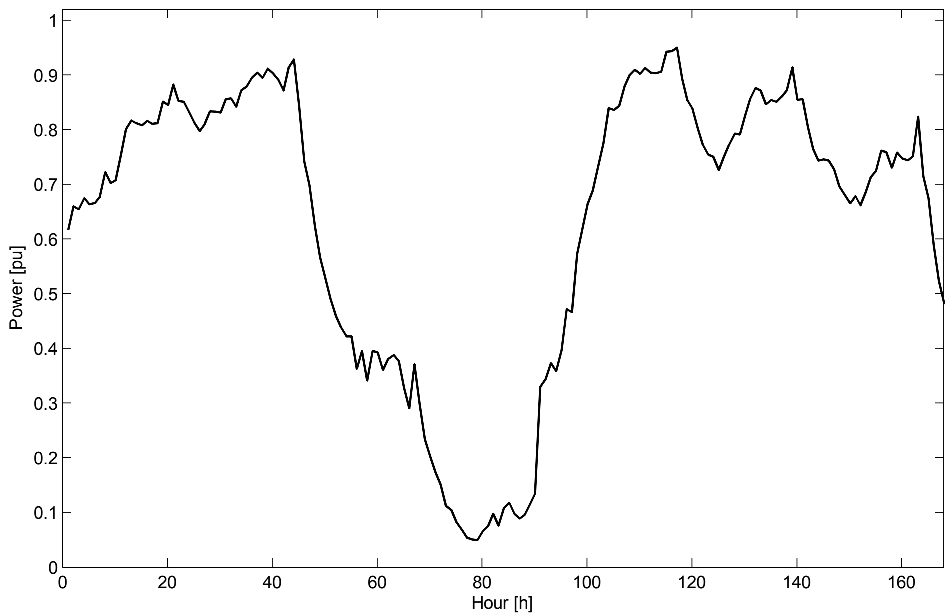

Figure 3.6 Week 51 wind profile

3.3.3 Economic Parameters

In addition to technical parameters from generators and distribution feeders required for the simulations, certain economic parameters must be defined to allow comparison between projects. Although the settings for the economic analysis are given in Appendix C, some of the parameters are briefly commented here:

- Initial costs: The program allows specification in detail of the different costs incurred during the project. These costs include preliminary studies, equipment, substation, roads, balance of system (BOS), etc. For simplicity, in the economic simulation it will be assumed a total unitary cost (i.e. total $/kW installed cost) plus a 15% for contingencies. The same assumption will be applied for annual operation and maintenance costs.

- Inflation rate: It is required to assume a projected annual inflation rate over the entire life of the project.
- Discount rate: The program applies this rate to obtain a discounted future cash flow in order to obtain the net present value (NPV) of the project. This rate then will define the financial viability of the project, and is according to the owner's cost of capital or expected minimum return.
- Project life: It defines the time over which the economic simulation will be evaluated. Generally, it is defined by the expected life of the generation equipment.
- Financing information: Electric power projects are highly capital intensive. Therefore, it is usual that the developer will obtain different sources of financing. The software requires information such as grants, debt ratio, and debt interest rate and term, to add the debt service to the annual costs.
- Fuel cost: For the natural gas engine case, the fuel cost must be entered to calculate operating costs. It is also possible to assume a fuel escalation rate over the project life.

3.4 Software

The following section provides a short description of the capabilities of the software tools used for technical and economic simulations. More comprehensive information and instructions are available through the software manuals and associated documentation, accessible in the references. However, a very important characteristic worth mentioning is that each one is publicly available. Analyses developed using free or open-source programs allows reproducibility of results and makes applicability of any methodology based on them quite simple, since they provide to the work proposed the possibility of being easily accessed, tested, and modified.

3.4.1 OpenDSS

The Distribution System Simulator (DSS) is an electrical system simulation tool developed by The Electric Power Research Institute (EPRI) for electric utility distribution systems. EPRI made available an open-source version of the software called OpenDSS [159]. The program is implemented as a stand-alone executable program with a basic user interface within which it is possible to work with scripts (to input data) and view and analyze simulation results. In addition, the simulation tool can be driven from different software, such as MathWorks-MATLAB, in order to model more specific power devices, or just solution data handling.

OpenDSS's simulation mode can be set up to perform a variety of analyses for distribution networks. The following modes are available in the program:

- Power Flow: OpenDSS is able to run a power flow over meshed and radial distribution networks. This mode can simulate a single snapshot providing the feeder voltage profile and power flow through the lines including circuit losses. Loads and generators varying as a function of time allow the network to be simulated on any period of time.
- Fault Studies: Short-circuit studies for all network buses is performed for different fault types such as three- phases, single line to ground, line to line, and line to line to ground faults. However, it is possible to define a specific fault on the network and test its behavior, or even define fault objects in different locations and simulate them randomly.
- Harmonics Analysis: The user can define harmonic sources associated with loads, generators and voltage sources. Then OpenDSS runs a power flow snapshot, initializes harmonic sources and captures results through monitor objects specified at different points of the circuit.
- Dynamics and Load Parametric Variation: Machine dynamic simulations and parametric evaluations can be modeled according to different functions. OpenDSS provide some basic functions, but the user is able to implement more detailed models from external programs and then call the DSS for a solution.

The settings added to the feeder script in order to perform the appropriate simulations are given in Appendix B.

3.4.2 RETScreen

The Renewable Energy Technologies Screening (RETScreen) tool is a clean energy project analysis software developed by different experts from government agencies, industry and universities. The project is managed and financed by CanmetENERGY, a research centre of Natural Resources Canada [160]. The software is based on Microsoft Excel, allowing an easy information exchange.

The software offers a complete user manual and help function within the program, allowing the user to ask the meaning or allowed values of every step or parameter. It also includes equipment and climate databases to assist in the process, along with a project database that provides clear examples of feasibility analyses.

The analysis is conducted in five steps, standard for any project type:

- Energy model: Definition of the energy source and distributed resource equipment, in order to obtain the annual energy production.
- Cost analysis: Input of cost information including initial and periodic costs, along with any credit from avoided costs.
- GHG analysis: It determines the annual reduction in GHG emission, compared with the grid generation mix, depending on the project location. It also allows the evaluation of whether or not the project has the potential to apply as clean development mechanism (CDM) project [144].
- Financial Summary: In this step it is possible to specify certain financial parameters for the project, for example, incentives, financing debt, inflation, discount rate, taxes, etc. Then, the program provides financial indicators to evaluate the project, along with a cumulative cash flow.
- Sensitivity and Risk Analysis: It provides the option to explore how certain parameters may impact the viability of the project due to uncertainty in others.

The settings used with this program are given in Appendix C.

Chapter 4: DG Technical and Economic Benefits Assessment – Case Study

This chapter presents a case study in order to illustrate the methodology presented in Chapter 3. Analysis steps, the benchmark, and tools previously defined are used here to obtain results exemplifying the impacts brought to distribution networks by distributed generation (DG) (technical analysis). When the impacts represent a positive outcome to the network, incentives are recognized to the DG having an effect on the financial viability (economic analysis) of the project. Finally, relevant results are discussed highlighting the usefulness of the proposed methodology for an efficient deployment of DG in distribution networks.

4.1 Technical Analysis

As stated in Chapter 3, the proposed methodology is applied twice: the connection of a conventional and a renewable DG to the benchmark feeder. After modeling the network in OpenDSS, a snap-shot power flow was run to validate the correctness of the solution and therefore, the model itself. The validation was made against the data provided in [155]. Once the model is correctly set in the script, the DG object is added, as well as yearly profiles for load and generation. Then, the software is set to run one year of hourly power flows in order to obtain the results presented next. Technical simulation settings are provided in Appendices A and B.

4.1.1 Conventional Source

A natural gas reciprocating engine is assumed for the conventional DG case (2 MVA operating at 1.0 pf). High availability of the generator is assumed due to high reliability and matureness of the technology, along with a secure fuel supply. Although 100% availability is not possible, unless the facility has redundant generators, the impact of the DG running all year is analyzed. Also, it is assumed that there is no DG energy production curtailment.

Table 4.1 Technical simulation results – Conventional DG case – 1 year simulation

	Base Case	DG	Voltage Reduction	Voltage Reduction + DG
E_{SUB} $[kWh]$	19,302,024	1,542,278	18,900,295	1,222,175
E_{DG} $[kWh]$	0	17,519,989	0	17,520,000
TES $[kWh]$	19,302,024	19,062,267	18,900,295	18,742,175
E_L $[kWh]$	472,225	205,566	490,828	223,539
% E_L/TES	2.45	1.08	2.6	1.19
TTO	7,562	6,293	7,138	6,050
TVE	233/1,345	0/92	52,007/0	35,900/0

TES: Total Energy Supplied to the feeder

TTO: Total Tap Operations of the transformer at the primary substation

TVE: Total Voltage Exceptions in the feeder to ANSI range A, expressed as under/over voltages

Table 4.1 contains the main results of interest for this study, obtained from one year simulation of hourly power flows (8,760). Since the proposed methodology is applicable to any situation, the following four cases were simulated: a base case that consists in the benchmark feeder simulated with the load profile defined, the base case with a DG connected to node 680 (refer to Figure 3.3), the base case with a voltage reduction at the primary substation as an energy conservation strategy, and the base case with voltage reduction and a DG connected at the same node 680. Notice that the total energy supplied to the feeder is calculated by:

$$TES = E_{SUB} + E_{DG} \tag{4.1}$$

For each case simulated, Table 4.1 provides the yearly totals of energy provided by the substation (E_{SUB}), the energy provided by the DG (E_{DG}), the addition of the last two as total energy supplied (TES) (Eq. 4.1), total system losses (E_L), the ratio of system losses and total energy supplied to the feeder, the total number of tap operations of the transformer at the primary substation (TTO), and the total number of voltage exceptions to range A (refer to Table 3.1) presented as under/over voltages (TVE).

For the interpretation of Table 4.1 it is necessary to take into consideration that the voltage regulator is modeled in OpenDSS as three single-phase regulators working independently. Therefore, the total number of tap operations (TTO) includes the sum of the three regulator tap changes. In addition, the voltage exceptions, although recorded within limits defined by ANSI range A, do not go beyond the ANSI range B; i.e. the voltage profile still remained within acceptable service limits. This fact was verified with a software registry, energy not provided to the load equals to zero; since range B limits were used as emergency voltage limits, OpenDSS uses them to record non-served load.

Figure 4.1 provides a look at the effect of constant DG generation on the electricity supply from the main grid. The figure shows week 51, that corresponds to the peak load week from the load profile used, including the peak hours of the year (hours 8442 and 8443). As can be seen, the DG becomes a base load supplier to the feeder, and therefore, the main grid is required to balance load. Also notice that an effect of having high DG penetration levels is that at times of low load the power injection from the grid becomes negative; i.e. there is energy exported to the main grid. The lower load hours shown in the graph corresponds to Saturday and Sunday mornings.

Although not economically valued in the quantification model, DG is bringing other benefits to this specific case studied. For example, the number of the primary transformer tap operations is reduced by approximately 17%. Also, the number of under voltage exceptions was brought to zero, and the over voltage exceptions reduced by 93%, meaning a significant improvement in the feeder voltage profile and consequently, in the quality of supply. In Figure 4.2, a reduction in the voltage profile dispersion (flattening) from 1 p.u. is observed between the base case (upper left plot) and the DG connection case (lower left plot).

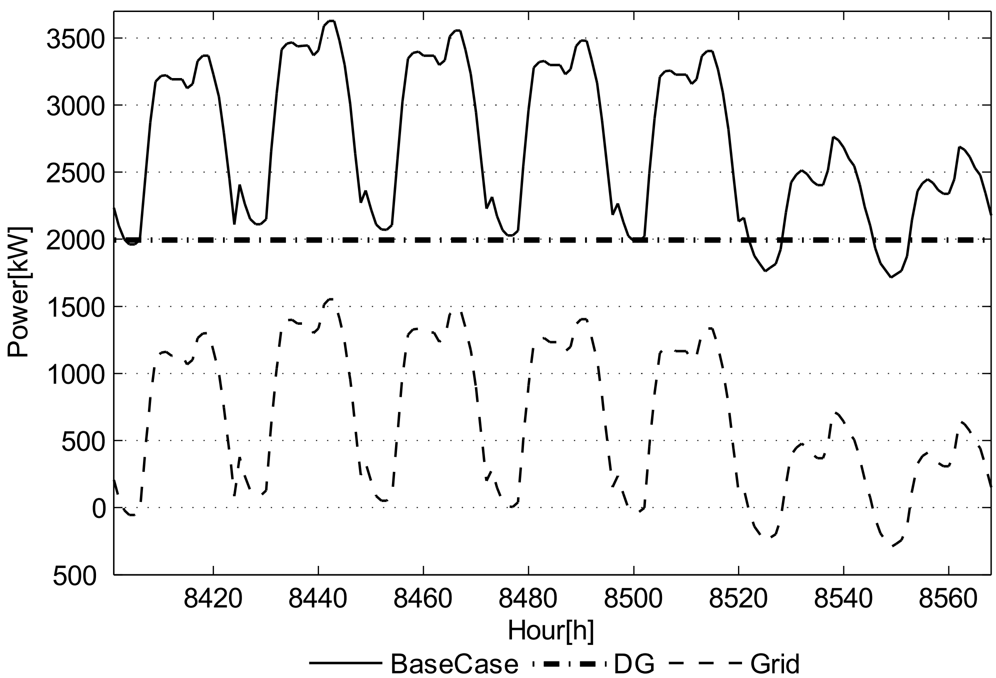

Figure 4.1 Energy supplied to the feeder: base case (solid) Vs DG (dot/dash) plus grid supply (dashed) – Week 51 – Conventional DG case

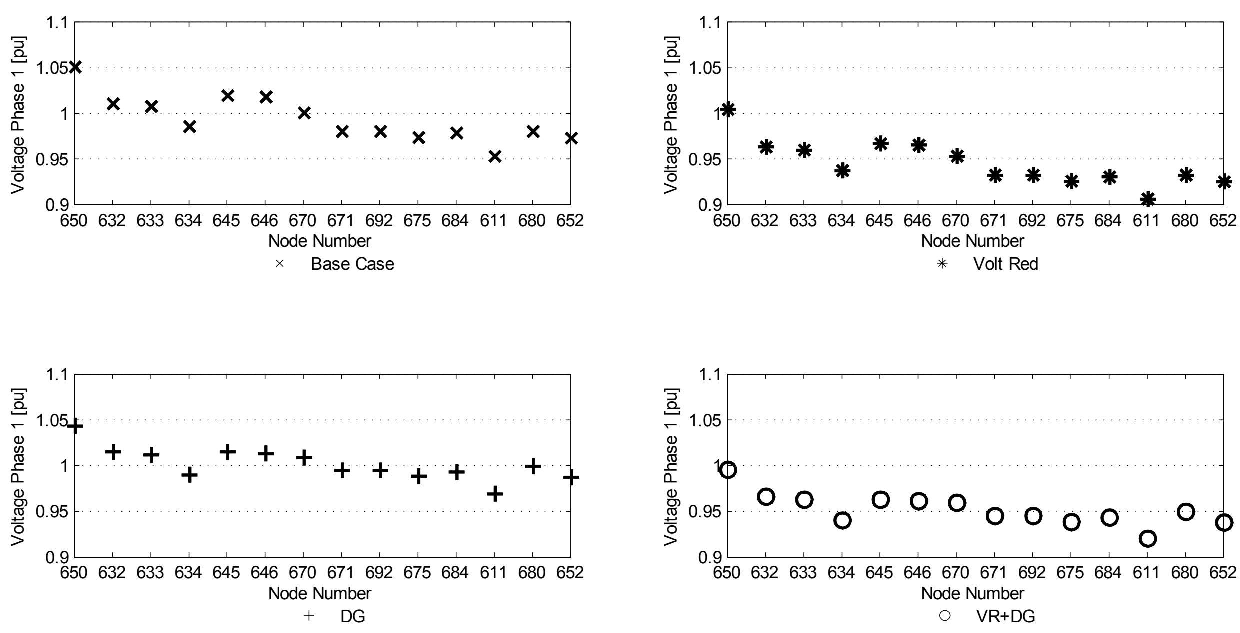

Figure 4.2 Feeder voltage profile (with load ratings): base case (x), voltage reduction (*), DG connection (+), and voltage reduction plus DG (o) – Power flow snap-shot simulation

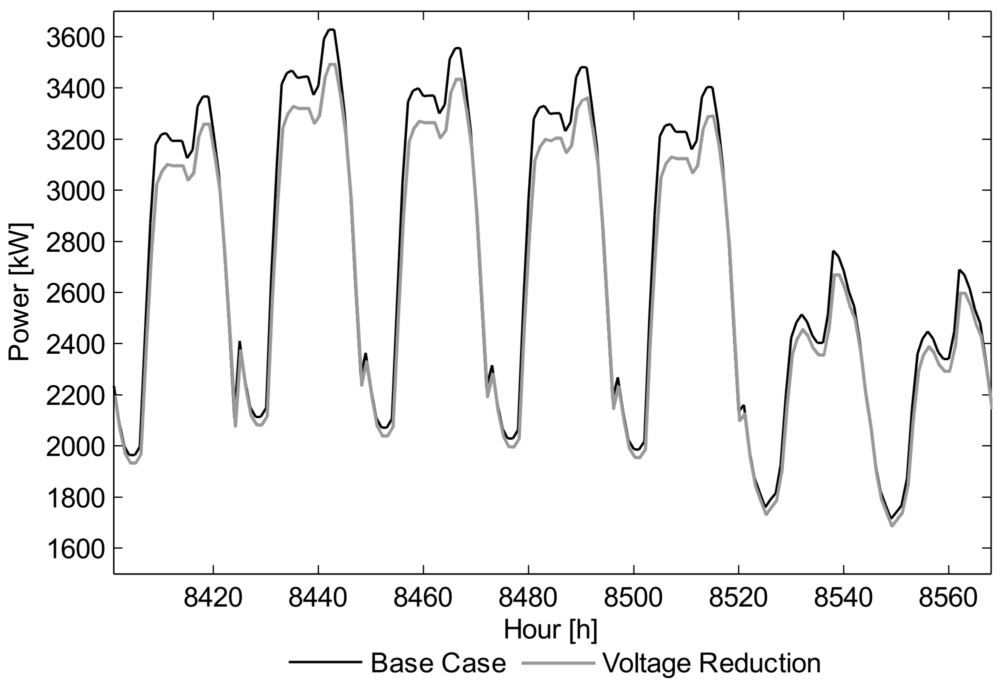

Figure 4.3 Energy conservation strategy: base case (black) vs voltage reduction (grey) – Week 51

The reduction of the network voltage as conservation strategy is implemented in OpenDSS by reducing the voltage level setting in the feeder voltage regulator model script. The base case voltage level (122 V) is reduced approximately 5% (116V). Figure 4.3 compares the energy supplied by the main grid during week 51, for the base case and for the voltage reduction implemented case. During the year, a total of 402 MWh are saved, a reduction of 2.1% from the base case (and 560 MWh or 2.9% with DG connected). It should be mentioned that reducing the voltage of a distribution feeder as a conservation strategy acts upon constant impedance loads, such as highly resistive loads. In the benchmark feeder used, only the loads connected to nodes 646 and 652 are modeled as constant impedances. However, notice that total system losses are increased by almost 4% due to the fact that a voltage reduction on constant power loads will increase current flow through the conductors.

Again, DG brings benefits during the operation under the conservation strategy. Besides the reduction in losses, analyzed later, transformer tap changer operations are reduced by 15% and the number of under voltage exceptions by 30%. Figure 4.2 shows an improvement on voltage profile around 0.95 p.u. between the voltage reduction case (upper right plot) and the voltage reduction operation with a DG connected (lower right plot).

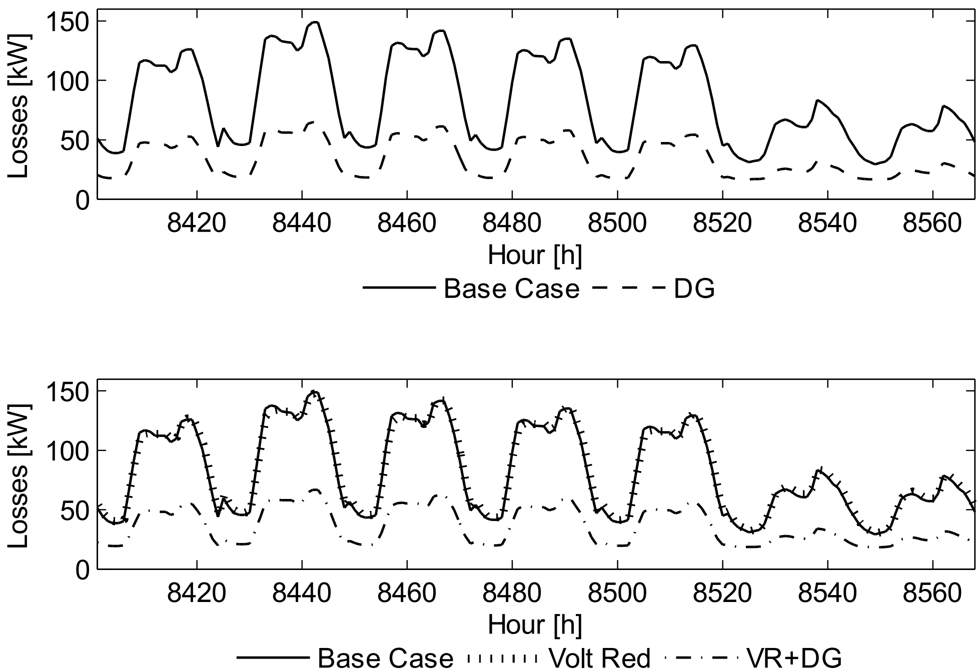

Figure 4.4 System losses week 51: base case (solid) vs DG (dashed) (TOP) – base case (solid) Vs voltage reduction (dotted) and voltage reduction plus DG (dot/dash) (BOTTOM) – Conventional DG case

As it is expected for moderately high DG penetration levels, the distributed resource is contributing to reduce total system losses in both cases simulated, normal operation and voltage reduction conservation scheme. Figure 4.4 shows one week (week 51) of total system losses comparing base case and DG connected (upper plot), and base case with voltage reduction scheme and voltage reduction scheme with DG connected (lower plot). In this study case, DG reduces system losses by 56% of the base case, and by 54% under reduced voltage operation. Losses reduced from the base case are used for the quantification model proposed in the methodology in Chapter 3:

$$E_{L\_RED} = E_L - E_{L\_DG} = 472.225 - 205.566 = 266.7\ MWh$$

Finally, the upgrade investment deferral is analyzed. A load growth rate of 3% per year is applied to every load connected to the benchmark feeder. Again, hourly power flows are run for every year of simulation. The OpenDSS energy meter object connected to the primary substation records, among other parameters, the total overload energy for each year according to the equipment normal and emergency ratings. An overload report is also generated in order to identify the elements overloaded for each hour of the simulations. Then, the network upgrade is assumed to be required for the first year when overload is recorded for the primary transformer and the first section of the feeder. Table 4.2 presents the results of interests for this study, for load growth simulations:

Table 4.2 Circuit overload occurrence with a load growth rate of 3% per year – Conventional DG case

	Base Case	DG
Year	9	20
Total Yearly Overload [kWh]	726	1,018

Although it is normal for DNOs to operate their networks slightly overloaded for short periods during a year, years 9 and 20 will be used as planning horizons in order to calculate the upgrade deferral incentive.

4.1.2 Renewable Source

The same steps defined in the methodology for technical assessment of impacts used in the previous section for a conventional generation technology, are applied simulating a wind turbine as the distributed resource. For a generator with the same capacity as the conventional source case, one year of hourly wind generation profile is placed as multipliers between 0 and 1, modeling a renewable energy source behavior. Such profile, as expected for wind generation, is characterized by its intermittence and lack of control. Neither generation curtailment nor energy storage systems are considered. Once again, the distribution network operator (DNO) is assumed to receive all the energy generated by the independent power producer (IPP), and the generator is modeled with 100% availability.

Table 4.3 presents the results obtained for one year's worth of simulation of hourly power flows. The base case and voltage reduction scheme columns are the same as presented for the conventional distributed generator source case. Both DG results are obtained connecting again the generator at node 680 and the total energy supplied to the feeder (TES) is obtained again using Eq. (4.1).

Table 4.3 Technical simulation results – Renewable DG case

	Base Case	DG	Voltage Reduction	Voltage Reduction + DG
E_{SUB} $[kWh]$	19,302,024	14,528,120	18,900,295	14,146,639
E_{DG} $[kWh]$	0	4,647,284	0	4,647,285
TES $[kWh]$	19,302,024	19,175,404	18,900,295	18,793,924
E_L $[kWh]$	472,225	337,852	490,828	351,262
% E_L/TES	2.45	1.76	2.6	1.87
TTO	7,562	7,335	7,138	6,966
TVE	233/1,345	122/869	52,007/0	48,249/0

TES: Total Energy Supplied to the feeder

TTO: Total Tap Operations of the transformer at the primary substation

TVE: Total Voltage Exceptions in the feeder to ANSI range A, expressed as under/over voltages

The intermittent characteristic of the wind turbine generation can be seen in Figure 4.5. It compares the base case with the DG profile and the energy supplied by the grid for week 51. Although the electricity imported from the main grid is reduced, technical benefits considered are less if compared with a conventional controllable source, Table 4.1. Transformer tap changer operations are reduced by only 3%. Under voltage exceptions are reduced by 47% and over voltages by 35%.

Loss analysis is also affected by the low capacity factor of the distributed generator, another characteristic of intermittent renewable sources. Total system losses are reduced by 28% from the base case, and same percentage under reduced voltage operation. Figure 4.6 compares system losses for base case and DG connected (upper plot), and base case with voltage reduction scheme and voltage reduction scheme with DG connected (lower plot). This lower loss reduction capacity can be seen, for example around hour 8480; when wind generation is low (Figure 4.5) system losses tend to match the base case as expected (Figure 4.6). Although less than conventional DG case, loss reduction from the base case is used again in the quantification model proposed in the methodology:

$$E_{L\_RED} = E_L - E_{L\_DG} = 472.225 - 337.852 = 134.373\ MWh$$

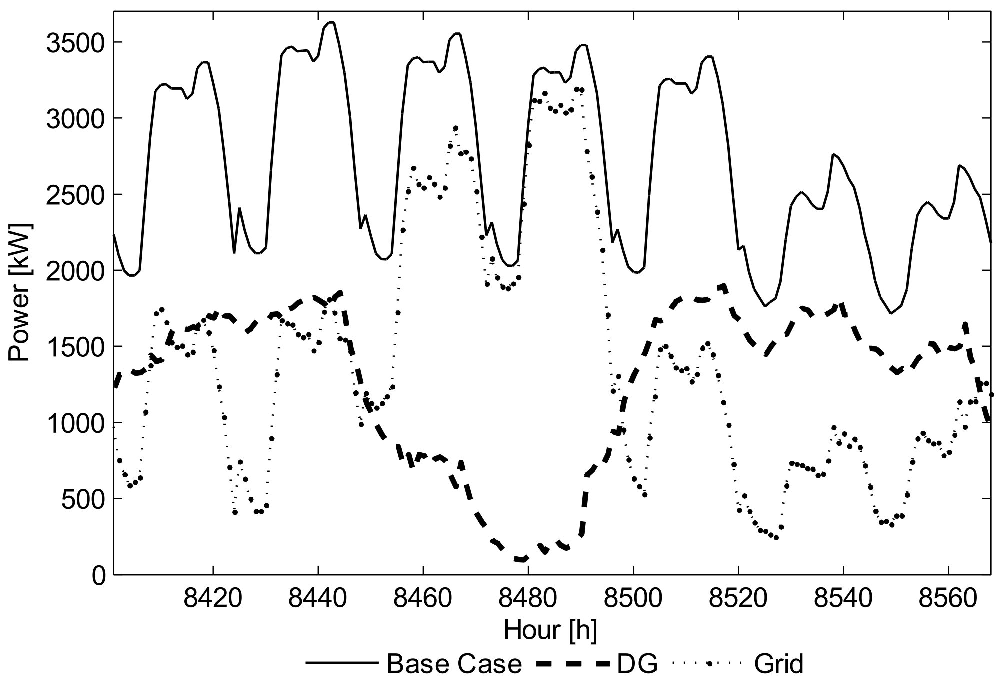

Figure 4.5 Energy supplied to the feeder: base case (solid) vs DG (dashed) plus grid supply (dotted) – Week 51 – Renewable DG case

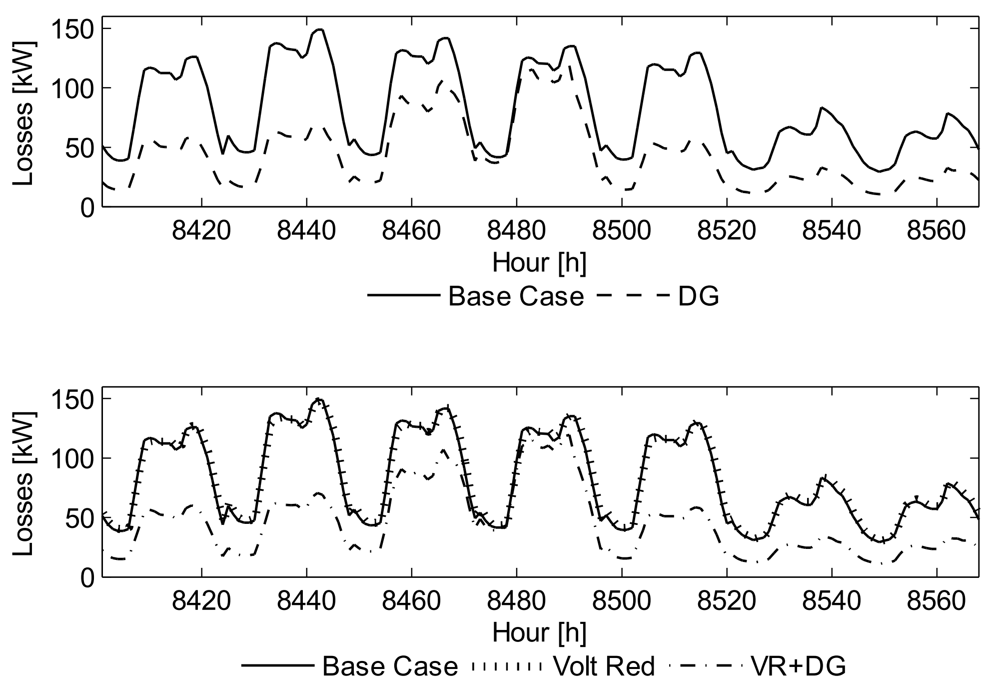

Figure 4.6 System losses week 51: base case (solid) Vs DG (dashed) (TOP) – base case (solid) vs voltage reduction (dotted) and voltage reduction plus DG (dot/dash) (BOTTOM) – Renewable DG case

Finally, as was mentioned in Section 3.4.4.2, the lack of firm capacity from a single wind turbine makes this generation technology unsuitable for the upgrade investment deferral strategy. Therefore, the incentive corresponding to upgrade deferral will not be assigned to the renewable energy source (RES). However, the analysis with load growth was performed and its results are presented in Table 4.4:

Table 4.4 Circuit overload occurrence with a load growth rate of 3% per year – Renewable DG case

	Base Case	DG
Year	9	11
Total Yearly Overload [kWh]	726	505

4.2 Economic Analysis

Following the steps proposed in Chapter 3, this section presents the results obtained for the economic analysis of the methodology. The energy generated by the DG is used as the starting point for the configuration of the RETScreen software. Both cases, conventional and renewable sources, are presented separated in order to properly describe the incentives and impacts of each. Since some results depend on the site where the distributed resource is installed, it was assumed a DG connected in the state of New York, U.S. In doing so, it is possible to use the data presented as example in Chapter 3, such as network upgrade costs and NYISO average electricity rate. Therefore, prices presented here are in U.S. dollars. Economic simulation settings are provided in Appendix C.

4.2.1 Conventional Source

The energy model in RETScreen comprises the energy produced by the generator and its technical characteristics. These characteristics, such as power rating and heat rate, will define the fuel consumption required for the natural gas reciprocating engine case. Electricity exported to the grid and fuel consumed will feed the GHG emissions analysis that will generate the information required for the GHG emissions reduction incentive.

Cost analysis information (fuel costs and DG initial and operation and maintenance O&M costs) and general financial parameters (project life and inflation and discount rates) define the production cost in dollars per MWh of the distributed generator. This production cost per output units sets the limit of the electricity rate that will allow the DG to run profitably. Therefore, as the base case for economic analysis simulations, it was assumed that the DNO is willing to pay to the IPP an electricity rate that covers the production cost plus a premium (PC+P). For the conventional DG case a production cost of 6.758 ¢/kWh was obtained and a premium of 0.2 ¢/kWh was assumed. The wholesale rate is not considered here since the DG production cost is above the average price for the area selected; i.e. more than half of the year the electricity rate will not cover the DG production cost affecting the viability of the project.

Then, project financing parameters are added to the software in order to obtain a base case for the economic analysis. It was assumed that the DG owner obtained a loan that covers 70% of the total project initial cost, with an interest rate of 5% during 20 years.

After the base case analysis is obtained, two additional cases are considered. The first one is based on the same electricity rate obtained for the base case with the addition of annual revenues from technical benefits (quantification model). The second one is based on a feed-in tariff (FIT) program where higher electricity rates are paid as part of policies that look to attract and promote renewable technologies to the networks, and where general incentives from benefits are considered included [161]. Table 4.5 shows first year revenues separated by income sources:

Table 4.5 First year revenues by income source [$] – Conventional DG case

Income source	Electricity production	GHG reduction	Upgrade deferral incentive	Losses reduction incentive	Total
PC+P	1,219,042	-	-	-	1,219,042
PC+P + Incentives	1,219,042	51,520	57,816	14,016	1,342,393
FIT	1,401,600	-	-	-	1,401,600

For this study, GHG emissions reduction is applied together with upgrade deferral and losses reduction incentives. However, this is an incentive that does not depend on any agreement between utilities and IPPs. Therefore, it could be indistinctly applied to the base case or to the FIT program. Table 4.6 shows GHG emissions reduced by the DG compared to the case where the same amount of electricity is obtained from the main grid (average GHG emissions in the U.S.). GHG emissions reduction incentive was found applying a rate of 16 $/tCO2e to Eq. (3.1) [162]:

$$CO2_{CR} = 3{,}220 * 16 = \$\ 51{,}520$$

Table 4.6 GHG emissions reduction – Conventional DG case

	GHG emissions tCO2e	Net annual reduction tCO2e	Equivalences	
			Cars not used	Barrels of crude oil not used
Grid	10,450	-	-	-
Conventional DG	7,230	3,220	590	7,480

From technical results (Section 4.1.1), it was established that a feeder upgrade is postponed from year 9 to year 20. These coincide with the years used for the numerical example presented in Section 3.1.3.2. If the same parameters used for Eq. (3.2), (3.3) and (3.4) are assumed, then the upgrade deferral incentive remains:

$$\Upsilon_{UD} = 0.33\ ¢/kWh$$

Also from Section 4.1.1, total system losses reduction was found to be 266.7 MWh. From Table 3.2 and applying Eq. (3.8) and (3.9), the losses reduction incentive will yield in the New York ISO (NYISO) area:

$$LRS = 266.7 * 53.56 = \$\ 14{,}284$$

$$\Upsilon_{LR} = 0.08\ ¢/kWh$$

Figure 4.7 presents a breakdown of the first year revenues obtained taking into account the incentives obtained applying the quantification model proposed in Chapter 3. All the incentives together, GHG emissions reduction (GHG), upgrade deferral incentive (UD), and losses reduction incentive (LR), represent 9% of the total first year income, increasing the base case revenue by 10.1%.

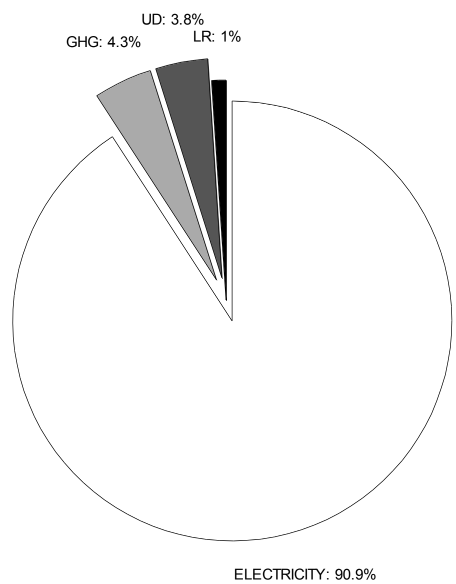

Figure 4.7 Total yearly revenues breakdown - PC+P + incentives income source - Conventional DG case

For the analysis of a feed-in tariff, a single electricity rate income source is applied again without the incentives found with the quantification model. An electricity rate of 80 \$/MWh was assumed. However, feed-in tariff (FIT) programs for generators burning biogas can offer tariffs as high as 123 \$/MWh (13 Canadian ¢/kWh [154]) and 136 \$/MWh (9 British pennies/kWh [163]).

Table 4.7 Project feasibility analysis – Conventional DG case

Income Source	IRR on equity %	IRR on assets %	Simple payback yr	Equity payback yr	NPV $	B-C ratio
PC+P	15.8	3.3	10.3	6.7	852,633	1.92
PC+P + Incentives	29.3	8.5	7.3	3.6	2,317,181	3.49
FIT	34.9	10.4	6.4	2.9	2,894,280	4.11

Table 4.7 presents the key parameters for the feasibility analysis of the project under each income source scheme. Internal rate of return (IRR) represents the interest yield that the project provides over its life[4]. Simple payback is the period of time that the project requires to recuperate the initial costs. Equity payback is the time required to recover the portion of the initial costs funded by the project's developer. Net present value (NPV) is the total value of the cash flow generated by the project, with each series

[4] Equity corresponds to the portion of total investment initial costs provided by the project developer and it is calculated with the debt ratio assumed. For this study a debt ratio of 70% was used, therefore, the project's owner is founding 30% of the investment. Asset represents the total cost of the project.

discounted to bring them to their net present values. Benefit-cost ratio relates the net benefits over the costs of the project (keeping in that these benefits are distinct from network benefits).

Higher IRR, NPV and B-C ratio indicate greater feasibility and more lucrative investments. Lower payback times benefit the project's owner with sooner positive cash flows that would especially help small companies. Figure 4.8 shows the cumulative cash flows over the project life for each of the cases simulated. As expected, a higher electricity rate will generate a higher NPV and IRR with a shorter equity payback (bottom plot). On the other hand, although it has a positive NPV, the base case assumed is generating an IRR lower than the weighted average cost of capital (WACC) assumed (8%), and even lower than government bond rates (4.375% for 30-year U.S. Treasury bond) [149].

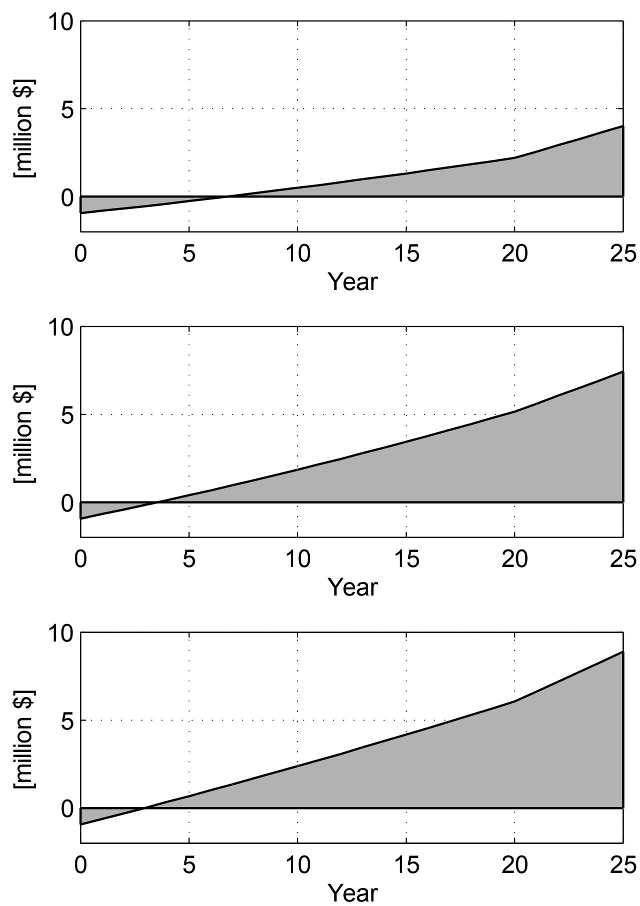

Figure 4.8 Cumulative cash flows of the project for different electricity rates: production cost plus premium (TOP), production cost plus premium and incentives (MIDDLE), and feed-in tariff (BOTTOM) – Conventional DG case

However, the high reliability assumed, even though it brings important technical benefits to the network, has a drawback on the fuel consumption required. High volatility on fossil fuel prices poses a risk for the feasibility of the proposed conventional DG case. Table 4.8 presents a sensitivity analysis for the two most important parameters for the evaluation of this specific project: electricity rate and fuel cost. The table shows the impact that a variation of ±10% of these parameters has on the internal rate of return (IRR) on the assets. The WACC of 8% assumed is used as a threshold for the evaluation of the sensitivity analysis. Shaded cells indicate the cases where the resulting IRR falls below the threshold. The analysis was done considering the production cost plus premium and incentives (PC+P + Incentives) since this is the main point of interest of this study.

Table 4.8 Sensitivity analysis for the IRR varying electricity rate and fuel cost – Conventional DG case with PC+P plus incentives as income source

Electricity rate	**Fuel cost**				
	-10%	**-5%**	**0%**	**5%**	**10%**
-10%	6.6%	5.1%	3.6%	1.9%	0.2%
-5%	8.9%	7.6%	6.1%	4.7%	3.1%
0%	11.1%	9.8%	8.5%	7.1%	5.7%
5%	13.3%	12.0%	10.7%	9.4%	8.0%
10%	15.3%	14.1%	12.8%	11.6%	10.3%

As expected, the upper right region of the table presents the riskiest scenario for the project (lower electricity rate – higher fuel cost). A risk analysis is presented in Figure 4.9. A high volatility is assigned to the fuel cost (20%), while less uncertainty is assumed for the electricity rate, initial costs, and O&M costs (10%). Again, the risk analysis is performed for the internal rate of return (IRR) on the assets, assuming the production cost plus premium and incentives case as the income source.

From Figure 4.9, higher volatility or uncertainty on the fuel cost has a higher impact on its inverse (negative) relationship with the IRR on assets. RETScreen performs this risk analysis by running 500 Monte Carlo simulations, obtaining same number of possible IRR on assets values, varying the parameters selected by the ranges assigned. Then, the software analyzes the statistical distribution of the results. For instance, with the values assumed, it was found that 90% of the cases will have an IRR on assets between 4.6% and 12.2%.

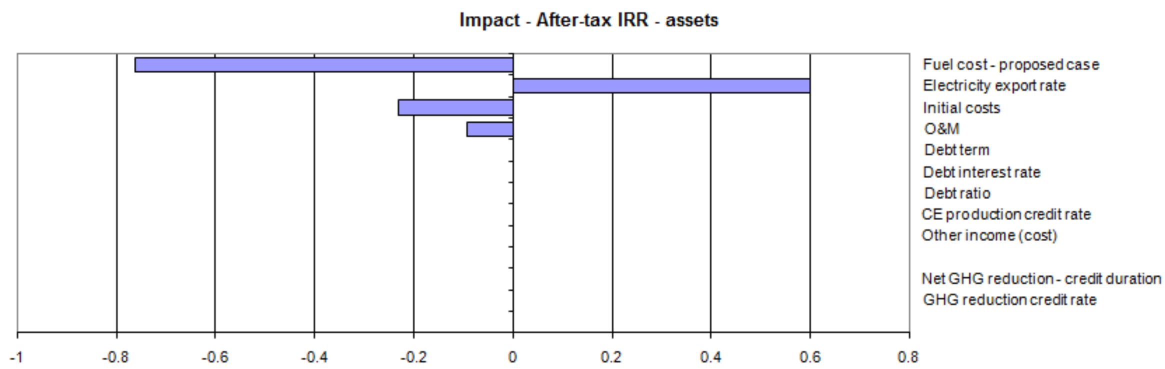

Figure 4.9 Risk analysis impact on IRR of the fuel cost, electricity rate, initial costs, and O&M costs - Conventional DG case with PC+P plus incentives as electricity rate

4.2.2 Renewable Source

A simplified method on RETScreen allows calculation of the wind turbine generation (renewable DG case) for one year by defining turbine rating and capacity factor. Using the Excel goal seek function in order to match the electricity generated with the technical results from OpenDSS, a capacity factor of 26.5256% is obtained. Wind turbine initial and O&M costs will define the production cost per output unit of the DG. Financing parameters defining the debt for the project construction are the same than those used for the conventional DG case.

The same three income sources assumed for the conventional case are reviewed for the wind turbine. The base case assumes an electricity rate comprised of the production cost found (8.65 ¢/kWh) and a premium (0.2 ¢/kWh) (PC+P). The second case assumes the same previous electricity rate plus the incentives found with the proposed quantification model. The last case is the implementation of a feed-in tariff (FIT) for wind turbines. Table 4.9 shows the revenues obtained for the first year:

Table 4.9 First year revenues by income source [$] – Renewable DG case

Income source	Electricity production	GHG reduction	Upgrade deferral incentive	Losses reduction incentive	Total
PC+P	411,285	-	-	-	411,285
PC+P + Incentives	411,285	44,352	-	7,203	462,840
FIT	511,201	-	-	-	511,201

GHG emissions reduction incentive was found with the information from Table 4.10 and a rate of 16 $/tCO2e applied to Eq. (3.1):

$$CO2_{CR} = 2{,}772 * 16 = \$44\ 352,$$

Table 4.10 GHG emissions reduction – Renewable DG case

	GHG emissions tCO2e	Net annual reduction tCO2e	Equivalences	
			Cars not used	Barrels of crude oil not used
Grid	2,772	-	-	-
Renewable DG	0	2,772	508	6,447

As it was explained in Chapter 3, the upgrade deferral incentive is not applied to the wind turbine due to its lack of firm capacity. The loss reduction incentive was calculated with the total system losses reduction (134.373 MWh) and the electricity average rate for the New York Independent System Operator (NYISO) area, applied to Eq. (3.8) and (3.9):

$$LRS = 134.373 * 53.56 = \$\ 7{,}197$$

$$\Upsilon_{LR} = 0.155\ ¢/kWh$$

Figure 4.10 depicts the breakdown of the revenues obtained with these incentives and the electricity rate assumed for the base case. Incentives account for up to 11% of the income for the first year, and represent a revenue increase of 12.5% from the base case.

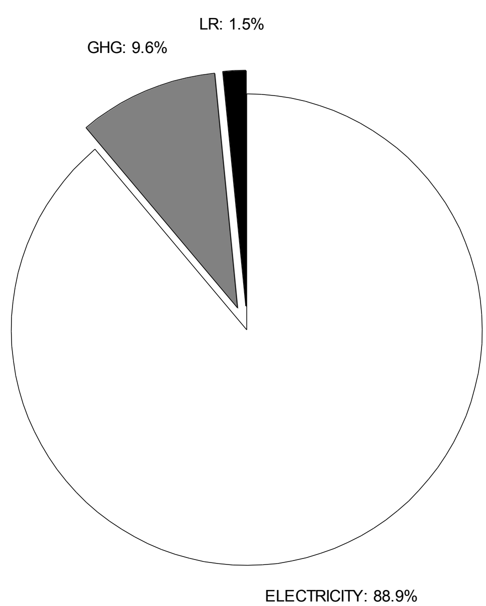

Figure 4.10 Total yearly revenues breakdown – PC+P + incentives income source – Renewable DG case

The feed-in tariff program assumed for the wind turbine assigns an electricity rate of 110 $/MWh. Feed-in tariff (FIT) programs for wind turbines on-shore could offer rates up to 129 $/MWh (13.5 Canadian ¢/kWh [154]) and 142 $/MWh (9.4 British pennies/kWh [163]). No other incentives are considered for the FIT income source.

Table 4.11 Project feasibility analysis – Renewable DG case

Income Source	IRR on equity %	IRR on assets %	Simple payback yr	Equity payback yr	NPV $	B-C ratio
PC+P	15.5	2.6	9.9	6.6	798,434	1.81
PC+P + Incentives	20.8	4.6	8.5	4.9	1,342,479	2.36
FIT	25.7	6.7	7.6	3.9	1,915,854	2.94

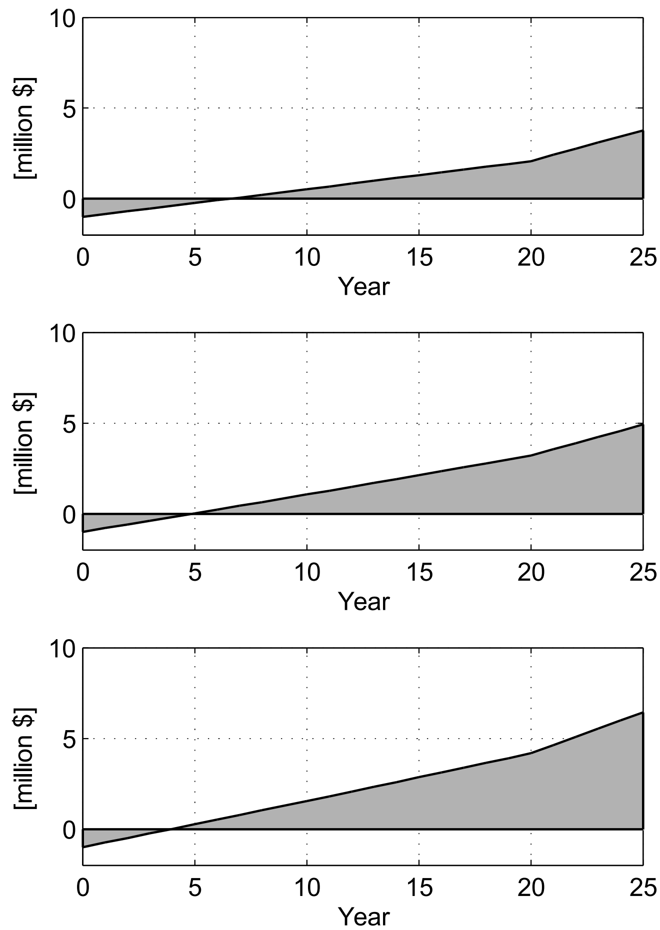

Figure 4.11 Cumulative cash flows of the project for different electricity rates: production cost plus premium (TOP), production cost plus premium and incentives (MIDDLE), and feed-in tariff (BOTTOM) – Renewable DG case

Table 4.11 contains the parameters necessary for the project feasibility evaluation. Again, the higher rate paid by the FIT program generates the best financial option, as expected. However, incentives do improve the attractiveness of the project if compared with the base case. High initial costs and low electricity production yield lower internal rate of return (IRR) on assets and net present value (NPV) than the conventional case previously presented.

Figure 4.11 displays the cumulative cash flows over the project life for each income source considered. As mentioned, the FIT program (bottom plot) presents a higher cash flow with a lower payback. Similar to the conventional DG analysis, the base case generates an IRR on assets lower than the weighted average cost of capital (WACC) assumed and government bond rates, despite having a positive NPV.

With the environmental and economic advantage of not using fossil fuels for electricity generation, renewable technologies have their major drawback in the initial costs. Table 4.12 contains a sensitivity analysis for the impact over IRR on assets by varying ±10% the electricity rate and turbine initial costs. The income source case evaluated corresponds to the production cost plus premium and incentives. Since the three income source cases analyzed have an IRR on assets lower than the WACC assumed, it was used as a threshold a rate of 4.375% (U.S. Treasury bond – 30 years [149])[5]. Shaded cells indicate the scenarios where the IRR on the assets fall below the threshold assumed.

Table 4.12 Sensitivity analysis for the IRR varying electricity rate and initial costs – Renewable DG case with PC+P plus incentives as income source

Electricity rate	**Initial Costs**				
	-10%	**-5%**	**0%**	**5%**	**10%**
-10%	4.4	3.6	2.8	2.1	1.4
-5%	5.3	4.5	3.7	3.0	2.3
0%	6.3	5.4	4.6	3.8	3.2
5%	7.2	6.3	5.4	4.7	4.0
10%	8.0	7.1	6.3	5.5	4.8

[5] In economic theory, another method of evaluating the viability of a project different than the company's cost of capital, is assuming a risk-free interest rate as an alternative for the project. Although in reality zero risk alternatives do not exist, U.S. Treasury bonds are considered risk free due to the extremely low probability of the government defaulting.

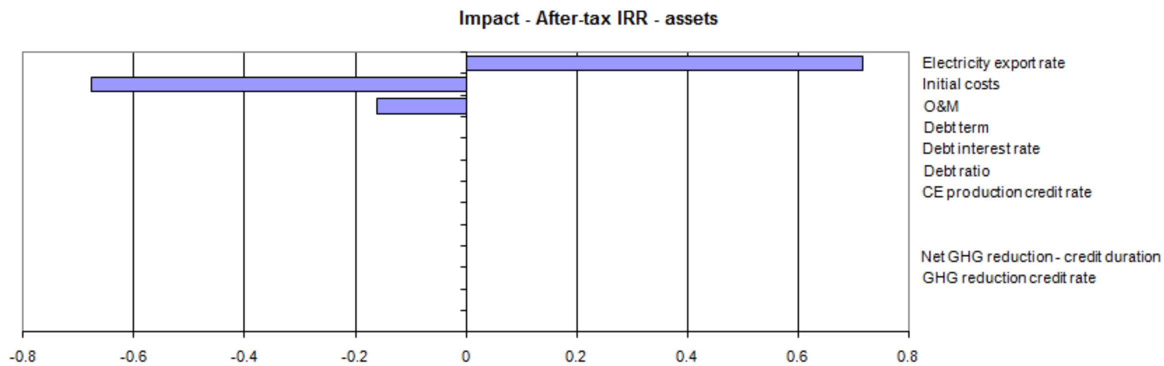

Figure 4.12 Risk analysis impact on IRR of the electricity rate, initial costs, and O&M costs - Renewable DG case with PC+P plus incentives as electricity rate

Lower electricity rates and higher equipment costs pose the greatest risks for this project (upper right region of Table 4.12). A risk analysis is presented on Figure 4.12, where an uncertainty of 10% is assigned to the electricity rate, initial costs, and O&M costs. Higher electricity rates that have a direct (positive) relationship with the IRR on assets will help to reduce the risk (negative impact) that high equipment costs have on this type of projects.

The 500 Monte Carlos simulations generated for this risk analysis, showed a statistical distribution with 90% of the results falling in a range of 3.3% and 5.9% for the IRR on assets. These results show how risky and sensitive this project is to the high cost of power equipment (initial costs).

4.3 The Role of DG Penetration Level

After a detailed analysis of technical and economic benefits and impacts of distributed generation on distribution networks, a short assessment of the role of DG penetration level is discussed here. It is known that some technical impacts have a U-shaped behavior, like for example, loss reduction and voltage improvement. Therefore, such behavior will generate different results when these technical impacts are quantified and translated into incentives.

DG penetration level for a particular feeder is defined as the ratio of the DG capacity and the peak load, expressed as a percentage:

$$\Gamma_{DG} = \frac{P_{DG}}{L_{PEAK}} \times 100\% \tag{4.2}$$

The peak load for the test feeder is 3,268 kW. Then, different penetration levels are assumed to find an approximate value for DG capacity. For each level found, the proposed methodology is applied, quantifying first the technical benefits and evaluating the feasibility for the project. Tables 4.13 and 4.14 presents the results obtained for both, conventional and renewable sources.

Table 4.13 First year revenues by DG penetration level – Conventional DG case

Γ_{DG} %	DG capacity MW	Electricity production	GHG reduction	Upgrade deferral incentive	Losses reduction incentive	Total incentives	Total income	IRR on assets
40	1.5	898,907	38,640	52,429	14,980	106,049	1,0004,956	15.5
60	2	1,198,543	51,520	57,115	14,366	123,001	1,321,544	9
80	2.9	1,737,888	74,704	61,478	5,081	141,263	1,879,151	7.7
100	3.6	2,157,378	92,736	57,080	-6,307	143,509	2,300,887	6.8
120	4.3	2,576,868	110,768	56,879	-24,108	143,539	2,720,407	6
140	5	2,996,358	128,800	47,742	-44,107	132,435	3,128,793	5.3

Table 4.14 First year revenues by DG penetration level – Renewable DG case

Γ_{DG} %	DG capacity MW	Electricity production	GHG reduction	Upgrade deferral incentive	Losses reduction incentive	Total incentives	Total income	IRR on assets
40	1.5	294,766	33,264	11,502	5,960	50,726	345,492	4.6
60	2	411,286	44,352	11,618	7,203	63,173	474,459	5.2
80	2.9	596,364	64,310	16,846	8,625	89,781	686,145	5.1
100	3.6	740,314	79,833	5,856	8,867	94,556	834,870	4.6
120	4.3	884,264	95,356	5,995	8,493	109,844	994,108	4.5
140	5	1,028,214	110,879	5,809	7,552	124,240	1,152,454	4.5

Two changes were made with respect to the methodology used: upgrade deferral incentive was applied to the renewable DG case, and when a negative impact appears compared with the base case, a negative incentive is applied as a penalty to the DG.

From Table 4.13, since the electricity rate was assumed only to cover production costs, the decrease in upgrade deferral and loss reduction incentives reduce the IRR on assets when increasing the DG penetration level. As expected, the increment on DG generation will eventually increase network losses. It should be mentioned that base case system losses and therefore any increase must be assumed by the DNO, who will purchase any additional energy required from the wholesale market. Moreover, with increased levels of DG, not only the losses reduction penalty will be bigger, but also a network upgrade will be required. This upgrade could be necessary either before the year simulated for the base case, or at the moment of the connection in order to accommodate the DG production. Figure 4.13 shows that, although environmental benefits increase with higher DG capacities, loss reduction and upgrade deferral benefits decrease and even become a negative impact (penalty) for the conventional case analyzed.

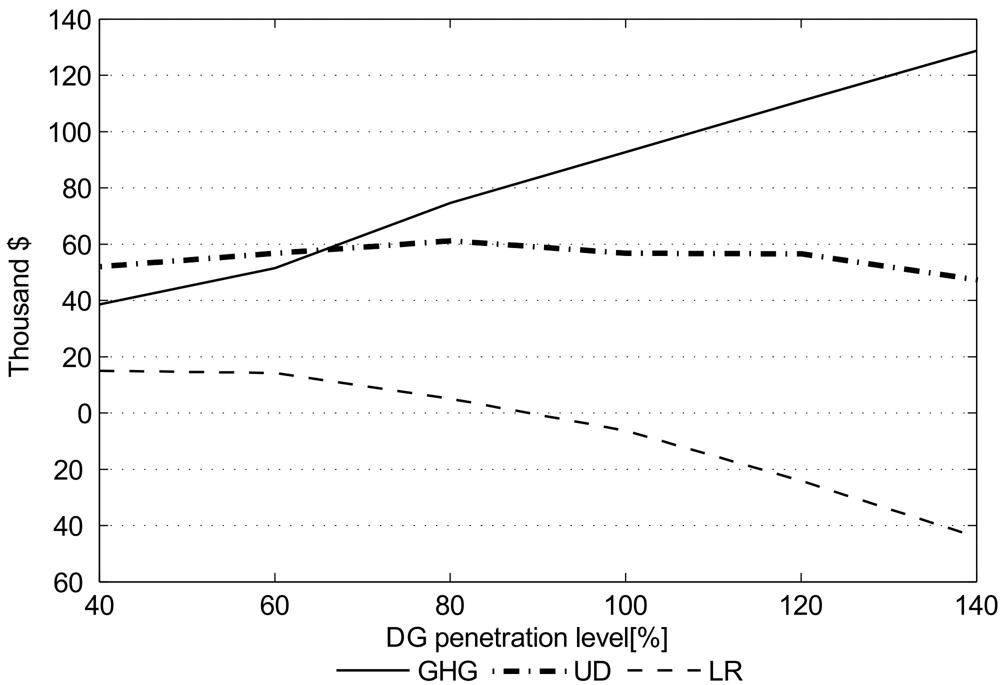

Figure 4.13 Incentives calculated with the proposed methodology vs DG penetration level: greenhouse gases reduction incentive (solid), upgrade deferral incentive (dot/dash) and loss reduction incentive (dashed) – Conventional DG case

The scenarios previously analyzed were then conducted for the renewable DG case. From Table 4.14, technical benefits incentives start decreasing when increasing the DG capacity. GHG emissions reductions increase as expected, but as this incentive depends on location, it is a benefit that cannot be generalized for every network. The upgrade deferral incentive is shown just as an economic exercise, where it can be seen that the incentive is not only small, but also begins to decrease with higher levels of DG (Figure 4.14). As it was mentioned before, with a wind farm of 7.5 MW (a penetration level of 230%), a feeder upgrade will be required in order to connect the DG, reflected as a negative incentive.

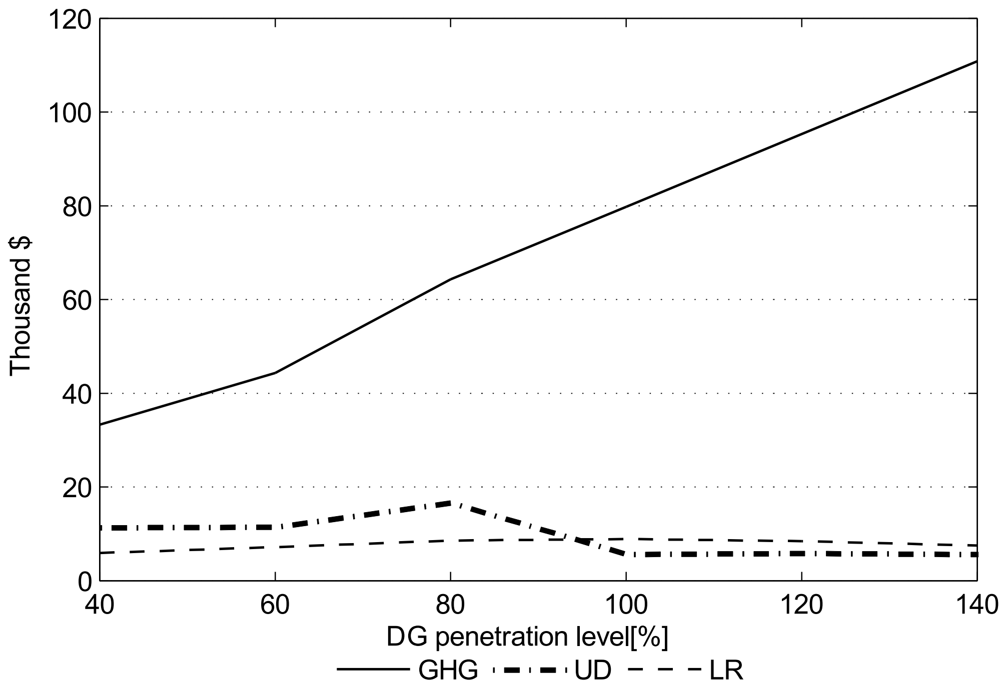

Figure 4.14 Incentives calculated with the proposed methodology vs DG penetration level: greenhouse gases reduction incentive (solid), upgrade deferral incentive (dot/dash) and loss reduction incentive (dashed) – Renewable DG case

A common point of discussion can be derived from both tables then. High levels of DG connected to the feeder under study will bring fewer technical benefits, and in extreme case will lead to negative impacts. In addition, when these benefits are quantified, negative impacts become penalties to the DG, reducing the profitability of the projects. Since any immediate network upgrade required to connect a new distributed resource is a negative impact either for the DNO or the IPP, policies forcing networks to allow every DG connection request could lead to economic inefficiencies.

4.4 Discussion

In order to discuss some of the results obtained, a preliminary conclusion must be outlined. All the technical and economic results previously presented were obtained with very specific parameters and assumptions configured in the tools used. Even small changes in any of the values assumed could lead to very different results for both cases, conventional and renewable sources. Therefore, any generalization about benefits and impacts brought by DG to utilities, networks, IPPs, and customers, has the potential to create technical and economic drawbacks, if a proper analysis is not conducted. However, methodologies for the assessment of DG projects create a common set of rules to analyze and understand different aspects of such developments, avoiding negative impacts from DG, while still encouraging new DG connections where they realize significant benefits.

In addition, it should be mentioned that the methodology applied to the study cases considers new DG connections at levels where an upgrade is not required to accommodate additional electricity generation. In situations where the distribution network operation (DNO) passes DG upgrade requirements to customers through the electricity rate, or to the IPP in its initial costs, a different analysis for costs and benefits would be required.

The most relevant points are discussed next.

Conventional DG Source – Technical Results

DG Capacity Level: The DG capacity chosen clearly brings technical benefits if compared against the base case yearly simulation: total system losses are reduced, fewer primary transformer tap operations are required, and the voltage profile remains within desired limits for almost the entire year. In addition, the improvement of the voltage profile even results in a small reduction in the total energy supplied to the network. Similar benefits are brought when comparing the voltage reduction conservation strategy with and without DG. However, as it was mentioned before, consider that the DG capacity assumed is not necessarily the optimal rating for the feeder used. Consequently, lower capacities could fail to fully exploit DG benefits, while higher levels will impose serious negative impacts to network operation and equipment security. Moreover, additional analyses and rules are required to the case of multiple DG connections across the feeder, including optimization algorithms [164].

DG P-Q Control Strategy: If the DG is allowed to vary its active and reactive power output, and/or it is controlled or dispatched by the DNO, extra benefits could be achieved. For example, improved management of system losses, improved voltage profile and power quality, intentional islanding of total or parts of the feeder improving reliability, etc. Since this variation on DG output will translate into reduced DG generation and increased equipment wear, some agreements must be put in place between DNOs and IPPs in order to appropriately compensate for such operating modes.

Voltage Reduction Conservation Scheme: Although the voltage reduction strategy showed a reduction in the total energy supplied, total system losses increased too. Not all feeders are suitable for such conservation strategy, it depends on the load characteristics; i.e. it is more effective on predominantly resistive loads.

Network Upgrade Investment Deferral: The DG capacity chosen is such that it can contribute to the upgrade deferral of the feeder. Smaller units controlled by DNOs can be used exclusively for the purpose of shaving peak load, although careful feasibility analysis must be conducted in order to determine the profitability of such a strategy. Also, the upgrade deferral capability must be coupled with a careful analysis of DG reliability. DG units failing to operate during peak load hours will force disconnection of loads in order to preserve feeder security.

Network Line Energy Loss Reduction: The DG chosen reduced network line energy loss during the year simulated. However, the capacity assumed and the DG location is not necessarily the optimal for the feeder analyzed. An in-depth analysis could explore the optimal zone in the U-shaped curve formed by network losses vs. DG capacity.

Conventional DG Source – Economic Results

Electricity and DG Production Costs: Quantifiable technical benefits are brought to distribution networks by controllable and reliable technologies such as reciprocating engines. However, a major drawback lies on their dependency on fossil fuel burning. This brings high operating costs for electricity generation with a polluting by-product like GHG emissions. This is true even for technologies considered “green” like natural gas, biogas and biofuels in general, and waste incineration, also known as energy-from-waste (EfW).

Economic Incentives: In this study, an electricity rate covering the production costs was assumed. This assumption yielded a low internal rate of return (IRR) on assets, therefore resulting on an unfeasible project. However, the same rate covering the DG production costs and incorporating proved technical benefit incentives, quantified with the proposed methodology, made the project attractive. Since the project remains very sensitive to fuel costs, and due to the high volatility of fuel prices, it would be necessary to have a flexible electricity rate for the DG coupled with the fuel price. For example, an increase of 10% on fuel prices would require an increase of at least 5% in the electricity rate in order to keep the project profitable within the parameters assumed.

GHG Emissions Reduction and DG Location: Although reductions in GHG emissions represent an important part of the incentives quantified, this reduction entirely depends on the project location. RETScreen provides emission factors (tCO2e/MWh of electricity generated) for every province in Canada, and for every country. This emission factor is the result of relating for a specific area, the total electricity generated and the energy source mix used by the power plants. Although carbon credits can be traded within different areas and countries, the net local GHG emission will vary according to the DG location. For example, when the New York ISO area was selected, 3,220 tCO2e where reduced. If the project is placed in Alberta, Canada, 7,854 tCO2e would be reduced, more than double the benefit; the IRR on assets increases from 8.5% to 10.9%. But if the DG is located in Quebec, Canada, where electricity generation is mainly from hydropower plants, a total of 7,061 tCO2e is emitted, losing this incentive; IRR on assets falls to 6.8%, without considering penalties for increased GHG emissions (carbon tax).

Renewable DG Source – Technical Results

DG Capacity Level: Assuming the same generator rating as the conventional case previously discussed, but with a lower capacity factor, the renewable DG source is not only producing less electricity, but also it is bringing lower technical benefits. Tap operations and voltage exceptions are not significantly reduced for example. Losses are still reduced, but without the possibility of any type of management due to its uncontrollable characteristic. This and its intermittent nature prevent the upgrade deferral benefit incentive to be suitable for remuneration to the DG owner. As it can be anticipated, technical benefits are not significant neither for the voltage reduction strategy.

DG P-Q Control Strategy: At present, several research projects are focused on implementing energy storage systems coupled with wind farms and PV cells in order to improve their technical performance in the networks. Optimal scheduling, wind forecasting, and power electronics interfaces will provide the flexibility required to provide technical benefits and even ancillary services. Nevertheless, as it can be easily inferred, the additional extra costs are not justified by the added gains.

Network Upgrade Investment Deferral and Line Loss Reduction: If it is desired to obtain the same energy production than the conventional DG case, at least a 7.5 MW wind farm should be installed. However, if the same wind profile assumed for the study is applied, the same technical benefits reported with the reciprocating engine are not achieved with the larger wind farm. For example, the feeder would require an immediate upgrade in order to accommodate the electricity generation from the wind farm. System losses are increased by 6.6% from the base case for one year simulation. As expected, high levels of intermittent and uncontrollable generation actually bring negative impacts to distribution networks operation.

Renewable DG Source – Economic Results

Electricity and DG Production Costs: In addition to reduced technical benefits, high initial costs and low electricity production made the renewable technology case less financially attractive. In the case analyzed, a higher production cost than a reciprocating engine of the same rating was obtained, even when considering the higher operating cost for the latter due to fuel consumption. As has being largely discussed worldwide, high initial costs represent a barrier for the deployment of renewable sources. From the risk and sensitivity analyses performed, lower initial costs will yield higher economic benefits improving the viability of the wind source project. But this statement does not necessarily apply to small projects: lower initials costs are more likely to be achieved for large turbines and wind farms in the coming years. In contrast, larger wind farms are more likely to negatively impact the technical performance of distribution networks; high levels of renewable sources are more suitable for connection at transmission levels where the stiffness of the system can absorb generation fluctuations with less impact.

GHG Emissions reduction and DG Location: GHG emissions reduction and loss reduction incentive improved again the viability of the project. It should be stressed that

GHG emissions are relative to the project location as it was mentioned for the conventional DG case. This means that the environmental benefits brought by renewable energies are more likely to be more adequate to make the business case in certain places than in others. Incentives based on such environmental benefits should then be assigned accordingly. Nevertheless, when compared against the reciprocating engine case, the environmental impact of a wind turbine or photovoltaic (PV) cell is considered almost nil, if noise and landscape obstruction complains are neglected.

Feed-in Tariff Programs for Renewable Source Projects

Results obtained in this study show the best investment opportunities under the feed-in tariff (FIT) scenario. For both conventional and renewable cases a FIT yielded higher internal rate of return (IRR) on assets and net present value (NPV) even though the rates assumed were lower than programs offered for example, in Ontario, Canada, and the United Kingdom. FIT programs have being implemented in different countries around the world as a policy looking to attract renewable sources generation to power systems. Some policies even force utilities to buy certain minimum percentage of “green energy” from renewable energy sources (RES) to supply electricity to their customers, the so-called renewable portfolio standards (RPS).

FIT programs are characterized by granting IPPs grid access, offering competitive rates, and guaranteeing long term contracts. The rates defined for such programs are supposedly calculated accordingly to high production costs from renewable technologies; i.e., electricity rates offered on FIT programs are designed to cover high equipment initial costs and make projects profitable, therefore, attractive. Moreover, feed-in tariffs supposedly account also for not easily quantifiable benefits brought by renewable generation like local health improvement and jobs creation.

As increased levels of renewable energy sources are connected to power systems, FIT programs could face two drawbacks:

- The tariff paid to IPPs is transferred to customers through higher electricity rates. Therefore, as more RES projects sign under FIT programs, higher electricity rates should be expected.

- By supply and demand economic equilibrium theory, a major reduction on conventional generation could lead to a drop in their costs, increasing the gap between cheaper but polluting energy and more onerous but clean electricity supply.

Many argue that a FIT program is a small price society should pay after many years of obtaining energy mainly from fossil fuels. However, greater effort should be made in order to quantify real benefits so they are properly transferred to IPPs. A perfect example of this is the carbon trade: while someone is charged with carbon taxes, that money collected can be assigned to green production (carbon credits). As shown in the results, technical benefits properly quantified and transferred have the potential to reach the economic attractiveness of FIT programs in distribution networks if the DG penetration level is around the optimal for a specific feeder.

In addition, and as it was discussed for the DG penetration level, FIT programs have the potential to attract large amounts of DG to distribution networks beyond the point where they also bring negative technical and economic impacts [165]. Utilities and system operators could still implement FIT programs under two non-exclusive premises:

- Limit renewable DG connections into distribution feeders: Each distribution network could be technically evaluated in order to determine the maximum DG capacity that could be allocated without generating major negative impacts to feeder.
- Aggregate plants to transmission networks: bigger renewable energy based power plants or aggregated small DGs connected at transmission levels could have a lower impact on the operation of a larger system. Power plants with higher capacities can also be benefited from economies of scale factors.

ADN Enabling Technologies for Connection of DG

Active distribution networks (ADN) enabling technologies and concepts were assumed to control and monitoring the feeder simulated. Specifically, active voltage control and line rating monitoring were in place to assess voltage violations and overloads due to DG connection and voltage reduction conservation strategy. However, as concluded in Chapter 2, there is a lack of tools for simulation of such technologies, including information and communication technologies performance and economic impact for the system.

Nevertheless, similarly was analyzed for incentives brought by DG in this work, specific technical benefits could be assessed for ADN technologies in distribution networks, and from there, incentives could be established creating the business case necessary to support the future deployment of these technologies. For example, decentralized active voltage control could accommodate more DG capacity into the network with an integrated control of DG's output. This specific technical benefit either for the distribution network operator or the independent power producer can be quantified then and transferred to the DNO.

Chapter 5: Conclusions

5.1 Summary of Work

This thesis presented an assessment of technical and economic benefits of distributed generation (DG) at distribution levels. Benefits and impacts brought by distributed generation require to be properly analyzed for a better understanding of their technical and economic capabilities. At present, technical benefits effectively brought by distributed generators are not appropriately compensated for. A methodology is outlined for the technical and economic evaluation of distributed generation connected to distribution networks. The methodology was applied to a benchmark feeder in order to validate the steps proposed and obtain results of interest for discussion. Some technical benefits were analyzed and quantified in order to convert them into economic incentives. The impact of these incentives in the viability of the project for a distributed generator was analyzed.

Chapter 1

Literature review was focused on categorizing the impacts and benefits brought by distributed generation to distribution levels. The most important impacts were analyzed. The main benefits were categorized from the point of view of customers and DG owners, utilities, and the transmission system operator and society. The scope of the work is presented stating the research purpose.

Chapter 2

Chapter 2 presented the contribution made by McGill University to the CIGRE C6.11 working group. This working group is focused on analyzing the current status of active distribution networks deployed or in trial stages around the world. A comprehensive list of projects was assessed and the main enabling technologies were mentioned. Such technologies were separated into hardware, network states control, and network operation. Some recommendations for future research were made according to common barriers and limits identified from the projects. Although some of these technologies were assumed for the analyses developed in Chapter 4, one of the results was the lack of tools for planning and economic evaluation of active distribution networks. However, such enabling technologies improved the operation and control of the feeder with distributed generators connected. This chapter provided information about what is being done around the world to facilitate increased levels of distributed generation at distribution levels.

Chapter 3

A methodology for the assessment of technical and economic benefits of DG was described in Chapter 3. The methodology was structured into concrete steps and generically defined so it can be applied to any distribution network and DG system. The methodology was divided into technical and economic analyses, with technical results feeding the economic assessment. The software used for the methodology was described, as well as the test feeder and the assumptions made. A quantification model was defined in order to assign monetary values to quantified technical benefits obtained through the methodology presented. Specific values and parameters were presented in the appendices.

Chapter 4

The proposed methodology was applied to the benchmark distribution feeder with a new distributed generation connection. The distributed resource was modeled as both a conventional source assuming a natural gas reciprocating engine, and as a renewable source assuming a wind turbine. Active distribution network technologies were also in place to control and monitoring the network. Technical and economic analyses results were presented highlighting the findings most relevant to the methodology. At the end of the chapter, a general discussion is provided about the usefulness of the selected approach, and the impacts that increased levels of distributed generation bring to distribution networks. In addition, despite the lack of tools to analyze active distribution networks technologies implementation, the possibility of creating business cases from verifiable technical benefits brought by them is stated.

5.2 Conclusions

The following anticipated conclusions from connecting distributed generation to distribution networks were corroborated with the proposed methodology: moderate levels of DG bring technical benefits to the networks; extreme levels of DG negatively impact feeder operation; controllable generation improves network performance; renewable energy sources bring important environmental benefits to the networks; high initial costs represent a significant barrier for renewable technologies; high controllability and reliable operation of reciprocating engines in part compensate for their dependence on fossil fuels and volatile prices of combustibles, etc.

But beyond these well known general facts, through the research presented in this thesis, an important conclusion can be extracted: several assumptions had to be made for the parameters used in order to obtain the results presented here making results heavily dependent on the choices. As seen to a certain extent with sensitivity analyses, small changes on values assumed can produce very different results. Any small change on the parameters selected, like for example, project location, DG capacity, financing parameters, electricity rate, connection point, etc., can dictate whether a project is feasible or not; i.e., each project has a specific set of parameters and conditions. Therefore, electricity sector programs and policies that generalize technical and economic benefits and performance of distributed generation projects will very likely create technical and economic inefficiencies in the electricity system.

However, methodologies, like the one proposed in this thesis, attempting to quantify generally accepted benefits brought by distributed generation will help to better understand and address its impacts, while encouraging its deployment. When benefits are properly assessed and quantified more efficient technical and economic performance of distribution networks with distributed generation can be achieved. Improved efficiency will benefit not only the distributed resource owner with higher incentives if it is improving network performance, but also power systems, utilities, and society in general.

All these discussions and conclusions lead to the main conclusion that can be made for the thesis presented: proper assessment of technical and economic impacts of distributed generation should be examined and implemented to allow further deployment that will bring clear benefits to all the power system participants. Technical benefits assessment will indicate where and how much DG is required or is acceptable in order to help an aging infrastructure, or to create future networks with a better performance in the presence of DG. An adequate economic benefits assessment will compensate DG projects, in addition for their electricity generation, with incentives properly quantified avoiding high subsidies that bring more inefficiency to the sector. In particular, the case presented showed how incentives significantly improved the financial viability of the DG projects.

Detailed methodologies accounting for more benefits associated with integration of DG -such that it is coordinated with the operation of the system- could lead to a higher monetary value for both the DG owner and the utility, creating the business case for active distribution network and deployment of smart grid technologies. Although some of these technologies are precisely intended to accommodate the increasing number of DG connections, consequently increased benefits will justify their implementation.

Finally, methodologies based on open-source and free programs facilitate sharing information and results. It also allows different participants to build their cases from basic assumptions or modify them according to each specific situation.

5.3 Recommendations for Future Work

The thesis has proposed a methodology for the assessment of benefits of distributed generation. As it has been pointed out in different excerpts through the thesis, several assumptions were made in order to obtain results of interest for the research developed. Some of these assumptions were also done in order to simplify the methodology and the interaction between technical and economic analyses. Some costs/benefits were defined while others were omitted in order to also limit the scope of the work. This opens some possibilities for future work that emerged from discussions and conclusions offered in this thesis. Some research needs for active distribution networks were defined in Chapter 2, therefore will not repeated here except for those cases where their integration can be studied with the proposed methodology. Thus, some recommendations for future work are listed next:

- Expand the methodology for the case of multiple DG: DG was considered as a single unit connected to a specific node. However, smaller and scattered DG units connected to the feeder would require redefining the proposed methodology, in terms on how to quantify individual benefits and compensate them accordingly. In addition, Each DG source brings its own set of parameters that make possible to explore multiple scenarios. DG technologies could include diesel engines, CHP, PV, hydro, fuel cells, gas turbines, etc.
- Expand the methodology to capture other benefits not covered by the quantification model: Three incentives were considered for the methodology: GHG emissions reductions, upgrade investment deferral, and systems loss reduction. However, distributed generation is bringing additional technical benefits that could be translated into incentives if proper quantification models are developed. Examples found could be: primary transformer tap operations reduction extending equipment's life, voltage exceptions reduction and islanding capabilities improving power quality and reliability, total energy supplied reduction due to improvement of voltage profiles and reduction of impacts to the feeder under conservation voltage reduction schemes, ancillary services provision, benefits for transmission networks, etc.
- Expand the methodology to consider smart grid and active distribution networks scenarios: Intermittent renewable sources with energy storage systems and/or demand response, islanding and microgrids (considering IEEE P1547.4 Draft Guide for Design, Operation, and Integration of Distributed Resource Island Systems with Electric Power Systems [166]), virtual power plants an DG aggregation, operating strategies varying the power factor and the number of hours the DG is on (optimal power flow dispatch), etc.
- Expand the methodology to optimize DG capacity and location: OpenDSS has the capacity of interaction with other programs, for example, *MATLAB*. Exploiting *MATLAB* data handling and programming capacities, an optimization problem could be solved in order to find the DG capacity and location that would bring the maximum technical and economic benefits for a specific feeder, including stochastic and risk based modeling.

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Appendix A: The IEEE 13 Node Test Feeder

This section presents the complete set of data for the benchmark feeder used for simulations, provided in [155]. Notice that the distributed load data between nodes 632 and 671 is concentrated in node 670 for this study.

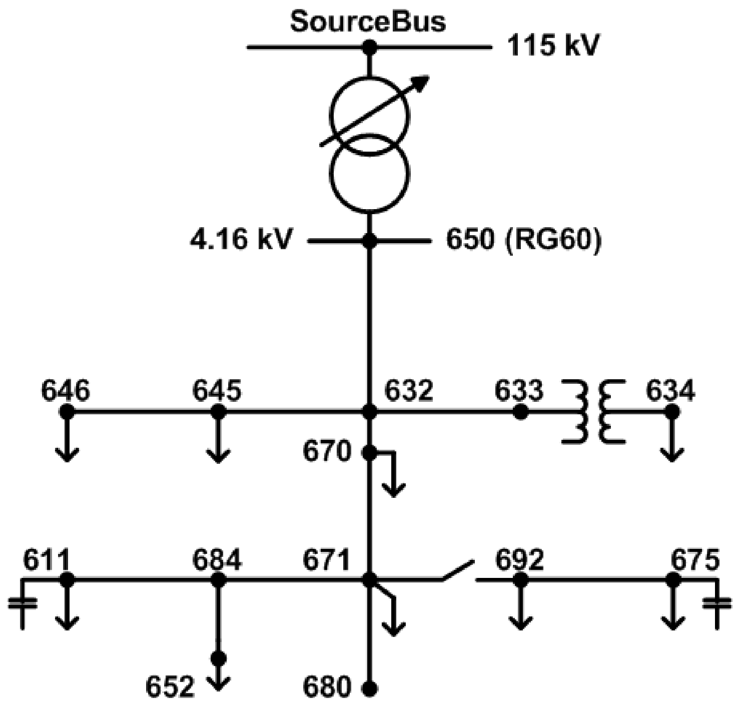

Figure A.1 The IEEE 13 Node Test Feeder

Table A.1 Overhead line spacing

Spacing ID	Type
500	Three-phase, 4 wire
505	Two-phase, 3 wire
510	Single-phase, 2 wire

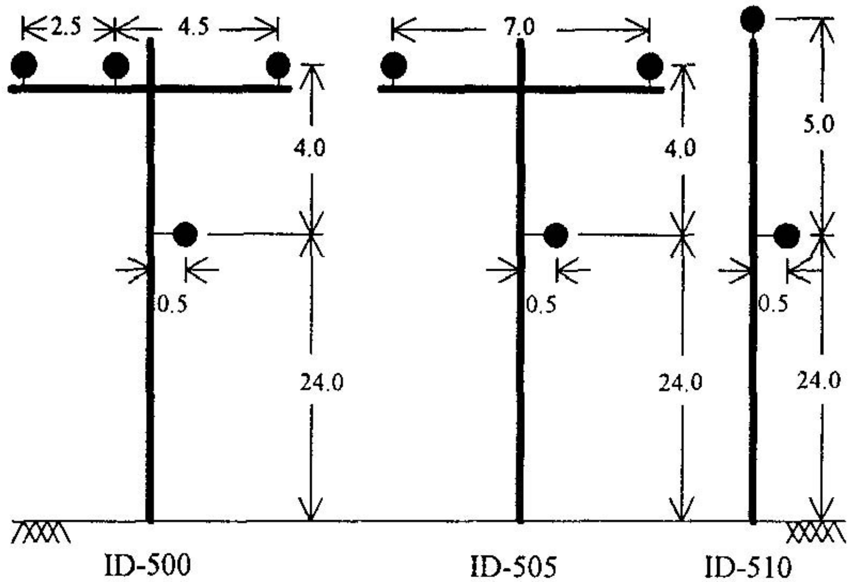

Figure A.2 Overhead line spacing [155]

Table A.2 Underground line spacing

Spacing ID	Type
515	Three-phase, 3 cable
520	Single-phase, 3 cable

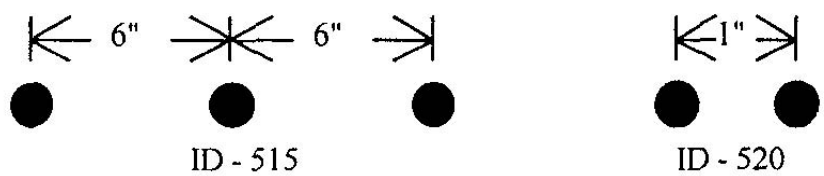

Figure A.3 Underground line spacing [155]

Table A.3 Underground line configuration data

Config.	Phasing	Cable	Neutral	Space ID
606	A B C N	250 AA	None	515
607	A N	1/0 AA	1/0 Cu	520

Table A.4 Overhead line configuration data

Config.	Phasing	Cable	Neutral	Space ID
601	B A C N	556.5 ACSR	4/0 ACSR	500
602	C A B N	4/0 ACSR	4/0 ACSR	500
603	C B N	1/0 ACSR	1/0 ACSR	505
604	A C N	1/0 ACSR	1/0 ACSR	505
605	C N	1/0 ACSR	1/0 ACSR	510

Table A.5 Line segment data

Node A	Node B	Length (ft.)	Config.
632	645	500	603
632	633	500	603
633	634	0	XFM-1
645	646	300	603
650	632	2000	601
684	652	800	607
632	671	2000	601
671	684	300	604
671	680	1000	601
671	692	0	Switch
684	611	300	605
692	675	500	606

Table A.6 Capacitor data

Node	Ph-A kVAr	Ph-B kVAr	Ph-C kVAr
675	200	200	200
611			100
Total	200	200	300

Table A.7 Regulator data

Regulator ID	1		
Line Segment	650-632		
Location	650		
Phases	A – B – C		
Connection	3-Ph, LG		
Monitoring Phase	A – B – C		
Bandwidth	2.0 Volts		
Pt Ratio	20		
Primary CT Rating	700		
Compensator Settings	Ph-A	Ph-B	Ph-C
R – Setting	3	3	3
X – Setting	9	9	9
Voltage Level	122	122	122

Table A.8 Transformer data

	kVA	kV-High	kV-Low	R - %	X - %
Substation	5,000	115 - D	4.16 - Gr. Y	1	8
XFM-1	500	4.16 - Gr. Y	0.48 - Gr. Y	1.1	2

Table A.9 Load data

Node	Load Model	Ph-1 kW	Ph-1 kVAr	Ph-2 kW	Ph-2 kVAr	Ph-3 kW	Ph-3 kVAr
634	Y-PQ	160	110	120	90	120	90
645	Y-PQ	0	0	170	125	0	0
646	D-Z	0	0	230	132	0	0
652	Y-Z	128	86	0	0	0	0
671	D-PQ	385	220	385	220	385	220
675	Y-PQ	485	190	68	60	290	212
692	D-I	0	0	0	0	170	151
611	Y-I	0	0	0	0	170	80
670	Y-PQ	17	10	66	38	117	68
	Total	1175	616	1039	665	1252	821

Table A.10 Load model codes

Code	Connection	Model
Y-PQ	Wye	Constant kW and kVAr
Y-I	Wye	Constant Current
Y-Z	Wye	Constant Impedance
D-PQ	Delta	Constant kW and kVAr
D-I	Delta	Constant Current
D-Z	Delta	Constant Impedance

Appendix B: OpenDSS Scripts

The original script for the IEEE 13 Node test feeder is provided with the OpenDSS installation folder, available in [159][6]. Additional settings required for the technical simulations are listed in this appendix.

- This part of the script provides a snap-shot power flow with the load ratings. The simulation of this script produces the voltage profile of the feeder as well the current flow through the conductors. The difference with the original script lies in the addition of a load profile, and the conductors current limits (ampacity) used to calculate overloads:

```
Clear
! This script is based on a script developed by Tennessee Tech Univ students
! Tyler Patton, David Woods, and Jon Wood, April 2009

! Initialize the circuit

new circuit.IEEE13Node
~ basekv=115   pu=1.000   phases=3   bus1=SourceBus
~ Angle=
~ MVAsc3=200000   MVASC1=210000

! SUBSTATION TRANSFORMER DEFINITION

New Transformer.Sub   Phases=3   Windings=2   XHL=(8)
~ wdg=1   bus=SourceBus   conn=delta   kv=115   kva=5000   %r=(0.5)   XHT=4
~ wdg=2   bus=650         conn=wye     kv=4.16  kva=5000   %r=(0.5)   XLT=4

! FEEDER SINGLE-PHASE VOLTAGE REGULATORS

! Define low-impedance 2-wdg transformers (bank)

New Transformer.Reg1   phases=1   XHL=0.01   kVAs=[1666 1666]
~ Buses=[650.1 RG60.1]   kVs=[2.4  2.4]   %LoadLoss=0.00001
new regcontrol.Reg1 transformer=Reg1 winding=2 vreg=122 band=2 ptratio=20
~ctprim=700 R=3 X=9

New Transformer.Reg2   phases=1   XHL=0.01   kVAs=[1666 1666]
~ Buses=[650.2 RG60.2]   kVs=[2.4  2.4]   %LoadLoss=0.00001
new regcontrol.Reg2 transformer=Reg2 winding=2 vreg=122 band=2 ptratio=20
~ctprim=700 R=3 X=9

New Transformer.Reg3   phases=1   XHL=0.01   kVAs=[1666 1666]
~ Buses=[650.3 RG60.3]   kVs=[2.4  2.4]   %LoadLoss=0.00001
new regcontrol.Reg3 transformer=Reg3 winding=2 vreg=122 band=2 ptratio=20
~ctprim=700 R=3 X=9
```

[6] Due to its complexity, the line codes script is not presented in this appendix. However, it is also provided with the OpenDSS installation folder (IEEELineCodes.dss).

```
! STEP-DOWN LOAD TRANSFORMER DEFINITION

New Transformer.XFM1   Phases=3   Windings=2   XHL=2
~ wdg=1   bus=633   conn=Wye   kv=4.16   kva=550   %r=0.55   XHT=1
~ wdg=2   bus=634   conn=Wye   kv=0.48   kva=550   %r=0.55   XLT=1

! LINE CODES

redirect IEEELineCodes.dss

! LOAD DEFINITIONS

New Load.634a Bus1=634.1 Phases=1 Conn=Wye Model=1 kV=0.277 kW=160 kvar=110
~ yearly=1year
New Load.634b Bus1=634.2 Phases=1 Conn=Wye Model=1 kV=0.277 kW=125 kvar=90
~ yearly=1year
New Load.634c Bus1=634.3 Phases=1 Conn=Wye Model=1 kV=0.277 kW=120 kvar=90
~ yearly=1year

New Load.645 Bus1=645.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=175 kvar=125
~ yearly=1year

New Load.646 Bus1=646.2.3 Phases=1 Conn=Delta Model=2 kV=4.16 kW=235 kvar=132
~ yearly=1year

New Load.652 Bus1=652.1 Phases=1 Conn=Wye Model=2 kV=2.4 kW=128 kvar=86
~ yearly=1year

New Load.671 Bus1=671.1.2.3 Phases=3 Conn=Delta Model=1 kV=4.16 kW=1155
kvar=660
~ yearly=1year

New Load.675a Bus1=675.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=485 kvar=190
~ yearly=1year
New Load.675b Bus1=675.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=75 kvar=60
~ yearly=1year
New Load.675c Bus1=675.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=290 kvar=212
~ yearly=1year

New Load.692 Bus1=692.3.1 Phases=1 Conn=Delta Model=5 kV=4.16 kW=170 kvar=151
~ yearly=1year

New Load.611 Bus1=611.3 Phases=1 Conn=Wye Model=5 kV=2.4 kW=170 kvar=80
~ yearly=1year

! Bus 670 is the concentrated point load of the distributed load
New Load.670a Bus1=670.1 Phases=1 Conn=Wye Model=1 kV=2.4 kW=17 kvar=10
~ yearly=1year
New Load.670b Bus1=670.2 Phases=1 Conn=Wye Model=1 kV=2.4 kW=70 kvar=38
~ yearly=1year
New Load.670c Bus1=670.3 Phases=1 Conn=Wye Model=1 kV=2.4 kW=117 kvar=68
~ yearly=1year

! CAPACITOR DEFINITIONS

New Capacitor.Cap1   Bus1=675   phases=3   kVAR=600   kV=4.16
New Capacitor.Cap2   Bus1=611.3   phases=1   kVAR=100   kV=2.4

! LINE DEFINITIONS

! Bus 670 is the concentrated point load of the distributed load
! on line 632 to 671 located at 1/3 the distance from node 632
```

```
New Line.632-645 Phases=2 Bus1=632.3.2 Bus2=645.3.2 LineCode=603 Length=.500
~units=kft Normamps=230 Emergamps=345

New Line.632-633 Phases=3 Bus1=632.1.2.3 Bus2=633.1.2.3 LineCode=602
~Length=.500 units=kft Normamps=340 Emergamps=510

New Line.645-646 Phases=2 Bus1=645.3.2 Bus2=646.3.2 LineCode=603 Length=.300
~units=kft Normamps=230 Emergamps=345

New Line.650-632 Phases=3 Bus1=RG60.1.2.3 Bus2=632.1.2.3 LineCode=601
~Length=2.000 units=kft Normamps=730 Emergamps=1095

New Line.684-652 Phases=1 Bus1=684.1 Bus2=652.1 LineCode=607 Length=.800
~units=kft Normamps=310 Emergamps=465

New Line.632-670 Phases=3 Bus1=632.1.2.3 Bus2=670.1.2.3 LineCode=601
~Length=.667 units=kft Normamps=730 Emergamps=1095

New Line.670-671 Phases=3 Bus1=670.1.2.3 Bus2=671.1.2.3 LineCode=601
~Length=1.333 units=kft Normamps=730 Emergamps=1095

New Line.671-684 Phases=2 Bus1=671.1.3 Bus2=684.1.3 LineCode=604 Length=.300
~units=kft Normamps=230 Emergamps=345

New Line.671-680 Phases=3 Bus1=671.1.2.3 Bus2=680.1.2.3 LineCode=601
~Length=1.000 units=kft Normamps=730 Emergamps=1095

New Line.684-611 Phases=1 Bus1=684.3 Bus2=611.3 LineCode=605 Length=.300
~units=kft Normamps=230 Emergamps=345

New Line.692-675 Phases=3 Bus1=692.1.2.3 Bus2=675.1.2.3 LineCode=606
~Length=.500 units=kft Normamps=329 Emergamps=494

! SWITCH DEFINITIONS

New Line.671-692 Phases=3 Bus1=671 Bus2=692 Switch=y r1=1e-4 r0=1e-4 x1=0.000
~x0=0.000 c1=0.000 c0=0.000

! Set Voltage bases

Set Voltagebases=[115, 4.16, .48]
calcv

!Solve
```

- The following commands call an external file (Comma Separated Value – CSV format) that contains the load profile defined in [156], as well the setting for load growth simulations as a percentage of the previous year load rating:

```
new loadshape.1year   8760   1.0   csvfile=1year.csv

set %growth=3
```

- In order to record the energy imported from the main grid and the total system losses, an energy meter object is required. The file generated also contains the energy produced by any generator connected to the zone covered by the meter:

```
New EnergyMeter.Circuit   Element=Transformer.Sub   Terminal=1
```

- A generator object is used to model the DG connected to the feeder at node 680. For the renewable source case a wind profile is loaded from an external CSV file. Both cases, conventional and renewable sources, are connected directly at the feeder voltage level, and modeled operating at constant PQ, as recommended in [140]. Each generator model was simulated separately. The wind profile corresponds to the data for Ontario, northern shore of lake Superior, Zone 2, 2002, available at [158]:

```
New Generator.DG bus1=680 kv=4.16 kw=2000 pf=1 model=4 conn=delta

!Or Wind Generator

New loadshape.wind 8760 1.0 csvfile=wind.csv

New Generator.DG bus1=680 kv=4.16 kw=2000 pf=1 model=4 conn=delta
~ yearly=wind
```

- Daily, weekly, and yearly simulations, based on load and generator profiles loaded, require the following commands, setting the control mode of the program (daily and weekly setting are shown only as examples since only yearly simulations were used for this study):

```
Set controlmode=time
Set mode=yearly   number=24   hour=8424   sec=0
Set mode=yearly   number=168   hour=8400   sec=0
Set mode=yearly   number=8760   hour=0   sec=0
```

- Voltage limits from [141] are set with the commands presented here. Range A is used for normal limits and range B for emergency limits. Voltage exception and overload reports are generated based on these limits:

```
Set Emergvminpu=0.9
Set Emergvmaxpu=1.06
Set Normvminpu=0.95
Set Normvmaxpu=1.05

Set DemandInterval=Yes
Set Voltexceptionreport=Yes
Set Overloadreport=Yes
```

- Load growth simulations require that the user configures the software to run several years, as many as desired to evaluate, for example, overloads. An example for 5 years:

```
Set year=1
Solve
Set year=2
Solve
Set year=3
Solve
Set year=4
Solve
Set year=5
Solve
```

- Finally, desired results must be called in order to visualize them, or alternatively they can be exported to CSV files for later handling and interpretation:

```
Show Voltages LN Nodes
Show Losses
Show Overloads
Show Unserved
Show EVentlog

Export Voltages
Export Overloads
Export Meters /m
Export Generators /m
```

Appendix C: RETScreen Settings

In this appendix, the values used for the economic simulations are presented. The settings are organized in a multilevel list, following the same order as the five-step analysis defined in RETScreen. The first level of the list corresponds to each sheet in the Excel based file.

C.1 Conventional Source Case

- Start
  - Project type: Power
  - Technology: Reciprocating engine
  - Grid type: Central-grid
  - Analysis type: Method 2
  - Heating value reference: Higher heating value (HHV)
  - Climate data location: New York J F Kennedy Int'
- Energy model
  - Availability: 92.63548% (goal seek to force electricity exported to grid equal to 17,520 MWh)
  - Fuel selection method: Single fuel
  - Fuel type: Natural gas – 100 ft^3
  - Fuel rate: 0.557 $/100 ft^3 (U.S. natural gas price for electric power generation in March 2010) [2].
  - Power capacity: 2,159 kW
  - Manufacturer: GE
  - Model: J616 GS [167]
  - Heat rate: 8,300 kJ/kWh (adjusted to assume high efficiency – low consumption)
  - Electricity export rate:
    - Production cost 67.58 $/MWh. Premium: 2 $/MWh
    - Feed-in tariff: 80 $/MWh (1.2 times production cost approximately)
- Cost analysis

- Settings
  - Method: 1
  - Notes/Range
- Initial costs (credits)
  - Power System
    - Reciprocating engine unit cost: 1,250 $/KW installed (average of range provided by RETScreen)
  - Balance of system & miscellaneous
    - Contingencies: 15%
- Annual costs (credits)
  - O&M
    - Parts and labor quantity: Paste electricity exported to grid from the energy model sheet.
    - Parts and labor unit cost: 0.008 $/kWh
    - Contingencies: 10%

- Emission analysis
  - Method: 1
  - Base case electricity system
    - Country – region: United States of America
    - Fuel type: All types
    - T&D losses: 6.5% (U.S. average national losses for 2009) [2].
  - Proposed case system GHG summary
    - T&D losses: 0% (DG assumed to be very close to loads connected to the feeder)
  - GHG emission reduction summary
    - GHG credits transaction fee: 0%
- Financial analysis
  - Financial parameters
    - General
      - Fuel cost escalation rate: 0%
      - Inflation rate: 2% (U.S. CPI forecast)

            - Discount rate: 8% (assumed WACC of the project's owner)
            - Project life: 25 yr (assumed equipment life)
        - Finance
            - Debt ratio: 70%
            - Debt interest rate: 5% (U.S. prime rate plus a spread of 1.75%)
            - Debt term: 20 yr
    - Annual income
        - Electricity export income
            - Electricity export escalation rate: 0.5% (assumed)
        - GHG reduction income
            - GHG reduction credit rate: 16 \$/tCO2 (European Union Emission Trading Scheme – European Climate Exchange Certified Emission Reductions futures contracts) [162].
            - GHG reduction credit duration: 20 yr (assumed)
            - GHG reduction credit escalation rate: 0%
        - Other income (cost)
            - Energy: Paste energy exported to grid from the energy model sheet (MWh)
            - Rate: 3.3 \$/MWh (upgrade deferral incentive obtained in the quantification model)
            - Duration: 25 yr
            - Escalation rate: 2% (inflation rate)
        - Clean energy (CE) production income
            - CE production credit rate: 0.0008 \$/kWh (loss reduction incentive calculated with NYISO average electricity rate)
            - CE production credit duration: 20 yr
            - CE production credit escalation rate: 5% (assumed)
            - Clean Energy: Yes
- Risk analysis
    - Sensitivity analysis
        - Perform analysis on: After-tax IRR assets

- Sensitivity range: 10%
- Threshold: 8% (assumed equal to the WACC of the project's owner)
- Parameters: Electricity export rate Vs fuel cost – proposed case

- Risk analysis
  - Perform analysis on: After-tax IRR assets
    - Parameter
      - Initial costs range: 10%
      - O&M range: 10 %
      - Fuel cost – proposed case range: 20% (greater uncertainty)
      - Electricity export rate range: 10%
      - Rest of parameters are fixed (0%)
  - Level of risk: 10%

C.2 Renewable Source Case

- Start
  - Project type: Power
  - Technology: Wind turbine
  - Grid type: Central-grid
  - Analysis type: Method 2
  - Heating value reference: Higher heating value (HHV)
  - Climate data location: New York J F Kennedy Int'
- Energy model
  - Power capacity: 2,000 kW
  - Manufacturer: Nordex
  - Model: N54 – 70 m (2 units) [168]
  - Capacity factor: 26.5256% (goal seek to force electricity exported to grid equal to 4,647 MWh)
  - Electricity export rate:
    - Production cost 86.5 $/MWh. Premium: 2 $/MWh
    - Feed-in tariff: 110 $/MWh (1.3 times production cost approximately)
- Cost analysis

- Settings
  - Method: 1
  - Notes/Range
- Initial costs (credits)
  - Power System
    - Wind turbine unit cost: 1,500 $/KW installed (average reported by NREL in 2007 – U.S. wind power installation annual report) [169].
  - Balance of system & miscellaneous
    - Contingencies: 10%
- Annual costs (credits)
  - O&M
    - Parts and labor quantity: Paste electricity exported to grid from the energy model sheet.
    - Parts and labor unit cost: 0.015 $/kWh
    - Contingencies: 10%

- Emission analysis
  - Method: 1
  - Base case electricity system
    - Country – region: United States of America
    - Fuel type: All types
    - T&D losses: 6.5% (U.S. average national losses for 2009) [2].
  - Proposed case system GHG summary
    - T&D losses: 0% (DG assumed to be very close to loads connected to the feeder)
  - GHG emission reduction summary
    - GHG credits transaction fee: 0%
- Financial analysis
  - Financial parameters
    - General
      - Fuel cost escalation rate: 0%
      - Inflation rate: 2% (U.S. CPI forecast)

            - Discount rate: 8% (assumed WACC of the project's owner)
            - Project life: 25 yr (assumed equipment life)
        - Finance
            - Debt ratio: 70%
            - Debt interest rate: 5% (U.S. prime rate plus a spread of 1.75%)
            - Debt term: 20 yr
    - Annual income
        - Electricity export income
            - Electricity export escalation rate: 0.5% (assumed)
        - GHG reduction income
            - GHG reduction credit rate: 16 \$/tCO2 (European Union Emission Trading Scheme – European Climate Exchange Certified Emission Reductions futures contracts) [162].
            - GHG reduction credit duration: 20 yr (assumed)
            - GHG reduction credit escalation rate: 0%
        - Clean energy (CE) production income
            - CE production credit rate: 0.00155 \$/kWh (loss reduction incentive calculated with NYISO average electricity rate)
            - CE production credit duration: 20 yr
            - CE production credit escalation rate: 5% (assumed)
            - Clean Energy: Yes
- Risk analysis
    - Sensitivity analysis
        - Perform analysis on: After-tax IRR assets
        - Sensitivity range: 10%
        - Threshold: 4.375% (assumed equal to U.S. Treasury Bond at 30 years) [149].
        - Parameters: Electricity export rate Vs initial costs
    - Risk analysis
        - Perform analysis on: After-tax IRR assets
            - Parameter
                - Initial costs range: 10%

    - O&M range: 10 %
    - Electricity export rate range: 10%
    - Rest of parameters are fixed (0%)
- Level of risk: 10%